of malfunction that affects only one channel. The trip signal furnished by the two remaining channels is unimpaired in this event.

Reactor trip is implemented by interrupting power to the magnetic latch mechanisms on all drives allowing the full-length rod clusters to insert by gravity. The reactor protection system is thus inherently safe in the event of a loss of power.

The engineered safety features actuation circuits are designed on the same “deenergize to operate” principle as the reactor trip circuits, with the exception of the containment spray actuation circuit, which is energized to operate in order to avoid spray operation on inadvertent power failure.
Automatic starting of all emergency diesel generators is initiated by under-voltage relays on any 480-V bus or by the safety injection signal. Engine cranking is accomplished by a stored energy system supplied solely for the associated diesel generator. The undervoltage relay scheme is designed so that loss of 480-V power does not prevent the relay scheme from functioning properly.

7.2.1.9 Redundancy of Reactivity Control

Criterion: Two independent control systems, preferably of different principles, shall be provided. (GDC 27)

One of the two reactivity control systems employs rod cluster control assemblies to regulate the position of Ag-In-Cd neutron absorbers within the reactor core. The other reactivity control system employs the chemical and volume control system to regulate the concentration of boric acid solution (neutron absorber) in the reactor coolant system.

7.2.1.10 Reactivity Control System Malfunction

Criterion: The reactor protection system shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (GDC 31)

Reactor shutdown with rods is completely independent of the normal control functions since the trip breakers completely interrupt the power to the full-length rod mechanisms regardless of existing control signals. Effects of continuous withdrawal of a rod control assembly and of deboration are described in Sections 7.3.1, 7.3.2, 9.2, and 14.1.

7.2.1.11 Seismic Design

For earthquake (operational basis or design basis), the equipment is designed to ensure that it does not lose its capability to perform its function, that is, shut the plant down and maintain it in a safe shutdown condition. For the maximum potential earthquake, there may be permanent deformation of equipment provided that the capability of the equipment to perform its function is maintained.

The instrumentation and electrical equipment, associated with emergency core cooling, will not cause an interruption of this function during the earthquake.

Instrumentation and control specifications include only static “g” level requirements. As a result of seismic criteria subsequently established, the static requirements were considered inappropriate and Westinghouse adopted the position of type testing equipment to demonstrate design adequacy. A safeguards signal may be initiated by an instrument or transmitter that has the ability to withstand seismic forces as demonstrated in WCAP-7397-L, Section 4.8.[2] This signal is carried in conduit and cable trays whose supports have been studied for resistance to seismic forces. The signal passes to the process control racks proved as described in WCAP-7397L, Section 4.2.[2] The signal is sent next to the safeguards actuation racks proved as described in WCAP-7397-L, Section 4.3.[2] The actuation signal proceeds through a switch on the control board to the appropriate switch-gear. The control boards were specified to “be designed such that the maximum stresses, including simultaneous seismic accelerations of 0.52g in the horizontal and 0.35g in the vertical directions, shall not dislodge or cause relative movement between components, such as to impair the functional integrity of circuits or equipment.” These accelerations exceed that calculated as input to the boards from the floor of the central control room. In shipment, boards of typical manufacture and construction have recorded shocks of 8 to 10g, and when wired, the switches have operated without repair.

The switchgear equipment has been specified to withstand accelerations in excess of 0.15g horizontally and 0.10g vertically. This capability was a matter of the procurement specification of Westinghouse and their design agents and design action of the vendors. The safeguards circuits for Indian Point Unit 2 employ Westinghouse Series W motor control centers, type DB circuit breakers, and associated metal-enclosed or metal-clad switchgear. A review of this switchgear for proof of adequacy of the seismic-resistant design determined that the Series W motor control centers and DB breakers, mounted in the metal enclosures, have been shock tested and proved to remain fully operable for shocks of at least 3g in any direction. Since original construction, five (5) new motor control centers have been installed and certain essential loads were rearranged to enhance reliability in a Loss of Offsite Power (LOOP) event. The new motor control centers were procured in accordance with IEEE-344 and seismically installed. Seismic qualification of the reactor trip breaker shunt trip attachments (type DB-50) was performed on a generic basis by the Westinghouse Owner’s Group. It has been determined that this generic qualification adequately envelopes Indian Point Unit 2 seismic parameters[4]. Proof of resistance of the similar DH metal-clad switchgear to a seismic response spectrum established for the Point Beach plant has been demonstrated by vibration testing of typical, equivalent metal-clad switchgear, incorporating the similar DHP circuit breaker. The DH circuit breakers installed in the Point Beach plant were of an earlier design than the DHP. However, the general configuration, weight distribution, and vibration-resistant design approach of the DH are essentially identical to the DHP. When subjected to a seismic spectrum equivalent to or greater than the seismic test envelope given in Figure B-2 of Reference 2, there was no loss of function of the DHP metal-clad switchgear. This seismic test envelope given in Reference 2 is estimated to include all low seismic plants, that is, plants with a design-basis earthquake horizontal ground acceleration of 0.2g or less. This similarity between the DH and DB circuit breakers gives added confidence in the seismic suitability of the DB circuit breakers installed at Indian Point Unit 2.

The power supply leaving the switchgear operates the safeguards equipment completing the actuation train. The seismic design of this equipment is described in Sections 7.1 and 1.11. The direct current power supply may be considered as a branch to this main train of actuation. The source of direct current power is the station batteries. The Class 1E station batteries and associated battery racks have been determined to be seismically qualified for their installation locations. The conduit and cable trays carrying the direct current power to the safeguards equipment train received the same study for seismic support as described above. The seismic qualification requirements for DC power panels 21 and 22 are enveloped by the generic equipment qualification described above. Additionally, these DC power panels were evaluated using Seismic Qualification Utility Group data. The evaluation shows a significant seismic margin for the two panels[5].

Westinghouse designed and procured all systems that actuate reactor trip and safety feature actions for Indian Point Unit 2. The design of protective grade instrumentation and logic systems are in accordance with the proposed IEEE criteria for nuclear power plant protection system (IEEE-279 Code), dated August 28, 1968. The functional design is originated at Westinghouse with equipment procurement through vendor supplies. Equipment compatibility and integration of component hardware are factored into the design by Westinghouse or under the direct supervision of Westinghouse.

7.2.2 Principles of Design

7.2.2.1 Redundancy and Independence

The protection systems are redundant and independent for all vital inputs and functions. Each channel is functionally independent of every other channel and receives power from an independent source. The isolation of redundant protection channels is described in further detail elsewhere in this section as well as in Section 7.2.3.

7.2.2.2 Manual Actuation

Means are provided for manual initiation of protection system action. Failures in the automatic system do not prevent the manual actuation of protective functions. Manual actuation requires the operation of a minimum of equipment.

7.2.2.3 Channel Bypass or Removal From Operation

The system is designed to permit any one channel to be maintained, and when required, tested or calibrated during power operation without protection system trip. Since the channel under test is either tripped or bypassed, superimposed test signals are used that do not negate the process signal. Systems are permitted to violate the single-failure criterion during channel bypass; acceptable reliability of operation has been demonstrated and the bypass time interval is short.

7.2.2.4 Capability for Test and Calibration

The bistable portions of the protection system (e.g., relays and bistables) provide trip signals only after signals from analog portions of the system reach preset values. Capability is provided for calibrating and testing the performance of the bistable portion of protection channels and various combinations of the logic networks during reactor operation.

The analog portion of a protection channel provides analog signals of reactor or plant parameters. The following means are provided to permit checking the analog portion of a protection channel during reactor operation:

1. Varying the monitored variable.
2. Introducing and varying a substitute transmitter signal.

3. Cross checking between identical channels or between channels, which bear a known relationship to each other and which have readouts available.

The design permits the administrative control of the means for manually bypassing channels or protection functions.

The design permits the administrative control of access to all trip settings, module calibration adjustments, test points, and signal injection points.

Protection system setpoints are maintained under procedural control and are the nominal values at which the bistables may be set. The limiting safety system settings (LSSS) for these setpoints have been determined in order to accommodate instrument drift (which is assumed to occur between operational tests) and the limitations on accuracy of measurement and calibration, and are contained in the Improved Technical Specifications as Allowable Valves. A setpoint is considered to be consistent with the nominal value when the "as left" value is within the band allowed for calibration accuracy, as defined by the plant setpoint study and calibration procedures.

7.2.2.5 Information Readout and Indication of Bypass

The protection systems are designed to provide the operator with accurate, complete, and timely information pertinent to their own status and to plant safety.

Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service. Trips are indicated and identified down to the channel level.

7.2.2.6 Safeguards Initiating Circuitry

The safeguards actuation circuitry and hardware layout are designed to maintain required circuit isolation throughout, from the process sensors through the slave relays, which actuate individual safeguards components. The channelization design is shown in Plant Drawing 243318 [Formerly UFSAR Figure 7.2-15].

The safeguards bistables, mounted in the analog protection racks, drive both A and B logic matrix relays. Each individual coincident matrix contains its own test light and test circuitry. The A and B logic matrices operate separate master relays to actuate channels A and B, respectively, as shown in Plant Drawing 243319 [Formerly UFSAR Figure 7.2-16]. Control power for logic trains A and B, is supplied from separate direct current sources 1 and 2, respectively. These redundant actuating channels operate the various safeguards components required, with the large loads sequenced as necessary.

Manual reset of the safeguards actuation relays may be accomplished 2 min following their operation. Manual initiation will override reset and result in safeguards actuation at all times.

Protection channel identity is lost in the intermixing of the relay matrix wiring. Physical separation of A and B logic trains is maintained by the separate logic racks.

7.2.2.7 Analog Channel Testing

The basic elements composing an analog protection channel are shown in Plant Drawing 243320 [Formerly UFSAR Figure 7.2-17]. This system consists of a transmitter, power supply, bistable, bistable trip switch and proving lamp, test signal injection switch, test signal injection jack, and test point.

Each protection rack includes a test panel containing those switches, test jacks, and related equipment needed to test the channels contained in the rack. A hinged cover encloses the signal injection switch and signal injection jack of the test panel.

Opening the cover or placing the test operate switch in the "test" position initiates an alarm identifying the rack under test. These alarms are arranged on a rack basis to preclude entry to more than one redundant protection rack (or channel) at any time. The test panel cover is designed such that it cannot be closed (and the alarm cleared) unless the test device plugs (described below) are removed. Closing the test panel cover mechanically returns the test switches to the “normal” position.

To minimize the risk of a trip during on-line testing of instrument channels, the bistables are bypassed to maintain the logic relays energized. A proving lamp across the bistable output facilitates checking the bistable trip setting during channel calibration. The bistable trip switches must be manually reset after the completion of a test. Closing the test panel cover will not restore these switches to the untripped mode. Procedures limit bistable testing to one circuit at a time.

Actual channel calibration consists of producing a test signal using the transmitter power supply external calibration device, which plugs into the signal injection jack. In this application, where specified the channel power supply serves as a power source for the calibration device to permit verifying the output load capacity of the power supply. Test points are located in the analog channel and provide an independent means of measuring and/or monitoring the calibration signal level.

7.2.2.8 <u>Logic Channel Testing</u>

Testing of the logic matrices is described in UFSAR Section 7.2.4.6.

7.2.2.9 <u>Isolation of Reactor Protection and Engineered Safety Feature Signals</u>

The following device is used to ensure that electrical isolation exists between protection and control grade signals: where protection signal intelligence is required for other than protection functions, an isolation amplifier (part of the protection set) is used to transmit the intelligence. The isolation amplifier prevents the perturbation of the protection channel signal (input) due to any disturbance of the isolated signal (output), which could occur near any termination of the output wiring external to the protection racks. A detailed discussion of the isolation amplifiers that are used in Indian Point Unit 2 is given in WCAP-9011.[3]

The isolation of reactor protection and engineered safety feature signals in the reactor protection logic racks is achieved by physical separation and circuit protection to meet the single failure criteria. There are three decks containing the contacts on each logic relay used. The configuration, in general, utilizes the rear deck for reactor protection and engineered safety feature signals. The center and front decks are typically used for annunciator and computer signals, respectively. The necessary isolation between the safety signals and the annunciator and/or computer signals is provided at the contacts of the relays. Separation is typically maintained by using separate wireways for safety signals, annunciator signals, and computer signals.

The design basis for protection of reactor protection and engineered safety system circuit cables include protection from failure of other non-safety system circuit cables routed in the same raceway by having the non-safety cables (like safety cables) (a) designed using conservative margins with respect to their current carrying capacities, insulation properties, and mechanical construction, (b) protected against overloads by coordinated fuses or circuit breakers, and (c) fire retardant.[8]

7.2.2.10 Vital Protection Functions and Functional Requirements

The reactor protection system monitors those parameters related to safe operation and trips the reactor to protect the reactor core against fuel rod cladding damage caused by departure from nucleate boiling, and to protect against reactor coolant system damage caused by high system pressure. The engineered safety features instrumentation system monitors parameters to detect failure of the reactor coolant system and initiates containment isolation and engineered safety features operation to contain radioactive fission products.

Section 7.2 covers those protection systems provided to:

1. Trip the reactor to prevent or limit fission product release from the core and to limit energy release.

2. Isolate containment and activate the isolation valve seal water system and weld channel penetration pressurization system when necessary.

3. Control the operation of engineered safety features provided to mitigate the effects of accidents.

The core protection systems in conjunction with inherent plant characteristics are designed to prevent anticipated abnormal conditions from causing fuel damage exceeding limits established in Chapter 3, or reactor coolant system damage exceeding effects established in Chapter 4.

7.2.2.11 Completion of Protective Action

Where operating requirements necessitate automatic or manual bypass of a protection function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are part of the protection system and are designed in accordance with the criteria of this section.

The protection systems are so designed that, once initiated, a protective action goes to completion. Return to normal operation requires administrative action by the operator.

7.2.2.12 Multiple Trip Settings

Where it is necessary to change to a more restrictive trip setting to provide adequate protection for a particular mode of operation or set of operating conditions, the design provides positive means of ensuring that the more restrictive trip setting is used. The devices used to prevent improper use of less restrictive trip settings are considered a part of the protection system and are designed in accordance with the other provisions of these criteria.

7.2.2.13 Interlocks and Administrative Procedures

Interlocks and administrative procedures required to limit the consequences of fault conditions other than those specified as limits for the protection function comply with the protection system criteria.

7.2.2.14 Deleted

7.2.3 System Design

7.2.3.1 Reactor Protection System Description

Plant Drawing 243321 [Formerly UFSAR Figure 7.2-18] is a block diagram of the reactor protection system. Reactor trips are described in Section 7.2.5.1.

Figure 7.2-19 illustrates the core thermal limits and shows the trip points that are used for the protection system. The solid lines are a locus of limiting design conditions representing the core thermal limits at four pressures. The core thermal limits are based on the conditions, which yield the applicable limit value for departure from nucleate boiling ratio (DNBR) or those conditions, which preclude bulk boiling at the vessel exit. The dashed lines indicate the maximum permissible trip points for the over-temperature high ΔT reactor trip including allowances for measurement and instrumentation errors.

The maximum and minimum pressures shown (2440 and 1860 psia) represent the limiting setpoints for the high-pressure and low-pressure reactor trips.

Adequate margins exist between the worst steady-state operating point (including all temperature, calorimetric, and pressure errors) and required trip points to preclude a spurious plant trip during design transients.

7.2.3.2 Engineered Safety Features Instrumentation Description

Plant Drawings 225102, 225103, and 225104 [Formerly UFSAR Figures 7.2-9, 7.2-10, and 7.2-12] show the logic diagrams, and Plant Drawings 243313 and 243314 [Formerly UFSAR Figures 7.2-20 and 7.2-21] show the level and pressure action initiating sensors and bistables for the engineered safety features instrumentation.

7.2.3.2.1 Indication

All transmitted signals (flow, pressure, temperature, etc.), which can cause a reactor trip, are either indicated or recorded for every channel.

The channel isolation and separation criteria as described for the reactor protection circuits are applied to the engineered safety features actuation circuits.

7.2.3.2.2 Protective Actions

The engineered safety features actuation system automatically performs the following vital functions:

1. Start operation of the safety injection system upon low pressurizer pressure signal, or high containment pressure signals (high pressure and high-high pressure), or on high differential pressure between any two steam generators, or on coincidence of high steam flow in any two steam lines (automatically blocked when T_{avg} and steam pressure are above certain limits).

2. Operate the containment ventilation isolation valves and the automatic containment isolation valves in nonessential process lines (phase A containment isolation) and generate a feedwater isolation signal upon detection of a safety injection signal as described in item 1 above. The isolation valve seal water system (IVSW) and the weld channel penetration pressurization system (WCPPS) are actuated automatically by the containment isolation signal. In addition, a high containment or plant ventilation radioactivity signal will operate the containment ventilation isolation valves.

3. Start the containment spray system and close the main steam line isolation valves upon detection of a higher containment pressure signal than in item 2 above (high-high containment pressure). The containment spray signal will operate the remaining automatic containment isolation valves (Phase B containment isolation) and the containment ventilation isolation valves. In addition, the main steam line isolation valves will close upon receipt of a signal from the steam line break protection logic.

4. Start operation of the safeguards equipment actuation sequence signal. This includes actuation signals to such components as auxiliary feedwater pumps, service water pumps, fan coolers, and diesel generators.

7.2.3.2.3 Safety Injection Trips

The safety injection is provided to detect breaks in the primary or secondary systems and to initiate operation of components associated with the engineered safeguards system. The reactor is tripped upon receipt of a safety injection signal to limit the severity of the accident. The initiation of these signals is discussed in this section. The safety injection signal diagram is shown in Plant Drawing 225105 [Formerly UFSAR Figure 7.2-12].

The safety injection trip signal is initiated by any one of the following events:

1. Low pressurizer pressure.
2. Steam break upstream of the steam line isolation valves.
3. Steam break downstream of the steam line isolation valves.
4. High containment pressure (approximately 2 psig).
5. High-high containment pressure (approximately 24 psig).
6. Manual signal.

In addition to providing a reactor trip, the safety injection signal will:

1. Initiate a turbine trip, which will, after an approximate 30 second delay, initiate a generator trip and bus transfer.
2. Initiate a feedwater system isolation.
3. Initiate a safeguards equipment sequence signal, including starting of the diesels.

4. Initiate a containment ventilation isolation.
5. Initiate a containment phase A isolation.
6. Place-the isolation valve seal water system and weld channel penetration pressurization system into service.

7.2.3.2.3.1 Low Pressurizer Pressure

This particular phase of the safety injection trip signal is provided to shut down the reactor in the event of a break in the reactor coolant system whereby the reactor coolant would be released either to containment or to the secondary side of the steam generators, depending on the location of the leak. This trip also serves as a backup to the steam break protection logic for the secondary plant. A steam break would be accompanied by excessive heat removal from the primary coolant and a rapid reduction in T_{avg}. This in turn will cause a drop in pressurizer pressure as well as an increase in reactivity.

There are three low pressurizer pressure channels, and any two of the three initiates a safety injection signal before pressurizer pressure drops below 1801 psig, in accordance with Technical Specification requirements. Pressurizer level channels that previously were included in this logic were eliminated as a direct result of the TMI incident, which demonstrated that pressurizer level will rise if the primary system leakage path is above the pressurizer vapor space.

The pressurizer pressure signals are derived from the same channels used for the low-pressure reactor trip; however lead/lag units are not used. This trip is manually bypassed on a reactor coolant system cooldown once the pressure (as sensed by two-out-of-three channels) has been reduced below 1940 psig, by manual action of the “Block SI” switch on the safeguards panel. This bypass will be automatically removed when pressurizer pressure exceeds 1940 psig. A manual unblock feature is also provided for the case where it is desired to place this circuit back in service following a block signal and with the pressurizer pressure below 1940 psig. The low pressurizer pressure signal logic is shown schematically in Plant Drawing 225105 [Formerly UFSAR Figure 7.2-12].

7.2.3.2.3.2 Steam Line Break Upstream of Steam Line Isolation Valves/High Steam Line ΔP

A steam line break in this section of pipe would be characterized by a low steam-generator pressure because the nonreturn valve would close and the particular steam generator in question would feed directly into containment or to the atmosphere through the open-ended pipe. An absolute value of steam-generator pressure cannot be used to indicate this type of break because the steam-generator pressure will vary from atmospheric pressure to a no-load value of approximately 1000 psig during startup and then back down to approximately 700 psig as full load is reached. Therefore, a comparison circuit (as shown in Plant Drawing 225103 [Formerly UFSAR Figure 7.2-10]) is employed whereby each steam generator’s pressure is compared to the pressure in each of the other three steam generators. A two-out-of-three logic is employed such that if a given steam-generator’s differential pressure increases above a fixed setpoint when compared to two of the remaining three steam generators, a safety injection signal will be initiated.

A steam generator being out of service would not affect the logic because, in this case, there will be a reverse reactor coolant flow through the steam generator and the pressure in the steam generator would be that corresponding to the saturation point for the reactor inlet temperature. This will be approximately 1000 psig assuming the air-operated steam line isolation valve was isolation valve was closed. If this valve were not closed, the pressure in the steam generator out of service would just follow that of the remaining steam generators, and likewise, this would not affect the logic. Although three-loop operational capability is possible on a continued basis, the plant Technical Specifications do not permit this mode of operation.

A steam line break, whether it be upstream or downstream of the isolation valves, will result in a cooldown of the reactor coolant system and a subsequent addition of reactivity, due to the negative moderator temperature coefficient, and also a decrease in the reactor coolant system water volume, due to the density change as discussed in Section 14.2.5.1. The safety injection signal, as previously discussed, will initiate safeguards systems to protect against the adverse conditions resulting from the steam line break.

7.2.3.2.3.3 Steam Line Break Downstream of the Isolation Valves

A steam line break in this section of pipe will be characterized by an abnormally high steam flow in the four steam lines because they are cross connected in a header arrangement and will all feed the break. To prevent the steam generators from continuing to feed the break, this particular mode of steam line break protection will close the four main steam isolation air-operated check valves.

An absolute value of steam flow cannot be used to initiate the protection since the steam flow will vary from 0 lb/hr at cold shutdown to approximately 3.5 x 10^6 lb/hr per steam generator at full load. Therefore, a comparison circuit is used in which steam flow is compared to a programmed signal on the basis of turbine inlet pressure.

Steam flow is sensed by measuring the differential pressure (ΔP) across a steam flow element in the main steam line. One flow element and two Δp transmitters are used for each main steam line associated with each steam generator; the steam flow is proportional to the square root of the ΔP across the nozzles. For this particular circuit, however, the steam flow signal is not used, but the steam flow squared or ΔP signal is used (steam flow squared –ΔP).

Turbine inlet pressure increases with load and varies from 0 psia at no load to approximately 655 psia at full load, based on modifications to the HP Turbine and its steam inlet configuration. It is sensed by two pressure transmitters and applied to a programmer (controller) that generates the function $K_1 + K_2 P_{turbine\ inlet}$. The constants K_1 and K_2 are chosen such that the output of the programmer will correspond to the ΔP signal for 40-percent steam flow from no load to 20-percent load and ramped to 110-percent for full load (see Plant Drawing 243315 [Formerly UFSAR Figure 7.2-22]).

The output from one programmer is used as an input to a comparison bistable. A steam flow signal from one steam generator is used as the second input. If the steam flow signal exceeds the programmed signal, that particular channel will be tripped.

The second steam flow and programmed turbine inlet pressure signals are used in a redundant bistable comparison circuit. The output of the two bistables is sent to a one-out-of-two logic circuit.

Each programmed turbine inlet pressure signal is applied to four comparison circuits, one for each steam generator.

Each of the four one-out-of-two logic circuits is then fed to a two-out-of-four logic for the generation of the steam line break signal. Thus, a steam line break downstream of the isolation valves must be sensed by two-out-of-four channels to initiate a safety injection signal. See Plant Drawing 225103 [Formerly UFSAR Figure 7.2-10] for the logic diagram of this circuitry.

The high steam line flow signal is so interlocked that it cannot initiate a safety injection signal unless it is accompanied by either a low T_{avg} signal (two-out-of-four T_{avg} channels below 542°F) or a low steam-generator pressure signal (two-out-of-four steam pressure channels below 565.3 psig).

The T_{avg} channels are derived from resistance temperature detectors in the reactor coolant system. These interlocks are provided to allow for startup, steam dump, or atmospheric relief valve protection. Under these conditions the steam flow will be greater than the value programmed by the turbine inlet pressure; however, it is acceptable under these circumstances. If a steam line break did actually occur, the average reactor coolant temperature would decrease as would the steam generator pressure because there is now an uncontrollable steam release.

The high steamline flow coincident with low T_{avg} or a low steam generator pressure signal is delayed up to two seconds prior to being sent out to safeguard activation logic to provide main steam line isolation and safety injection.

7.2.3.2.3.4 High Containment Pressure

A containment pressure of 2.0 psig, as indicated by two-out-of-three containment pressure signals, will initiate a safety injection trip signal. This protection is provided for the case where a small leak into containment (either primary or secondary) exists and is within the bounds of the control and protection systems. It is required in order to limit the maximum pressure inside containment should the leak increase to major proportions. See Plant Drawing 225105 [Formerly UFSAR Figure 7.2-12] for this logic diagram.

7.2.3.2.3.5 High-High Containment Pressure

High-high containment pressure, as indicated by the actuation of redundant two-out-of-three logics, will initiate a containment spray actuation signal. The bistable devices will be actuated when the containment pressure reaches 24 psig. In addition to initiating containment spray, high-high containment pressure will also result in a phase B containment isolation, a containment ventilation isolation, safety injection trip signal, and steam line isolation. This safety injection actuation acts as a backup to the high containment pressure logic. The steam line air-operated check valves are closed to prevent overpressurization of containment from a steam break inside containment with simultaneous failure of the nonreturn check valve in that loop, as discussed in UFSAR Section 14.2.5.4, Cases C and D. A secondary reason is that had the increase in pressure been caused by a steam line rupture, a path through the rupture will exist, which connects the containment atmosphere to the secondary plant or outside atmosphere. This path must be blocked to prevent any uncontrolled radioactivity release. This path must be blocked to prevent any uncontrolled radioactivity release. Dual actuation logic is used in the formation of the high-high containment pressure signal in each redundant Train, to prevent containment spray system actuation on a spurious signal. See Plant Drawing 225105 [Formerly UFSAR Figure 7.2-12]for this logic diagram.

7.2.3.2.3.6 Manual Push Buttons

Two push buttons are provided for manual initiation of safety injection. Each button will activate one train of safety injection logic. While the primary purpose of these push buttons is to initiate safety injection manually, pressing these buttons will also result in a reactor trip.

Safety injection can be reset without first clearing the automatic initiating signal(s), by placing the Train A or Train B "Normal - Defeat" key interlock switches in the "Defeat" position, and then using the reset push buttons. When these key switches are in "Defeat" position, lights above the switches illuminate and an alarm annunciates in the CCR. The manual actuation push button will override the defeat and reset function to reinitiate safety injection.

Push buttons for manual system actuation are provided for the containment isolation Phase A, containment isolation Phase B, and containment spray functions. Key interlock "Defeat" switches for system level reset are not provided for these functions. However, key bypass switches are provided for containment isolation Phase A and containment ventilation isolation (Train B only) to enhance reset capability at the equipment level in case of a failure in the daisy chain reset logic.

The automatic initiating signal(s) for containment isolation Phase A, containment isolation Phase B, and containment spray functions must first be cleared before the system actuation can be reset. The manual system actuation push buttons may be used at any time to reinitiate the system function.

7.2.3.2.3.7 Steam Line Isolation

Any of the following signals (discussed in Sections 7.2.3.2.3.2 and 7.2.3.2.3.3) will close all steam line isolation valves:

1. Coincidence of high steam flow in any two steam lines with low T_{avg} (2/4) or low steam pressure (2/4). Automatically blocked when T_{avg} and steam pressure are above certain limits.

2. High-high containment pressure signals (2/3 high-high + 2/3 high-high pressure).

3. Steam line isolation valves can also be closed one at a time by manual action.

7.2.3.2.3.8 Main Feedwater Line Isolation

A safety injection signal or high-high water level (2/3) in any steam generator will close the discharge valves from both main feedwater pumps and will close feedwater control (main and low flow bypass) valves. Each main feedwater pump will trip on closure of its discharge valve. See Plant Drawing 225106 [Formerly UFSAR Figure 7.2-13].

7.2.3.2.3.9 Deleted

7.2.4 System Safety Features

7.2.4.1 Separation of Redundant Protection Channels

The reactor protection system is designed on a channelized basis to achieve separation between redundant protection channels. The channelized design, as applied to the analog as well as the logic portions of the protection system, is illustrated by Figure 7.2-23 and is discussed below. Although shown for four-channel redundancy, the design is applicable to two- and three-channel redundancy.

The separation of redundant analog channels originates at the process sensors and continues through the field wiring and containment penetrations to the analog protection racks. Physical separation is used to the maximum practical extent to achieve the separation of redundant transmitters. The separation of field wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Analog equipment is separated by locating redundant components in different protection racks. Each channel is energized from a separate AC power feed.

The reactor trip bistables are mounted in the protection racks and are the final operational component in an analog protection channel. Each bistable drives two logic relays ("C" and "D"). The contacts from the C relays are interconnected to form the required actuation logic for trip breaker 1 through DC power feed 1. The transition from channel identity to logic identity is made at the logic relay coil/relay contact interface. As such, there is both electrical and physical separation between the analog and the logic portions of the protection system. The above logic network is duplicated for trip breaker 2 using DC power feed 2 and the contacts from the D relays. Therefore, the two redundant reactor trip logic channels will be physically separated and electrically isolated from one another. Overall, the protection system is composed of identifiable channels that are physically, electrically, and functionally separated and isolated from one another.

7.2.4.1.1 Reactor Protection and Engineered Safety Equipment Identification

A color code of red, white, blue, and yellow is established for analog protection channel sections I, II, III, and IV, respectively. Large identification plates with the appropriate background color are attached at the front and back surface of each analog rack for the identification of analog protection channel racks. Protection and safeguards relay racks are identified similarly on the input side of the racks where protection signals from the various protection channels are received.

Cable trays and cables have numbered tags for identification, which in conjunction with plant drawings, can be related to specific functions. The identification tags do not themselves differentiate between protection and nonprotection cables and trays.

7.2.4.1.2 Access to Reactor Protection System Panels

Because of the control room arrangement, access to the protection racks is under the administrative control of the plant operator as authorized by the shift supervisor. The opening of a rack door is not annunciated; however, the opening of any of the test panel covers that give access to the switches and signal injection points are annunciated on a protection set basis (i.e., four windows, one for each protection set). Access to these switches and signal injection points permits the channel to be defeated.

7.2.4.1.3 Physical Separation

The physical arrangement of all elements associated with the protection system reduces the probability of a single physical event impairing the vital functions of the system.

System equipment is distributed between instrument cabinets so as to reduce the probability of damage to the total system by some single event. Wiring between vital elements of the system outside of equipment housing is routed and protected so as to maintain the true redundancy of the systems with respect to physical hazards.

The separation of channels is established wherever practical by the use of separate trays and conduits. In the cable spreading room, electrical tunnel, and other areas with a high density of electrical cables, multiple channels are run in a single ladder tray, but separation is generally maintained within the tray by the use of 16-gauge sheet metal divider, equal in height to the tray side (typically four inches), between the different channels. Where such dividers are used in heavy power or medium power cable trays, a double sheet metal divider with approximately 1-in. of space between is used. The double divider is used in congested trays (e.g., heavy power trays to the Electrical Penetration Area) a single divider is used. In addition, whenever a power tray is located beneath an instrument or control channel tray, or a different channel of heavy power cables, a transite barrier or sheet metal barrier of sufficient thichness (approximately 0.25 inches) is installed between the trays. Such barriers are considered to be redundant as the power cable insulation being used is fire retardant and will not support combustion without excitation. Thermal blankets are used to enhance separation of cables in certain locations. Use of blankets inside the containment has been evaluated to show they will not degrade and block the recirculation sump in the event of a loss-of-coolant accident. Thermal blankets are not intended to be rated fire barriers for purposes of meeting requirements of NFPA or I0 CFR 50 Appendix R.

A few non-safety related power cables run with or cross-over redundant safety circuits. Fuses and/or current limiters (which are similar to fuses) have been installed in these circuits to ensure that an overload or fault will not cause them to exceed thermal limits and affect redundant channels.

The electrical tunnel consists of a square concrete conduit having an inside dimension of approximately 10-ft wide and 8-ft high. Arrayed on either side of a 3-ft aisle are seven 36-in. ladder trays on one side and four 36-in. and one 1-ft tray on the other side. These trays in the Electrical Tunnel are arranged in two vertical stacks with one stack supplying the PAB upper elevations and EDG Building and the other supplying the PAB lower elevations, the Auxiliary Feedwater Building and the Containment. Separation between redundant channels is a minimum of 7.5" vertically and varies horizontally from a 16-gauge sheet metal divider to the width of the aisle. The four channels on nuclear instrumentation sensor cables are in individual conduits that are supported at the end of the four trays and have a separation of approximately 12-in.

Inside the Electrical Tunnel, the power channels have a vertical separation of 7.5-in. which includes a 0.25-in. transite barrier or 16-gauge sheet metal barrier between trays as previously described. Power channels are separated horizontally by two 16-gauge sheet metal dividers with approximately 1-in. space between them.

Trays outside the Electrical tunnel are generally arranged in stacked configurations. Trays are separated vertically to the maximum extent practicable since vertical separation between trays varies based on cable functionality and location within the plant.

Plant Drawing 243317 [Formerly UFSAR Figure 7.2-24] shows a section view of the tunnel and identifies the channeling used within the area.

7.2.4.1.4 Reactor Protection and Engineered Safety System Cable Circuits

The reactor protection and engineered safety system cable circuits are divided into as many channels as is required to preserve the basic redundancy and independence of the systems. Channel separation is maintained as indicated below and is continuous from the sensors at the entrance to the receiver racks to logic cabinets to actuation devices in such a manner that failure within a single channel is not likely to cause the loss of the basic protection system or cause a failure that would prevent the actuation of the minimum safeguards devices when called for.

To satisfy the above criteria, the following are provided: for instrument cables, four separate channels throughout; for control and small power cables, a minimum of two separate channels throughout, a third in many portions of the raceway system and a fourth as required; for heavy power cables, a minimum of two separate channels throughout and a third in most portions of the raceway system; and diesel and switchgear direct current control feeds that originally utilized two battery power supplies have been upgraded to four battery power supplies as part of the improvements made to the 125-V DC supplies. In addition to such channels of separation, cables are also assigned to individual routing systems in accordance with voltage level, size, and function category.

Seven (7) major independent conduit and/or tray systems are used for such purposes and establish the separation of the following:

1. 6.9-kV AC power cables.
2 Heavy 125-V DC power cables and heavy 480-V AC (over 100 hp) power cables.
3. Lighting panel feeders and medium power (greater than No. 12 AWG wire size) 480-V AC cables.
4. Control and small power cables.
5. Instrument cables.
6. Rod control cables.
7. 13.8KV AC power cables.

Typically, cables are routed in cable trays consistent with their voltage level classification. There are instances where cables are routed in a cable tray that is associated with a different voltage class, which results in a mixing of cables. The voltage class mixing of certain cables is governed by the IP2 Electrical Separation Design Criteria standard or by approved Design Engineering evaluations.

7.2.4.1.5 Electrical Penetrations

The electrical penetrations are in a single area, composed of about 60 assemblies arrayed in a group of low voltage power, control, and instrument wire assemblies and a separate group of 6.9-kV assemblies. The 6.9-kV assemblies are separated from the rest of the units by a distance

distance of approximately 6-ft.

The main group of assemblies (penetration canisters) are arranged in four rows high, with each row separated from another row by 3-ft. Each assembly in a row is spaced on approximately 3-ft centers. Each assembly has only one category of circuit within it. The various penetration canisters consist of units of No. 12 AWG, No. 16 AWG shielded twisted pairs, No. 16 AWG shielded twisted quads, No. 10 AWG, No. 4 AWG, 250 MCM No. 4/0 AWG, and triax. Channel separation is maintained to and from the penetrations and no two safety system channels are run through a single penetration. Heavy power assemblies are placed in the bottom two rows of penetrations. The bottom row of penetrations is below the postulated post-LOCA flood level and included no safety-related assemblies. Redundant heavy power penetrations are not adjacent to each other nor are they vertically stacked. The northwest portion of the Electrical Penetration area is dedicated for Train "A", the middle portion for Train "B" and the southeast potion for Train "C" heavy power penetrations.

In general, the separation between redundant or channelized circuits is expected to be greater than the spacing between two adjacent assemblies.

In the containment electrical penetration area, the free air spacing between redundant channel conductors, located in adjacent penetrations is at least twenty-eight (28") inches. It is unlikely that any incident could affect more than one penetration. However, transite barriers above the power cables at the penetrations inside and outside of containment are designed to give added protection against damage to cables located above in the event of a high-capacity fault.

However, some low voltage power, control and instrumentation channels, located in adjacent electrical penetrations, have free air spacing between redundant channel conductors, of at least twenty-eight (28") inches. The control instrument and small power assemblies are furnished with factory installed pigtails, and field splices are therefore well away from the canister face. The electrical penetration area is in a concrete vault, dead ended at one end so that no traffic is expected in this area.

7.2.4.1.6 Cable Separation

The design and use of fire stops, seals and barriers to meet 10 CFR 50.48 criteria for the prevention of flame propagation where cable and cable trays pass through walls and floors is found in the document under separate cover entitled, "IP2 Fire Hazards Analysis."

The safeguards control panels (SB-1, SB-2) have protective barriers installed to prevent inadvertent contact or damage to control cables, fuses, relays, and switches by personnel in the service aisle. These devices consist of barriers over horizontal terminal strips, vulnerable switch terminals, and expanded metal covers over the back of the front safeguards panels and the front of the rear safeguards panels.

Cables are protected in hostile environments by a number of devices. Running the cable in a rigid, galvanized conduit is the most frequently used method of protection. For underground runs, polyvinyl chloride heavy wall conduit encased in a concrete envelope provides maximum protection. When cable is run in a tray, peaked covers are used in areas where physical damage to cables may result from falling objects or liquids. In addition, covers are provided on horizontal cable trays that are exposed to the sun.

Conduits and cables are marked by tags attached at each end. These tags are embossed to conform to the identification given in the Conduit and Cable Schedule. At each conductor cable termination, the conductors are marked to indicate the terminal designation of each conductor.

The control over and administrative responsibility for all of the above during design and installation rested with United Engineers and Constructors, Inc., as the architect-engineer and with WEDCO as the construction contractor.

In the containment electrical penetration area, the free air spacing between redundant channel conductors, located in adjacent penetrations, is at least twenty-eight (28") inches. It is considered unlikely that any incident could affect more than one penetration. However, transite barriers above the power cables at the penetrations inside and outside of containment are designed to give added protection against damage to cables located above in the event of a high-capacity fault.

Redundancy and separation requirements were initiated by the cognizant electrical or mechanical design engineer. These were then reviewed by the designers of the electrical system installation, thus providing a check. The work of the designer, who prepared the applicable circuit schedule sheet (which designates the cable routing and termination), was spot checked by the cognizant electrical engineer.

The construction group installed the cable as directed by the circuit schedule sheet. The installations were followed by Westinghouse field engineers, and spot checks of circuit installations were made to ensure further that the installation was in accordance with the design. Con Edison also spot checked the installation.

7.2.4.1.7 Cables

The bulk of original plant cables outside the containment, with the exception of the 8-kV, are insulated with polyvinyl chloride with a fire retardant asbestos jacket. Excluding the 8-kV cables, cables used inside the containment are silicone rubber or Kerite insulated to provide greater radiation resistance. The 8-kV cables are insulated with XLPE and are run in separate trays with maintained spacing. Cables used for plant additions include EPR/neoprene insulation for outside the containment and cross-linked polyethylene insulation for inside and outside of the containment. [Deleted] Cables used for plant additions or cables entering the Safeguards Raceway have been designed to originally referenced FSAR cable tests and the latest applicable versions of IEEE-323 and IEEE-383. Cables that do not enter the Safeguards Raceway, i.e. cables rated above 600V, maintenance and test cables, grounding and communication / data processing cables and Unit 1 cables are not designed to meet the requirements of IEEE-323 or IEEE-383.

Physical loading of cable trays was controlled by means of the conduit and cable schedule. Trays containing instrumentation, control and small / medium power cables were regulated to have a maximum full of 70-percent of the tray area, while those containing larger power cables were limited to one or two layers depending on the size and use of the cables.

Cables in trays with no maintained spacing were derated according to their temperature rating, the number of cables in the tray, and size variation of these cables. The base rating and foundation for all derating calculations was taken from IPCEA Publication P-46-426, "Power Cable Ampacities – Copper Conductors," using the proper conductor temperature and ambient conditions for the application. A derating factor was then applied to the base rating according to the number of conductors in the tray. Cables on opposite sides of the dividers in power trays were considered to be in different trays for this calculation. The derating factor used was based on standard load diversity. Lastly, the cables were derated to eliminate any hot spots that might occur due to the presence of larger-than-average size conductors in the tray. For the pressurizer heater cables that have no diversity, a thermal study was made using actual load conditions to determine that the internal temperature of the cables was within safe limits.

All cables serving 6.9-kV motors, station service transformers, 480-V switchgear supplied motors, and 480-V motor control centers are protected against overloads by circuit breakers. The 480-V circuits for motors under 125 hp are protected by fuses and/or circuit breakers. In some instances, fuses are backed up by circuit breakers or overload devices in the starters for these motors. Instrumentation and direct current circuits are protected by circuit breakers.

To provide forced-air circulation to maintain cable conductor temperatures within acceptable limits, two separate fans either of which is capable of removing all heat necessary to prevent excessive cable temperatures during operation of the safeguard equipment, have been provided for the electrical tunnel. These fans are supplied from separate diesel-generator buses.

7.2.4.2 Electrical Equipment Design

The safety-related electrical equipment is designed to operate and perform its design function within specified safe limits without degradation of performance (accuracy, repeatability, time response) under the expected normal and abnormal ambient conditions associated with its location. The normal ambient design temperature range is 75°F plus or minus 10°F for equipment located in the central control room. The abnormal ambient condition associated with the design of the safety equipment in the central control room is 120°F for short-term operation associated with a loss of air conditioning. Safety-related electrical equipment in other than the central control room is designed to operate under the worst-case environment for which it is required to perform its function. For example, in the containment, the ex-core neutron detectors and cables are designed to operate continuously in an ambient temperature of 135°F and for a period of at least eight (8) hours in an ambient temperature of 175°F, and a maximum pressure of 100 psia, provided the detector connectors are protected against moisture intrusion. However, as discussed in the NRC's November 27, 1995 Supplemental Safety Evaluation, the excore neutron flux instrumentation doesn't need to be environmentally qualified per Regulatory Guide 1.97 Revision 2 because accident diagnosis and plant recovery can be accomplished using alternate instrumentation and boron capability as directed by plant Emergency Operating Procedures. All plant areas which can be subjected to harsh environmental conditions as a result of LOCA or HELB and environmental parameters for those areas, at IP2, are identified by Calculation #PGI-00408-00 Rev. 0 (Reference 9). Environmentally qualified safety related process transmitters and sensors throughout the plant will function normally in a normal environmental conditions, and under an accident situation to abnormal environmental conditions, subjected to environmental parameters as defined by their site specific locations per Tables 9.1-1 & 9.1-2 of the Electrical Equipment Environmental Qualification Program (Reference 10) and IP2-EQ Master List (Reference 11). The effective inside containment normal temperature for calculating equipment qualified life is a continuous annual temperature of 120°F. It has been demonstrated by analyses that a continuous annual temperature of 120°F is a conservative temperature for equipment qualification purposes, as it envelopes the thermal degradation resulting from utilization of average monthly temperatures ranging from 95 to 130°F (Reference 9).

The ventilation systems of concern outside the central control room are designed to cope with a single active failure. For example, in the event of a design basis accident with the single active failure occurring in the PAB ventilation system, all safety related systems would survive the resulting increase in area temperature. Credit is taken for operator action upon entry into the recirculation phase. The limiting case is the Small Break Loss of Coolant Accident, wherein recirculation is delayed until 4 hours after the accident. At this point the maximum temperature is 144°F (by analysis) in the SI pumps room.

The central control room contains most of the safety-related equipment; therefore, it represents the limiting condition for temperature that would require reactor shutdown. The central control room ventilation system is designed to accommodate certain active or passive failures. Operator action is not required to prevent unacceptable temperatures in safety-related equipment located in the central control room.

The central control room air conditioning system consists of an air conditioning unit with design flow of 9,200 cfm, a back-up ventilation fan in parallel with the same design capacity, one 2,000 cfm high efficiency particulate air (HEPA) charcoal filter unit, two (for redundancy) 2,000 cfm booster fans for filter operation, one 2,300 cfm emergency ventilation fan located in the supervisory control panel exhaust system, and associated duct work and dampers. The back up fan unit starts automatically on a loss-of-air flow. The Indian Point Unit 2 central control room air conditioning and ventilating system is powered from redundant buses serviced by the emergency diesel generators.

It is design policy that the functional capacity of the central control room shall be maintained at all times inclusive of accident conditions, such as a maximum credible accident (MCA) or a fire. Hence, to specify the limiting conditions, two cases must be considered: failure of the air conditioning system during normal operation and failure subsequent to or coincident with an MCA. Considering first the case where failure occurs during normal operation, the objective is to ensure that temperatures do not exceed levels where reactor protection system and safeguards system setpoints are altered appreciably and to ensure that remote hot shutdown capability is not compromised. The maximum tolerable upper limit is 120°F.

On a loss of the Indian Point Unit 2 air conditioning system, the control room temperature under operating conditions and outside design temperatures of 93°F dry bulb and 75°F wet bulb will rise to a level where the heat released to the room by the equipment and lights will balance the transmission losses through the walls, floor, and ceiling. This temperature has been calculated for the following condition:

Unit 1 air conditioning system operating with 100-percent recirculated air (no outside air).

In this case, when the loss of Unit 2 air conditioning occurs, the following action will take place:

1. All lights except emergency lights will be turned off.
2. The emergency vent fan on the supervisory control panel exhaust system will start automatically.

Under these conditions, the maximum room temperature will be 104.6°F.

The room supply air to the supervisory panel will be at a temperature approximately 2°F lower than this room temperatures because of stratification. Therefore, the supervisory panel temperatures will be approximately:

104.6°F - 2°F + 4.7°F = 107.3°F

[Note: 4.7°F = temperature rise due to heat pickup in supervisory control panel based on 3-kW load]

There is no latent heat released to the room from equipment and an insignificant amount from the operators. Therefore, the humidity will remain 50-percent or lower and will decrease as the temperature increases.

The design basis is that the safety-related analog-type electrical equipment will perform its required functions within the required accuracies for ambient conditions of 120°F. If the central control room (CCR) temperature reaches 104°F with no outside air, or 109°F with outside air intake, a plant shutdown will be initiated. If the CCR temperature reaches 120°F, the reactor will be manually tripped. Central control room annunciation is not provided for high ambient temperatures or loss of air conditioning.

A self-contained refrigerant air conditioning system has been installed to further circulate and cool air within the central control room. The system provides more cooling for operator comfort during the summer months. The system is not required for an accident. For this reason, the system does not meet seismic Class I design criteria, but it has been reinforced to withstand the safe-shutdown earthquake in order to prevent it from damaging the central control room postaccident ventilation system on the roof and the safety equipment inside the central control room.

The outside makeup air to the Indian Point Unit 1 control room has been cut off. The outside control dampers are disconnected and sheet metal closure plates are installed.

During the postaccident period, the Indian Point Unit 2 charcoal filter and fan system for the central control room ventilation system functions to remove fission products as described in Section 9.9.

Factory testing was performed on various safety-related systems such as process control, nuclear instrumentation, and logic relay racks. This testing involved demonstrating the operation of proper safety functions with increased ambient temperatures of at least 120°F for process control and nuclear instrumentation. The logic relay racks were tested to determine temperature rise of the cabinet under full-load conditions. From this test, it was determined that the relays would perform their function in an ambient temperature of 130°F.

7.2.4.2.1 Loss of Instrument Power

A loss of power in the reactor protection system ensures the affected channel to trip. All bistables operate in a normally energized state and go to a deenergized state to initiate action. Loss of power thus automatically forces the bistables into the tripped state.

The availability of power at each instrument bus is continuously monitored by selecting individual bus voltage indication at a common voltmeter located at the rear of Flight Panel FD. The loss of instrument power to sensors or instruments in a protection channel deenergizes the bistable(s) to actuate the engineered safety features (ESF) logic associated with that channel, except for containment spray, where the bistable(s) energize to actuate the containment spray logic.

7.2.4.2.2 Primary Power Source

The primary source of control power for the reactor protection system is the vital instrument buses described in Section 8.2. The source of power for the measuring elements and the actuation circuits in the engineered safety features instrumentation is also from those buses. The safety injection master and auxiliary relays are energized to actuate by the 125-V DC system.

7.2.4.3 Reactor Trip Signal Testing

Provisions on nonnuclear instrumentation are made for “at power” testing of all portions of each trip circuit including the reactor trip breakers. Administrative procedures require that the final element in a trip channel (required during power operation) is placed in the trip or bypass mode before that channel is taken out of service for repair or testing. In the source and intermediate ranges where the trip logic is one-out-of two for each range, bypasses are provided for this testing procedure.

Nuclear power range channels are tested by superimposing a test signal on the normal sensor signal so that the reactor trip protection is not bypassed. On the basis of coincident logic (two-out-of-four), this will not trip the reactor; however, a trip will occur if a reactor trip is required.

Provision is made for the insertion of test signals in each analog loop. The verification of the test signal is made by station instruments at test points specifically provided for this purpose. This enables testing and calibration of meters and bistables. Transmitters and sensors are checked against each other and against precision readout equipment during normal power operation.

7.2.4.3.1 Analog Channel Testing

Testing of analog protection channels is discussed in Section 7.2.2.7.

Administrative controls prevent the nuclear instrumentation source range and intermediate range protection channels from being disabled during periodic testing. Power range overpower protection cannot be disabled because this function is not affected by the testing of circuits. Administrative controls also prevent the power range dropped rod protection from being disabled by testing. In addition, the rod position system would provide indication and associated corrective actions for a dropped rod condition.

7.2.4.3.2 Logic Channel Testing

The general design features of the logic system are described below. The trip relays for typical trip functions are shown in Figure 7.2-26. The analog portions of these channels are described in Plant Drawings 243324 and 243311 [Formerly UFSAR Figures 7.2-27 and 7.2-28]. Each bistable drives two relays ("A" and "B" for level and "C" and "D" for pressure). Contacts from the A and C relays are arranged in two-out-of-three and two-out-of-four trip matrices, which actuate the trip relays for trip breaker A. These configurations are duplicated for trip relays for breaker B using contacts from the B and D relays. A series configuration is used for the trip breakers as they are actuated (opened) by undervoltage coils. This approach is consistent with a deenergize-to-trip preferred failure mode. Additionally, the reactor trip breakers are equipped with shunt trip coils, which are activated on a trip signal (Figure 7.2-30). The logic system testing

testing includes exercising the reactor trip breakers to demonstrate system integrity. Bypass breakers are provided for this purpose. During normal operation, these bypass breakers are open and racked out. Administrative control is used to minimize the amount of time these breakers are closed. Closure of the breaker is controlled from its respective logic test panel in the central control room. An interlock is provided that trips both bypass breakers open if a second bypass breaker is closed. The status of the reactor trip breaker is indicated in the central control room by indicating lights.

As shown in Figure 7.2-26, the trip signal from the logic network is simultaneously applied to the main trip breaker associated with the specific logic chain as well as the bypass breaker associated with the alternative trip breaker. Should a valid trip occur while BYA is bypassing RTA, RTB will be opened through its associated logic train. The trip signal applied to RTB is simultaneously applied to BYA, thereby opening the bypass around RTA. RTA would either have been opened manually as part of the test or would be opened through its associated logic train, which would be operational or tripped during a test.

An auxiliary relay is located in parallel with the undervoltage coils of the trip breakers. This relay is tied to the safety assessment system to indicate the transmission of a trip signal through the logic network during testing, and to record trip system demands. Lights are also provided to indicate the status of the individual logic relays.

The following procedure illustrates the method used for testing trip breaker A and its associated logic network:

1. With the bypass breaker BYA racked out, manually close and trip BYA to verify operation.

2. Rack in and close BYA. Trip RTA.

3. Sequentially deenergize the trip relays (A1,A2,A3) for each logic combination (1-2,1-3,2-3). Verify that the logic network deenergizes the undervoltage coil on RTA for each logic combination. Neon lights have been provided to indicate the operation of the undervoltage coil.

4. Repeat step 3 for every logic combination in each matrix.

5. Reset RTA. Rack BYB to the test position.

6. Trip RTA and BYB by their undervoltage coils to validate prior test results as evidenced by the neon lights.

7. Reset RTA, then trip it by the shunt trip coil.

8. Reset RTA. Trip and rack out BYA and BYB.

7.2.4.4 Bypass Breakers

The intention is to leave the bypass breakers, housed in their respective switchgear units, locked in the withdrawn (non-operating) position. The positioning of these breakers to the operating position for logic system testing is under the administrative control of the operator. The closing of the breaker is controlled from its respective logic test panel in the central control room. The room. The status of the breaker is indicated in the control room by indicating lights. An interlock is provided that will trip both bypass breakers open if a second bypass breaker is closed. Reactor trip breaker position lights for both the main and bypass breakers (four) are in the control room on the reactor protection test panels.

In order to minimize the possibility of operational errors from either the standpoint of tripping the reactor inadvertently or only partially checking all logic combinations, each logic network includes a logic channel test panel. This panel includes those test switches and indicating lights, needed to verify correct functional performance of the reactor protection system logic trip matrices. The test switches used to deenergize the trip bistable relays operate through interposing relays as shown in Plant Drawings 243322 and 243324 [Formerly UFSAR Figures 7.2-25 and 7.2-27]. This approach avoids violating the separation philosophy used in the analog channel design. Thus, although test switches for redundant channels are conveniently grouped on a single panel to facilitate testing, physical and electrical isolation of redundant protection channels is maintained by the inclusion of the interposing relay, which is actuated by the logic test switches.

7.2.4.5 Engineered Safety Features Actuation Instrumentation Description

The engineered safety features actuation circuitry is designed to maintain channel isolation up to and including the bistable operated logic relay, similar to that of the reactor protection circuitry. The general arrangement of this layout is shown in Figure 7.2-15, with supplemental details in Plant Drawings 243319 and 243320 [Formerly UFSAR Figures 7.2-16 and 7.2-17]. Although a four-channel system is illustrated in Figure 7.2-15, circuitry and hardware layout discussion is sufficiently general to apply to an “n” channel system. Channel separation is maintained by providing separate racks for each analog protection channel and separate relay rack compartments for each logic train. Channel identity is lost in the relay wiring required for matrix logic makeup. It should be noted that although channel individualization is lost, twin matrix logic trains are developed, thus ensuring a redundant actuation system.

The engineered safety feature bistables drive the logic relay coils C and D as shown in Figures 7.2-15 and 7.2-17. These logic relay coils are deenergized by their bistables when an abnormal condition exists; exceptions to this deenergized-to-operate principle are initiation of containment spray and the pressurizer pressure manual block permissive. Each bistable will actuate two (2) logic relays, one for each Train, which contacts are utilized to develop the logic matrices for initiating safeguards action. In Figure 7.2-15, these relay contacts are shown directly below the relay coil. Because these coils would normally be energized, their contacts would remain open and thus an open circuit between the voltage source and master actuating relay would exist. Deenergizing any of the two logic relay coils would cause their corresponding contacts to close, which would complete the circuit and energize the master actuating relays. Although the illustration here is for a two-out-of-four matrix, the design and sequence of operation for any of the logic matrices is the same. The master actuating relay (M) is a latch-type relay having an operate (M/0), an intermediate (K) and a reset (M/R) coil. Once the logic matrix is made up, as described above, the circuit that energizes the master actuating relay is complete. Figure 7.2-15 illustrates the master actuating relay (M); an enlarged view may be found in Plant Drawing 243319 [Formerly UFSAR Figure 7.2-16]. With potential applied to the relay, the operate coil (M/0) is energized, thus closing the (M) contacts that energize the slave relays (SRs), as shown in Figure 7.2-15. The master relay is latched in this position until the reset coil (M/R) is energized.

As a minimum, slave relay outputs from the Train A logic system actuate the Train A safeguards components, and slave relay outputs from the Train B logic system actuate the Train B safeguards components. All components not identified with a specific Train and many safeguards components are actuated by both logic systems.

After an approximately 2-min time delay to ensure the completion of the actuation sequence, the master actuating relay may be manually reset by operating the reset switch (see Figure 7.2-15 and Plant Drawing 243319 [Formerly UFSAR 7.2-16]). With the reset coil (M/R) energized, all of the (M) contacts are returned to their deenergized positions as shown in Figure 7.2-15. Resetting the master relay does not interfere with the operation status of the engineered safety features equipment. Manual safety injection initiation is maintained even with reset activated.

A study was conducted to determine whether or not, upon the reset of an engineered safety features actuation signal, all associated safety-related equipment remains in its emergency mode. The review resulted in the addition of some actuation relays with a self-seal-in feature that will maintain the respective safeguards equipment in the emergency or safeguards mode when the engineered safety features signal is reset.

7.2.4.6 Engineered Safety Features Logic Testing

Figures 7.2-15 and 7.2-17, and Plant Drawing 243319 [Formerly UFSAR Figure 7.2-16] illustrate the basic logic test scheme. Test switches are located in the associated relay racks rather than in a single test panel. The following steps indicate the method of testing the logic matrices:

1. Test of either train A or train B is performed one train at a time; this is under administrative control.

2. A selection of the matrix function to be tested is made. Plant Drawing 243319 [Formerly UFSAR Figure 7.2-16], for example, illustrates some of these functional matrices.

3. The logic test switch is a dual function switch that is first turned to operate one series of contacts and then depressed to operate other contacts. Turning the logic test switch to the right will illuminate the “test switch in test position” lamp. The slave actuating relays are removed from this part of the test by opening Flexitest switches located in the output circuit of the master relay in order to avoid unintentional starting of the engineered safety features equipment. Intentional start is available through the other train that has operational status.

4. Depressing the logic test switch, will deenergize the logic relay coil, thus closing contacts of that logic relay (i.e., closing logic relay contacts forms the logic matrix to energize the associate master relay as shown in Figure 7.2-15 or 7.2-17). By performing the above sequence, it is possible to simulate all actuating logic combinations required to develop the matrix. When the matrix is made, the master relay is actuated, which verifies proper operation of this matrix. As indicated in paragraph 3 above the slave relays remain deenergized, preventing actuation of ESF equipment.

5. Proper test development of a logic matrix would be indicated by illumination of a matrix test lamp, as shown in Figure 7.2-17.

6. When testing of the logic matrix is complete, the equipment is returned to operational status by turning all test switches to the left and closing the Flexitest

switches. The control board annunciator warns the operator of any test switch left in the test position; thus, return to operational status by action of the individual doing the test is verified by the operator at the control board. Testing steps for the logic matrices of train B are identical to that described above for train A.

7.2.5 Protective Actions

7.2.5.1 Reactor Trip Description

Rapid reactivity shutdown is provided by the insertion of the rod cluster control assemblies by gravity fall to compensate for fast reactivity effects (e.g., doppler and moderator temperature effects). Duplicate series-connected circuit breakers supply all power to the control rod drive mechanisms. The full-length control rod drive mechanism coils must be energized for the rod cluster control assemblies to remain withdrawn from the core. The rod cluster control assemblies fall by gravity into the core upon loss of power to the control rod drive mechanism coils. The trip breakers are opened by the undervoltage coils on both breakers (normally energized), which become deenergized by any of several trip signals.

The shunt trip coils of the breakers provide a backup to the undervoltage trip coils for the automatically initiated reactor trip signals with the utilization of relays ST and ST-1 in the trip coil circuits shown schematically in Figure 7.2-30. Both relays must be deenergized to actuate the shunt coil.

The electrical state of the devices providing signals to the circuit breaker undervoltage trip coils is such as to cause these coils to trip the breaker in the event of reactor trip or power loss.

Certain reactor trip channels are automatically bypassed at low power where they are not required for safety. Nuclear source range and intermediate range trips that are specifically provided for protection at low-power or subcritical operation are bypassed by operator manual action after receiving a permissive signal from the next higher range of instrumentation to establish operational status to permit low-power operation.

During power operation, a sufficiently rapid shutdown capability in the form of rod cluster control assemblies is administratively maintained through the control rod insertion limit monitors. Administrative control requires that all shutdown rods be in the fully withdrawn position during power operation.

A resume of reactor trips, means of actuation, and the coincident circuit requirements is given in Table 7.2-1. The permissive circuits (e.g., P-7) are listed in Table 7.2-2.

7.2.5.1.1 Manual Trip

The manual actuating devices are independent of the automatic trip circuitry and are not subject to failures that make the automatic circuitry inoperable. Either of two manual trip devices located in the control room will initiate a reactor trip. There are no interlocks associated with these trip actuating devices.

A manual trip energizes the shunt trip coils of the reactor breakers. The coils are fed by two independent sources. The channelization matches the power trains of the reactor protection trip logic channels associated with each reactor breaker, enhancing the manual reactor trip availability.

7.2.5.1.2 High Nuclear Flux (Power Range) Trip

This circuit trips the reactor when two-out-of-four power range channels read above the trip setpoint. There are two independent trip settings, a high and a low setting. The high trip setting provides protection during power operation. The low setting, which provides protection during startup, can be manually bypassed when two-out-of-four power range channels read above approximately 10-percent power (P-10). Three-out-of-four channels below 10-percent automatically reinstates the trip protection. The high setting is always active.

7.2.5.1.3 High Nuclear Flux (Intermediate Range) Trip

This circuit trips the reactor when one-out-of-two intermediate range channels reads above the trip setpoint. This trip, which provides protection during reactor startup, can be manually bypassed if two-out-of-four power range channels are above approximately 10-percent power (P-10). Three-out-of-four channels below this value automatically reinstates the trip protection. To prevent inadvertent and unnecessary reactor trips during power reductions prior to shut down, operating procedures allow these trips to be manually bypassed until they have reset to the untripped condition and the reset has been verified. The intermediate channels (including detectors) are separate from the power range channels.

7.2.5.1.4 High Nuclear Flux (Source Range) Trip

This circuit trips the reactor when one of the two source range channel count levels (neutron flux) reads above the level trip setpoint. The trip, which provides protection during reactor startup, can be manually bypassed when one-out-of-two intermediate range channels reads above the P-6 setpoint value. This trip is also bypassed by two-out-of-four high power range signals (P-10). It can be reinstated below P-10 by an administrative action requiring coincident manual actuation.

The trip point is set between the source range cutoff power level and the maximum source range power level.

7.2.5.1.5 Overtemperature ΔT Trip

The purpose of this trip is to protect the core against departure from nucleate boiling (DNB). This circuit trips the reactor on coincidence of two-out-of-four signals, with two sensors (two sets of temperature measurements, hot and cold) per loop. The setpoint for this reactor trip is continuously calculated for each channel by solving equations of this form:

$$\Delta T_{setpoint} = \Delta T_0 \left[K_1 - K_2 \left(\frac{1+\tau_1 s}{1+\tau_2 s} \right) (T - T') + K_3 (P - P') - f_1(\Delta I) \right]$$

where

ΔT_0 = loop specific indicated ΔT at rated power (°F)

K_1 = setpoint bias

K_2, K_3 = constants based on the effect of temperature and pressure on the DNB limits
S = laplace transform operator, sec $^{-1}$

T = measured reactor coolant average temperature (^oF), two measurements (Tc, Th) in each loop)
T' = loop specific indicated average temperature at rated power (^oF)

$\tau_1 \tau_2$ = time constants, sec

P = measured pressurizer pressure, four independent measurements (psig)

P' = nominal pressure at rated power, 2235 psig

$F_1(\Delta I)$ = function of the indicated difference between top and bottom detectors of the power range nuclear ion chambers with gains to be selected on the basis of measured instrument response during plant startup tests

7.2.5.1.6 Overpower ΔT Trip

The purpose of this trip is to protect against excessive power (fuel rod rating protection). This circuit trips the reactor on coincidence of two-out-of-four signals, with two hot and cold sensors (two sets of temperature measurements) per loop.

The setpoint for this reactor trip is continuously calculated for each channel by solving equations of the form:

$$\Delta T_{setpoint} = \Delta T_o \left[K_4 - K_5 \left(\frac{\tau_3 s}{1+\tau_3 s} \right) T - K_6 (T - T'') - f_2(\Delta I) \right]$$

where

ΔT_O= loop specific indicated ΔT at rated power (°F)

K_4 = setpoint bias

K_5 = constant

τ_3 = time constants, sec

S= laplace transform operator, sec $^{-1}$

T = measured reactor coolant average temperature (°F), two measurements (T_c, T_h) in each loop (°F)

K_6 = constant

T" = loop specific indicated average temperature at rated power (°F)

$F_2(\Delta I)$ = function of the indicated difference between top and bottom detectors of the power range nuclear ion chambers with gains to be selected on the basis of measured instrument response during plant startup tests

7.2.5.1.7 Low Pressurizer Pressure Trip

The purpose of this circuit is to protect against excessive core steam voids that could lead to departure from nucleate boiling. The circuit trips the reactor on coincidence of two-out-of-four low pressurizer pressure signals. This trip is blocked when three-out-of-four power range channels and two-out-of-two turbine inlet pressure channels read below approximately 10-percent power (P-7).

7.2.5.1.8 High Pressurizer Pressure Trip

The purpose of this circuit is to limit the range of required protection from the overtemperature ΔT trip and to protect against reactor coolant system overpressure. This circuit trips the reactor on coincidence of two-out-of-three high pressurizer pressure signals.

7.2.5.1.9 High Pressurizer Water Level Trip

This trip is provided as a backup to the high pressurizer pressure trip. The coincidence of two-out-of-three high pressurizer water level signals trips the reactor. This trip is bypassed when any of three-out-of-four power range channels and two-out-of-two turbine inlet pressure channels read below approximately 10-percent power (P-7).

7.2.5.1.10 Low Reactor Coolant Flow Trip

A reactor trip on underfrequency is generated by a signal indicating an underfrequency condition on two-out-of-four buses, which opens all reactor coolant pump breakers, which in turn trips the reactor. The purpose of this trip is to provide protection following a major network frequency disturbance. This design satisfies the proposed IEEE criteria for nuclear power plant protection system (IEEE-279 Code), dated August 28, 1968.

An undervoltage trip is also generated on a signal indicating an under-voltage condition of two-out-of-four buses, with one signal per bus.

An undervoltage trip is provided for protection following a complete loss of power. This design satisfies the proposed IEEE criteria for nuclear power plant protection system (IEEE-279 Code), dated August 28, 1968.

With a reactor coolant pump bus underfrequency, all reactor coolant pumps are tripped with this signal generating a reactor trip. In the event of a frequency disturbance, the primary requirement is to release the reactor coolant pumps from the network to preserve their kinetic energy.

The means of sensing a loss-of-coolant-flow accident are as follows:

1. Measured low flow in the reactor coolant loop - The low flow trip signal is actuated by the coincidence of two-out-of-three signals for any reactor coolant loop. The loss of flow in any two loops causes a reactor trip in the power range above approximately 10-percent (P-7). Above approximately 20-percent power (P-8), the

(P-8), the loss of flow in any loop causes a reactor trip. The instrument used for flow measurement is an elbow tap and is discussed in Chapter 4.

2. Undervoltage on any two-out-of-four reactor coolant pump buses will cause a reactor trip above approximately 10-percent power (P-7).

3. Reactor coolant pump circuit breaker open

   a. Underfrequency on any two-out-of-four reactor coolant pump buses will trip the breakers of all four reactor coolant pumps and cause a reactor trip above approximately 10-percent power (P-7).

   b. Undervoltage on any single bus will trip the breaker of the associated reactor coolant pump after a time delay. Above approximately 10-percent power (P-7) a reactor trip will occur if any two reactor coolant pump circuit breakers are open. Above approximately 20-percent power (P-8) any open reactor coolant pump circuit breaker will cause a reactor trip.

Technical Specification 3.3.1 allows the single loop loss of flow trip to be bypassed whenever reactor power is below approximately 20-percent power (P-8 setpoint). Below this setpoint and above the permissive setpoint P-7, a loss of flow in two loops would cause a reactor trip. This permits an orderly plant shutdown under administrative control following a single-loop loss of flow during low-power operation. Since the plant will not be maintained in operation above permissive power setting P-7 without three loops in service, independent accidents simultaneous with a single-loop loss of flow at low power are not considered in the protection system design.

7.2.5.1.11 Control Rod Protection Trip

This trip provides a backup to the manually initiated action (during reactor coolant system cooldown) of opening the reactor trip breakers prior to T_{cold} decreasing below 381°F. This trip is required to avoid mechanical interference caused by thermal contraction between the fuel and control rods. Two-out-of-three channels will actuate this trip.

7.2.5.1.12 Deleted

7.2.5.1.13 Safety Injection System Actuation Trip

A reactor trip occurs when the safety injection system is actuated. The means of actuating the safety injection system trip are listed below. This design satisfies the proposed IEEE criteria for nuclear power plant protection system (IEEE-279 Code), dated August 28, 1968.

1. Low pressurizer pressure (2/3).
2. High containment pressure (2/3), set at approximately 2 psig. (10.0 psig assumed in safety analysis).
3. High differential pressure between any two steam lines (2/3).
4. High steam flow (2/4) coincident with low T_{avg} (2/4) or low steam line pressure (2/4).
5. High-high containment pressure (2 sets of 3, 2/3, high-high pressure) set at approximately 50-percent of containment design pressure.
6. Manual.

7.2.5.1.14 Pressurizer Signal Diversity

In 1970, the available pressurizer automatic protection functions were a reactor trip on low pressurizer pressure and an ESF trip on low pressurizer pressure coincident with low pressurizer water level. These two trips provided functional diversity in the event of depressurizations of the primary system. To provide additional diversity in the event of small breaks in the primary system, a Containment Pressure High ESF trip setpoint of 2.0 psig was chosen.

In 1979 following the Three Mile Island Unit 2 (TMI-2) event, IE Bulletin 79-06A (Revision 0 and Revision 1) identified actions to be taken by the licensees of reactors designed by Westinghouse. One of the actions identified in IE Bulletin 79-06A was to eliminate the coincident requirement of low pressurizer water level with low pressurizer pressure for an ESF trip. As a result, an ESF trip occurs on low pressurizer pressure only. In the review of the TMI-2 event, it was determined that the low pressurizer water level coincidence limited the reliability of the pressurizer ESF trip. Also, analyses of small breaks located at the top of the pressurizer showed that the pressurizer water level would increase (although the pressure and mass of the primary system would be decreasing), which would preclude an ESP trip. The NRC in their Safety Evaluation Report dated July 10, 1979, concluded that this change satisfied the requirements of IEEE 279-1971 and that none of the transient and accident analyses are adversely affected by the change.[7]

As such, the diversity of the pressurizer trip functions was strengthened by removing the pressurizer water level coincidence logic from the pressurizer ESF trip function. The low pressurizer pressure reactor trip signal and the low pressurizer ESF trip signal are actuated by separate and diverse logic trains. Also, the overtemperature delta-temperature (OTΔT) reactor trip is available depending on initial conditions for providing diverse reactor trip in the event of a depressurization of the primary system. Although the Containment Pressure High ESF safety analysis trip setpoint is relaxed to 10.0 psig, it is still available to provide diverse protection for a range of breaks in the primary system.

7.2.5.1.15 Deleted

7.2.5.1.16 Steam/Feedwater Flow Mismatch Trip

This trip protects the reactor from a sudden loss of heat sink. The trip is actuated by (1/2) steam/feedwater flow mismatch, coincident with (1/2) low steam-generator water level, in the same loop. Plant Drawing 225103 [Formerly UFSAR Figure 7.2-10] shows the logic of this trip. The design satisfies the Control and Protection System Interaction Criteria of the proposed IEEE criteria for nuclear power plant protection system (IEEE-279 Code), dated August 28, 1968, for plants with three level channels per steam generator.

7.2.5.1.17 Low-Low Steam-Generator Water Level Trip

The purpose of this trip is to protect the steam generators in case of a sustained steam/feedwater flow mismatch. The trip is actuated on two-out-of-three low-low water level signals in any steam generator. A diagram of the steam-generator level control and protection system is shown in Plant Drawing 243328 [Formerly UFSAR Figure 7.2-32].

7.2.5.1.18 Turbine Trip/Reactor Trip

A turbine trip is sensed by two-out-of-three signals from auto-stop oil pressure. The analysis discussed in Section 14.1.8 indicates that an immediate reactor trip on turbine trip is not required for reactor protection; therefore, the design need not satisfy the proposed IEEE criteria for nuclear power plant protection system (IEEE-279 Code), dated August 28, 1968.

Plant Drawing 225096 [Formerly UFSAR Figure 7.2-3] is a logic diagram for the turbine and generator trips. A turbine trip signal redundantly dumps the auto-stop oil, which, in turn, closes all turbine stop valves. Conversely, a reactor trip on turbine trip is generated by redundantly sensing the loss of auto-stop oil.

7.2.5.1.19 Steam Line Isolation

Any of the following conditions will generate a steam line isolation signal; the design satisfies the proposed IEEE criteria for nuclear power plant protection system (IEEE-279 Code), dated August 28, 1968.

1. High steam flow (2/4) in coincidence with low T_{avg} (2/4) or low steam pressure (2/4).
2. High-high containment pressure (2/3, twice).
3. Manual action.

7.2.5.1.20 Turbine Runback

A turbine runback is employed following a rod drop event (bypass switches have been installed, which are normally in the DEFEAT position, so as to bypass the runback on this signal) or loss of one main feedwater pump. A turbine runback, which uses the mechanical hydraulic turbine governor control, is achieved by reducing the signal to each of two load limit valves as required to achieve the required load reduction. Turbine runback is not required for reactor protection; therefore, this design need not satisfy the proposed IEEE criteria for nuclear power plant protection system (IEEE-279 Code), dated August 28, 1968. Beginning with the Cycle 11 reload up to and including the current cycle, dropped rod analyses with and without Turbine Runback were used and the DNB design basis was satisfied as discussed in Section 14.1.4.

7.2.5.2 Rod Stops

A list of rod stops is provided in Table 7.2-3. Some of these have been previously noted under permissive circuits, but are listed again for completeness.

7.2.5.2.1 Rod Drop Protection

Two independent systems are provided to sense a dropped rod: (1) a rod bottom position detection system and (2) a system, which senses sudden reduction in ex-core neutron flux. Both protection systems initiate protective action in the form of a turbine load cutback if above a given power level (see below). This action compensates for possible adverse core power distributions and permits an orderly retrieval of the dropped rod cluster control (as discussed in Section 14.1.4).

The primary protection for the dropped rod cluster control accident is the rod bottom signal derived for each rod from its individual position indication system. With the position indication systems, initiation of protection is independent of rod location or reactivity worth (as discussed in Section 14.1.4).

Backup protection is provided by use of the out-of-core power range nuclear detectors and is particularly effective for larger nuclear flux reductions occurring in the region of the core adjacent to the detectors. Bypass switches have been installed, which are normally in the DEFEAT position, so as to bypass this runback signal. The use of these bypass switches is acceptable based on the results of analyses discussed in Section 14.1.4.

The rod drop detection circuit from nuclear flux consists basically of a comparison of each ion chamber signal with the same signal taken through a first-order lag network. Since a dropped rod cluster control assembly will rapidly depress the local neutron flux, the decrease in flux will be detected by one or more of these four sensors. Such a sudden decrease in ion chamber current will be seen as a different signal as discussed in Section 14.1.4. A signal greater than 5-percent reactor power reduction with an impulse unit time constant of 5 sec from any one of the four power range channels will actuate the rod drop protection circuitry if the turbine runback switches are not in the DEFEAT position.

Figure 7.4-2 indicates schematically the dropped rod detection circuit and the nuclear protection system in general. The potential consequences of any dropped rod cluster control assembly are discussed in Section 14.1.4.

7.2.5.2.2 Alarms

Any of the following conditions actuate an alarm:

1. Reactor trip (first-out annunciator).

2. Trip of any reactor trip analog channel.

3. Actuation of any permissive circuit or override. (Note: P-7, P-8, pressurizer low pressure trip block permissive, and auto rod control permissive (15-percent power) are provided with an indication light only on the flight panel.)

4. Significant deviation of any major control variable (pressure, T_{avg}, pressurizer water level, and steam-generator water level).

7.2.5.2.3 Control Group Rod Insertion Limits

The lower insertion limit system is used in an administrative control procedure with the objective to maintain a rod cluster control assembly shutdown margin.

The control group rod insertion limits, $Z_{LL,}$ are calculated as a linear function of reactor power and reactor coolant average temperature. The equation is

$$Z_{LL} = A(\Delta T)_{avg} + B(T_{avg}) + C$$

where A and B are preset manually adjustable gains and C is a preset manually adjustable bias. The $(\Delta T)_{avg}$ and (T_{avg}) are the average of the individual temperature differences and the coolant average temperatures, respectively, measured from the reactor coolant hot leg and the cold leg.

One insertion limit monitor with two alarm setpoints is provided for control bank D. A description of control and shutdown rod groups is provided in Section 7.3.2. The “APPROACHING ROD INSERTION LIMIT 12.5″” alarm alerts the operator of an approach to a reduced shutdown reactivity situation requiring boron addition by following normal procedures with the chemical and volume control system (Section 9.2). Actuation of “ROD INSERTION LIMIT 0″” alarm requires the operator to take immediate action to add boron to the system by any one of several alternative methods.

7.2.6 System Evaluation

7.2.6.1 Reactor Protection System and Departure From Nucleate Boiling

The following is a description of how the reactor protection system prevents departure from nucleate boiling (DNB).

The plant variables affecting the DNB ratio (DNBR) are as follows:

1. Thermal power.
2. Coolant flow.
3. Coolant temperature.
4. Coolant pressure.
5. Core power distribution (hot-channel factors).

Figures 7.2-33 Sh. 1 & 2 illustrates the core limits for which DNBR for the hottest rod is at the design limit and shows the overpower and overtemperature ΔT reactor trips locus as a function of T_{avg} and pressure.

Reactor trips for a fixed high pressurizer pressure and for a fixed low pressurizer pressure are provided to limit the pressure range over which core protection depends on the variable overpower and overtemperature ΔT trips.

Reactor trips on nuclear overpower and low reactor coolant flow are provided for direct, immediate protection against rapid changes in these variables. However, for all cases in which the calculated DNBR approaches the applicable DNBR limit, a reactor trip on overpower and/or overtemperature ΔT would be actuated.

The ΔT trip functions are based on the differences between measurements of the hot-leg and cold-leg temperatures, which are proportional to core power.

The ΔT trip functions are provided with a nuclear flux feedback to reflect a measure of axial power distribution. This will assist in preventing an adverse distribution that could lead to exceeding allowable core conditions.

7.2.6.1.1 Overpower Protection

In addition to the high power range nuclear flux trips, an overpower ΔT trip is provided (two-out-of-four logic) to limit the maximum overpower. This trip is of the following form:

$$\Delta T_{setpo\ \mathrm{int}} = \Delta T_0 \left[K_4 - K_5 \left(\frac{\tau_3 \mathrm{s}}{1+\tau_3 \mathrm{s}} \right) T \ - K_6 \left(T - T'' \right) - \ f_2 \left(\Delta I \right) \right]$$

where

ΔT_0 = loop specific indicated ΔT at rated power (°F)

K_4 = setpoint bias

K_5 = constant

τ_3 = time constants, sec

S = laplace transform operator, sec $^{-1}$

T = measured reactor coolant average temperature (°F), two measurements (T_C, T_h) in each loop

K_6 = constant

T”= loop specific indicated average temperature at rated power (°F)

$F_2(\Delta I)$ = function of the indicated difference between top and bottom detectors of the power range nuclear ion chambers with gains to be selected on the basis of measured instrument response during plant startup tests

In addition, a rod stop function is provided in the form:

$$\Delta T_{\mathrm{rod\ stop}} = \Delta T_{\mathrm{trip}} - B_p$$

where B_P is the setpoint bias (°F).

7.2.6.1.2 Overtemperature Protection

A second ΔT trip (two-out-of-four logic) provides an overtemperature trip that is a function of coolant average temperature and pressurizer pressure derived as follows:

$$\Delta T_{setpo\ \mathrm{int}} = \Delta T_0 \left[K_1 - K_2 \left(\frac{1+\tau_1 s}{1+\tau_2 s} \right) \left(T - T' \right) + K_3 \left(P - P' \right) - \ f_1 \left(\Delta I \right) \right]$$

where

ΔT_0 = loop specific indicated ΔT at rated power (°F)

K_1 = setpoint bias

K_2, K_3 = constants based on the effect of temperature and pressure on the DNB limits

τ_3 = time constants, sec

S = laplace transform operator, sec $^{-1}$

T = measured reactor coolant average temperature (°F), two measurements in each loop (T_c, T_h)

T' = loop specific indicated average temperature at rated power (°F)

P = measured pressurizer pressure, four independent measurements (psig)

P' = nominal pressure at rated power, 2235 psig

$F_1(\Delta I)$ = function of the indicated difference between top and bottom detectors of the power range nuclear ion chambers with gains to be selected on the basis of measured instrument response during plant startup tests

Four long ion chamber pairs are provided, and each one independently feeds a separate overtemperature ΔT trip channel. Thus, a single failure neither defeats the function nor causes a spurious trip. The reset function is only in the direction of decreasing the trip setpoint; it cannot increase the setpoint.

As shown above, if the difference between the top and bottom detectors exceeds a preset limit indicative of excess power generation in either half of the core, a proportional signal is transmitted to the overtemperature ΔT trip to reduce its setpoint.

A similar rod stop function is provided in the form:

$$\Delta T_{stop} = \Delta T_{trip} - B_T$$

where B_T is the setpoint bias (°F).

Automatic feedback signals are provided to reduce the overpower-overtemperature trip setpoints and block rod withdrawal to the trip setpoint.

7.2.6.2 Interaction of Control and Protection

The design basis for the control and protection system permits the use of a detector for both protection and control functions. Where this is done, all equipment common to both the protection and control circuits are classified as part of the protection system. Isolation amplifiers prevent a control system failure from affecting the protection system. In addition, where failure of a protection system component can cause a process excursion that requires protective action, the protection system can withstand another independent failure without loss of function. Generally, this is accomplished with two-out-of-four trip logic. Also, wherever practical, provisions are included in the protection system to prevent a plant outage because of single failure of a sensor.

7.2.6.2.1 Specific Control and Protection Interactions

7.2.6.2.1.1 Nuclear Flux

Four power range nuclear flux channels are provided for overpower protection. Isolated outputs from all four channels are averaged for automatic control rod regulation of power. If any channel fails in such a way as to produce a lower output, that channel is incapable of proper overpower protection. Two-out-of-four overpower trip logic will ensure an overpower trip if needed, even with an independent failure in another channel.

In addition, the control system will respond only to rapid changes in indicated nuclear flux; slow changes or drifts are overridden by the temperature control signals. The setpoint for this rod stop is below the reactor trip setpoint.

7.2.6.2.1.2 Coolant Temperature

Four T_{avg} channels are used for overtemperature-overpower protection. (See Plant Drawing 243330 [Formerly UFSAR Figure 7.2-34] for single channel.) Isolated output signals from all four channels are also averaged for automatic control rod regulation of power and temperature.

In addition, channel deviation alarms in the control system will block automatic rod insertion if any temperature channel deviates significantly from the others. Two-out-of-four trip logic is used to ensure that an overtemperature trip will occur if needed even with an independent failure in another channel. Finally, as shown in Section 14.1, the combination of trips on nuclear overpower, high pressurizer water level, and high pressurizer pressure also serve to limit an excursion for any rate of reactivity insertion.

Additional reactor coolant temperature measurements are provided for the alternate safe shutdown system by four strap-on resistance temperature detectors installed on loops 21 and 22 with display in the fan house. These provide measurements of the hot- and cold-leg temperatures of their respective loops.

7.2.6.2.1.3 Pressurizer Pressure

Four pressure channels are used for high- and low-pressure protection and for overpower protection. Isolated output signals from these channels also are used for pressure control and compensation signals for rod control. These are discussed separately below.

1. Control of rod motion: The discussion for coolant temperature is applicable (i.e., two-out-of-four logic for overpower protection as the primary protection), with backup from multiple rod stops and “backup” trip circuits. In addition, the pressure compensation signal is limited in the control system such that failure of the pressure signal cannot cause more than about a 10°F change in T_{avg}. This change can be accommodated at full power without a DNBR being reduced below the applicable safety analysis DNBR limit. Finally, the pressurizer safety valves are adequately sized to prevent system overpressure.

2. Pressure control: Spray, power-operated relief valves, and heaters are controlled by isolated output signals from the pressure protection channels.

a. Low Pressure

A spurious high-pressure signal from one channel can cause low pressure by spurious actuation of a pressurizer spray valve. Additional redundancy is provided in the protection system to ensure underpressure protection, i.e., two-out-of-four low pressure reactor trip logic and two-out-of-three logic for safety injection.

In addition, interlocks are provided in the pressure control system such that a relief valve will close if either of two independent pressure channels indicates low pressure. Spray reduces pressure at a lower rate, and some time is available for operator action (about 3 min. at maximum spray rate) before a low pressure trip is reached.

b. High Pressure

The pressurizer heaters are incapable of overpressurizing the reactor coolant system. Maximum steam generation rate with heaters is about 15,000 lb/hr, compared with a total capacity of 1,224,000 lb/hr for the three safety valves and a total capacity of 358,000 lb/hr for the two power-operated relief valves. Therefore, overpressure protection is not required for a pressure control failure. Two-out-of-three high-pressure trip logic is therefore used.

In addition, either of the two relief valves can easily maintain pressure below the high-pressure trip point. The two relief valves are controlled by independent pressure channels, one of which is independent of the pressure channel used for heater control. Finally, the rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available for operator action.

7.2.6.2.1.4 Pressurizer Level

Three pressurizer level channels are used for high-level reactor trip (2/3). Isolated output signals from these channels are used for volume control, increasing or decreasing water level. A level control failure could fill or empty the pressurizer at a slow rate (on the order of half an hour or more).

1. High Level

A reactor trip on pressurizer high level is provided to prevent rapid thermal expansions of reactor coolant fluid from filling the pressurizer: the rapid change from high rates of steam relief to water relief can be damaging to the safety valves and the relief piping and pressure relief tank. However, a level control failure cannot actuate the safety valves because the high-pressure reactor trip is set below the safety valve set pressures. Therefore, a control failure does not require protection system action. In addition, ample time and alarms are available for operator action.

2. Low Level

For control failures that tend to empty the pressurizer, a signal of low level from either of two independent level control channels will isolate letdown, thus preventing the loss of coolant. Also, ample time and alarms exist for operator action.

7.2.6.2.1.5 Steam-Generator Water Level/Feedwater Flow

Before describing control and protection interaction for these channels, it is beneficial to review the protection system basis for this instrumentation.

The basic function of the reactor protection circuits associated with low steam generator water level and low feedwater flow is to preserve the steam generator heat sink for removal of long-term residual heat. Should a complete loss of feedwater occur with no protective action, the steam generators would boil dry and cause an overtemperature-overpressure excursion in the reactor coolant. Reactor trips on temperature, pressure, and pressurizer water level will trip the plant before there is any damage to the core or reactor coolant system. However, residual heat after trip would cause thermal expansion and discharge of the reactor coolant to containment through the pressurizer relief valves. Redundant auxiliary feedwater pumps are provided to prevent this. Reactor trips act before the steam generators are dry to reduce the required capacity and starting time requirements of these pumps and to minimize the thermal transient on the reactor coolant system and steam generators. Independent trip circuits are provided for each steam generator for the following reasons:

1. Should severe mechanical damage occur to the feedwater line to one steam generator, it is difficult to ensure the functional integrity of level and flow instrumentation for that unit. For instance, a major pipe break between the feedwater flow element and the steam generator would cause high flow through the flow element. The rapid depressurization of the steam generator would drastically affect the relation between downcomer water level and steam-generator water inventory.

2. It is desirable to minimize thermal transient on a steam generator for credible loss of feedwater accidents.

   It should be noted that controller malfunctions caused by a protection system failure affect only one steam generator. Also, they do not impair the capability of the main feedwater system under either manual control or automatic T_{avg} control. Hence, these failures are far from being the worst case with respect to decay heat removal with the steam generators.

   a. Feedwater Flow

      A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow and prevent that channel from tripping. A reactor trip on low-low water level, independent of indicated feedwater flow, will ensure a reactor trip if needed.

In addition, the three-element feedwater controller incorporates reset on level, such that with expected gains, a rapid increase in the flow signal would cause only a 12-in. decrease in level before the controller reopens the feedwater valve. A slow increase in the feedwater signal would have no effect at all.

b. Steam Flow

A spurious low steam flow signal would have the same effect as a high feedwater signal, discussed above.

c. Level

A spurious high water level signal from the protection channel used for control will tend to close the feedwater valve. This level channel is independent of the level and flow channels used for reactor trip on low flow coincident with low level.

(1) A rapid increase in the level signal will completely stop feedwater flow and actuate a reactor trip on low feed-water flow coincident with low level.

(2) A slow drift in the level signal may not actuate a low feedwater signal. Since the level decrease is slow, the operator has time to respond to low-level alarms. Since only one steam generator is affected, automatic protection is not mandatory and reactor trip on two-out-of three low-low level is acceptable.

REFERENCES FOR SECTION 7.2

1. Letter from J. D. O'Toole, Con Edison, to D. G. Eisenhut, NRC, Subject: Control Room Habitability Studies, Enclosure 2, dated May 12, 1981.

2. E. L. Vogeding, Seismic Testing of Electrical and Control Equipment, WCAP-7397-L (Proprietary), Westinghouse Electric Corporation, January 1970.

3. J. Lipchak and R. Bartholomew, Test Report of Isolation Amplifier, WCAP-9011 (Proprietary), Westinghouse Electric Corporation.

4. Letter from J. D. O'Toole, Con Edison, to S. A. Varga, NRC, Subject: Seismic Qualification of Reactor Trip Breaker Shunt Trip Attachment, dated February 14, 1986.

5. Letter from M. Selman, Con Edison, to S. A. Varga, NRC, Subject: Seismic Qualification of DC Power Panels No. 21 and 22, Indian Point Unit 2, dated August 14, 1986.

6. Letter (with attachments) from S. A. Varga, NRC, to J. D. O'Toole, Con Edison, Subject: NUREG-0737, Item No. III.D.3.4 Control Room Habitability for Indian Point Unit No. 2, Dated January 27, 1982

7. Letter from A. Schwencer, NRC, to W.J. Cahill, Subject: Safety Evaluation Report – Indian Point Station Unit 2 - Evaluation of Safety Injection System Actuation Technical Specification Change Request –Amendment No. 56 dated July 10, 1979

8. Letter from J. Durr, NRC, to S. Bram, Subject: Inspection Report No. 50-247/89-12 (including Attachment 1 – Safety Evaluation Relating to Design Criteria for Electrical Cable Separation)

9. Calculation #PGI-00408-00 Rev. 0, Identification Of Plant Areas Which Can Be Subjected To Harsh Environmental Conditions As A Result Of LOCA or HELB And The Environmental Parameters For The Area, Indian Point 2, dated December 1999.

10. Electrical Equipment Environmental Qualification Program Rev. 13, dated April 1999.

11. IP2-EQ Master List.

TABLE 7.2-1 (Sheet 1 of 5)
List of Reactor Trips and Causes for Reactor Trips

	Reactor trip	Coincidence Circuitry and Interlocks	Comments
1.	Manual	1/2, no interlocks	
2.	Overpower nuclear flux	2/4	High and low settings; manual block and automatic reset of low setting by P-10 Permissive 10, Table 7.2-2
3.	Overtemperature ΔT	2/4, no interlocks	
4.	Overpower ΔT	2/4, no interlocks	
5.	Low pressurizer pressure	2/4, blocked by P-7	
6.	High pressurizer pressure (fixed setpoint)	2/3, no interlocks	
7.	High pressurizer water level	2/3, blocked by P-7	
8a.	Low reactor coolant flow	2/3 per loop, 2/4 loops, blocked by P-7 2/3 per loop, 1/4 loops, blocked by P-8	
8b.	Reactor coolant pump breaker open	1/1 per loop, 2/4 loops, blocked by P-7 1/1 per loop, 1/4 loops, blocked by P-8	Underfrequency on 2/4 reactor coolant pump buses trips all reactor coolant pump breakers.
8c.	Undervoltage on reactor coolant pump bus	2/4, blocked by P-7	

TABLE 7.2-1 (Sheet 2 of 5)
List of Reactor Trips and Causes for Reactor Trips

	Reactor trip (continued)	Coincidence Circuitry and Interlocks	Comments
9.	Safety injection signal (actuation)	2/3 low pressurizer pressure, provided safety injection is not manually blocked (i.e., manual block permitted for 2/3 low pressurizer pressure if reactor coolant system pressure is below 1940 psig); or 2/3 high containment pressure (Hi pressure); or 2/3 high differential pressure between any two steam generators; or two sets of 2/3 high-high containment pressure (Hi-Hi pressure); or 1/2 manual; or 2/4 high steam flow coincident with 2/4 low T_{avg} or 2/4 low steam line pressure.	
10.	Turbine generator (Low auto stop oil pressure signal)	2/3, blocked by P-7 or P-8	Trip not activated until both P-7 and P-8 have been unblocked.
11.	Steam/feedwater flow mismatch	1/2 steam/feedwater flow mismatch, coincident with 1/2 low steam generator water level, in the same loop.	
12.	Low-low steam generator water level	2/3, per loop	
13.	High intermediate range nuclear flux	1/2, manual block permitted by P-10	Manual block and automatic reset
14.	High source range nuclear flux	1/2, manual block permitted by P-6, also blocked by P-10	Manual block Manual reset

TABLE 7.2-1 (Sheet 3 of 5)
List of Reactor Trips and Causes for Reactor Trips

Containment isolation actuation	Coincidence Circuitry and Interlocks	Comments
15. Safety injection signal (phase A)	See item 9	Actuates all nonessential service containment isolation trip valves and actuates isolation valve seal water system.
16. Containment pressure (phase B)	Coincidence of two 2/3 containment pressure (high-high pressure, same signal which actuates containment spray), or manual 1/2	Actuates all essential service containment isolation trip valves.
17. Containment or plant ventilation activity	High-High activity signal, from the containment air particulate or the plant ventilation radiogas detector (1/3)	The containment air particulate and radiogas monitors also directly actuate the containment purge supply and exhaust valves and the containment pressure relief valves on high-high activity.
Engineered safety features actuation		
18. Safety injection signal (S) (phase A)	See Item 9	
19. Containment spray signal (P) (phase B)	Coincidence of two sets of 2/3 containment pressure (high-high pressure); or manual 1/2	Manual (1/2 spray push buttons) initiation will position valves and start the spray pumps anytime before or after automatically safety injection initiated pump sequencing is in progress. Safety injection reset will block automatic spray initiation.

TABLE 7.2-1 (Sheet 4 of 5)
List of Reactor Trips and Causes for Reactor Trips

	Engineered safety features actuation (continued)	Coincidence Circuitry and Interlocks	Comments
20.	Deleted		
21.	Containment air recirculation cooling signal	Safety injection signal initiates starting of all fans in accordance with the safety injection starting sequence, 2/3 high containment pressure or manual 1/2	
22.	Isolation valve seal water signal	Containment isolation (phase A) signal	
Steam line isolation actuation			
23.	Steam flow	High steam flow in 2/4 lines plus (a) low T_{avg} in 2/4 lines or (b) low steam line pressure in 2/4 lines.	
24.	Containment pressure	Coincidence of two sets of 2/3 containment pressure (high-high pressure) (NOTE: bistables are energized-to-operate)	
25.	Manual	1/1 per steam line	

TABLE 7.2-1 (Sheet 5 of 5)
List of Reactor Trips and Causes for Reactor Trips

Auxiliary feedwater actuation	Coincidence Circuitry and Interlocks	Comments
26. Turbine driven pump	Low-low level in any two steam generators; or Blackout (i.e., 1/2 480-V busses 5A and 6A undervoltage), coincident with a unit trip without safety injection; or 1/2 AMSAC; or 1/2 manual.	
27. Motor driven pumps	2/3 low-low level in any steam generator; Blackout (i.e., 1/2 480-V busses 5A and 6A undervoltage) and a unit trip; or trip of 1/2 main feedwater pump turbines; or 1/2 AMSAC; all without safety injection; or safety injection (i.e., with either offsite or onsite power available), coincident with a sequenced pump start; or 1/2 manual.	
Main feedwater isolation		
28. Close main feedwater control valves trip main feedwater pumps	Any safety injection signal (see item 9)	
Control rod protection		
29. Reactor trip breakers	2/3	During RCS cooldown prior to T_{cold} decreasing below 381°F

TABLE 7.2-2
Interlock and Permissive Circuits

Number	Function	Input for Blocking
1	Prevent rod withdrawal on overpower	1/4 high nuclear flux (power range) or 1/2 high nuclear flux (intermediate range) or 1/4 overtemperature ΔT or 1/4 overpower ΔT
2	Deleted	
3	Deleted	
5	Steam dump interlock	Rapid decrease of MWe load signal
6	Manual block of source range level trip	1/2 high intermediate range flux allows manual block, 2/2 low intermediate range defeats block
7	Permissive power (block various trips required only at power)	3/4 low nuclear flux signals (power range) and 2/2 low turbine inlet pressure signals
8	Block single primary loop loss of flow trip	3/4 low nuclear flux (power range)
10	Manual block of low trip (power range) and intermediate range trips	2/4 high nuclear flux allows manual block, 3/4 low nuclear flux (power range) defeats manual block

TABLE 7.2-3
Rod Stops

	Rod Stop	Actuation Signal	Rod Motion to be Blocked
1	Deleted		
2	Nuclear overpower	1/4 high power range nuclear flux or 1/2 high intermediate range nuclear flux	Manual withdrawal
3	High ΔT	1/4 overpower ΔT or 1/4 overtemperature ΔT	Manual withdrawal
4	Deleted		
5	T_{avg} deviation	1/4 T_{avg} deviation from average T_{avg}	Automatic insertion

7.2 FIGURES

Figure 7.2-26	Typical Simplified Control Schematic, Replaced With Plant Drawing 243323
Figure 7.2-27	Analog Channels, Replaced With Plant Drawing 243324
Figure 7.2-28	Analog System Symbols, Replaced With Plant Drawing 243311
Figure 7.2-29	Deleted
Figure 7.2-30	Reactor Trip Breaker Actuation Schematic
Figure 7.2-31	Deleted
Figure 7.2-32	Steam Generator Level Control And Protection System, Replaced With Plant Drawing 243328
Figure 7.2-33 Sh. 1	Illustrations Of Overpower And Temperature ΔT Trips High Temperature Operation
Figure 7.2-33 Sh. 2	Illustrations Of Overpower And Temperature ΔT Trips Low Temperature Operation
Figure 7.2-34	$T_{avg}/\Delta T$ Control And Protection System, Replaced With Plant Drawing 243330

7.3 REGULATING SYSTEMS

7.3.1 <u>Design Basis</u>

The reactor control system is designed to limit nuclear plant transients for prescribed design load perturbations, under automatic control, [*Note - The automatic control rod withdrawal feature in plant operation has been physically disabled, allowing only the automatic control rod insertion mode to be in effect when rod control is automatic.*] within prescribed limits to preclude the possibility of a reactor trip in the course of these transients.

Overall reactivity control is achieved by the combination of chemical shim and 53 control rod clusters of which 29 are in control bank and 24 are in shutdown bank. Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short term reactivity control for power changes or reactor trip is accomplished by the movement of control rod clusters.

The primary function of the reactor control system is to provide automatic control of the rod clusters during power operation of the reactor. The system uses input signals including neutron flux, coolant temperature and pressure, and plant turbine load. The chemical and volume control system (Section 9.2) serves as a secondary reactor control system by the addition and removal of varying amounts of boric acid solution.

There is no provision for a direct continuous visual display of primary coolant boron concentration. When the reactor is critical, the best indication of reactivity status in the core is the position of the control group in relation to plant power and average coolant temperature. There is a direct, predictable, and reproducible relationship between control rod position and power, and it is this relationship that establishes the lower insertion limit calculated by the rod insertion limit monitor. There are two alarm setpoints to alert the operator to take corrective action in the event a control bank approaches or reaches its lower limit.

Any unexpected change in the position of the control group when under automatic control or a change in coolant temperature when under manual control provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, periodic samples of coolant boron concentration are taken. The variation in concentration during core life provides a further check on the reactivity status of the reactor including core depletion.

The reactor control system is designed to enable the reactor to follow load reductions automatically when the plant output is above 15-percent of nominal power. Control rod insertion may be performed automatically when plant output is above this value. Control rod insertion and withdrawal may be performed manually at any time.

The system as originally designed enabled the plant to accept a generation step load increase of 10-percent and a ramp increase of 5-percent per minute within the load range of 15 to 100-percent without reactor trip subject to possible xenon limitations. The elimination of the automatic rod withdrawal function could require the use of manual rod control to have the reactor respond to the turbine load change and to restore the coolant average temperature to the programmed value during these load increase transients. Similar step and ramp load reductions are possible within the range of 100 to 15-percent of nominal power with automatic control rod insertion operational.

The operator is able to select any single bank of rods (shutdown or control) for manual operation. Using a single switch, he may not select more than one bank from these two groups. During reactor startup with the rod control bank selector switch in manual, the control banks can be moved only in their normal sequence with some overlap as one bank reaches its full withdrawal position and the next bank begins to withdraw. Power supplied to the rod banks is controlled so that no more than two banks can be withdrawn simultaneously.

The control system is capable of restoring coolant average temperature to within the programmed temperature deadband following a load reduction.

The reactor can be placed under automatic control in the power range between 15-percent of load and full load for the following design transients:

1. 10-percent step reduction in load without turbine bypass.

2. 5-percent per minute unloading.

3. 25-to-50-percent change in load at 200%/minute maximum turbine unloading rate from approximately 100-percent load with steam dump (load change capability depends on full power T_{avg}; see Section 7.3.3.1).

A programmed pressurizer water level as a function of load is provided in conjunction with the programmed coolant average temperature to minimize the requirements of the chemical and volume control system and waste disposal system resulting from coolant density changes during loading and unloading from full power to zero power.

Following a reactor and turbine trip, sensible heat stored in the reactor coolant is removed without the actuation of steam-generator safety valves by means of controlled steam bypass to the condenser and by the injection of feedwater to the steam generators. Reactor coolant system temperature is reduced to the no-load condition. This no-load coolant temperature is maintained by steam bypass to the condensers to remove residual heat.

The control system was originally designed to operate as a stable system over the full range of automatic control throughout core life without requiring operator adjustment of setpoints other than normal calibration procedures.

7.3.2 System Design

A block diagram of the reactor control system is shown in Figure 7.3-1.

7.3.2.1 Rod Control

There were originally 61 total rod cluster control assemblies of which 53 are full-length and 8 were part-length rods. The part-length rods have been since removed. The full-length rods are divided into (1) a shutdown group comprised of two shutdown banks of eight rod clusters each and two shutdown banks of four rod clusters each, and (2) a control group comprised of four control banks containing eight, four, eight, and nine rod clusters.

Figure 3.2-2 shows the locations of the full-length rods in the core. The four banks of the control group are the only rods that can be manipulated under automatic control. The banks are divided into subgroups to obtain smaller incremental reactivity changes. All rod cluster control assemblies in a subgroup are electrically paralleled to step simultaneously. Position indication for each rod cluster control assembly type is the same. There are two types of drive mechanism for the rod cluster control assemblies, those for the control and shutdown groups and those for the part-length rod group since removed.

7.3.2.1.1 Control Group Rod Control

The automatic rod control system maintains a group programmed reactor coolant average temperature with adjustments inward of control group rod position for equilibrium plant conditions. The system is capable of restoring programmed average temperature following a scheduled or transient reduction in load. The coolant average temperature increases linearly from zero power to the full-power conditions. Wherein, the plant is being operated on a T_{avg} program of 547°F to 562°F.

Compensation for fuel depletion and/or xenon transients is periodically made with adjustments of boron concentration. The control system has the ability to readjust the control group rod in the inward direction in response to changes in coolant average temperature resulting from changes in boron concentration.

The average coolant temperature is determined by using the hot-leg and the cold-leg temperature measurements in each reactor coolant loop. The average of the four loop average temperatures is the main control signal. This signal is sent to the control group rod programmer through a proportional plus rate compensation unit. The control group rod programmer commands the direction and speed of control group rod motion. A compensated pressurizer pressure signal and a power-load mismatch signal are also employed as control signals to improve the plant performance. The power-load mismatch channel takes the difference between nuclear power (average of all four power range channels) and a signal of turbine load (turbine inlet pressure), and passes it through a high-pass filter so that only a rapid change in flux or power causes rod motion. The power-load mismatch compensation serves to speed up system response and to reduce transient peaks.

The rod control group is divided into four banks comprised of eight, four, eight, and nine rod cluster controls, respectively, to follow load changes over the full range of power operation. Each rod control bank is driven by a sequencing, variable speed rod drive control unit. The rods in each control bank are divided into two subgroups, and the subgroups are moved sequentially one step at a time. The sequence of motion is reversible; that is, a withdrawal sequence is the reverse of the insertion sequence. Any reactor trip signal causes the rods to insert by gravity into the core.

Manual control is provided to move a control bank in or out at a preselected fixed speed.

Proper sequencing of the rod cluster control assembly is ensured first, by fixed programming equipment in the rod control system, and second, through administrative control of the reactor plant operator. Startup of the plant is accomplished by first manually withdrawing the shutdown rods to the full-out position. This action requires that the operator select the SHUTDOWN BANK position on a control board mounted selector switch and then position the IN-HOLD-OUT level (which is spring return to the HOLD position) to the OUT position.

Rod cluster control assemblies are then withdrawn under manual control of the operator by first selecting the MANUAL position on the control board mounted selector switch and then positioning the IN-HOLD-OUT lever to the OUT position. A hinged mechanical interlock is also installed on top of the In-Out-Hold rod control lever that requires operator action to lift the interlock away from the rod control lever prior to rod withdrawal. The hinged mechanical interlock does not inhibit rod insertion. In the MANUAL selector switch position, the rods are withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment.

The predetermined programmed sequence is set so that as the first bank out (control bank C-2) reaches a preset position near the top of the core, the second bank out (control bank C-3) begins to move out simultaneously with the first bank. When control bank C-2 reaches the top of the core, it stops, and control bank C-3 continues until it reaches a preset position near the top of the core where control bank C-4 motion begins. This withdrawal sequence continues until the plant reaches the desired power level. The programmed insertion sequence is the opposite of the withdrawal sequence, i.e., the last control bank out is the first control bank in.

A permissive interlock limits automatic control to reactor power levels above 15-percent. In the AUTOMATIC position, the rods can only be inserted in a predetermined programmed sequence by the automatic programming equipment.

With the simplicity of the rod sequence program, the minimal amount of operator selection, and two separate position indications available to the operator, there is very little possibility that rearrangement of the control rod sequencing could be made.

7.3.2.1.2 Shutdown Rod Group Control

The shutdown group of control rods together with the control group are capable of shutting the reactor down. They are used in conjunction with the adjustment of chemical shim and the control group to provide shutdown margin of at least 1-percent following reactor trip with the most reactive control rod in the fully withdrawn position for all normal operating conditions.

The shutdown banks are manually controlled during normal operation and are moved at a constant speed with staggered stepping of the subgroups within the banks. Any reactor trip signal causes them to insert by gravity into the core. They are fully withdrawn during power operation and are withdrawn first during startup. Criticality is always approached with the control group after withdrawal of the shutdown banks. Four shutdown banks with a total of 24 clusters are provided.

7.3.2.1.3 Part-Length Rod Control

Eight part-length rods were provided in the reactor in the original operating configuration in addition to the normal control rods. The function of these rods, which had neutron absorber material in only the bottom one quarter of the length (3-ft), was intended to shape the axial power distribution and thus stabilize axial xenon oscillations. In addition, they would flatten the axial power distribution and thus reduce hot-channel factors. The part-length rods were intended for operation only by manual control by the operator from the control console. They were moved together as a bank to make the upper and lower ion chamber readings approach a prescribed relationship within a prescribed allowable region of travel. However, subsequent to the initial plant operation, the part-length control rods were physically removed from the reactor. Their associated rod position indication system has been removed from the central control room.

7.3.2.1.4 Interlocks

The rod control group is interlocked with measurements of turbine-generator load and reactor power to prevent automatic control below 15-percent of nominal power. The manual controls are further interlocked with measurements of nuclear flux, ΔT, and rod drop indication to prevent approach to an overpower condition.

7.3.2.1.5 Rod Drive Performance

The control banks are driven by a sequencing, variable speed rod drive programmer. In the control bank of rod cluster control assemblies, control subgroups (each containing a small number of rod cluster control assemblies) are moved sequentially in a cycle such that all subgroups are maintained within one step of each other. The sequence of motion is reversible, that is, withdrawal sequence is the reverse of the insertion sequence. The sequencing speed is proportional to the control signal from the reactor coolant system. This provides control group speed control proportional to the demand signal from the control system.

A solid-state control system provides power to the rod drive mechanism coils from the output of two paralleled motor-generator sets. Two reactor trip breakers are placed in series with the output of the motor-generator sets. To permit online testing, a bypass breaker is provided across each of the two breakers.

7.3.2.1.6 Rod Cluster Control Assembly Position Indication

Two separate systems are provided to sense and display control rod position as described below:

1. <u>Analog System</u> - An analog signal is produced for each individual rod by a linear position transmitter.

   An electrical coil stack is located above the stepping mechanisms of the control rod magnetic jacks, external to the pressure housing, but concentric with the rod travel. When the associated control rod is at the bottom of the core, the magnetic coupling between the primary and secondary coil winding of the detector is small and there is a small voltage induced in the secondary. As the control rod is raised by the magnetic jacks, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is obtained.

Direct, continuous readout of every control rod is presented to the operator on individual indicators.

A deviation monitor alarm is actuated if an individual rod position deviates from its group position by a preselected distance.

Lights are provided for rod bottom positions for each rod. The lights are operated by bistable devices in the analog system.

2. Digital System - The digital system counts pulses generated in the rod drive control system. One counter is associated with each subgroup of control and shutdown rods. Readout of the digital system is in the form of electromechanical add-subtract counters reading the number of steps or rod withdrawal with one display for each subgroup. These readouts are mounted on the control panel.

The digital and analog systems are separate systems; each serves as backup for the other. Operating procedures require the reactor operator to compare the digital and analog readings upon recognition of any apparent malfunction. Therefore, a single failure in rod position indication does not in itself lead the operator to take erroneous action in the operation of the reactor.

7.3.2.1.7 Part-Length Rod Position Indication

Deleted

7.3.2.2 Full-Length Rod Drive Power Supply

The full-length control rod drive power supply concept using a single scram bus system has been successfully employed on all Westinghouse PWR plants. Potential fault conditions with a single scram bus system are discussed in this section. The unique characteristics of the latch-type mechanism with its relatively large power requirements make this system with the redundant series trip breakers particularly desirable.

The solid-state rod control system is operated from two parallel connected 438-kVA generators that provide 260-V line-to-line, three-phase, four-wire power to the rod control circuits through two series connected reactor trip breakers. This AC power is distributed from the trip breakers to a line-up of identical solid-state power cabinets using a single overhead run of enclosed bus duct that is bolted to and therefore composes part of the power cabinet arrangement. Alternating current from the motor-generator sets is converted to a profiled direct current by the power cabinet and is then distributed to the mechanism coils. Each complete rod control system includes a single 70-V DC power supply that is used for holding the mechanisms in position during maintenance of normal power supply.

This 70-V supply, which receives its input from the AC power source down-stream of the reactor trip breakers, is distributed to each power cabinet and permits holding mechanisms in groups of four by manually positioning switches located in the power cabinets. The 50-A output capacity limits the holding capability to six rods cold or eleven rods hot.

7.3.2.2.1 Reactor Trip

Current to the mechanisms is interrupted by opening either of the reactor trip breakers. The 70-V DC maintenance supply will also be interrupted as this supply receives its input power through the reactor trip breakers.

7.3.2.2.2 Trip Breaker Arrangement

The trip breakers are arranged in the reactor trip switchgear in individual metal-enclosed compartments. The 1000-A bus work, making up the connections between scram breakers, is separated by metal barriers to prevent the possibility that any conducting object could short circuit, or bypass, scram breaker contacts.

7.3.2.2.3 Maintenance Holding Supply

The 70-V DC holding supply and associated switches have been provided to avoid the need for bringing a separate DC power source to the rod control system during maintenance on the power cabinet circuits. This source is adequate for holding a maximum of six mechanisms cold or eleven mechanisms hot and will satisfy all maintenance holding requirements.

7.3.2.2.4 Control System Construction

The rod control system is assembled in enclosed steel cabinets. Three-phase power is distributed to the equipment through a steel-enclosed bus duct bolted to the cabinets. Direct current power connections to the individual mechanisms are routed to the reactor head area from the solid-state cabinets through insulated cables, enclosed junction boxes, enclosed reactor containment penetrations, and sealed connectors. In view of this type of construction, any accidental connection of either an AC or DC power source, either internal or external to the cabinets, is not considered credible.

7.3.2.2.5 Alternating Current Power Connections

The three-phase four-wire supply voltage required to energize the equipment is 260-V line-to-line, 58.3-Hz, 438-kVA capacity, zig-zag connected. It is unlikely that any power supply, and in particular one as unusual as this four-wire power source, could be accidentally connected, in phase, in the required configuration. Also, it should be noted that this requires multiple connections, not single connections. The closest outside sources available in the plant are 480-V auxiliary power sources and 208-V lighting sources.

Connection of either a 480 or 208 volt, 60-Hz source to the single AC bus supplying the Rod Control System will cause currents to flow between the sources due to an out-of-phase condition. These currents will flow until the generator accelerates to a speed synchronous with the 60-Hz out-of-phase source, a time sufficient to trip the generator breakers. The out-of-phase currents for an unlimited capacity outside source, an outside source with a capacity equivalent to the normal generator kVA, and for either one or two M-G Sets in service, are tabulated below:

Out-of-Phase Currents (Amperes)

	One M-G Set In Service	Two M-G Sets In Service
Unlimited Capacity 480-V	25,000	50,000
400–kVA Capacity	12,500	25,000
Unlimited Capacity 208-V	16,000	32,000
400-kVA Capacity	8,000	16,000

All of the foregoing currents are sufficiently high to trip out the generator breakers on either overcurrent or reverse current. This trip-out is detectable by annunciation in the control room. If the outside power source trips, the connection is of no concern.

Each solid-state power cabinet is tied to the main AC bus through three fused disconnect switches: one for the stationary gripper coil circuits, one for the movable gripper coil circuits, and one for the lift coil circuits. Reference voltages to operate the control circuits for all three coil circuits must be in phase with the supply to all coil circuits for proper operation of the system. If the outside power source were brought in to an individual cabinet, nine normal source connections would have to be disconnected and the outside source would have to be tied in phase to the proper nine points plus one neutral point to allow the movement of the rods. This is not considered credible.

The connection of a single-phase AC source (i.e., one line to neutral) is also considered improbable. This would again require a high-capacity source that would have to be connected in phase with the nonsynchronous motor-generator set supply. Again, more than one connection is needed to achieve this condition. Each power cabinet contains three alarm circuits (stationary, movable, and lift) that would annunciate the condition to the operator. In addition, calculations show that a single phase source of 208-V, 260-V, or 480-V will not supply enough current to hold the rods. Therefore, a jumper across two trip circuit breaker contacts in series, which results in a single phase remaining closed would not provide sufficient current to hold up the rods.

The normal source generators are connected in a zig-zag winding configuration to eliminate the effects of direct current saturation of the machines resulting from the direct currents that flow in the half-wave bridge rectifier circuits. If this connection were not used, the generator core would saturate and loss of generating action would occur. This condition would also occur in a transformer. An outside source not having the zig-zag configuration would have to have a large capacity (>400 kVA) to avoid the loss of transformer action from saturation.

Most of the components in the equipment are applied with a 100-percent safety factor. Therefore, the possibility exists that the system will operate at 480-V with a source of sufficient capacity. The system will definitely operate at 208-V with a source of sufficient capacity.

The connection of an outside source of AC power to one rod control system would first require a need for this source. No such need exists since two power sources (motor-generator sets) are already provided to supply the system. If the source were connected in spite of the need, extreme measures would have to be taken by the intruder to complete the connection. The outside source would have to be a large capacity (400 kVA). The currents that flow would require the routing of large conductors or bus bars, not the usual clip leads. Then, the disassembly of switchgear or the enclosed bus duct would be required to expose the single alternating current bus. Large bolted cable or bus bar terminations would have to be completed. A total of four conductors would have to be connected in phase with a non-synchronous source. To expect that a connection could be completed with the equipment either energized or deenergized in view of the obstacles that would prevent such a connection is incredible. However, even if the connection were completed, the outside source connection would be detectable by the operator through the tripping of the generator breakers.

7.3.2.2.6 Direct Current Power Connections

An external DC source could, if connected inside the Power Cabinet, hold the rods in position. This would require a minimum supply voltage of 50-V. Since the holding current for each mechanism coil is 4 amperes, the DC capacity would have to be approximately 180 amperes to hold all rods. Achieving this situation would require several acts bringing in a power source which is not required for any type of operation in the Rod Control System, preferentially connecting it into the system at the correct points, and actuating specific holding switches so as to interconnect all rods. Closure of twelve switches, in four separate cabinets would be required to hold all rods. One switch could hold as many as four rods.

The application of a DC voltage to an individual rod external to the Power Cabinet would affect only a single rod; connection with other rods in the group would be prevented by the blocking diodes in the power circuits.

Should an external DC source be connected to the system, the system is provided with features to permit its detection.

Each Power Cabinet contains circuitry, which compares the actual currents in the stationary and movable gripper coils with the reference signals from the step sequencing unit (Slave Cycler). In taking a single step, the current to the stationary gripper coil will be profiled from the holding value to the maximum, to zero, and return to the holding level after the completion of the step. Correspondingly, the movable gripper coil must change from zero to maximum and return to zero. The presence of an external DC source on either the stationary or movable coils would prevent the related currents from returning to zero.

This situation would be instantaneously annunciated by way of the comparison circuit. Therefore, any rod motion would actuate an alarm indicating the presence of an external DC source. In addition, an external DC source would prevent rods from stepping. Thus, an external source could be detected by the rod position indication system indicating failure of the rod(s) to move. Connection of an external DC power source to the output lines of the 70-V DC power supply can be detected by opening the three-phase primary input of the supply and checking the output with a built-in indicating lamp.

7.3.3 <u>Evaluation Summary</u>

In view of the preceding discussion, the postulated connection of an external power source (either AC or dc) or the occurrence of short circuits that could prevent dropping of the rods is not considered credible. Specifically:

1. The need for an outside power source has been eliminated by incorporating built-in holding sources as part of the rod control system and by providing two motor-generator sets.

2. The equipment is contained within enclosed steel cabinets precluding the possibility of an accidental connection of either AC or DC power in the cabinets.

3. Alternating current power distribution is accomplished using a steel-enclosed bus duct. The high-capacity (400-kVA) AC power source is unique and not readily available. Multiple connections are required.

4. Direct current power is distributed to the individual mechanisms through insulated cables and enclosed electrical connections precluding the accidental connection of an outside DC source external to the cabinets. The high-capacity DC source required to hold rods is not readily available in the rod control system, would require multiple connections, and would require deliberate positioning of switches within the enclosed cabinets.

5. Provisions are made in the system to permit the detection of an external DC source that could preclude a rod release.

The total capacity of the system including the overload capability of each motor-generator set is such that a single set out of service does not cause limitations in rod motion during normal plant operation. In order to minimize reactor trip as a result of a unit malfunction, the power system is normally operated with both units in service.

7.3.3.1 Turbine Bypass

A turbine bypass system is provided to accommodate a reactor trip with turbine trip and in conjunction with automatic reactor control can accommodate a load rejection without reactor and turbine trip. The maximum load rejection that can be accommodated without reactor and turbine trip depends on the full load T_{avg}. A maximum of 25% load rejection can be accommodated for the minimum acceptable full load T_{avg} of 550.5^{o}F. As the full load T_{avg} is increased, larger load rejections can be accommodated until for full load T_{avg} values of 558oF or higher a maximum load rejection of 50% can be accommodated. The turbine bypass system removes steam to reduce the transient imposed upon the reactor coolant system so that the control rods can be positioned to reduce the reactor power to a new equilibrium value without allowing overtemperature and overpressure conditions in the reactor coolant system.

A turbine bypass is actuated by the coincidence of compensated coolant average temperature higher than the programmed value by a preset value and turbine load decrease greater than a preset value. All the turbine bypass valves open immediately upon receiving the bypass signal. The bypass valves are modulated by the compensated coolant average temperature signal after they are open. The turbine bypass reduces proportionally as the control rods act to reduce the coolant average temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value.

The turbine bypass steam capacity is 40-percent of full-load steam flow at full-load steam pressure. The bypass flows to the main condenser.

7.3.3.2 Part-Length Power Supply

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7.3.3.3 Feedwater Control

Each steam generator is equipped with a three-element feedwater controller that maintains a programmed water level as a function of load on the secondary side of the steam generator. The three-element feedwater controller continuously compares actual feedwater flow with steam flow compensated by steam pressure with a water level setpoint to regulate the feedwater valve opening. The individual steam generators are operated in parallel, both on the feedwater and on the steam side.

Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the primary coolant following a reactor trip and turbine trip. A low-low steam generator water level initiates a reactor trip and also generates an increased level demand signal for the feedwater control system. The main feedwater valves move to the fully open position in response to this level demand. This provides an additional heat sink for the reduction of reactor coolant temperature to the no-load average temperature value. The feedwater regulating valves close on high steam-generator water level, safety injection, or a reactor trip coincident with low T_{avg}. In the latter case, the low flow feedwater bypass valve closure may be delayed by means of an installed timer to allow main feedwater to moderate the cooler auxiliary feedwater before it enters steam generators. Manual override of the feedwater control systems is also provided.

7.3.3.4 Pressure Control

The reactor coolant system pressure is controlled by electrical immersion heaters located near the bottom of the pressurizer, and spray in the steam region. A portion of the heater groups are proportional heaters and are used for pressure variation control and to compensate for ambient heat losses. The remaining (backup) heaters are turned on either when the pressurizer pressure is below a preset value or when the pressurizer level exceeds the programmed level setpoint by a preset amount. A small continuous spray flow is maintained when required to reduce boron stratification in the pressurizer and/or control the thermal gradient in the surge line. Heaters are operated as required to compensate for the spray and control pressure.

A spray nozzle is located at the top of the pressurizer. Spray is initiated when the pressure controller signal is above a preset setpoint. Spray rate increases proportionally with increasing pressure until it reaches the maximum spray capacity. Steam condensed by spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock when the spray valves open and to help maintain uniform water chemistry and temperature in the pressurizer.

Two power relief valves are designed to limit system pressure to 2335 psig for large load reduction transients. The relief valves are operated on the actual pressure signal. A separate interlock (set at approximately 2300 psig) is provided for each so that if a pressure channel indicates abnormally low, the valve activation is blocked. The logic for each is thus basically two out of two.

7.3.3.5 Overpressurization Protection System

This system uses a two-out-of-three actuation logic on high reactor coolant pressure, when reactor coolant temperature is less than a predetermined arming temperature, to open the power-operated relief valves automatically. This relief prevents the reactor coolant system from exceeding pressure limits given in 10 CFR 50, Appendix G.

Three spring-loaded safety valves are sized to limit system pressure to 2750 psia following a complete loss of load without direct reactor trip or turbine bypass. (See Section 4.3.4.)

7.3.4 System Design Evaluation

7.3.4.1 Plant Stability

Automatic Rod Control is only used once the plant has reached stable conditions. This allows for inward rod motion during the early stages of a plant transient without the need for operator action to limit Reactor Coolant System temperature increase. Operator action is required following the transient to restore reactor coolant average temperature to the programmed setpoint.

7.3.4.2 Step-Load Changes Without Turbine Bypass

A typical reactor power control requirement is to accept a 10-percent step-load decrease, without a plant trip, over the 15 to 100-percent power range for automatic control. The design must necessarily be based on conservative conditions, and a greater transient capability is expected for actual operating conditions.

The function of the control system is to minimize the reactor coolant average temperature increase during the transient within an acceptable value. Excessive pressurizer pressure variations are prevented by using spray and heaters in the pressurizer. Operator action is required following the transient to restore reactor coolant average temperature to the programmed setpoint.

7.3.4.3 Loading and Unloading

Ramp unloading is provided over the 15 to 100-percent power range under automatic control. Loading is performed under manual operator control only.

The coolant average temperature is increasing during loading, and there is a continuous insurge to the pressurizer resulting from coolant expansion. The sprays limit the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during unloading, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The heaters limit the resulting system pressure decrease. The pressurizer level is programmed such that the water level has an acceptable margin above the low-level heater cutout setpoint during the loading and unloading transients. Operator action is required to restore reactor coolant average temperature to the programmed setpoint.

7.3.4.4 Loss of Load With Turbine Bypass

The reactor coolant system is designed to accept -25 to 50-percent (depending on full power T_{avg}; see Section 7.3.1 and 7.3.3.1) loss of load accomplished as a turbine runback at a maximum rate of 200%/minute. No reactor trip or turbine trip will be actuated. The automatic turbine bypass system is able to accommodate this abnormal load rejection and to reduce the transient imposed upon the reactor coolant system. The reactor power is reduced at a rate consistent with the capability of the rod control system. The reducing of the reactor power is automatic down to 15-percent of full power. Manual control is used when the power is below this value. The bypass is removed as fast as the control rods are capable of inserting negative reactivity.

The pressurizer relief valves might be actuated for the most adverse conditions, for example, the most negative Doppler coefficient, and the minimum incremental rod worth. The relief capacity of the power-operated relief valves is sized large enough to limit the system pressure to prevent the actuation of high-pressure reactor trip for the most adverse conditions.

7.3.4.5 Turbine-Generator Trip With Reactor Trip

Turbine-generator unit trip is accomplished by reactor trip. With a secondary-system design pressure of 1100 psia, the plant is operated with a programmed average temperature as a function of load, with the full-load average temperature higher than the saturation temperature corresponding to the steam-generator safety valve setpoint. This, together with the fact that the thermal capacity in the reactor coolant system is greater than that of the secondary system, requires a heat sink to remove heat stored in the reactor coolant to prevent the actuation of steam-generator safety valves for turbine and reactor trip from full power.

This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of auxiliary feedwater to the steam generators. The turbine bypass system is controlled from the reactor coolant average temperature signal whose reference setpoint is reset upon trip to the no-load value. Turbine bypass actuation must be rapid to prevent steam-generator safety valve actuation. With the bypass valves open, the coolant average temperature starts to reduce quickly to the no-load setpoint. A direct feedback of reactor coolant average temperature acts proportionally to close the valves to minimize the total amount of steam bypassed.

Following turbine trip, the steam voids in the steam generators will collapse, and the opened feedwater valves will provide sufficient feedwater flow to restore water level in the downcomer. The feedwater flow is cut off when the reactor coolant average temperature decreases below a preset temperature value or when the steam-generator water level reaches a preset high setpoint.

Additional auxiliary feedwater makeup is then controlled manually to restore and maintain the steam-generator level while maintaining the reactor coolant at the no-load temperature. Residual heat removal (manually selected) is maintained by the steam-generator pressure controller, which controls the amount of turbine bypass to the condensers. This controller operates the same bypass valves to the condensers that are controlled by coolant average temperature during the initial transient following turbine and reactor trip.

The pressurizer pressure and level fall during the transient resulting from the coolant contraction. If heaters become uncovered following the trip, the chemical and volume control system will provide full charging flow to restore water level in the pressurizer. Heaters are then turned on to heat pressurizer water and restore pressurizer pressure to normal.

The turbine bypass and feedwater control systems are designed to prevent the coolant average temperature from falling below the programmed no-load temperature following the trip to ensure adequate reactivity shutdown margin.

7.3 FIGURES

Figure No.	Title
Figure 7.3-1	Simplified Block Diagram Of Reactor Control Systems
Figure 7.3-2	Deleted

7.4 NUCLEAR INSTRUMENTATION

7.4.1 Design Bases

7.4.1.1 Fission Process Monitors and Controls

Criterion: Means shall be provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in reactivity of the core. (GDC 13)

The nuclear instrumentation system is provided to monitor the reactor power from source range through the intermediate range and power range up to 120-percent full power. The system provides indication, control, and alarm signals for reactor operation and protection.

The operational status of the reactor is monitored from the central control room. When the reactor is subcritical (i.e., during cold or hot shutdown, refueling, and approach to criticality), the relative status (neutron source multiplication) is continuously monitored and indicated by proportional counters located in instrument wells in the primary shield adjacent to the reactor vessel. Two source-detector channels are provided for supplying information on multiplication while the reactor is subcritical. A reactor trip is actuated from either channel if the neutron flux level becomes excessive. This system is checked prior to operations in which criticality may be approached. This is accomplished by the use of an incore source to provide a meaningful count rate even at the refueling shutdown condition. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate, is slow enough to give ample time to start corrective action (boron dilution stop and/or emergency boron injection) to prevent the core from becoming critical (as discussed in Sections 14.1.5.2.3 and 14.1.5.3). A third channel is provided for use under conditions requiring alternate safe-shutdown system operation. The third channel may be used for core monitoring in MODE 6 with a safety related power supply and a read out in the Control Room.

Means for showing the relative reactivity status of the reactor are as follows:

1. Rod position.
2. Source, intermediate, and power range detector signals.
3. Boron concentration.
4. RCS average temperature.

The position of the control banks is directly related to the reactivity status of the reactor when at power, and any unexpected change in the position of the control banks under automatic control or change in the RCS average temperature (Calculated from hot-leg and cold-leg temperatures) under manual or automatic control provides a direct and immediate indication of a change in the reactivity status of the reactor. Periodic samples of the coolant boron concentration are taken.

The variation in concentration during core life provides a further check on the reactivity status of the reactor including core depletion.

High nuclear flux protection is provided both in the power and intermediate ranges by reactor trips actuated from either range if the neutron flux level exceeds trip setpoints. When the reactor is critical, the best indication of the reactivity status in the core (in relation to the power level and average coolant temperature) is the control room display of the rod control group position.

7.4.2 System Design

The three instrumentation ranges are provided with overlap between adjacent ranges so that continuous readings will be available during transition from one range to another as indicated in Figure 7.4-1. The sensitivities of the neutron detectors are also shown in Figure 7.4-1. The nuclear instrumentation system diagram is shown in Figure 7.4-2.

7.4.2.1 Detectors

The system consists of six detector assemblies located in instrument wells around the reactor as shown in Figure 7.4-3. The six assemblies provide the following instrumentation:

1. Power Range.

   This range consists of four independent long uncompensated ionization chamber assemblies. Each assembly is made up of two sensitive lengths. One sensitive length covers the upper half of the core, and the other length covers the lower half of the core.

   The arrangement provides in effect a total of eight separate ionization chambers approximately one-half the core height. The eight uncompensated (guard-ring) ionization chambers sense thermal neutrons in the range from 2.5×10^3 to 2.5×10^{10} neutrons/cm^2-sec.

   Each has a nominal sensitivity of 1.7×10^{-13} amperes per neutron/cm^2-sec. The four long ionization chamber assemblies are located in vertical instrument wells adjacent to the four "corners" of the core. The assembly is manually positioned in the assembly holders and is electrically isolated from the holder by means of insulated standoff rings.

2. Startup Range (Intermediate and Source).

   There are two separate assemblies. Each assembly covers two ranges. Each assembly contains one compensated ionization detector (intermediate range) and one proportional counter (source range). A third source range assembly is also provided for use under alternate safe-shutdown conditions.

   The source range neutron detectors are integral cable proportional counter assemblies. The proportional counter is filled with Boron Trifluoride (BF_3) gas enriched to greater than 90% in the B^{10} isotope, with a thermal neutron sensitivity of approximately 13 counts/neutron cm² at an operating voltage of 2000 volts. The detectors sense thermal neutrons in the range from 10^{-1} to 5×10^4

neutrons/cm^2-sec, to produce a pulse rate between 10^0 and 5×10^5 counts/sec. The range of the source range channel is 10^0 to 10^6 counts/sec.

The neutron detectors are positioned in detector assembly containers by means of a linear, high-density moderator insulator. The detector and insulator units are packaged in a housing that is inserted into the guide thimbles.

The detector assembly is electrically isolated from the guide thimble by means of insulated standoff rings.

The intermediate-range neutron detectors are compensated ionization chambers that sense thermal neutrons in the range from 2.5×10^2 to 2.5×10^{10} neutrons/cm^2-sec and have a nominal sensitivity of 4×10^{-14} amperes per neutron/cm^2-sec. They produce a corresponding direct current of 10^{-11} to 10^{-3} A. These detectors are located in the same detector assemblies as the proportional counters for the source range channels.

The electronic equipment for each of the source, intermediate, and power range channels is contained in a draw-out panel mounted adjacent to the main control board.

7.4.2.1.1 Power Range Channels

There are three sets of power range measurements. Each set uses four individual currents as follows:

1. Four currents directly from the lower sections of the long ionization chambers.
2. Four currents directly from the upper sections.
3. Four total currents of items 1 and 2, equivalent to the average of each section.

For each of the four currents in items 1 and 2, the current measurement is indicated directly by a microammeter, and isolated signals are available for control console indication and recording. Analog signals proportional to individual currents are transmitted through buffer amplifiers to the over-temperature and overpower ΔT channels and provide automatic reset of the trip point for these protection functions. The total current, equivalent to the average, is then applied through a linear amplifier to the bistable trip circuits. The amplifiers are equipped with gain and bias controls for adjustment to the actual output corresponding to 100-percent rated reactor power.

Each of the four amplifiers also provides amplified isolated signals to the main control board for indication and for use in the reactor control system. Each set of bistable trip outputs is operated as a two-out-of-four coincidence to initiate a reactor trip. Bistable trip outputs are provided at low- and high-power setpoints depending on the operating power. To provide more protection during startup operation, the low-range power bistable is used. This trip is manually blocked after a permissive condition is obtained by two-out-of-four power range channels. The high-power trip bistable is always active.

The four amplifier signals corresponding to item 3 above are supplied to circuits that compare a referenced channel output with the corresponding signal from the other channels. Alarms are provided to present deviations that might be indicative of quadrant flux asymmetries.

Signals derived from the power range instruments are also supplied to the plant computer. These signals are used to monitor radial and axial flux tilt in the following manner:

1. Radial flux tilt is determined by comparing the signals obtained from the upper sections of the ionization chambers. The signals obtained from the lower sections are also compared to each other in the same manner. The value of the deviation is supplied to the operator by means of a visual display. The existence of a radial flux tilt can be verified by the use of incore instrumentation.

2. Axial flux tilt is determined by comparing the sum and/or average of the upper sections of the ionization chambers to the sum and/or average of the signals from the lower sections. The operator will be informed by a computer alarm if the deviation exceeds a preset value of 20-percent full power. A visual display is provided by four meters located on the flight panel, each of which indicates individual detector axial flux tilt.

3. Delta flux is determined by comparing the difference in signals between the upper and lower power range detectors. The program outputs two types of alarm messages. Above a preset power level (90-percent), an alarm message is printed out immediately upon discovering a delta flux alarm. Below this power level, an alarm message is printed if the delta flux has exceeded its allowable limits for a preset cumulative amount of time in the past 24 hr.

The overpower trip will be set so that, for operating limit reactor conditions concurrent with the maximum instrumentation and bistable setpoint error, the maximum reactor overpower condition will be limited to 118-percent, as discussed in Chapter 14. This limit is accomplished by the use of solid-state instrumentation and long ionization chambers, which permit an integration of the flux external to the core over the total length of the core, thereby reducing the influence of axial flux distribution changes resulting from control rod motion.

The ion chamber current of each detector is measured by sensitive meters with an accuracy of 0.05-percent. A shunt assembly and switch in parallel with each meter allows the selection of one of four meter ranges. The available ranges are 0 to 100, 0 to 500, 0 to 1000, and 0 to 5000 μA. The shunt assemblies are designed in such a manner that they will not disconnect the detector current to the summing assembly upon meter failure or during switching. An isolation amplifier provides an analog signal proportional to ion chamber current for recording, data logging, and delta flux indication. A test calibration unit provides necessary switches and signals for checking and calibrating the power range channels.

The linear amplifier accepts the output currents from each of the two chamber sections and derives a nuclear power signal proportional to the summed direct currents. This unit amplifies the currents, and converts the normal current signal to a voltage signal suitable for operation of associated components such as bistables and isolation amplifiers.

Multiple power supplies furnish necessary positive and negative voltages for the individual channels and detector power.

Mounted on the front panel of each power range channel drawer are the ion chamber current meters, shunt selector switches with appropriate positions, and the nuclear power indicator (0 to 120-percent full power).

The isolated nuclear power signals are available for recording by the nuclear instrumentation system recorder. An isolated nuclear power signal is available for recording overpower conditions up to 200-percent full power.

Alarm signals for dropped-rod - rod stop, overpower - rod stop, over-power reactor trip, and channel test are annunciated on the main control board. Control signals sent to the reactor control and protection system include dropped-rod - rod stop, overpower - rod stop, overpower - reactor trip, and permissive circuit signals. These are described in Section 7.2.

7.4.2.1.2 Intermediate-Range Channels

There are two intermediate range channels that use two compensated ionization chambers. Direct current from the ion chambers is transmitted through triaxial cables to transistor logarithmic current amplifiers in the nuclear instrumentation equipment.

The logarithmic amplifier derives a signal proportional to the logarithm of the current as received from the output of the compensated ion chamber. The output of the logarithmic amplifier provides an input to the level bistables for reactor protection purposes and source range cutoff. The bistable trip units are similar to those in the other ranges. The trip outputs can be manually blocked after receiving a permissive signal from the power range channels. On decreasing power, the intermediate-range trips for reactor protection are automatically inserted when the power range permissive signal is not present. To prevent inadvertent and unnecessary reactor trips during power reductions prior to shutdown, operating procedures allow these trips to be manually bypassed until they have reset to the untripped condition and the reset has been verified.

Low-voltage power supplies contained in each drawer furnish the necessary positive and negative voltages for the channel electronic equipment. Two medium-voltage power supplies, one in each channel, furnish compensating voltage to the two compensated ion chambers. The high voltage for the compensated ion chambers is supplied by separate power supplies also located in the intermediate-range drawers.

On the front panel of the intermediate range channel cabinet and on the control board are mounted a neutron (log N) flux level indicator calibrated in terms of ion chamber current (10^{-11} to 10^{-3} A).

Isolated neutron flux level signals are available for recording and startup rate computation. The startup rate for each channel is indicated at the main control board in terms of decades per minute over the range of -0.5 to 5.0 decades/min.

Channel test, intermediate channel above source range cutoff point, intermediate range trips not armed, block rod withdrawal, and reactor trip signals are alarmed on the main control board annunciator. The latter signal is sent to the reactor protection system.

7.4.2.1.3 Source Range Channels

There are two source range channels using boron-10-lined proportional counters. Neutron flux, as measured in the primary shield area, produces current pulses in the detectors. These preamplified pulses are applied to transistor amplifiers and discriminators located in the central control room. Triaxial cable is used for all interconnections from the detector assemblies to the instrumentation in the central control room. The preamplifiers are located outside the reactor containment.

These channels indicate the source range neutron flux and startup rate and provide high flux level reactor trip and alarm signals to the reactor control and protection system. The reactor trip signal is manually blocked when a permissive signal from the intermediate range is available. They are also used at shutdown to provide audible alarms in the reactor containment and central control room of any inadvertent increase in reactivity. An audible count rate signal is used during initial phases of startup and is audible in both the reactor containment and central control room.

Amplifiers are used to obtain a high-level signal prior to the elimination of noise and gamma pulses by the discriminator. The discriminator output is shaped for use by the log integrator.

The log integrator derives an analog signal, proportional to the logarithm of the number of pulses per unit time, as received from the output of the previous unit. This unit performs log integration of the pulse rate to determine the count rate; a linear amplifier amplifies the log integrator output for indication, recording, control, and rate computation through isolation amplifiers.

Each source range contains two bistable trip units. Both units trip on high flux level, but one is used during shutdown to alarm reactivity changes and the other provides overpower protection during shutdown and startup. The shutdown alarm unit is blocked manually prior to startup or can serve as a startup alarm. When the input to either unit is below its setpoint, the bistable is in its normal position and assumes a "fully-on" status. When an input from the log amplifier reaches or exceeds the setpoint, the unit reverses its condition and goes "fully-off." The output of the reactor trip unit controls relays in the reactor protection system.

Power supplies furnish the positive and negative voltages for the transistor circuits and alarm lights and the adjustable high voltage for the neutron detector.

A test calibration unit can insert selected test or calibration signals into the preamplifier channel input or the log amplifier input. A set of precalibrated level signals are provided to perform channel tests and calibrations. An alarm is registered on the main control board annunciator whenever a channel is being tested or calibrated. A trip bypass switch is also provided to prevent a reactor trip during channel test under certain reactor conditions.
The neutron detector high-voltage cutoff assembly receives a trip signal when a one-of-two matrix controlled by intermediate-range channel flux level bistables and manual block condition are present and disconnects the voltage from the source range channel high-voltage power supply to prevent operation of the boron-10-lined counter outside its design range. In addition, a high-voltage manual control switch is installed to prevent inadvertent energization of the source range high voltage while at power. The position of the switch is administratively controlled to ensure that the source range high voltage is energized upon a reactor trip or normal shutdown when the detector current is less than 10^{-10} amps.

Mounted on the front panel of the source range channel is a neutron flux level indicator calibrated in terms of count rate level (1 to 10^6 cps). Mounted on the control board is a neutron count rate level indicator (1 to 10^6 cps). Isolated neutron flux signals are available for recording by the nuclear instrumentation system recorder and startup rate computation. The startup rate for each channel is indicated at the main control board in terms of decades per minute over the range of -0.5 to +5.0 decades/min. The isolation network for these signals prevents any electrical malfunction in the external circuitry from affecting the signal being supplied to the flux level bistables. The signals for channel test, high neutron flux at shutdown, and source reactor trip are alarmed on the main control board annunciator. In addition, there are annunciators for the following source range conditions: "Source Range High Shutdown Flux Alarm Blocked", "NIS Channel Test", "Source Range Loss of Detector Voltage", and "NIS Trip Bypass".

7.4.2.2 Auxiliary Equipment

7.4.2.2.1 Comparator Channel

The comparator channel compares the four nuclear power signals of the power range channels with one another. A local alarm on the channel is actuated when any two channels deviate from one another by a preset adjustable amount. During full-power operation, the comparator serves to sense and annunciate channel failures and/or deviations.

7.4.2.2.2 Dropped Rod Protection

As backup to the primary protection for the dropped rod cluster control accident, the rod bottom signal, an independent detection means is provided using the out-of-core power range nuclear channels. The dropped-rod sensing unit contains a difference amplifier, which compares the instantaneous nuclear power signal with an adjustable power lag signal and responds with a trip signal to the bistable amplifier when the difference exceeds a preset adjustable amount. Above a given power level the signal initiates protective action in the form of a turbine load cutback. Bypass switches have been installed, which are normally in the DEFEAT position, so as to bypass the runback of this signal.

7.4.2.2.3 Audio Count Rate Channel

The audio count channel provides audible source range information during refueling operations in both the central control room and the reactor containment. In addition, this channel signal is fed to a scaler-timer assembly, which produces a visual display of the count rate for an adjustable sampling period.

7.4.2.2.4 Recorders

One large, two-pen strip-chart recorder is mounted on the main control board for recording the complete range of the source and intermediate channels. It is also possible to record any two power range channels as linear signals. Variable chart speeds are provided with controls for changing the span and zero during intermediate-range operation.

The switching of inputs to the recorders does not cause any spurious signals that would initiate false alarms or reactor trips.

Four 2-pen recorders are provided, one for each power range, to record the flux level from each of the eight sections comprising the four long ion chambers.

7.4.2.2.5 Power Supply

The nuclear instrumentation system is powered by four 120-V independent vital instrument AC bus circuits (see Chapter 8).

7.4.3 System Evaluation

7.4.3.1 Loss of Power

Loss of nuclear instrumentation power would result in the initiation of all reactor trips associated with the channel power failure. In addition, all trips that were blocked prior to loss would be unblocked and initiated.

7.4.3.2 Reliability and Redundancy

The requirements established for the reactor protection system apply to the nuclear instrumentation. All channel functions are independent of every other channel.

7.4.3.3 Safety Factors

The relation of the power range channels to the reactor protection system has been described in Section 7.2. To maintain the desired accuracy in trip action, the total error from drift in the power range channels will be held to ± 1-percent at full power. Routine tests and recalibration will ensure that this degree of deviation is not exceeded. Bistable trip setpoints of the power range channels will also be held to an accuracy of ± 1-percent of full power. The accuracy and stability of the equipment have been verified by vendor tests.

7.4.3.4 Overpower Trip Setpoint

The overpower trip setpoint for the Indian Point Unit 2 reactor is $\leq$ 107.4-percent of rated thermal power. This trip point was selected to provide adequate assurance that spurious reactor trips will not occur in normal operation.

TABLE 7.4-1
DELETED

TABLE 7.4-2
DELETED

7.4 FIGURES

7.5 PROCESS INSTRUMENTATION

7.5.1 Design Bases

The nonnuclear process instrumentation measures temperatures, pressures, flows, and levels in the reactor coolant system, steam system, reactor containment, and auxiliary systems. Process variables required on a continuous basis for the startup, operation, and shutdown of the unit are indicated and controlled from the control room. Essential parameters are also recorded. The quantity and types of process instrumentation provided ensures safe and orderly operation of all operation of all systems and processes over the full operating range of the plant.

Certain controls that require a minimum of operator attention, or are only in use intermittently, are located on local control panels near the equipment to be controlled. The monitoring of the alarms of such control systems are provided in the control room. Table 7.5-1 includes a list of important process instrumentation, indication, and safeguards functions.

7.5.2 System Design

Much of the process instrumentation provided in the plant has been described in the reactor control and protection and nuclear instrumentation system. The most important instrumentation used to monitor and control the plant has been described in the above systems descriptions. The remaining portion of the process instrumentation is generally shown on the respective systems process flow diagrams.

Condensate pots and wet legs are used to prevent process temperatures from actually reaching the transmitters.

7.5.2.1 Engineered Safety Features

The following instrumentation ensures coverage of the effective operation of the engineered safety features. Compliance with the requirements of Regulatory Guide 1.97 is referenced in Section 7.1.5.

7.5.2.1.1 Containment Pressure

The containment pressure is transmitted to the main control board for postaccident monitoring. Six (-5 to +75 psig) transmitters are installed outside the containment for protection against potential missile damage. The pressure is indicated (all six channels) on the main control board.

The six channels monitoring containment pressure initiate containment spray, phase B containment isolation, containment ventilation isolation, and steam line isolation, as well as reflecting the effectiveness of engineered safety features.

As part of the TMI Action Plan modifications for Indian Point Unit 2, (NUREG-0737), a continuous indication of containment pressure is provided in the central control room by two recorder indicator units covering a range of -10 to 150 psig.

7.5.2.1.2 Containment Water Level

Redundant containment water level indicators, one in each sump (LT-939 in the recirculation sump and LT-941 in the containment sump) are relied upon to show that water has been delivered to the containment following a loss-of-coolant accident, and subsequently show that sufficient water has been collected by the sump to permit recirculation to the reactor and/or to the spray headers and to show that water is below the flood level to protect electrical equipment from submergence. These transmitters are mounted inside the containment and have been environmentally qualified. The level indications in the central control room are as follows:

For the containment sump: one “thermal type” detector (LT-941) provides a series of five lights each energized from the associated instrument as a preset level is exceeded; one differential pressure “bubbler type” transmitter (LT-3304) provides a series of five lights each energized from the associated instrument as a preset level is exceeded; and one differential pressure transmitter (LT-3300) provides a calibrated sump level span that is continuously indicated. An audible alarm is also provided for increasing sump level (see Section 6.7.1.2.13). For the recirculation sump: two magnetic switch/float type detectors (LT-938 and LT-939) provide a series of five lights each energized from the associated instrument as a preset level is exceeded; and one differential pressure transmitter (LT-3301) provides a calibrated sump level span that is continuously indicated (see Section 6.7.1.2.14). Refer to Section 6.2 for further description of the two sumps serving the internal and external recirculation loops. In addition, a differential-pressure–level transmitter has been installed in the reactor cavity pit (see Section 6.7.1.2.15).

7.5.2.1.3 Containment Hydrogen Concentration

As part of the TMI Action Plan modifications for Indian Point Unit 2, (NUREG-0737), a continuous indication of hydrogen concentration in the containment atmosphere is provided in the central control room. The containment hydrogen/oxygen monitor system is described in Section 6.8.2.3.

7.5.2.1.4 Refueling Water Storage Tank Level

Refueling water storage tank level measurement is provided by:

1. A local level indicator at the tank, and

2. Two separate, redundant transmitting channels, which provide level indication and level alarms in the central control room for the initiation of the changeover to the postaccident recirculation phase.

In the case of a large-break loss-of-coolant accident (LBLOCA) and full operation of all safeguards and spray pumps, the RWST level alarms will annunciate after approximately 20 minutes. At this time, the operator is required to proceed with the changeover sequence. The tank level indicator is available for confirmation. Information on the level of water in both the recirculation and containment sumps is also available to the operator during this period via the sump level instrumentation.

In view of the information provided to the operator, together with the procedure, which he is required to follow, no single instrument failure would cause him to follow a course of action that could in any way jeopardize core cooling.

The water in the storage tank is protected from freezing by a thermostat that turns the heating medium on and off. Instrument lines are freeze protected.

7.5.2.1.5 Condensate Water Storage Tank Level

An additional channel has been added to the original water level indication channel. The added level channel includes an alarm switch to actuate the low-level alarm in the central control room. In addition, there is a low-temperature alarm to indicate heat tracing failure or a low instrument ambient temperature. The instrument lines are freeze protected.

7.5.2.1.6 Safety Injection Pumps Discharge Pressure

These channels show that the safety injection pumps are operating. The transmitters are outside the containment.

7.5.2.1.7 Accumulator Level

Each of the safety injection system accumulator tanks contains two differential-pressure-type liquid level transmitters providing the electrical signal for separate channel level indicators and high- and low-level alarms in the central control room.

7.5.2.1.8 Pump Energization

All pump motor power feed breakers indicate that they have closed by energizing indicating lights on the control board.

7.5.2.1.9 Valve Position

All engineered safety features valves have position indication on the control board to show proper positioning of the valves. Air-operated and solenoid-operated valves are selected so as to move in a preferred direction on the loss of air or power. Motor-operated valves remain in the position at time of loss of power to the motor.

Acoustic sensors installed on the code safety valves discharge lines provide indication in the central control room of the "flow" or "non-flow" condition of line safety valves. The power-operated relief valves have a direct valve position indication in the central control room. The acoustic monitoring system was installed to comply with the requirements of NUREG-0578.

7.5.2.1.10 Residual Heat Exchangers

Combined exit flow is indicated and combined inlet and combined exit temperatures are recorded on the control board to monitor the operation of the residual heat exchangers. A high pressure is annunciated on the auxiliary coolant system panel in the central control room.

7.5.2.1.11 Fan Coolers

The service water discharge flow is indicated in the control room. The flow transmitters are located inside the containment. The temperature of each of the five fan coolers' service water is indicated locally. A control room alarm is actuated if the flow is low during safety injection. In addition, the exit flow is monitored for radiation and alarmed in the control room if high radiation should occur. There are redundant radiation monitors, and the faulty cooler can be identified by manually sampling the flow from each unit in turn and using these monitors.

7.5.2.1.12 Bus Undervoltage

The normal 480-V feeds to the safeguard buses are tripped upon sustained undervoltage. An alarm and indicator light are also provided in the control room to alert the operator in advance of attaining the actual undervoltage trip level. Each bus is monitored by two undervoltage relays (set at approximately 88-percent). Two-out-of-two logic will activate an agastat relay (set at approximately 150 sec), which in turn trips its respective 480-V feeder breaker. This trip has been added to provide additional Class A/Class 1E protection of the safeguards loads against degraded voltage conditions. Two separate Asea Brown Boveri (ABB) type 27N high accuracy relays are used for each bus. A separate category alarm and lights on a panel in the central control room alert the operator when any 480-V bus voltage falls to approximately 94-percent. These may actuate during load-sequencing operations, but they are primarily intended to alert the operator to sustained degraded voltages that result from problems on the offsite power system. A separate Westinghouse type CP relay is used for each bus. These alarm circuits and relays are subject to an actuation operability test each 31 days and a channel calibration each 24 months.

In the unlikely event of a sustained degraded voltage coincident with a safety injection signal for approximately 10 $\pm$2 sec, the 480-V feed breaker to the safeguards bus will trip.

7.5.2.1.12.1 Station Auxiliary Transformer Load Tap Changer SI Signal

The Load Tap Changer (LTC) is used to maintain the nominal voltage level on the Station Auxiliary Transformer's (SAT's) 6.9 KV buses by automatically raising or lowering the SAT secondary winding taps in response to voltage variations on the 6.9 KV buses. During a SI event the SI signal will raise the LTC tap position increasing the voltage towards a pre-selected voltage in anticipation of the increased loads from the fast transfer of the loads held by the four 6.9 KV in-house buses to the SAT, thus reducing the severity of a degraded voltage condition on the 480V and 6.9KV buses.

7.5.2.1.13 Reactor Coolant Pump Seal Injection

The seal injection flow rate to each reactor coolant pump is indicated locally by a ΔP gauge. A flow transmitter in parallel with each of the ΔP gauges provides remote flow indication in the central control room. The system does not provide an alarm or initiate any safety action.

7.5.2.1.14 Reactor Vessel Level

A reactor vessel level indication system has been installed to assist the operator in determining the presence of voids in the reactor vessel. The reactor vessel level indication system, which is mainly part of the inadequate core cooling instrumentation (Section 4.2.11), indicates the water level from the bottom to the top of the reactor vessel and under different coolant flow conditions with and without reactor coolant pumps operating. The system is described in Section 4.2.11.

7.5.2.1.15 Subcooling Margin Monitoring System

The subcooling margin monitoring system has been installed in accordance with the requirements of NUREG-0578 and NUREG-0737. The system provides indication for aiding the operator in diagnosing early symptoms of inadequate core cooling during transients and accidents and determining whether or not safety injection can be terminated.

The system has two independent, redundant channels, each providing indication in the control room. The inputs of one subcooling margin monitoring channel (reactor coolant system pressure, hot-leg temperature, cold-leg temperature) are provided by a wide-range reactor coolant system pressure transmitter in reactor coolant loop 21, and the reactor coolant system cold- and hot-leg resistance temperature detectors in loops 21 and 23. The redundant channel receives pressure input from a transmitter in loop 24, and temperature input from detectors in loops 22 and 24.

The system is energized from Class 1E power supplies.

The subcooling margin monitors are located in the central control room along with its associated signal conditioning equipment.

7.5.2.1.16 Reactor Coolant System Pressure

RCS pressure is monitored on three of the four primary loops.

Signals from PT 402 and PT 403 on loops 21 and 24 provide wide range pressure indication in the Central Control Room and independent, redundant interlock signals to the RHR isolation valves (730 and 731) to prevent opening them at high RCS pressures. RCS pressure for PT 402 and PT 403 is transmitted through a filled capillary system to transmitters located outside containment in the Pipe Penetration Area. The sensing lines are connected to the pressure sensor bellows to capillary lines extending through the penetrations, to hydraulic isolators, which are located outside of containment. The capillary lines are routed through separate penetrations as shown on Figure 7.5-1.

Signals from PT 413, PT 433 and PT 443 on loops 21, 23 and 24 provide input to the Overpressure Protection System (Section 7.3.3.5).

7.5.2.1.17 Pressurizer Relief Tank Temperature

Temperature in the pressurizer relief tank may be used as an indication of pressurizer relief valve position, backing up the acoustic monitors. A temperature indicator is provided in the control room.

7.5.2.1.18 Alarms

Visual and/or audible alarms are provided to call attention to abnormal conditions. The audible alarms are of the individual acknowledgment type; that is, the operator must recognize and silence the audible alarm for each alarm point. For most control systems, the sensing device and circuits for the alarms are independent, or isolated from, the control devices.

In addition to the above, the following local instrumentation is available:

1. Containment spray test lines total flow.
2. Safety injection test line pressure and flow.

7.5.3 <u>System Evaluation</u>

Redundant instrumentation has been provided for all inputs to the protection systems and vital control circuits.

Where wide process variable ranges and precise control are required, both wide-range and narrow-range instrumentation are provided.

Instrumentation components are selected from standard commercially available products.

All electrical and electronic instrumentation required for safe and reliable operation is supplied from four redundant instrumentation buses.

TABLE 7.5-1
Process Instrumentation, Indication, and Safeguards Functions

Parameter	Transmitters/ Sensors	Read-Out[1]	Power[2]	Prot/Safeguards Use	Taps
Reactor coolant temperature	8 RTDs	CB meter	Ext.	ΔT trips T_{avg} permissives	1 each
Pressurizer pressure	4 transmitters	CB meter	Ext.	Hi/low pressure trips, SIS	3 (top level), one shared, 3 pairs
Pressurizer level	3 ΔP transmitters	CB meter	Ext.	Hi Level trip	3 (top level), one shared, 3 pairs
Steam flow	8 ΔP transmitters	CB meter	Ext.	Mismatch trip, SIS	1 pair each
Feedwater flow	8 ΔP transmitters	CB meter	Ext.	Mismatch trip	1 pair each
Steam pressure	12 transmitters	CB meter	Ext.	SIS	1 each
Steam generator level	12 ΔP transmitters	CB meter	Ext.	Mismatch trip Low level trip	1 pair each
Reactor coolant flow	12 ΔP transmitters	CB meter	Ext.	Low flow trip	1 high pressure each, 1 low pressure shared/loop
Containment pressure	6 transmitters	CB meter	Ext.	SIS (2/3), Spray (2/3+2/3)	3 shared
Steam Header pressure	2 transmitters	Blind	Ext.	Setpoint programs and turbine power permissives	1 each

Notes:
1. CB is control board.
2. Ext. is external.

7.5 FIGURES

Figure No.	Title
Figure 7.5-1	Reactor Coolant Wide Range Pressure Instrument System – Flow Diagram

7.6 INCORE INSTRUMENTATION

7.6.1 Design Basis

The incore instrumentation is designed to yield information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations. Using the information obtained from the incore instrumentation system, it is possible to confirm the reactor core design parameters and calculated hot-channel factors. The system provides means for acquiring data and performs no operational plant control. The incore thermocouples are also designed to provide information for diagnosing the onset of inadequate core cooling and for mitigating its effects.

7.6.2 System Design

The incore instrumentation system consists of thermocouples, positioned to measure fuel assembly coolant outlet temperature at preselected locations, and flux thimbles, which run the length of selected fuel assemblies to measure the neutron flux distribution within the reactor core.

The experimental data obtained from the incore temperature and flux distribution instrumentation system, in conjunction with previously determined analytical information, can be used to determine the fission power distribution in the core at any time throughout core life. This method is more accurate than using calculational techniques alone. Once the fission power distribution has been established, the maximum power output is primarily determined by thermal power distribution and the thermal and hydraulic limitations determine the maximum core capability.

The incore instrumentation provides information that may be used to calculate the coolant enthalpy distribution, the fuel burnup distribution, and an estimate of the coolant flow distribution.

Both radial and azimuthal symmetry of power may be evaluated by combining the detector and thermocouple information from the one quadrant with similar data obtained from the other three quadrants.

7.6.2.1 Thermocouples

Chromel-alumel thermocouples are threaded into guide tubes that penetrate the reactor vessel head through seal assemblies and terminate at the exit flow end of the fuel assemblies. The thermocouples are provided with two primary seals, a conseal and swage-type seal from conduit to head. The thermocouples are enclosed in stainless steel sheaths within the above tubes to allow replacement if necessary. Thermocouple readings are recorded in the control room. The support of the thermocouple guide tubes in the upper core support assembly is described in Chapter 3.

A total of 65 thermocouples are installed at preselected core locations to provide core exit temperature data up to 2300°F. There are two microprocessors, one to process data for 34 thermocouples and the other for the remaining 31. Two display units are provided on the central control room accident assessment panels. Each presents a graphic core location map with an alphanumeric display of core exit temperatures. Temperature signals from the microprocessors are

are sent to the plant computer.

Microprocessors, display units and cables are separated into two redundant channels. Thermocouples, cables, microprocessors and display units are seismically designed. Cables and components inside the containment and in the electrical penetration area are environmentally qualified. The two channels receive power from redundant instrument busses.

7.6.2.2 Movable Miniature Neutron Flux Detectors

Six fission chamber detectors (employing U_3O_8, which is 90-percent enriched in U-235) can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. Maximum chamber dimensions are 0.188-in. in diameter and 2.10-in. in length. The stainless steel detector shell is welded to the leading end of the helical-wrap drive cable and the stainless steel sheathed coaxial cable. Each detector is designed to have a minimum thermal neutron sensitivity of 1.5×10^{-17} A/nv and a maximum gamma sensitivity of 3×10^{-14} A/rad-hr. Operating thermal neutron flux range for these probes is 1×10^{11} to 5×10^{13} nv. Other miniature detectors, such as gamma ionization chambers and boron-lined neutron detectors, can also be used in the system. The basic system for the insertion of these detectors is shown in Figures 7.6-1 through 7.6-3. Retractable thimbles into which the miniature detectors are driven are pushed into the reactor core through conduits that extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal zone.

The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the reactor water pressure and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal line. The thimbles are seismic Class I, and the supports for the flux mapping frame support assembly are seismically designed.

During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal line is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists basically of six drive assemblies, six path group selector assemblies and six rotary selector assemblies, as shown in Figures 7.6-1 and 7.6-2. The drive system pushes hollow helical-wrap drive cables into the core with the miniature detectors attached to the leading ends of the cables and small-diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly generally consists of a gear motor that pushes a helical-wrap drive cable and detector through a selective thimble path by means of a special drive box and includes a storage device that accommodates the total drive length. Further information on mechanical design and support is described in Chapter 3.

The control and readout system for the movable miniature neutron flux detectors provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors at a selected speed while plotting a level of induced radioactivity versus detector position. The control system consists of two sections, one physically mounted with the drive units, and the other contained in the control room. Limit switches in each drive conduit provide means for prerecording detector and cable positioning in preparation for a flux mapping operation. One group path selector is provided for each drive unit to route the detector into one of the flux thimble groups. A rotary transfer assembly is a transfer device that is used to route a detector into any one of up to ten selectable paths. Ten manually operated isolation valves allow free passage of the detector and drive wire when open, and when closed prevent leakage from the core in case of a thimble rupture.

rupture. A path common to each group of flux thimbles is provided to permit cross calibration of the detectors.

The central control room contains the necessary equipment for control, position indication, and flux recording. Panels are provided to indicate the core position of the detectors and for plotting the flux level versus the detector position. Additional panels are provided for such features as drive motor controls, core path selector switches, plotting, and gain controls. A "flux-mapping" consists, briefly, of selecting (by panel switches) flux thimbles in given fuel assemblies at various core quadrant locations. The detectors are driven or inserted to the top of the core and stopped automatically. An X-Y plot (position vs. flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner other core locations are selected and plotted.

Each detector provides axial flux distribution data along the center of a fuel assembly. Various radial positions of detectors are then compared to obtain a flux map for a region of the core.

7.6.3 System Evaluation

The thimbles are distributed nearly uniformly over the core with about the same number of thimbles in each quadrant. The number and location of thimbles have been chosen to permit the measurement of local-to-average peaking factors to an accuracy of $\pm$10-percent (95-percent confidence). Measured nuclear peaking factors are increased to allow for possible instrument error. The departure from nucleate boiling ratio calculated with the measured hot-channel factor is compared to the departure from nucleate boiling ratio calculated from the design nuclear hot-channel factors. If the measured power peaking is larger than expected, reduced power capability will be indicated.

7.6.4 System Operation

A minimum of 2 thimbles per quadrant and sufficient movable in-core detectors shall be operable during re-calibration of the excore axial offset detection system.

7.6 FIGURES

Figure No.	**Title**
Figure 7.6-1	Typical Arrangement Of Moveable Miniature Neutron Flux Detector System, replaced with Plant Drawing 1999MC3880
Figure 7.6-2	Arrangement Of Incore Flux Detector, replaced with Plant Drawing 1999MC3881
Figure 7.6-3	Incore Instrumentation – Details, replaced with Plant Drawing 1999MC3882

7.7 OPERATING CONTROL STATIONS

7.7.1 Station Layout

The principal criterion of control station design and layout is that all controls, instrumentation displays, and alarms required for the safe operation and shutdown of the plant are readily available to the operators in the central control room.

During other than normal operating conditions, other operators will be available to assist the control room operator. Plant Drawing 209812 [Formerly UFSAR Figure 1.2-7 Sheet 1], shows the central control room arrangements for the unit. The control board is divided into relative areas to show the location of control components and information display pertaining to various subsystems.

Early control room reviews performed in 1980 and 1981 resulted in implementation of several changes including:

1. Installation of battery-operated emergency lighting fixtures to provide for continuously available emergency lighting.
2. Installation of several new multipoint recorders and relocation of some recorders to be adjacent to the flight panel.
3. Revised flash rate of supervisory annunciators from one to two flashes per second.
4. Relocation of annunciators to provide a more functional grouping and a more systems oriented display.

In response to NRC's Generic Letter 82-33 and the requirements of Supplement 1 to NUREG-0737, Requirements for Emergency Response Capability, a detailed control room design review was conducted (Reference 1). The purposes of this review were:

to review and evaluate the control room workspace, instrumentation, controls and other equipment from a human factors engineering point of view; to identify human engineering observations and human engineering discrepancies; and to establish a plan for implementing corrective action.

The review was conducted by a multi-disciplined team having qualifications consistent with the guidelines of NUREG-0700. The team conducted the review through the following major activities:

1. Operating experience review.
2. Function and task analysis.
3. Control room survey.
4. Verification of task performance capabilities.
5. Validation of control room as an integrated system.

Numerous changes were made in the central control room to implement human engineering enhancements. Among the changes made were:

1. Improved panel demarcation and annunciator tile/panel device labeling.
2. Replacement, relocation and provision of additional indicators for a number of parameters.
3. Removal of retired indicators/controls. Improvements to communications between the control room and other plant areas.

The detailed control room design review was reviewed by the NRC as documented in their SER dated January 12, 1989 (Reference 3) and found acceptable.

7.7.2 Information Display And Recording

7.7.2.1 Operational Information

Alarms and annunciators in the central control room provide the operators with warning of abnormal plant conditions that might lead to the damage of components, fuel, or other unsafe conditions. Other displays and recorders are provided for indication of routine plant operating conditions and for the maintenance of records.

Consideration is given to the fact that certain systems normally require more attention from the operator. The control system, therefore, is centrally located on the three-section board.

On the left section of the control board, individual indicators present a direct, continuous readout of every control rod position. Fault detectors in the rod drive control system are used to alert the operator should an abnormal condition exist for any individual or group of control rods. Displayed in this same area are limit lights for each control rod group and all nuclear instrumentation information required to start up and operate the reactor. Control rods are manipulated from the left section.

Variables associated with the operation of the secondary side of the station are displayed and controlled from the control board. These variables include steam pressure and temperature, feedwater flow and temperature, electrical load, and other signals involved in the plant control system. The control board also contains provisions for indications and control of the reactor coolant system. Redundant indication is incorporated in the system design since pressure and temperature variables of the reactor coolant system are used to initiate safety features. Control and display equipment for station auxiliary systems are also located here.

The engineered safety features systems are controlled and monitored from a vertical panel to the left of the control board. Valve position indicating lights are provided as a means of verifying the proper operation of the control and isolation valves following initiation of the engineered safety features. Control switches located on this panel allow manual operation or test of individual units. Also located on this section are the control switches, indicating lights, and meters for fans and pumps required for emergency conditions. Also mounted on this section are auxiliary electrical system controls required for manual switching between the various power sources described in Section 8.2.2.

Controls and indications for Containment Purge and Exhaust, Primary Auxiliary Building and Fuel Service Building ventilation systems are located on CCR panel SL. Controls and indications for the containment isolation valves, and the isolation valve seal-water system are located on a CCR panel SN. Radiation monitoring information is indicated immediately behind and to the left of the main control board.

Audible reactor building alarms are initiated from the radiation monitoring system and from the source range nuclear instrumentation. Audible alarms will be sounded in appropriate areas throughout the station if high-radiation conditions are present.

As a result of considerations arising from experience at TMI, the instrument panels in the control room were modified to receive monitors and recorders associated with the following:

1. Reactor coolant system hot-leg temperature.
2. Main steam line radiation monitors.

3. High-range containment radiation monitors.
4. High-range noble gas monitors.
5. Containment sump level indication.
6. Hydrogen and oxygen containment air analyzers.
7. Containment high-range pressure indication.
8. Reactor vent valve position indication.
9. Reactor vent temperature monitor.
10. Reactor vessel level indication.
11. Power-operated relief valve block valve position indication.
12. Subcooling monitor system indications.
13. Wide range hot-leg temperature indication

A plant process computer system is installed with color graphic displays in the central control room that monitors operating plant data as well as easily accessible sets of key plant safety parameters. It also provides data links with the technical support center, the emergency operations facility and the Alternate emergency operations facility. It has the capability of long term data storage and retrieval.

7.7.2.2 Safety Parameter Information

A system for monitoring safety parameter information is provided in accordance with the requirements of NUREG-0737, Supplement 1. It is an operator aid and not a safety-grade system and performs no safety function. The operation and potential failure of the plant computer system will not degrade the performance of safety systems.

The plant computer system consists of a data acquisition system, redundant computer systems with associated peripherals, and color displays.

The data acquisition system receives digital and analog signals required to monitor critical safety functions, which are:

-Reactivity control
-Reactor core cooling
-Reactor coolant system heat sink
-Reactor coolant system integrity
-Containment conditions
-Reactor coolant system inventory control

Several parameters (measures of plant status or performance) are monitored for each critical safety function, and each parameter is measured by signals input from one or more plant sensors. The data acquisition system samples each input 10 times per second. The redundant computer systems receive, process, analyze, and store the data and provide outputs to the system displays. The computer performs data acquisition and processing, and drives the displays. The backup computer acquires data in parallel with the primary computer and periodically performs data processing and calculation functions for intracomputer verification. The loss of any critical component in the primary system triggers a switchover to the backup system, which then provides all primary system functions.

The plant computer display system consists of seven-color graphic displays. The displays are located in the Central Control Room, Technical Support Center, Emergency Operations Facility, and Alternate Emergency Operations Facility.

Types of primary displays available are the plant mode, thirty-minute trend, and critical safety function status tree. Also available are a display of emergency core cooling inventories and a display of availability of emergency core cooling inventories and a display of availability of emergency power. The system, which originally consisted of ten secondary displays, has provision for future expansion as warranted.

7.7.3 Emergency Shutdown Control

The central control room, its equipment, and furnishings have been designed so that the likelihood of conditions that could render the control room inaccessible even for a short time is extremely small.

A criterion of the station design and layout is that all controls, instrumentation displays, and alarms required for the safe operation and shutdown of the plant are readily available to the operators in the central control room.

It is design policy that the functional capacity of the central control room shall be maintained at all times inclusive of accident conditions, such as a maximum credible accident or a design basis event. The following features are incorporated in the design to ensure that this criterion is met:

1. Structural and finish materials for the central control room and the cable-spreading room below were selected on the basis of fire-resistant characteristics. Structural floors are concrete reinforced. Interior partitions are metal paneling joints. The control room ceiling covering is fire-retardant egg crate diffusers. Door frames and doors are metallic.

2. The central control room is equipped with portable fire extinguishers. The extinguishers carry the Underwriters' Laboratory label of approval.

3. The cable-spreading room has a smoke detection system and a manually operated Halon system. The smoke detection system actuates an alarm in the control room. The cable tunnel has heat-sensitive devices, which actuate alarms in the control room and a water spray deluge system for fire extinguishing.

4. The control room ventilation consists of a system having a large percentage of recirculated air. The fresh air intake can be diverted to charcoal filters to remove airborne activity if monitors indicate that such action is appropriate.

5. Control cables used throughout the installation have been selected on the basis of flame testing described in Chapter 8 and have superior flame-retardant capability. Each conductor has a flame-retardant glass braid over the insulation. In addition, electrical circuits are limited in the control room to those associated with lighting, instrumentation, and control. Lighting circuits operate on 120-V; instrumentation and control circuits operate at either 120-V ac, 125-V DC, or at millivolt level. All 120-V and 125-V circuits are protected against both overload and short circuits by either fuses or circuit breakers. The power levels on the millivolt circuits are so low that the probability of fire hazard due to short circuits is very low.

6. All control and indication is transmitted into the control room ensuring that no combustible process fluids are carried into the room.

7. Cables that penetrate the control room floor pass through firestops to minimize fume and flame transmission from possible fire sources external to the control room.

8. All internal wiring in switchboards and instrument racks is type SIS cross-linked polyethylene, which has excellent resistance to the propagation of flame. As a result of the design criterion discussed above, the amount of combustible material in the control room is of such small quantity that a fire of the magnitude that would require the evacuation of the control room is not credible.

As a further measure to ensure safety, provisions have been made so that plant operators can shut down and maintain the plant in a safe condition by means of controls located outside the control room. During such a period of control room inaccessibility, the reactor will be tripped and the plant maintained in a hot shutdown condition. If the period extends for a long time, the reactor coolant system can be borated to maintain shutdown as xenon decays.

In the unlikely event that the control room becomes inaccessible or the controls and/or instrumentation becomes nonfunctional due to a fire, the plant is equipped with an alternate safe shutdown system (ASSS) as discussed in Section 8.3, which provides the capability to safely shutdown and maintain the plant in a safe shutdown condition.

Abnormal operating procedures are in effect, to be used in their entirety or in part, to safely shutdown the plant in the event of inaccessibility of the control room. These procedures would be implemented based upon loss of normal and preferred alternate methods of control. These procedures do not include all the available normal methods of control described below.

The functions for which local control provisions have been made are listed below along with a brief description of the type of alternate controls and their location in the plant. Transfer to these local controls is annunciated in the central control room.

7.7.3.1 <u>Reactor Trip</u>

If the central control room should be evacuated suddenly without any action by the operators, the reactor can be manually tripped by any of the following:

1. Operation of the Reactor Trip Breakers' local trip button.
2. Tripping the Control Rod Drive MG Set breakers.
3. Tripping/opening of any one of the MG Set power supply sources.

Following evacuation of the central control room, the following systems and equipment are provided to maintain the plant in a safe shutdown condition from outside the central control room:

1. Residual heat removal.
2. Reactivity control, i.e., boron injection to compensate for fission product decay.
3. Pressurizer pressure and level control.
4. Electrical systems as required to supply the above systems.
5. Other equipment, as described.

7.7.3.1.1 Residual Heat Removal

Following a normal plant shutdown, an automatic steam dump control system bypasses steam to the condenser and maintains the reactor coolant temperature at its no-load value. This implies the continued operation of the steam dump system, condensate circuit, condenser cooling water, feed pumps, and steam-generator instrumentation. Failure to maintain water supply to the steam generators would result in steam-generator dry-out after some 2400 sec and loss of the secondary system for decay heat removal. Redundancy and full protection where necessary is built into the system to ensure the continued operation of the steam-generator units. If the automatic steam dump control system is not available, independently controlled relief valves on each steam generator maintain the steam pressure. These relief valves are further backed up by coded safety valves on each steam generator. Numerous calculations have shown that with the steam generator safety valves operating alone, the reactor coolant system maintains itself close to the nominal no-load condition. The steam relief facility is adequately protected by redundancy and local protection. For decay heat removal, it is only necessary to maintain the control on one steam generator.

For the continued use of the steam generators for decay heat removal, it is necessary to provide a source of water, a means of delivering that water and, finally, instrumentation for pressure and level indication.

The normal source of water supply is the secondary feed circuit; this implies satisfactory operation of the condenser, air ejector, condenser cooling circuit, etc. In addition to the normal feed circuit, the plant may fall back on:

1. The condensate storage tank.
2. The city water storage tank.
3. The city water supply.

Feedwater can be supplied to the steam generators by the two motor-driven auxiliary feedwater pumps or by the steam-driven auxiliary feedwater pump, these pumps and associated valves having local controls.

7.7.3.1.2 Reactivity Control

Following a normal plant shutdown to hot shutdown condition, soluble poison is added to the primary system to maintain subcriticality. For boron addition, the chemical and volume control system is used. Routine boration requires the use of the following:

1. Charging pumps and volume control tank with associated piping.

2. Boric acid transfer pumps with tanks and associated piping. (Not included in abnormal operating instructions on control room inaccessibility).

3. Letdown station, nonregenerative heat exchanger and associated equipment, component cooling, and service water systems. Compressed air for manual valve operation could be adopted if necessary.

It is worthy of note that with the reactor held at hot shutdown conditions, the boration of the plant is not required immediately after shutdown. The xenon transient does not decay to the equilibrium level until about 20 hr for 100-percent power shutdown. However, for other power levels, this decay

decay time can be lower, that is, as much as 5 hr for a 10-percent power shutdown. A further period would elapse before the 1-percent reactivity shutdown margin provided by the full-length control rods has been cancelled. This delay would provide useful time for emergency measures.

7.7.3.1.3 Pressurizer Pressure and Level Control

Following a reactor trip, the primary temperature will automatically be reduced to the no-load temperature condition as dictated by the steam-generator temperature conditions. This reduction in the primary water temperature reduces the primary water volume, and if continued pressure control is to be maintained, primary water makeup is required.

The pressurizer level is controlled in normal circumstances by the chemical and volume control system. This implies the charging pump duty referred to for boration plus a guaranteed borated water supply. The facility for boration is provided as described above; it is only necessary to supply water for makeup. Water may readily be obtained from normal sources, that is, the volume control tank.

7.7.3.2 Startup of Other Equipment

The containment air recirculation fan coolers should be continued in operation to remove heat generated within the containment building. If they have stopped, at least one should be restarted within 5 min with the others started later as required. Similarly the nuclear service water pumps are to be checked and at least one of them restarted if none are already operating. The fan coolers and the service water pump remote controls are located in the switchgear room.

Offsite or onsite emergency power should be available to supply the above systems and equipment for the hot shutdown condition.

7.7.3.3 Indications and Controls Provided Outside the Central Control Room

The specific indications and controls provided outside the central control room for the above capabilities are summarized in the following sections.

7.7.3.3.1 Indications

1. Level indication for the individual steam generators. One set for local control of steam generator level is visible from the auxiliary feedwater pump area; another set is visible from the main feedwater control valve area.

2. Pressure indication for the individual steam generators, visible from the auxiliary feedwater pump area.

3. Pressurizer level and pressure indicators. One set is visible from the auxiliary feedwater pump area, and one set is in the primary auxiliary building in the vicinity of the charging pump local control point. All instruments at the auxiliary feedwater pumps are grouped on a local gauge board.

4. Level indicators for steam generators 21 and 22 are located in the primary auxiliary building in the vicinity of the charging pumps.

7.7.3.3.2 Controls

Local stop/start motor controls with a local/remote selector switch are provided at each of the following motors. The selector switch will transfer the control of the switchgear from the central control room to "local" at the motor. Placing the local selector switch in the local operating position will give an annunciator alarm in the central control room and will turn out the motor control position lights on the central control room panel.

1. Auxiliary motor-driven feedwater pumps.
2. Charging pumps.
3. Boric acid transfer pumps. (Not included in administrative operating instructions on control room inaccessibility).

Local stop/start motor controls with a local/remote selector switch are provided for each of the following motors. These controls are grouped at one point in the switchgear room convenient for operation. The selector switch will transfer the control of the switchgear from the central control room to this local point. Placing the selector switch to local operation will give an annunciator alarm in the central control room and will turn out the motor control position lights on the central control room panel.

1. Service water pumps.
2. Containment air recirculation fans.
3. Central control room air-handling unit, including control for the air inlet dampers.

Alternative motor control points are not required for the following:

1. Component cooling water pumps. (Automatically restarted on a blackout once the diesel generators are operating.)
2. Instrument air compressors and cooling pumps. (These will start automatically on low pressures in the air and water services once the diesel automatically energizes the bus and the motor control centers are manually energized. The control point is local to the compressors. The compressors must be initially re-energized after the motor control centers are reset.)

7.7.3.3.3 Speed Control

Speed control is provided locally for the following:

1. Auxiliary turbine-driven feedwater pump.
2. Charging pumps.

7.7.3.3.4 Valve Control

Local valve control is provided at the following:

1. Main feedwater regulators.
2. Auxiliary feedwater control valves.(These valves are located local to the auxiliary feedwater pumps.)
3. Atmospheric dump (auto control normally at hot shutdown).
4. All other valves requiring operation during hot standby can be locally operated at the valve.

5. Letdown orifice isolation valves local to the charging pumps. Local control (e.g., "close-remote-open" selector switches) and indication (e.g., valve "open" position indicating lights) are provided for the regenerative heat exchanger letdown outlet flow control orifice isolation valves and the letdown inlet stop valve.

7.7.3.3.5 Pressurizer Heater Control

Stop and start buttons with selector switch and position lamp are provided locally at the charging pumps for Pressurizer Backup Heater Group 21.

7.7.3.3.6 Lighting

Emergency lighting is provided in all operating areas. In addition, fixed battery pack emergency lighting units with at least an 8-hr battery power supply have been installed in areas needed for operation of safe-shutdown equipment and in access and egress routes to and from these areas in accordance with the requirements of 10 CFR 50, Appendix R.

7.7.3.3.7 Central Control Room Emergency Lighting

The emergency lighting in the central control room (CCR) consists of a combination of AC and DC lighting. These lights are strategically located to illuminate the instrument panels, flight panel, supervisory control panels, and the operator's desk. The normal voltage supply for CCR lighting is the AC lighting panels. The CCR emergency lighting is normally deenergized. If the CCR normal AC lighting failed, the CCR emergency AC or emergency DC lighting would illuminate. The CCR DC emergency lighting is supplied from Unit 2 Battery #21, whereas, the CCR AC emergency lighting is supplied from the Unit 1 M-G Sets. In addition, dual-lamp battery pack emergency lighting fixtures and remote-mounted battery pack emergency lighting fixture spotlights are located in the CCR, to provide additional illumination for the supervisory panel, flight panel, and accident assessment panel.

7.7.4 <u>Communications</u>

Plant communications are conducted via telephone, radio, and Public Address (paging) systems.

The plant telephone and radio communications systems include two (2) PBX electronic switches, backup phone lines and a UHF radio system. A third PBX electronic switch is located at the Buchanan Service Center (EOF).

The public address system for Indian Point Unit 2 consists of "Page" and "Party" communications, which are common to both the primary (nuclear) and secondary (conventional) portions of Units 1 and 2. The “Page” and “Party” communications are also monitored at a speaker panel located in the CCR. Two radio channels are available at the Indian Point Unit 2 control room. These radio channels are as follows:

1. Central radio channel - Provides the central control room with radio communication to the Con Edison system operator.

2. Indian Point area radio - Provides the central control room with radio communication to the emergency operation facilities, offsite monitoring teams, and the site security forces.

If the control room were to become inaccessible, safe shutdown communications would be conducted with the use of portable radios. This in-house radio system is also provided for communicating with in-plant personnel throughout the plant.

7.7.4.1 Central Control Room Communication Facilities

The central control room is provided with telephone-radio-page/party communication consoles and page/party handset stations.

The consoles have automatic pushbutton dialers which are capable of storing telephone numbers and which will automatically dial a selected number at the touch of a button. Dedicated point-to-point private lines, PBX extensions, direct outside auxiliary lines, and hotlines are assigned to these pushbuttons.

A State/County Radiological Emergency Communication System (RECS) hotline is available. The NRC Emergency Notification System (ENS) hotline is available in a separate location.

A separate printer and its telephone modem is also available for meteorological data reception.

7.7.4.2 Radio Communication

The two radio channels are available at the radio/page/party line consoles in the central control room.

The station-type transceivers for the radio channels are located in the elevator machine room of Indian Point Unit 1. Wired audio/control pairs connect the station-type transceivers with the communication consoles in the central control room for remote operation.

7.7.4.3 Page/Party Line Communication

“Page” or “Party” line communication can be initiated in the CCR from either communication consoles or from handset stations.

An emergency alarm switch is provided in the CCR to connect and actuate the existing alarm oscillators to the “Page” system for the "Evacuation," "Fire," or "Air Raid" alert signals.

Another switch is provided on the central control room desk, which allows all outdoor speakers of the Indian Point 2 plant to be turned off at night.

7.7.4.4 Emergency Backup Power for Communications

The plant radio and telephone communications systems are automatically supplied from a back-up power source, upon failure of the normal power source. In addition, each PBX is provided with two (2) battery chargers (rectifiers) and a back-up battery capable of eight (8) hours of operation. The page/party system is powered from the DC system (through an inverter) with backup power from the emergency bus.

7.7.4.5 In-house Radio System

An in-house radio system provides communications between the Technical Support Center, the I&C office, and in-plant personnel. Field units are low-wattage, hand-held units, which are not to be used in areas containing equipment, which is potentially sensitive to radio-frequency interference.

REFERENCES FOR SECTION 7.7

1. Letter from J.D. O'Toole, Con Edison, to Hugh L. Thompson, NRC, Subject: Indian Point Unit 2 Detailed Control Room Design Review Final Summary Report, dated June 30, 1986.

2. Letter from S. Bram, Con Edison, to Document Control Desk, NRC, Subject: Safety Assessment System/Safety Parameter Display System (SAS/SPDS) Safety Analysis Report, Revision 1, dated April 30, 1988.

3. Letter from M. M. Slosson, NRC, to S. B. Bram, Con Edison, Subject: Safety Evaluation Report - Detailed Control Room Design Review Summary Report For Indian Point Nuclear Generating Unit No. 2 (TAC 56131), dated January 12, 1989.

7.7 FIGURES

Figure No.	**Title**
Figure 7.7-1	Deleted

7.8 LIMITING SAFETY SYSTEM SETTINGS AND LIMITING CONDITIONS FOR OPERATION

Table 7.2-1 lists the reactor protection, engineered safety features, and other plant protection actuation systems. Table 7.2-2 lists associated plant interlocks and permissive circuits. Settings for these functions for safe plant operation are given in the facility Technical Specifications or Technical Requirements Manual.

7.9 SURVEILLANCE REQUIREMENTS

Channel surveillance action (i.e., test, calibration, or check function) to be taken during the operation of the plant and the minimum frequencies (each refueling, shift, or month) for the indicated instrument channels are included in the Technical Specifications or Technical Requirements Manual.

The instrumentation channels that are covered include, for example, nuclear, reactor coolant temperature and flow, pressurizer pressure and level, and auxiliary process channels or components necessary to ensure that facility operation is maintained within the safe limits. The frequencies of periodic tests and checks of related systems and/or system components are also included in the Technical Specifications or Technical Requirements Manual.

7.10 ANTICIPATED TRANSIENT WITHOUT SCRAM MITIGATION SYSTEM ACTUATION CIRCUITRY

In response to NRC requirements, Indian Point Unit 2 has been modified to incorporate features to protect against anticipated transients without scram (ATWS). These provisions are the ATWS mitigation system actuation circuitry (AMSAC), described in this section.

7.10.1 Design Bases

The Indian Point Unit 2 AMSAC provides a means, diverse from the reactor protection system, to trip the turbine, start the auxiliary feedwater pumps, and initiate closure of the steam generator blowdown isolation valves. It was designed to meet the requirements of 10CFR50.62. The NRC Staff has concluded[1] that the design is acceptable and is in compliance with the ATWS Rule, 10CFR50.62, paragraph (c) (1).

The Indian Point Unit 2 AMSAC design is based on a modified Logic 1 option as described in Reference 2. The plant specific modification involves the deletion of permissive and time delay circuits, which is conservative compared to the generic design.

AMSAC utilizes signals from existing steam generator narrow-range level transmitters associated with other systems. It actuates immediately on a predetermined level in any three steam generators.

The logic power supplies for the AMSAC system components are independent from the power supplies for the reactor protection system. AMSAC is capable of performing its intended function without off-site power.

Alarm and/or annunciation is provided for AMSAC actuation, bypass or removal from service, and deviations such as loss of power or partial trip.

7.10.2 System Design

AMSAC receives signals from one steam generator narrow-range level transmitter per steam generator. Bistables give trip signals on level below the setpoint, which is between 5 and 8-percent of the transmitter span. Either of two relay logic channels provides AMSAC actuation on low level in any three steam generators.

AMSAC was designed and components selected to provide diversity from the reactor protection system. Electrical isolation from both protection and control systems is also provided.

Power is supplied to the relay logic channels, which are energized to trip, from separate class 1E 125-VDC battery-backed distribution panels.

A two-position bypass switch, four test pushbuttons, and a status-indicating light are provided for each logic channel, allowing surveillance testing a maintenance to be performed during reactor operation. Bypassing either channel actuates an annunciator. While one channel is bypassed for testing, the other remains capable of performing its mitigation function.

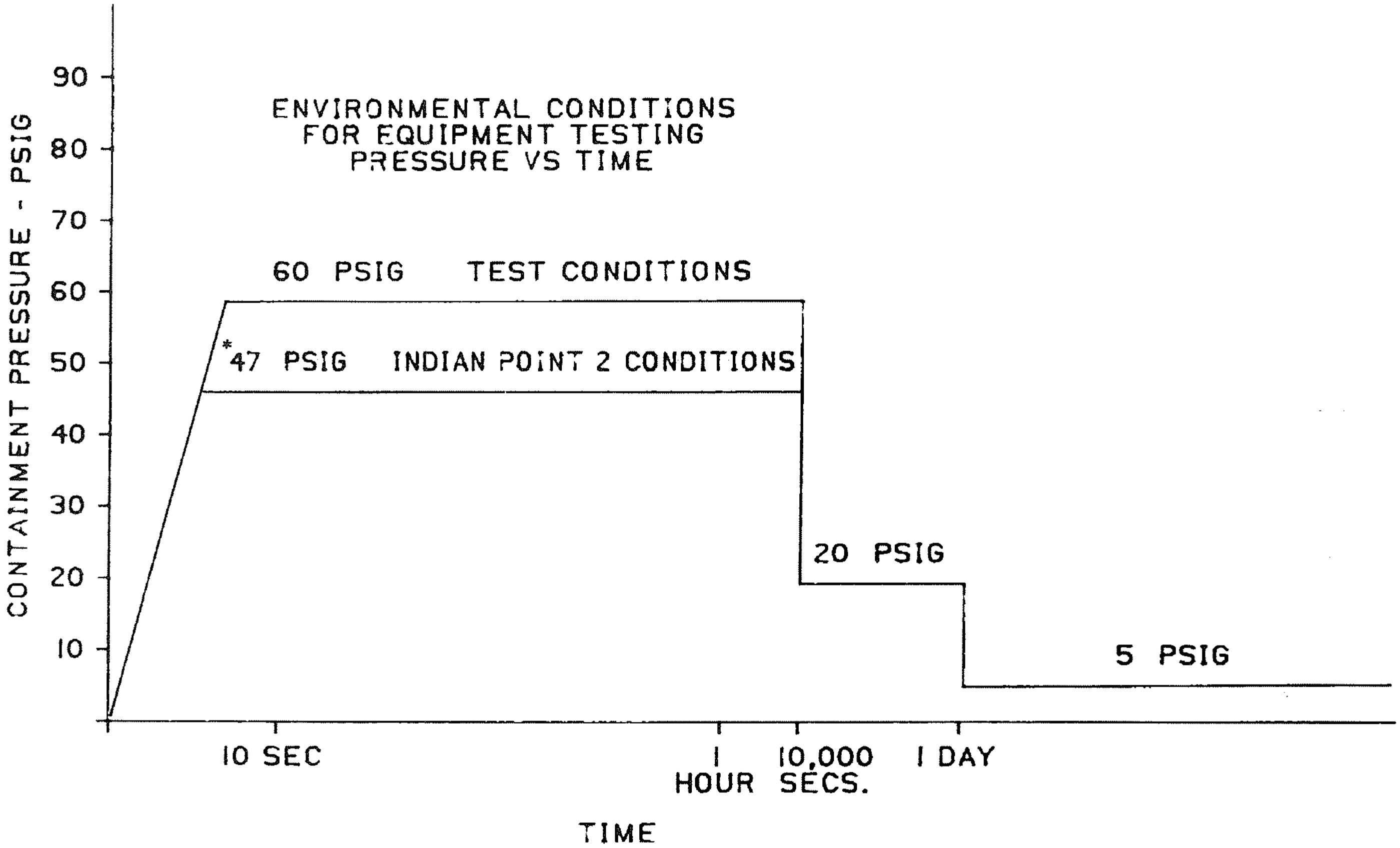
The AMSAC system does not affect either manual or automatic actuation of turbine trip or auxiliary feedwater initiation. These circuits are self-latching such that their actions will go to completion if initiated, and subsequent operator action is required to reset them.

REFERENCES FOR SECTION 7.10

1. Letter from Donald S. Brinkman, NRC, to Stephen B. Bram, Con Edison, subject: Indian Point Unit 2 ATWS RULE (10CFR50.62) (TAC NO. 59103), dated May 16, 1989.

2. WCAP-10858-P-A, Rev. 1

*40.6 PSIG BASED ON MAY 21, 1981 NRC STAFF SER AND CONSOLIDATED EDISON RESPONSE OF SEPTEMBER 4, 1981 (REFERENCE 11) TO THAT SER. 47 PSIG REMAINS THE CONTAINMENT DESIGN BASIS AND PROVIDES ADDITIONAL MARGIN



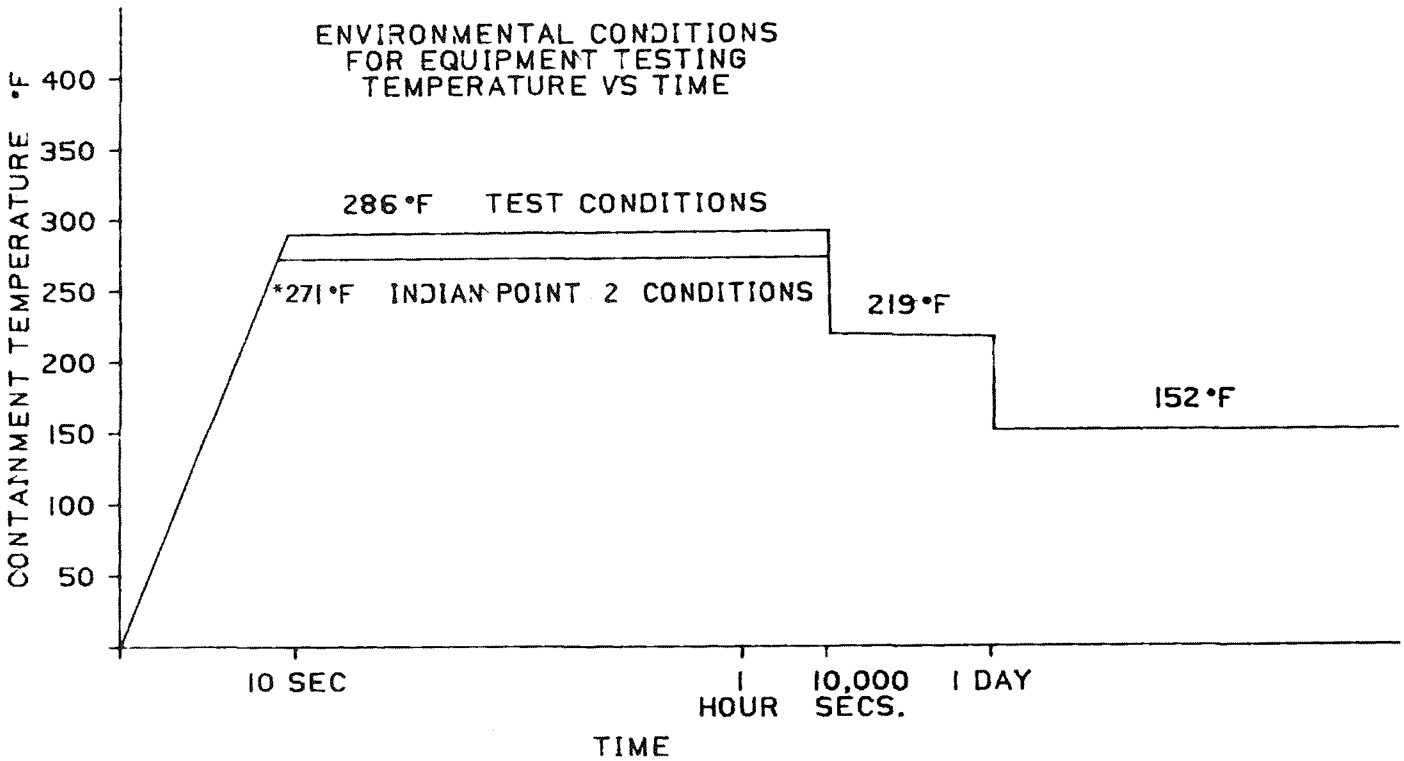
INDIAN POINT UNIT No. 2

UFSAR FIGURE 7.1-1

ENVIRONMENTAL CONDITIONS FOR EQUIPMENT TESTING – PRESSURE vs TIME

MIC. No. 1999MC3869	REV. No. 17A

*287°F BASED ON THE MAY 21, 1981 NRC STAFF SER AND CONSOLIDATED EDISON RESPONSE OF SEPTEMBER 4, 1981 (REFERENCE 11) TO THAT SER (BASED ON 40.6 PSIG AND SATURATED CONDITIONS)

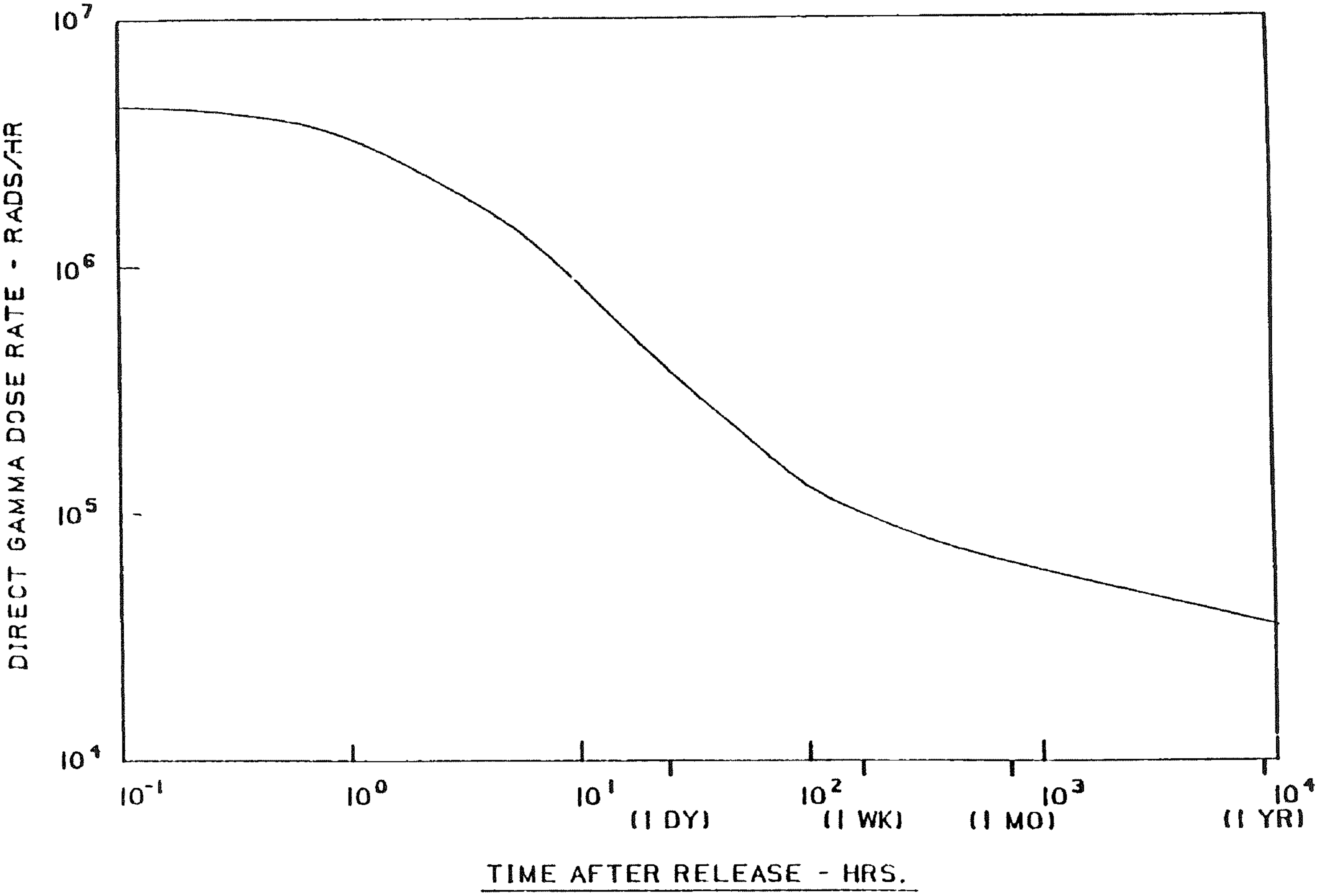


INDIAN POINT UNIT No. 2

UFSAR FIGURE 7.1-2

ENVIRONMENTAL CONDITIONS FOR EQUIPMENT-TEMPERATURE vs TIME

MIC. No. 1999MC3870 | REV. No. 17A

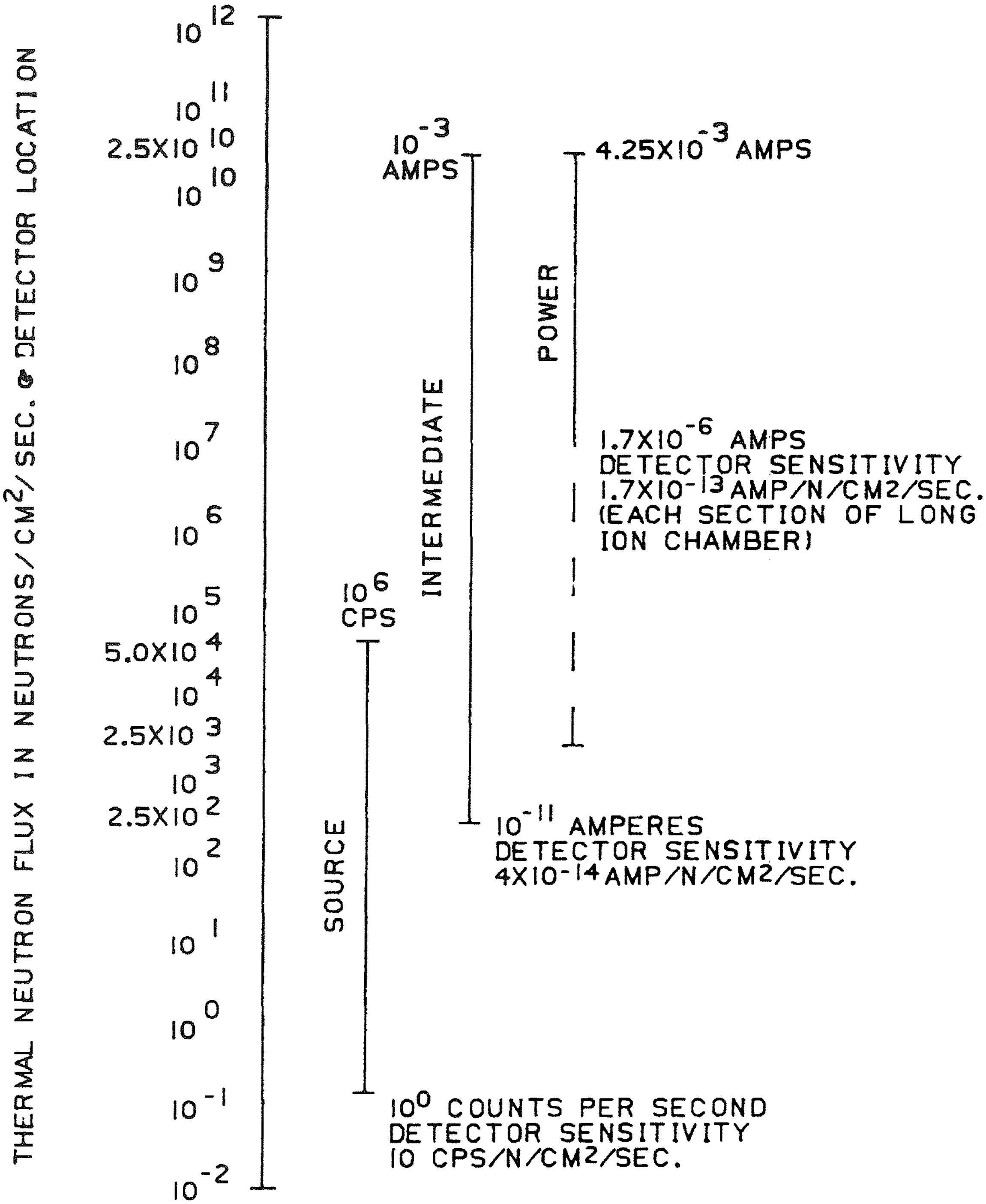


INDIAN POINT UNIT No. 2

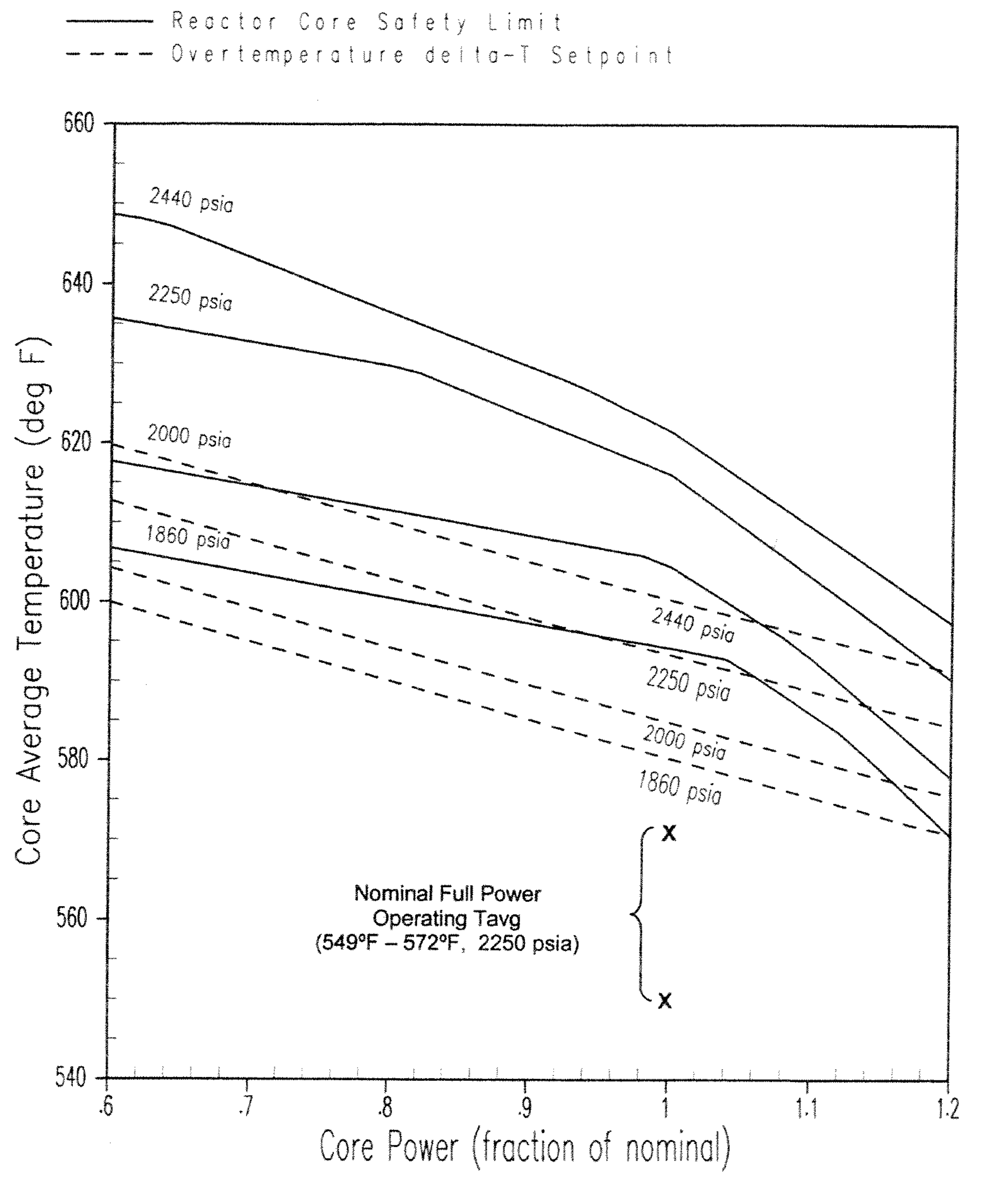
UFSAR FIGURE 7.1-3

INSTANTANEOUS GAMMA DOSE RATE INSIDE THE CONTAINMENT AS A FUNCTION OF TIME AFTER RELEASE – TID-14844 MODEL

MIC. No. 1999MC3871	REV. No. 17A



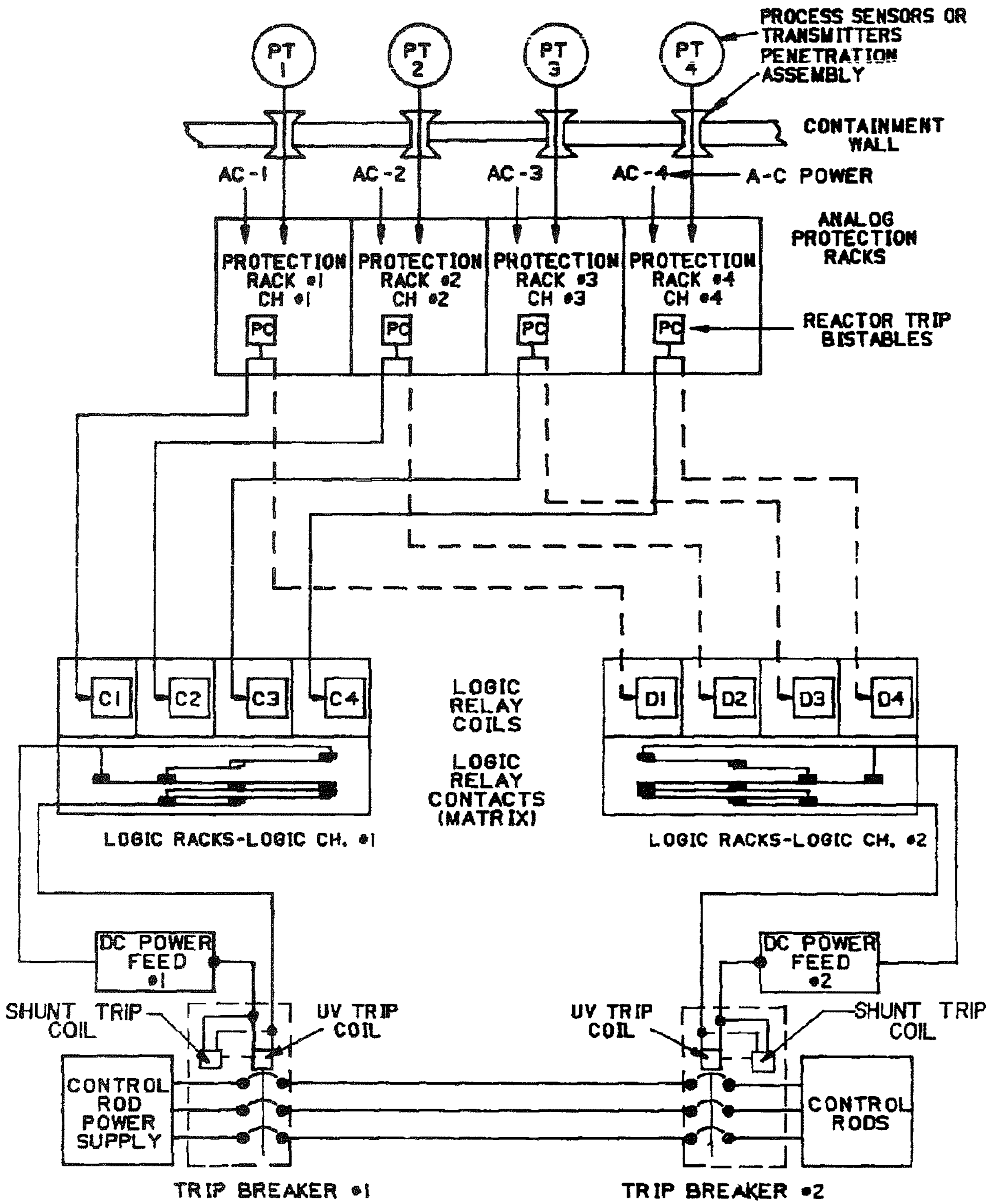
INDIAN POINT UNIT No. 2	
UFSAR FIGURE 7.4-1 NEUTRON DETECTORS AND RANGE OF OPERATION	
MIC. No. 1999MC3877	REV. No. 17A



INDIAN POINT UNIT No. 2

CORE AVERAGE TEMPERATURE vs FRACTION OF NOMINAL POWER

UFSAR FIGURE 7.2–19	REV. No. 19

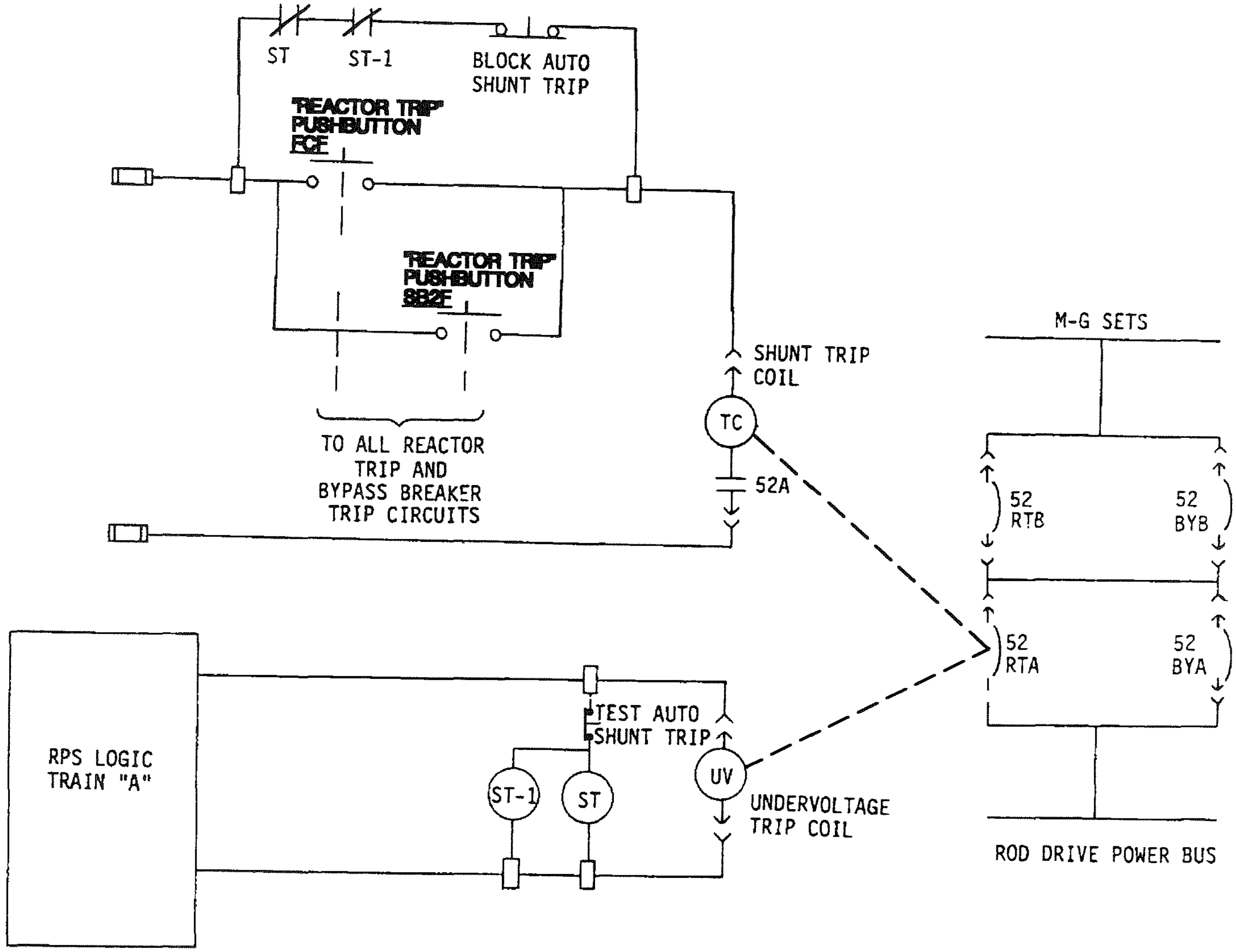


INDIAN POINT UNIT No. 2

UFSAR FIGURE 7.2–23

DESIGN PHILOSOPHY TO ACHIEVE ISOLATION BETWEEN CHANNELS

MIC. No. 1999MC3901	REV. No. 17A

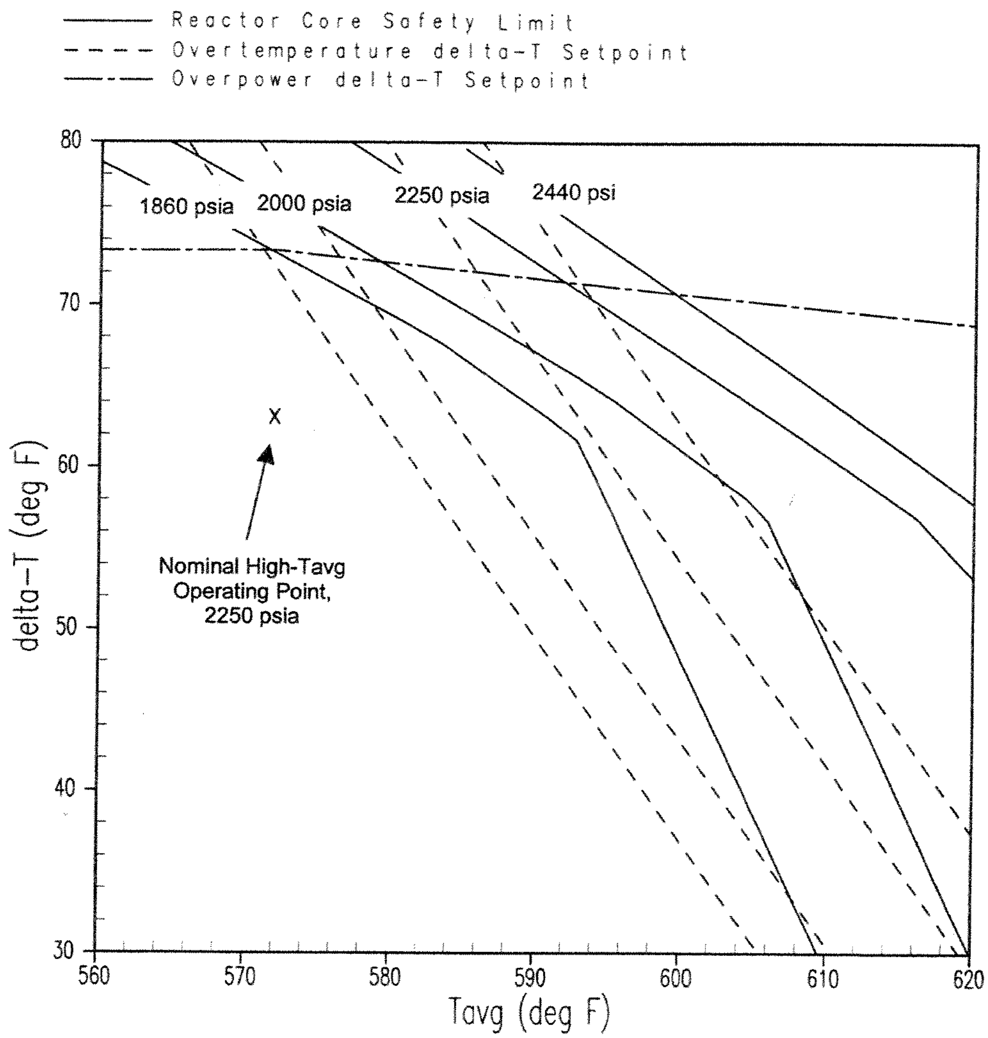


INDIAN POINT UNIT No. 2

UFSAR FIGURE 7.2-30

REACTOR TRIP BREAKER
ACTUATION SCHEMATIC

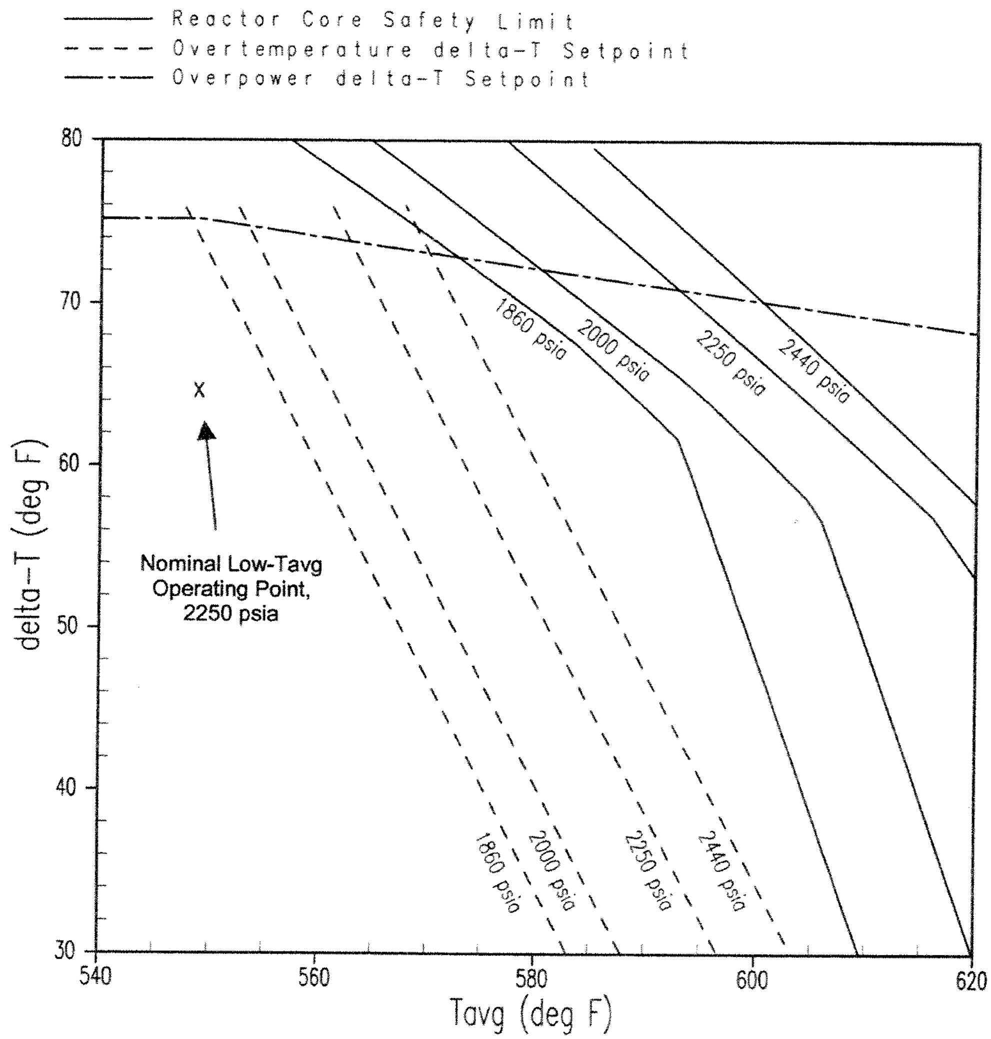
MIC. No. 1999MC3874 | REV. No. 17A



INDIAN POINT UNIT No. 2

ILLUSTRATION OF OVERPOWER and OVERTEMPERATURE $\triangle$T TRIPS HIGH TEMPERATURE OPERATION

UFSAR FIGURE 7.2-33,sht.1	REV. No. 19

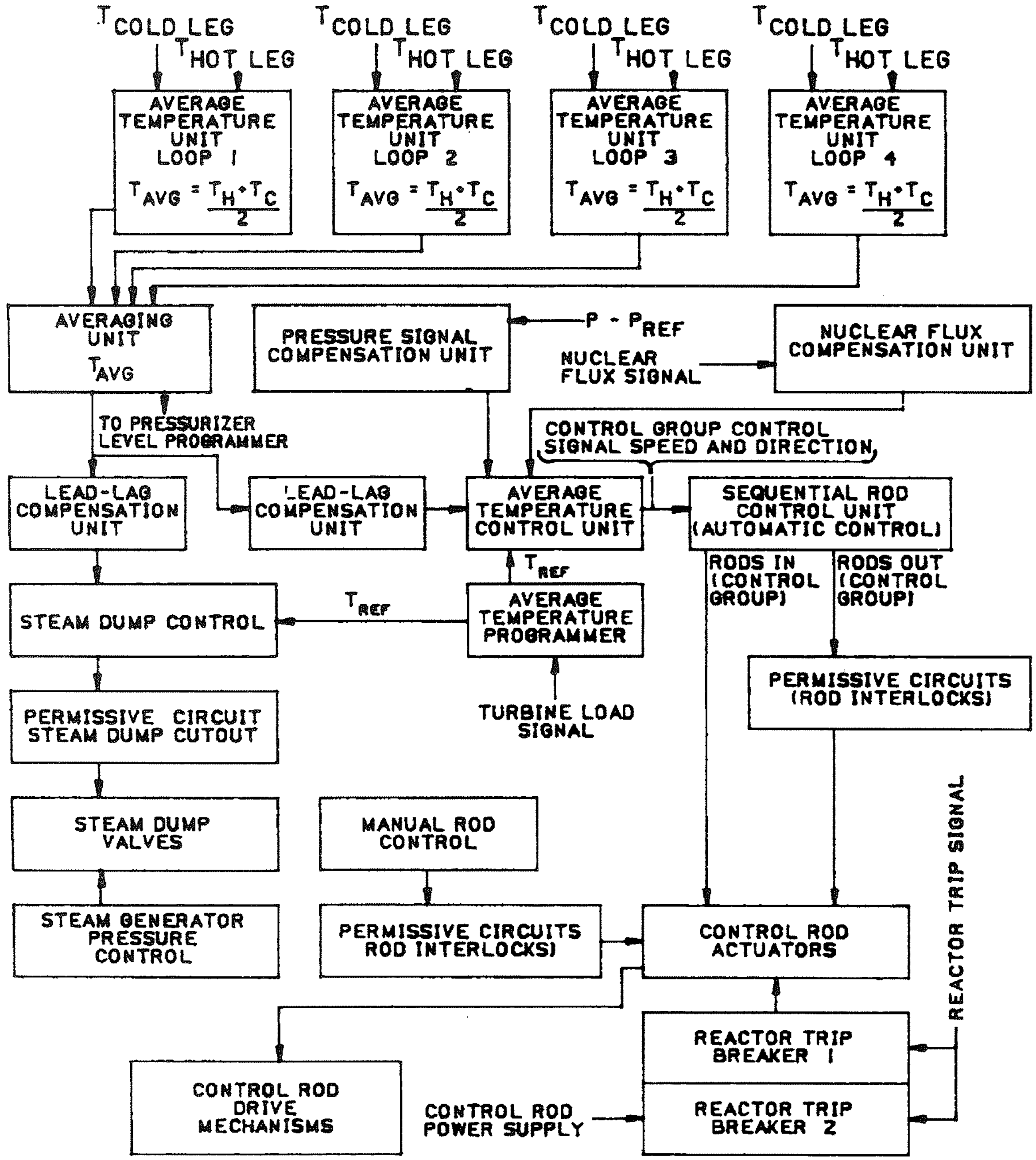


INDIAN POINT UNIT No. 2

ILLUSTRATION OF OVERPOWER and OVERTEMPERATURE △T TRIPS LOW TEMPERATURE OPERATION

UFSAR FIGURE 7.2–33,sht.2	REV. No. 19

NOTES:
1. TEMPERATURES ARE MEASURED AT STEAM GENERATOR'S INLET AND OUTLET.
2. PRESSURE IS MEASURED AT THE PRESSURIZER.

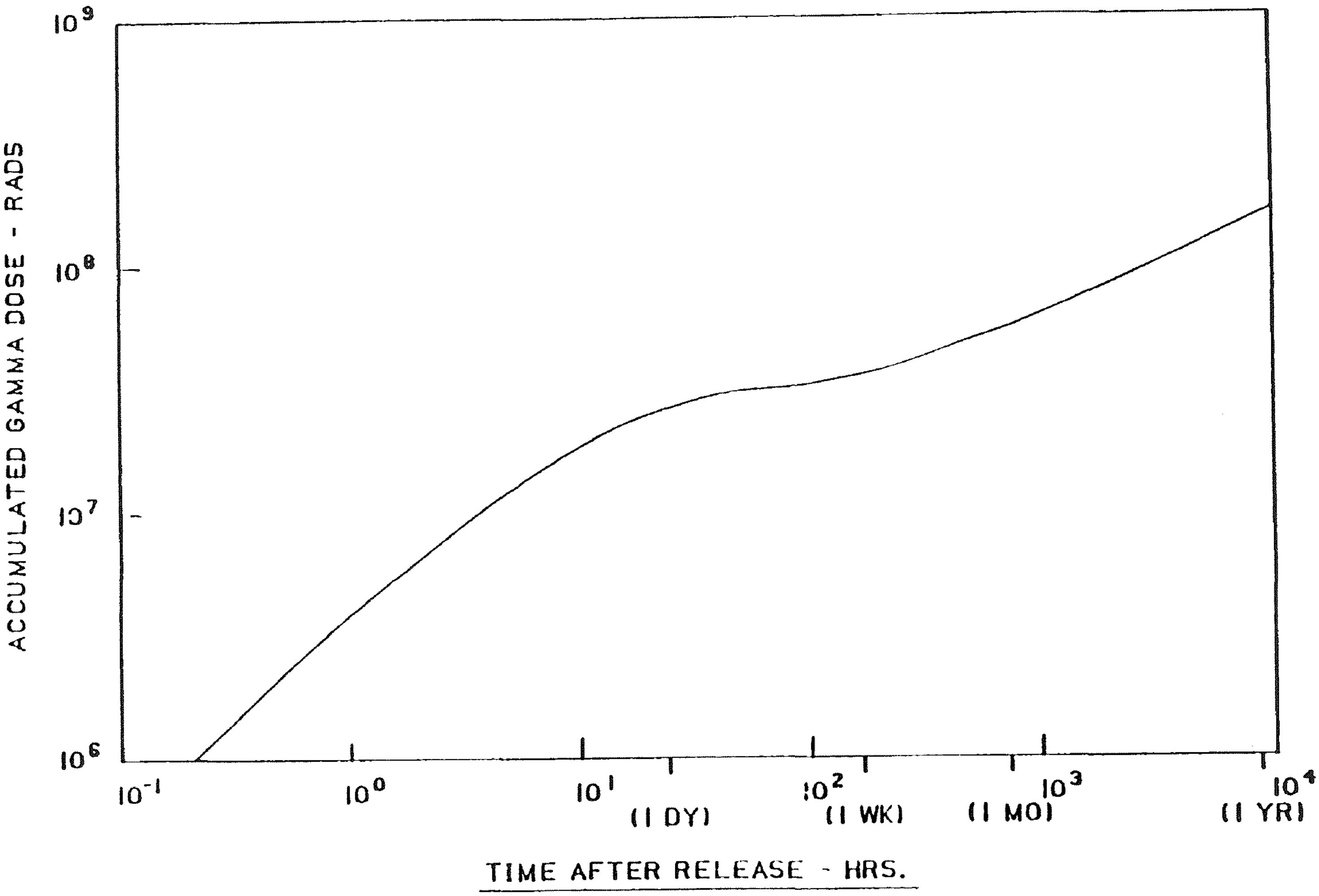


INDIAN POINT UNIT No. 2

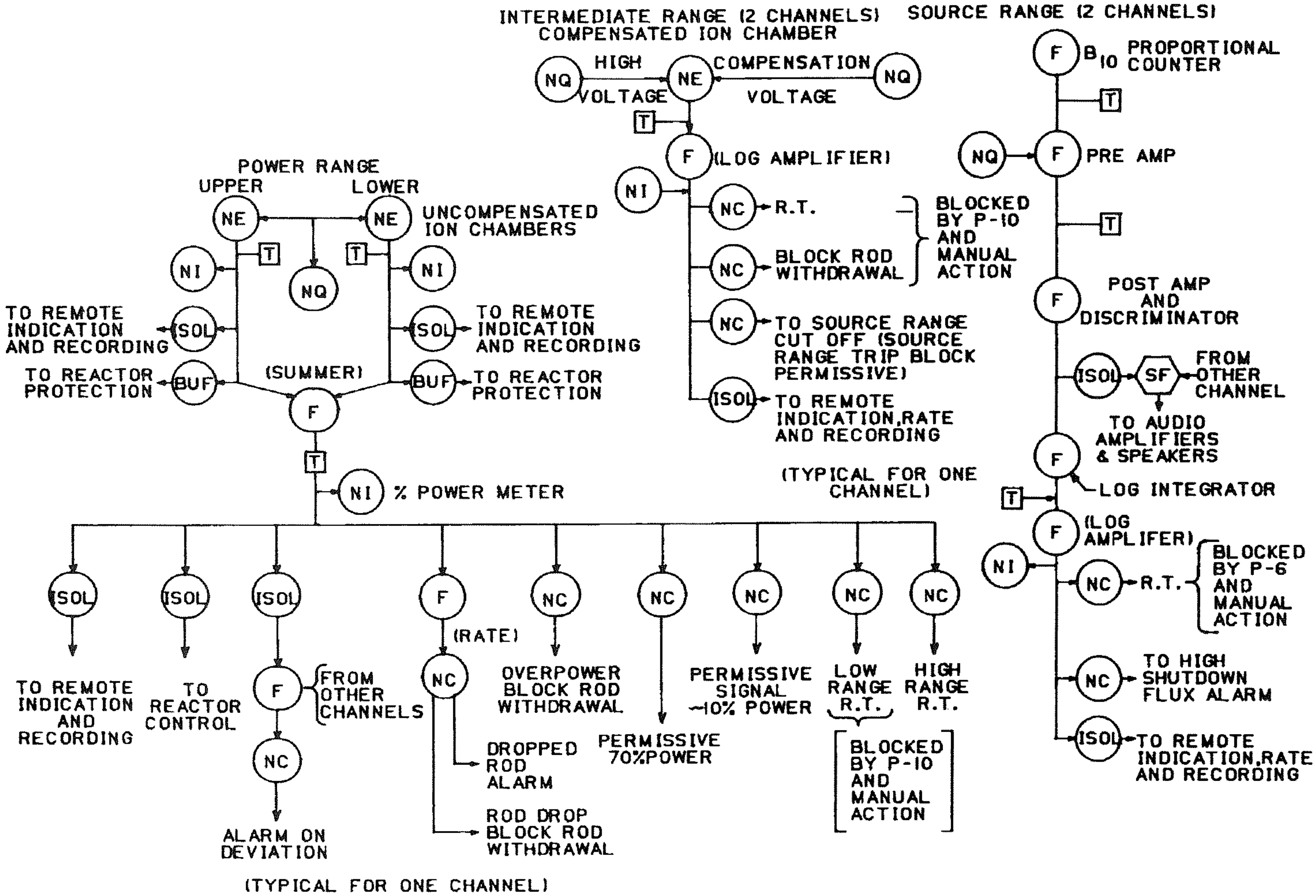
UFSAR FIGURE 7.3–1

SIMPLIFIED BLOCK DIAGRAM OF REACTOR CONTROL SYSTEMS

MIC. No. 1999MC3876	REV. No. 17A



INDIAN POINT UNIT No. 2	
UFSAR FIGURE 7.1-4 INTEGRATED GAMMA DOSE RATE INSIDE THE CONTAINMENT AS A FUNCTION OF TIME AFTER RELEASE - TID-14844 MODEL	
MIC. No. 1999MC3872	REV. No. 17A

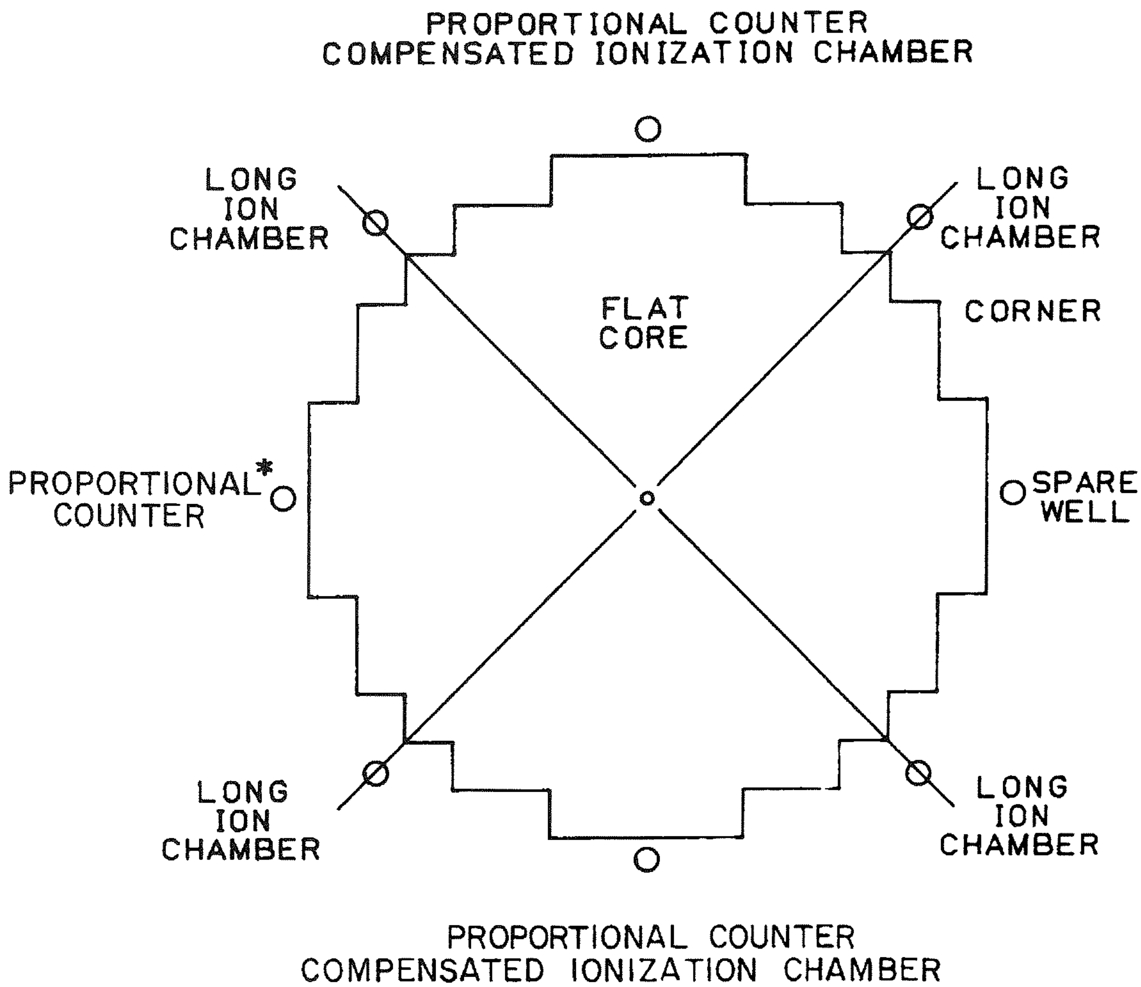


INDIAN POINT UNIT No. 2

UFSAR FIGURE 7.4-2

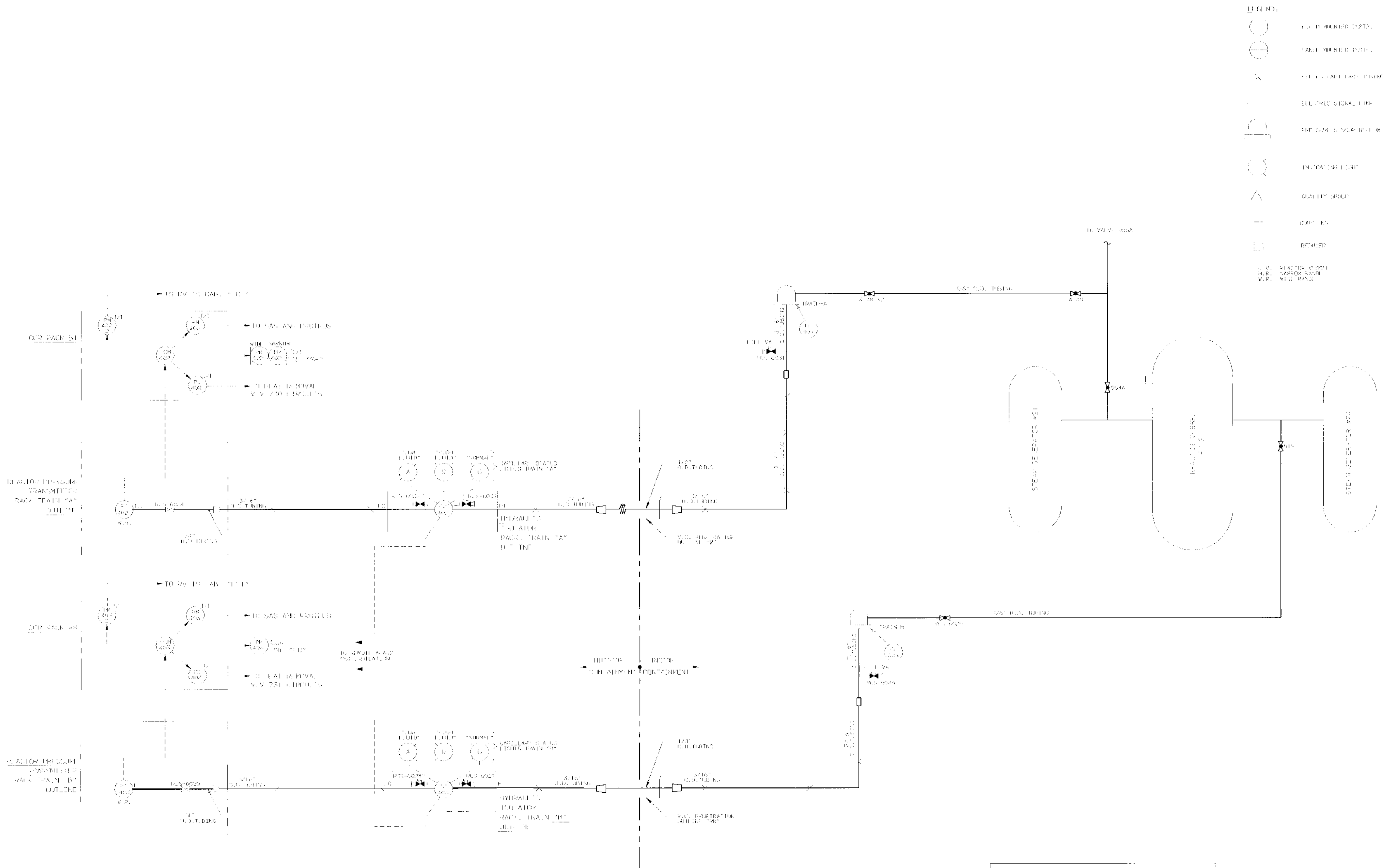
NUCLEAR INSTRUMENTATION SYSTEM

MIC. No. 1999MC3878	REV. No. 17A



* PART OF THE ALTERNATE SAFE-SHUTDOWN SYSTEM INSTRUMENTATION.

INDIAN POINT UNIT No. 2	
UFSAR FIGURE 7.4–3 PLAN VIEW INDICATING DETECTOR LOCATION RELATIVE TO CORE	
MIC. No. 1999MC3879	REV. No. 17A



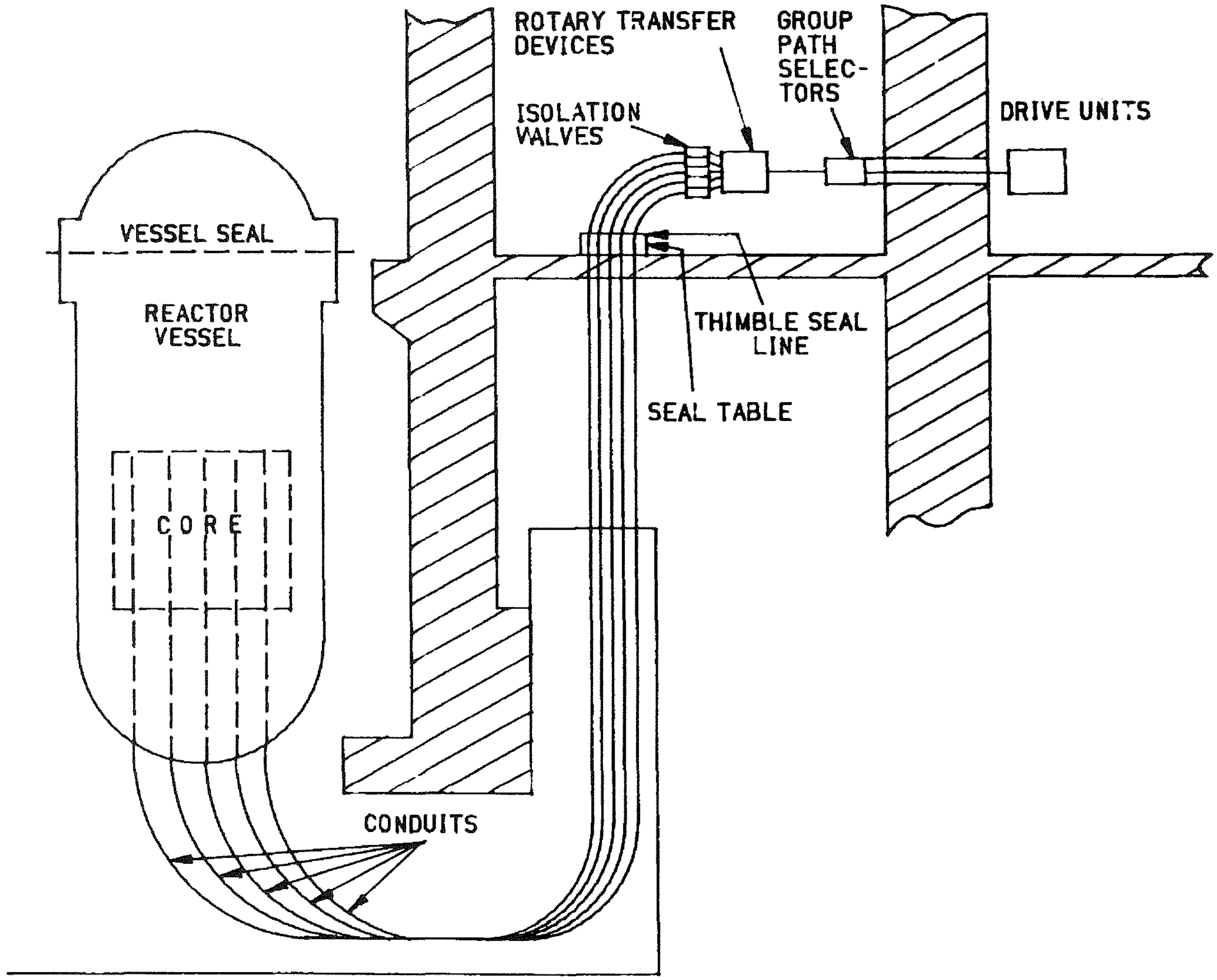
INDIAN POINT UNIT No. 2

UFSAR FIGURE 7.5-1

REACTOR COOLANT WIDE RANGE PRESSURE INSTRUMENT SYSTEM - FLOW DIAGRAM

MIC. No. 1999MC3543 REV. No. 17A

VALVE POSITIONS ARE NOT CONTROLLED BY THIS FIGURE

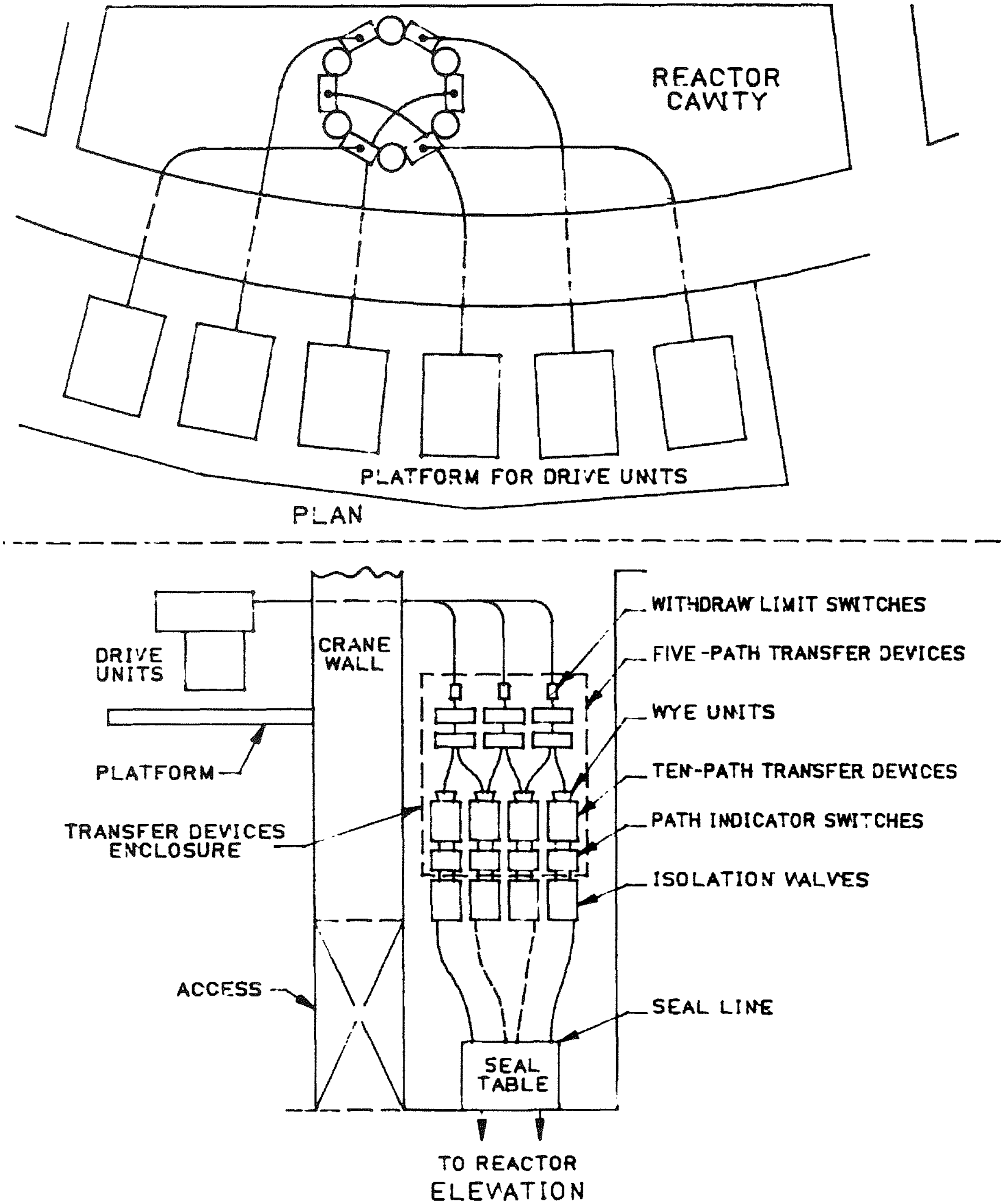


INDIAN POINT UNIT No. 2

UFSAR FIGURE 7.6-1

TYPICAL ARRANGEMENT OF MOVABLE MINIATURE NEUTRON FLUX DETECTOR SYSTEM

MIC. No. 1999MC3880	REV. No. 17A

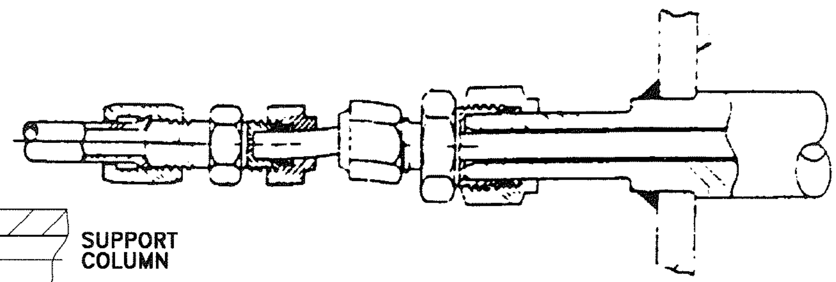


INDIAN POINT UNIT No. 2

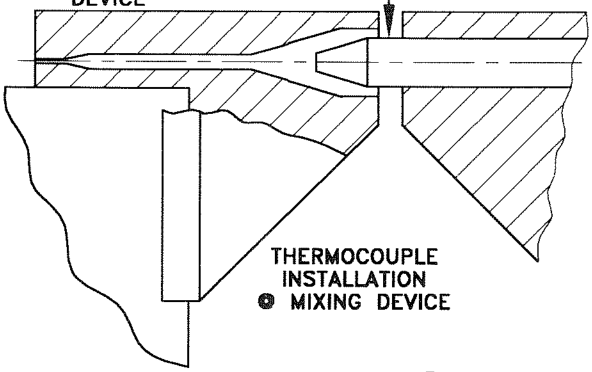
UFSAR FIGURE 7.6-2

ARRANGEMENT OF INCORE FLUX DETECTOR

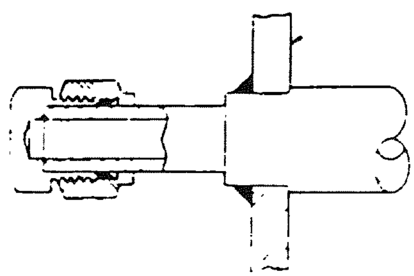
MIC. No. 1999MC3881	REV. No. 17A



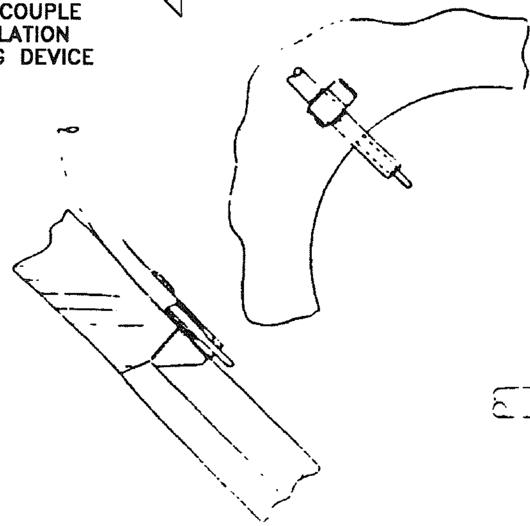
THIMBLE HIGH PRESSURE SEAL



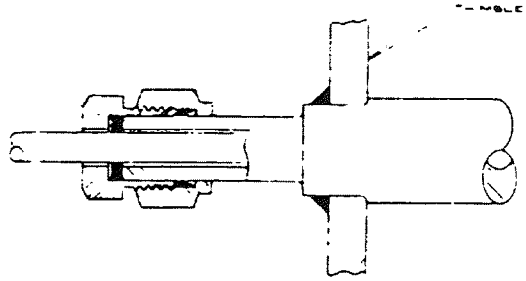
THERMOCOUPLE
INSTALLATION
@ MIXING DEVICE



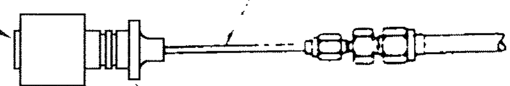
THIMBLE SEAL PLUG
(HYDROSTATIC TEST)



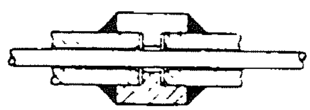
THERMOCOUPLE END MOUNT



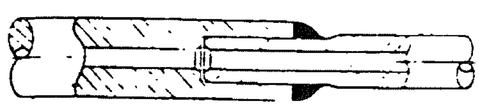
THIMBLE LOW PRESSURE SEAL
(REFUELING ONLY)



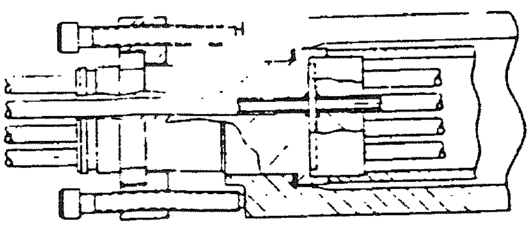
THERMOCOUPLE CONNECTOR TO
MI CABLE CONNECTOR ASSEMBLY



THIMBLE CONDUIT WELD UNION



THIMBLE CONDUIT TO VESSEL PENETRATION TUBE WELD JOINT



THERMOCOUPLE CONDUIT TO VESSEL SEAL

INDIAN POINT UNIT No. 2

UFSAR FIGURE 7.6-3

INCORE INSTRUMENTATION – DETAILS

MIC. No. 1999MC3882	REV. No. 17A

REVISIONS

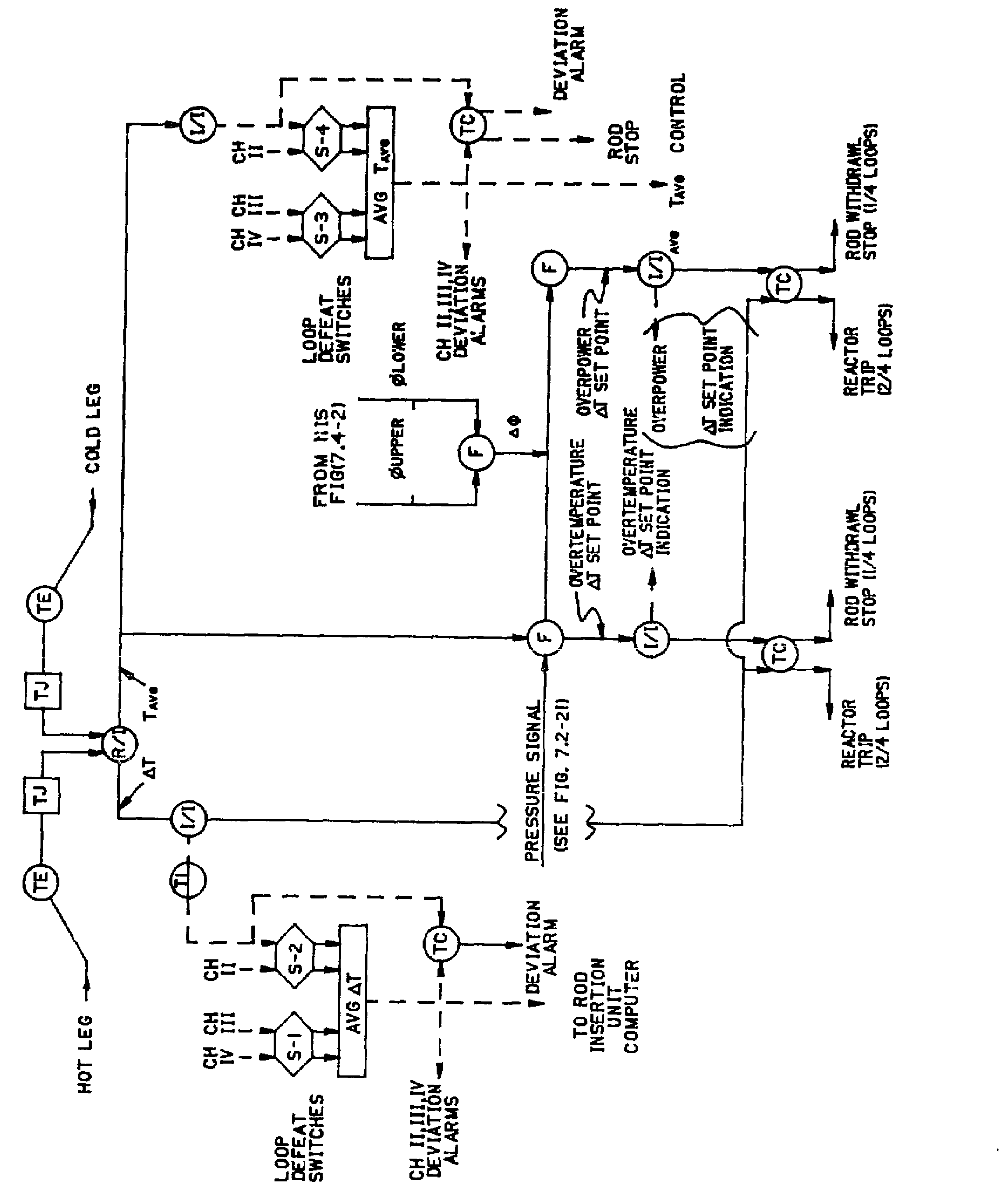
		O

THIS REV. IS NON-CLASS. AS PER CI-240-1 RELEASED FOR INFO ONLY PN 32357 4-24-85

V.I. 4/18/99	01

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO INCLUDE UFSAR FIG. NO. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA 4/18/99

STRATUS ENGINEERING



T_{AVG}/ΔT CONTROL AND PROTECTION SYSTEM (SINGLE CHANNEL)

01

MI

STATION- INDIAN POINT 2	APPROVALS	CHIEF DESIGN ENG. 3/14/85	CONSOLIDATED EDISON CO. OF N.Y., INC.
UFSAR FIGURE NO. 7.2-34		DE ENG. 9/9/85	DWG. NO. E 243330-01
DRAWN BY KC/KU CHECKED			
SCALE NONE J.O. 32357-00		ENG.	RECORDED

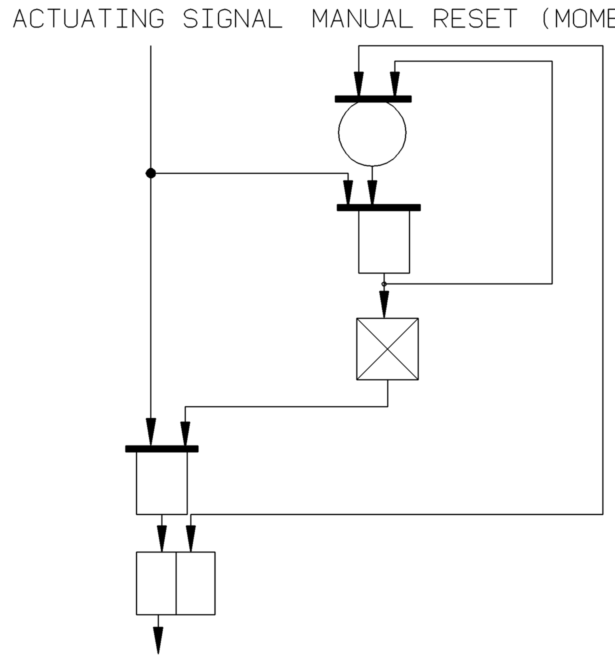
57952

92906 GEN ENG.

LOGIC SYMBOLS

(REF: NEMA STANDARD ICI-OCT. 1961)

SYMBOL	LOGIC FUNCTION	
2/2	AND	A DEVICE WHICH PRODUCES AN OUTPUT ONLY WHEN EVERY INPUT IS ENERGIZED.
	NOT	A DEVICE WHICH PRODUCES AN OUTPUT ONLY WHEN THE INPUT IS NOT ENERGIZED.
1/2	OR	A DEVICE WHICH PRODUCES AN OUTPUT WHEN ONE INPUT (OR MORE) IS ENERGIZED.
	OFF-RETURN MEMORY	A DEVICE WHICH RETAINS THE CONDITION OF OUTPUT CORRESPONDING TO THE INPUT LAST ENERGIZED EXCEPT UPON INTERRUPTION OF POWER IT RETURNS TO THE OFF CONDITION.
	RETENTIVE MEMORY	A DEVICE WHICH RETAINS THE CONDITIONS OF OUTPUT CORRESPONDING TO THE INPUT LAST ENERGIZED.
	ADJUSTABLE TIME DELAY ENERGIZING	A DEVICE WHICH PRODUCES AN OUTPUT FOLLOWING DEFINITE INTENTIONAL TIME DELAY AFTER ITS INPUT IS ENERGIZED.
	DE-ENERGIZING	A DEVICE WHICH PRODUCES AN OUTPUT FOLLOWING A DEFINITE INTENTIONAL TIME DELAY AFTER ITS INPUT IS DE-ENERGIZED.
2/3	COINCIDENCE (2 OUT OF 3 SHOWN)	A DEVICE WHICH PRODUCES AN OUTPUT WHEN THE PRESCRIBED NUMBER OF INPUTS EXIST (EXAMPLE 2 INPUTS MUST EXIST FOR AN OUTPUT
L R —M.R.	RETENTIVE MEMORY WITH MANUAL RESET	A DEVICE HAVING THE LOGICAL FUNCTION. AS INDICATED BY THE DIAGRAM BELOW:



ADDITIONAL SYMBOLS

PIC 143 — INSTRUMENT CHANNEL (SEE E-SPEC G765164 FOR CODE LETTER EXPLANATION)

INDICATES THAT THE DEVICE OR INSTRUMENT CHANNEL HAS A BISTABLE LOGIC OUTPUT WHEN:
- ⎍ -PARAMETER MEASURED IS GREATER THAN A PRESET VALUE
- ⎍ -PARAMETER MEASURED IS LESS THAN A PRESET VALUE

OR OR SAME AS ABOVE EXCEPT WITH AN AUTOMATICALLY SET VARIABLE VALUE.

- (A) ALARM ANNUNCIATOR ALARMS ON THE SAME SHEET WITH THE SAME SUBSCRIPT SHARE A COMMON ANNUNCIATOR WINDOW
- (R) REACTOR TRIP "FIRST OUT" ANNUNCIATOR
- (T) TURBINE TRIP "FIRST OUT" ANNUNCIATOR

52/ P17
- DEVICE FUNCTION NUMBER
- CONTROL CIRCUIT CHANNEL OR COMPONENT ITEM NUMBER

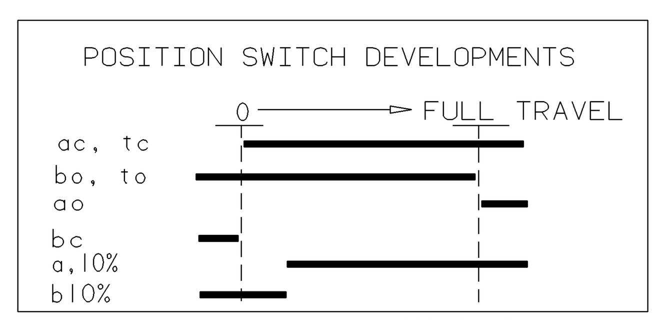
——— LOGIC INFORMATION TRANSMISSION

- ACTION CALLED FOR BY LOGIC INPUT
- COMPONENT CONTROL CIRCUIT

RIC 16 P — INDICATES THAT THE INSTRUMENT CHANNEL HAS AN OUTPUT AS FOLLOWS
- P-PROPORTIONAL TO THE PARAMETER MEASURED
- R-PROPORTIONAL TO THE RATE OF CHANGE OF THE PARAMETER MEASURED

BISTABLE DEVICE OR INDICATE SAME AS EXPLAINED ABOVE

(T) INDICATOR LAMP
- T TRIP STATUS LIGHTS
- P PERMISSIVE STATUS LIGHTS
- B BYPASS STATUS LIGHTS



DETAIL "A"

DEVICE FUNCTION NUMBERS AND LETTERS

(Ref: ASA Standard 37.2-1956 and Nema Standard S G 5-1959)

1-MASTER ELEMENT (CONTROL SWITCH)
20-ELECTRIC OPERATED VALVE
27-UNDERVOLTAGE RELAY
33-POSITION SWITCH
  SUFFIX LETTER:
  ac, ao, bc, bo-LIMIT SWITCH — SEE DETAIL "A"
  to, tc — TORQUE SWITCH — FOR OPERATION
43-MANUAL SELECTOR SWITCH

52-AC CIRCUIT BREAKER OR CONTACTOR
  SUFFIX LETTER:
  a-AUXILIARY CONTACT-OPEN WHEN MAIN CONTACTS ARE OPEN
  b-AUXILIARY CONTACT-CLOSED WHEN MAIN CONTACTS ARE OPEN
  (C)-REVERSING CONTACTOR OPERATING COIL-ENERGIZE TO CLOSE VALVE
  (O)-REVERSING CONTACTOR OPERATING COIL-ENERGISE TO OPEN VALVE
  (CC)-BREAKER CLOSING COIL
  (TC)-BREAKER TRIP COIL
  (UV)-BREAKER UNDER VOLTAGE TRIP COIL
63-LIQUID OR GAS PRESSURE LEVEL, OR FLOW RELAY
69-PERMISSIVE SWITCH
72-DC CIRCUIT BREAKER OR CONTACTOR
  SUFFIX LETTER:
  a-AUXILIARY CONTACT-OPEN WHEN MAIN CONTACTS ARE OPEN
  b-AUXILIARY CONTACT-CLOSED WHEN MAIN CONTACTS ARE OPEN
  (C)-REVERSING CONTACTOR OPERATING COIL-ENERGIZE TO CLOSE VALVE
  (O)-REVERSING CONTACTOR OPERATING COIL-ENERGIZE TO OPEN VALVE
  (CC)-BREAKER CLOSING COIL
  (TC)-BREAKER TRIP COIL
  (UV)-BREAKER UNDER VOLTAGE TRIP COIL

SUFFIX LETTER
  P-PRIMARY
  BU-BACK-UP

REFERENCES:

TITLE	SHEET	DRAWING
REACTOR TRIP SIGNALS	2	A225095
TURBINE TRIP SIGNALS	3	A225096
6900V BUS AUTOTRANSFER	4	A225097
NUCLEAR INSTRUMENTATION TRIP SIGNALS	5	A225098
NUCLEAR INSTR. PERMISSIVES & BLOCKS	6	A225099
EMERGENCY GENERATOR STARTING	7	A225100
SAFEGUARDS SEQUENCE	8	A225101
PRESSURIZER TRIP SIGNALS	9	A225102
STEAM GENERATOR TRIP SIGNALS	10	A225103
REACTOR COOLANT SYSTEM TRIP SIGNALS & MANUAL TRIP	11	A225104
03 SAFEGUARDS ACTUATION SIGNALS	12	A225105
FEEDWATER ISOLATION	13	A225106
ROD STOPS & TURBINE LOAD CUTBACK	14	A225107

NOTES:

1. ALL CIRCUITS ON SHEETS 1 THROUGH 14 ARE REDUNDANT EXCEPT WHERE INDICATED OTHERWISE.
2. PROTECTION CHANNELS 1 AND 2 ARE CONNECTED TO INVERTER BUSSES.
3. MANUAL CONTROLS DO NOT HAVE REDUNDANT ACTUATORS, BUT DO HAVE REDUNDANT CONTACTS WHERE LOGIC IS REDUNDANT.
4. THIS DRAWING SUPERCEDES WESTINGHOUSE DRAWING 882B627 SHEET 1, MICROFILM 190B75.

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS "CLASS A" ITEMS PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

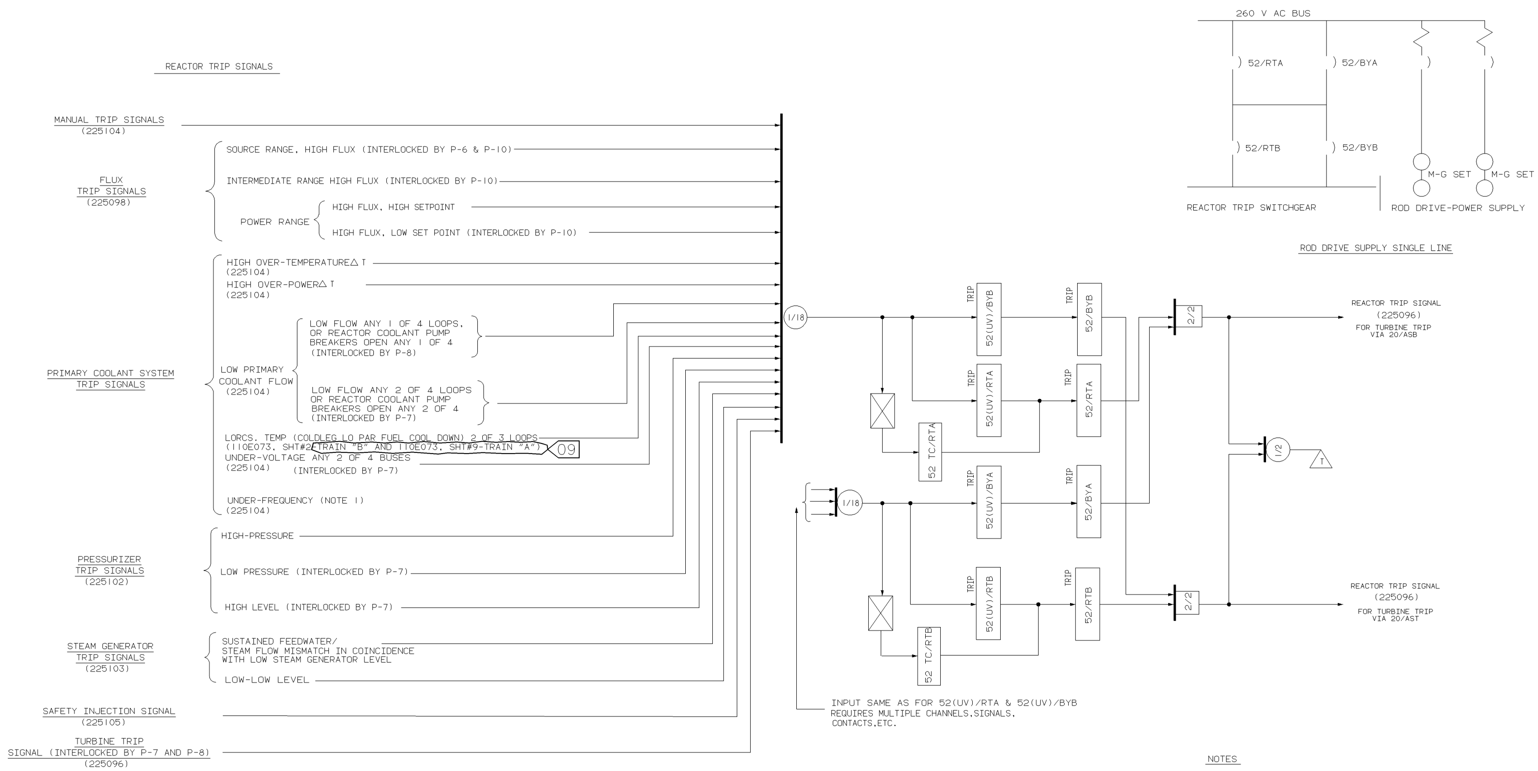
REVISION							
TQW 7/12/99 DES / ENG	THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO SHOW CRS 199904915 RELEASED FOR RECORD P/N 69982-CD DT 7/12/99	DATE	CKR. / SUPV. (REVIEW)	JOHN J LOWNEY (DESIGN ENG)	DISC. ENG.	GERARD L. BLENKLE (ENG. MGR.)	APPROVALS

TITLE: LOGIC DIAGRAMS
INDEX & SYMBOLS
(SHEET 1)
- UFSAR FIGURE No. 7.2-1

DRWN. BY | SCALE NTS | REC'D

Con Edison — STATION: INDIAN PT. #2

DWG. NO. A225094-03 DB



NOTES

1- UNDER-FREQUENCY ON ANY 2 OF 4 BUSES WILL OPEN THE BREAKERS OF ALL REACTOR COOLANT PUMPS AND CONSEQUENTLY CAUSE REACTOR TRIP.
2- FOR SYMBOLS AND REFERENCES SEE A225094.
3- THIS DRAWING SUPERSEDES WESTINGHOUSE DRAWING #882D627 SHEET 2, MICROFILM 190876.
4- FOR SCHEMATIC DWGS OF REACTOR PROT RACKS (E2 THRU E6 & F2 THRU F6) SEE WH'SE DWG 110E073,SHTS 1 THRU 11

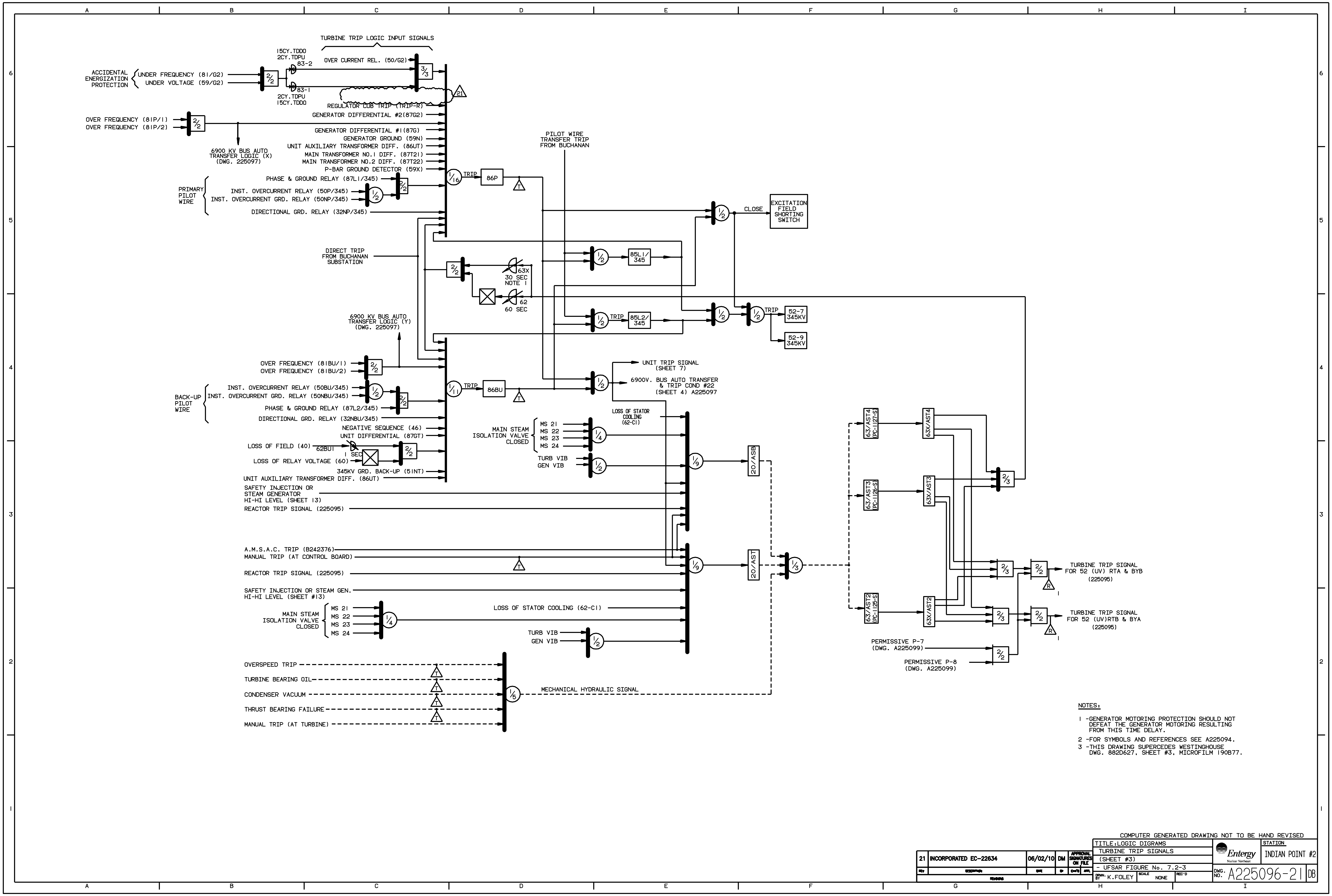
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS:
" CLASS A" ITEMS
PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION								
V.JAYARAMAN 5/30/01	THIS REVISION IS NON-CLASS AS PER THE QAPD UPDATED DWG. PER CRS 200103361				JOHN J LOWNEY		GERARD L BLENKLE	
	RELEASED FOR RECORD P/N 69901-AF VJ/TD	DATE	CHK.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.	
			REVIEW		APPROVALS			

TITLE: LOGIC DIAGRAMS REACTOR TRIP SIGNALS (SHEET 2)
- UFSAR FIGURE No. 7.2-2

STATION: INDIAN POINT #2
Con Edison
DRAWN BY: REPRO SCALE: NONE REC'D
DWG. NO. A225095-09 DB



TURBINE TRIP LOGIC INPUT SIGNALS
ACCIDENTAL ENERGIZATION PROTECTION
UNDER FREQUENCY (81/G2)
UNDER VOLTAGE (59/G2)
15CY.TDDO
2CY.TDPU
83-2
83-1
2CY.TDPU
15CY.TDDO
OVER CURRENT REL. (50/G2)
REGULATOR CUB TRIP (TRIP-R)
GENERATOR DIFFERENTIAL #2(87G2)
OVER FREQUENCY (81P/1)
OVER FREQUENCY (81P/2)
GENERATOR DIFFERENTIAL #1(87G)
GENERATOR GROUND (59N)
UNIT AUXILIARY TRANSFORMER DIFF. (86UT)
MAIN TRANSFORMER NO.1 DIFF. (87T21)
MAIN TRANSFORMER NO.2 DIFF. (87T22)
P-BAR GROUND DETECTOR (59X)
6900 KV BUS AUTO TRANSFER LOGIC (X) (DWG. 225097)
PRIMARY PILOT WIRE
PHASE & GROUND RELAY (87L1/345)
INST. OVERCURRENT RELAY (50P/345)
INST. OVERCURRENT GRD. RELAY (50NP/345)
DIRECTIONAL GRD. RELAY (32NP/345)
TRIP
86P
PILOT WIRE TRANSFER TRIP FROM BUCHANAN
CLOSE
EXCITATION FIELD SHORTING SWITCH
DIRECT TRIP FROM BUCHANAN SUBSTATION
63X
30 SEC
NOTE 1
62
60 SEC
85L1/345
TRIP
85L2/345
TRIP
52-7 345KV
52-9 345KV
6900 KV BUS AUTO TRANSFER LOGIC (Y) (DWG. 225097)
OVER FREQUENCY (81BU/1)
OVER FREQUENCY (81BU/2)
BACK-UP PILOT WIRE
INST. OVERCURRENT RELAY (50BU/345)
INST. OVERCURRENT GRD. RELAY (50NBU/345)
PHASE & GROUND RELAY (87L2/345)
DIRECTIONAL GRD. RELAY (32NBU/345)
NEGATIVE SEQUENCE (46)
UNIT DIFFERENTIAL (87GT)
LOSS OF FIELD (40)
62BU1
1 SEC
LOSS OF RELAY VOLTAGE (60)
345KV GRD. BACK-UP (51NT)
UNIT AUXILIARY TRANSFORMER DIFF. (86UT)
TRIP
86BU
UNIT TRIP SIGNAL (SHEET 7)
6900V. BUS AUTO TRANSFER & TRIP COND #22 (SHEET 4) A225097
LOSS OF STATOR COOLING (62-C1)
MAIN STEAM ISOLATION VALVE CLOSED
MS 21
MS 22
MS 23
MS 24
TURB VIB
GEN VIB
20/ASB
20/AST
SAFETY INJECTION OR STEAM GENERATOR HI-HI LEVEL (SHEET 13)
REACTOR TRIP SIGNAL (225095)
A.M.S.A.C. TRIP (B242376)
MANUAL TRIP (AT CONTROL BOARD)
REACTOR TRIP SIGNAL (225095)
SAFETY INJECTION OR STEAM GEN. HI-HI LEVEL (SHEET 13)
MAIN STEAM ISOLATION VALVE CLOSED
MS 21
MS 22
MS 23
MS 24
LOSS OF STATOR COOLING (62-C1)
TURB VIB
GEN VIB
OVERSPEED TRIP
TURBINE BEARING OIL
CONDENSER VACUUM
THRUST BEARING FAILURE
MANUAL TRIP (AT TURBINE)
MECHANICAL HYDRAULIC SIGNAL
63/AST4 (PC-1127-S)
63/AST3 (PC-1126-S)
63/AST2 (PC-1125-S)
63X/AST4
63X/AST3
63X/AST2
TURBINE TRIP SIGNAL FOR 52 (UV) RTA & BYB (225095)
TURBINE TRIP SIGNAL FOR 52 (UV)RTB & BYA (225095)
PERMISSIVE P-7 (DWG. A225099)
PERMISSIVE P-8 (DWG. A225099)
NOTES:
1 -GENERATOR MOTORING PROTECTION SHOULD NOT DEFEAT THE GENERATOR MOTORING RESULTING FROM THIS TIME DELAY.
2 -FOR SYMBOLS AND REFERENCES SEE A225094.
3 -THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #3, MICROFILM 190B77.
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
TITLE:LOGIC DIGRAMS
TURBINE TRIP SIGNALS
(SHEET #3)
- UFSAR FIGURE No. 7.2-3
K.FOLEY
SCALE NONE
STATION INDIAN POINT #2
Entergy
DWG. NO. A225096-21 DB
21 INCORPORATED EC-22634 06/02/10 DM
APPROVAL SIGNATURES ON FILE

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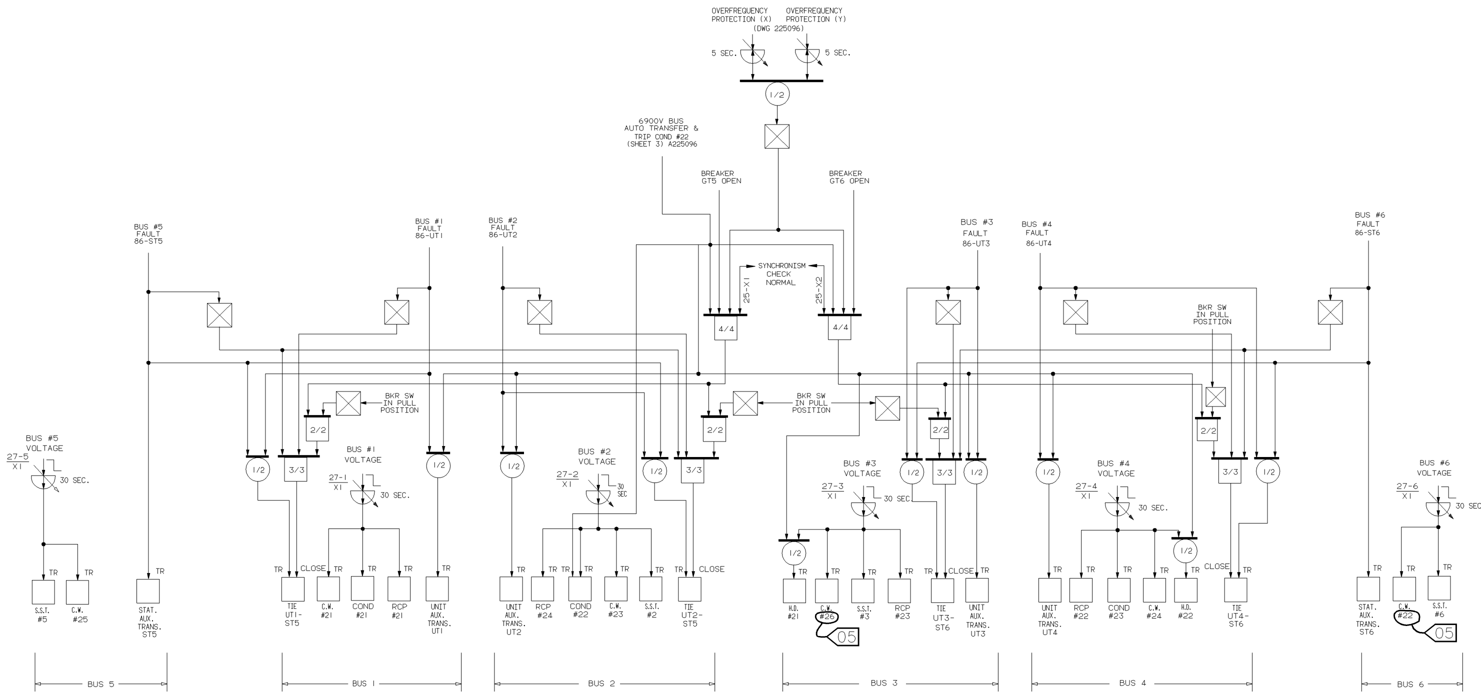
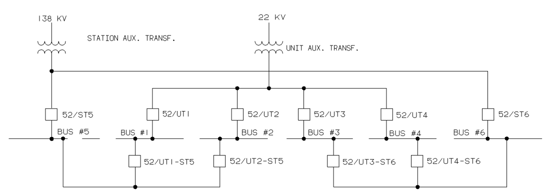




PARTIAL 6900V ONE LINE

NOTES:

1 -FOR SYMBOLS AND REFERENCES SEE A225094.

2 -THIS SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #4, MICROFILM 190B78.

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLED WITHIN CON EDISON AS

"CLASS A" ITEMS
PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION						
DES	THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. PER CRS #1999-05005 ISSUED FOR RECORD P/N 69982-CD	DATE	CKR. / SUPV. (REVIEW)	JOHN J LOWNEY (DESIGN ENG)	DISC. ENG.	GERARD L BLENKLE (ENG. MGR.)
V.I. 05/10/00 / ENG	WD/TM 05/10/00 RCMT			APPROVALS		

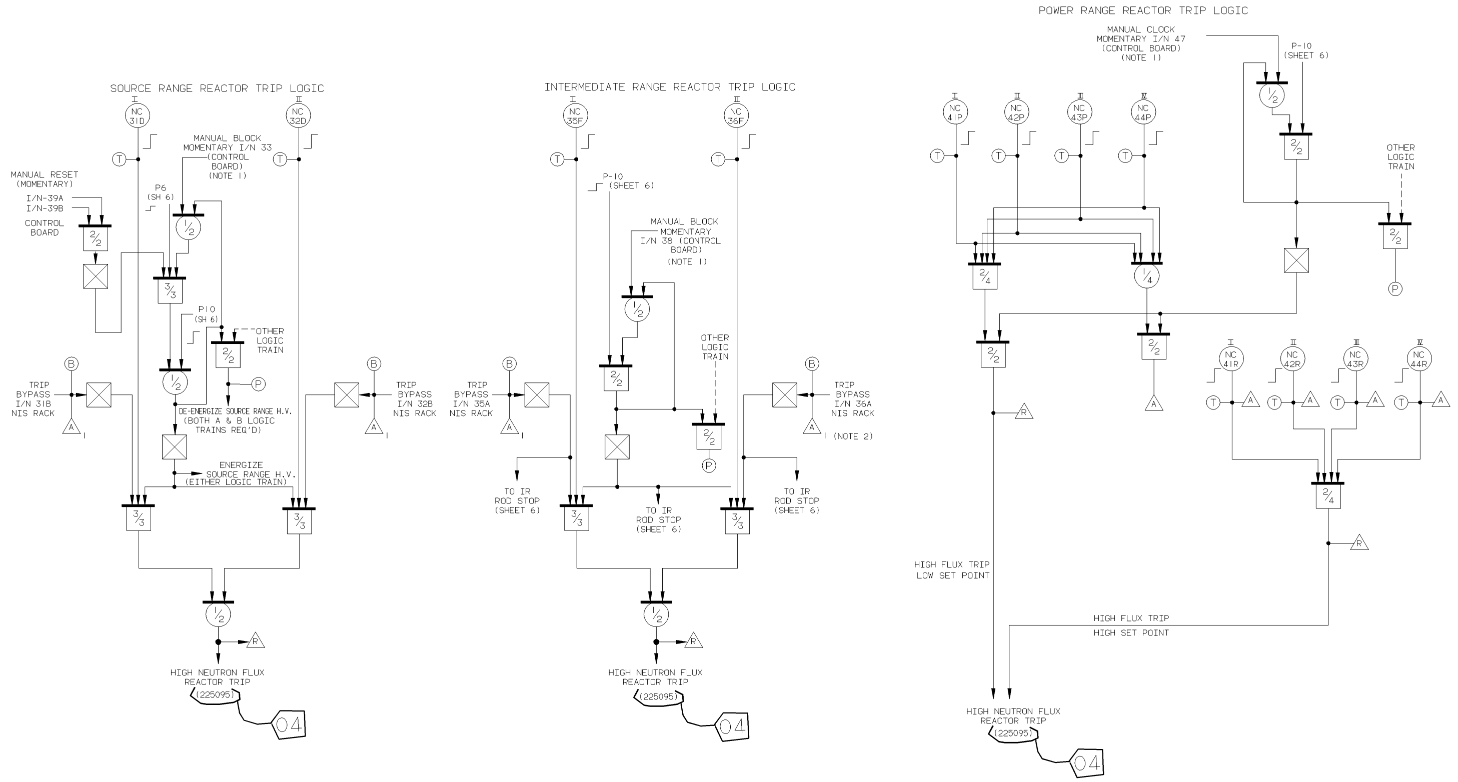
TITLE: LOGIC DIAGRAM 6900V
BUS AUTO TRANSFER
(SHEET #4)
- UFSAR FIGURE No. 7.2-4

DRWN. BY | SCALE NONE | REC'D

Con Edison

STATION: INDIAN POINT #2

DWG. NO. A225097-05 DB



NOTES:

1 - I/N 33A → LOGIC TRAIN A
I/N 33B → LOGIC TRAIN B
I/N 38A → LOGIC TRAIN A
I/N 38B → LOGIC TRAIN B
I/N 47A → LOGIC TRAIN A
I/N 47B → LOGIC TRAIN B

2 - A 1 SAME WINDOW AS ALARM 1 ON SHEET 6

3 - FOR SYMBOLS AND REFERENCES SEE A225094.

4 - THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627. SHEET #5. MICROFILM 208B75.

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLED WITHIN CON EDISON AS "CLASS A" ITEMS PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

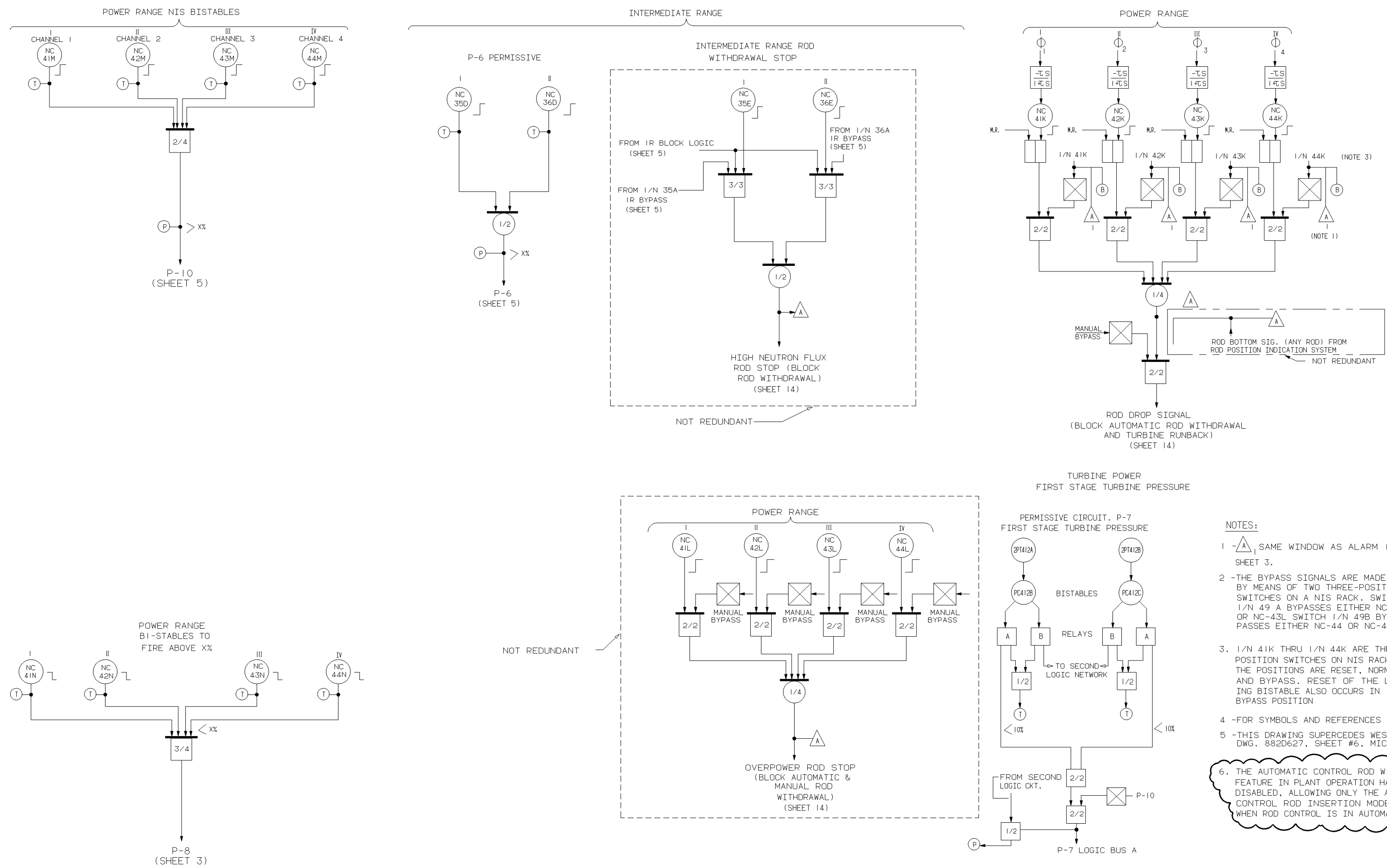
REVISION						
PMD 5/11/99 ENG	THIS REV IS NON-CLASS AS PER CI-240-1 UPDATED DWG PER CRS199901224 & CRS199903752 PKG D-2412 RELEASED FOR RECORD P/N 69911-NP SP	DATE	CKR. / SUPV. (REVIEW)	JOHN J LOWNEY (DESIGN ENG)	DISC. ENG.	GERARD L BLENKLE (ENG. MGR.)

TITLE: LOGIC DIAGRAM NUCLEAR INSTRUMENTATION TRIP SIGNALS (SHEET #5) – UFSAR FIGURE No. 7.2-5

DRWN. BY | SCALE NONE | REC'D

Con Edison — STATION: INDIAN POINT #2

DWG. NO. A225098-04 DB



NOTES:

1 - A SAME WINDOW AS ALARM 1 ON SHEET 3.

2 - THE BYPASS SIGNALS ARE MADE UP BY MEANS OF TWO THREE-POSITION SWITCHES ON A NIS RACK. SWITCH I/N 49 A BYPASSES EITHER NC-41L OR NC-43L SWITCH I/N 49B BY PASSES EITHER NC-44 OR NC-44L

3. I/N 41K THRU I/N 44K ARE THREE-POSITION SWITCHES ON NIS RACKS THE POSITIONS ARE RESET, NORMAL AND BYPASS. RESET OF THE LATCHING BISTABLE ALSO OCCURS IN BYPASS POSITION

4 - FOR SYMBOLS AND REFERENCES SEE A225094.

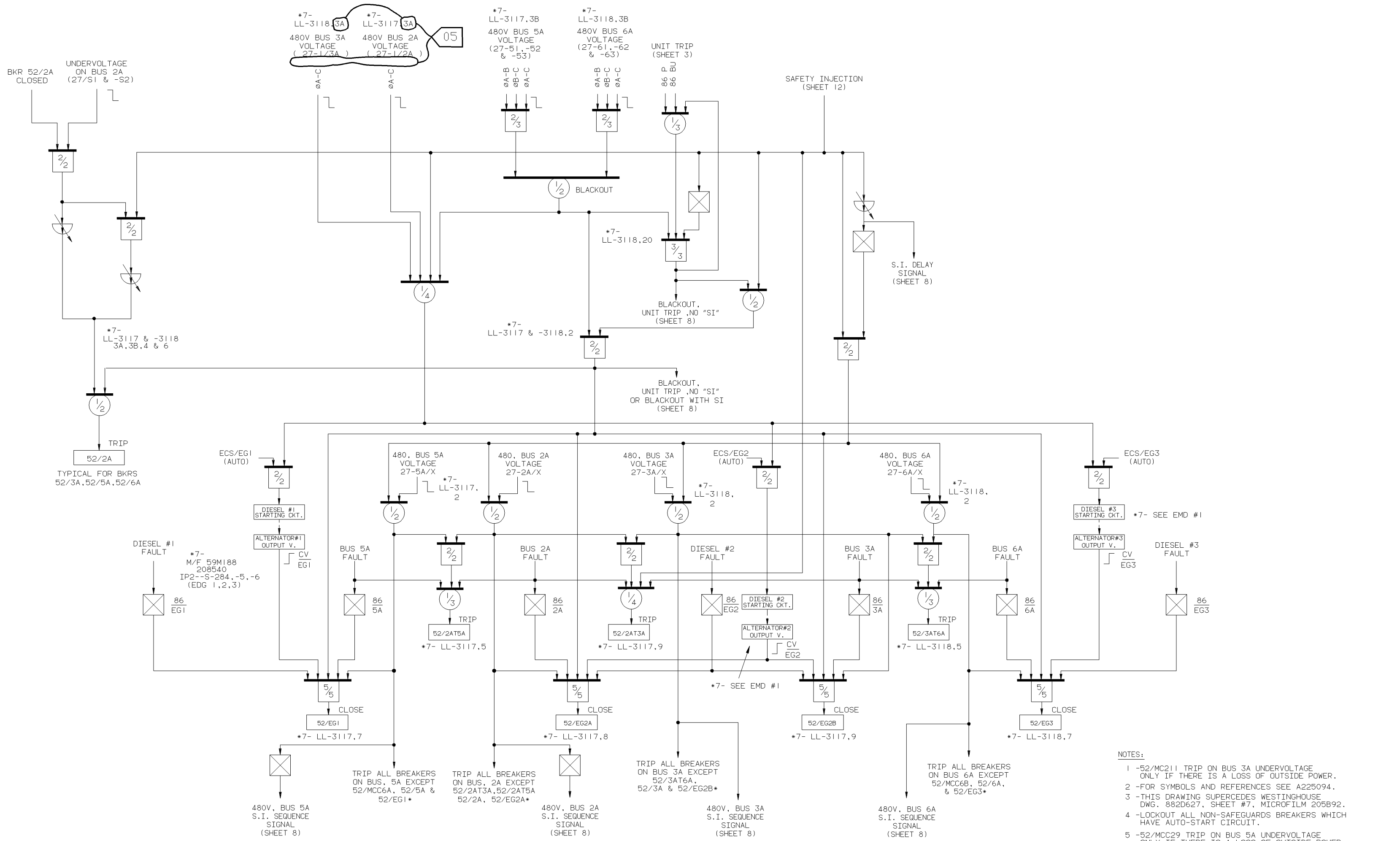
5 - THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #6, MICROFILM 208B76.

6. THE AUTOMATIC CONTROL ROD WITHDRAWAL FEATURE IN PLANT OPERATION HAS BEEN PHYSICALLY DISABLED, ALLOWING ONLY THE AUTOMATIC CONTROL ROD INSERTION MODE TO BE IN EFFECT WHEN ROD CONTROL IS IN AUTOMATIC. 07

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLED WITHIN CON EDISON AS
"CLASS A" ITEMS
PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION			DATE	CKR.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.		
CH 12-19-01 DES / PW 12-19-01 ENG	THIS REVISION IS CLASS "A" PER THE QAPD. REVISED DRAWING PER CR# 200108050 RELEASED FOR RECORD P/N 69901-AF 12-19-01 CH			REVIEW		JOHN J. LOWNEY	APPROVALS	GERARD L. BLENKLE	TITLE: LOGIC DIAGRAMS NUCLEAR INSTR. PERMISSIVES & BLOCKS (SHEET 6) – UFSAR FIGURE No.7.2-6 DRWN. BY SCALE NONE REC'D	Con Edison STATION INDIAN POINT #2 DWG. NO. A225099-07 DB



NOTES:

1 -52/MC211 TRIP ON BUS 3A UNDERVOLTAGE ONLY IF THERE IS A LOSS OF OUTSIDE POWER.
2 -FOR SYMBOLS AND REFERENCES SEE A225094.
3 -THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #7, MICROFILM 205B92.
4 -LOCKOUT ALL NON-SAFEGUARDS BREAKERS WHICH HAVE AUTO-START CIRCUIT.
5 -52/MCC29 TRIP ON BUS 5A UNDERVOLTAGE ONLY IF THERE IS A LOSS OF OUTSIDE POWER.
6 -52/MCC24 TRIP BUS 2A UNDERVOLTAGE ONLY IF THERE IS A LOSS OF OUTSIDE POWER.
*7 -NUMBERS PREFIXED WITH THIS REFERS TO THE APPLICABLE SCHEMATIC DIAGRAM
A) EG. IP2--S-200 MEANS IP2--S-000200
B) EG. LL-3117.25 MEANS 9321-LL-3117.SHEET 2

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLED WITHIN CON EDISON AS
"CLASS A" ITEMS
PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION: V.J. 03/22/00 — THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. AS PER CRS 199909374 RELEASED FOR RECORD P/N 69982-CM — SR/VJ/DJM

ENG | DATE | CHR. | SUPV. | REVIEW

JOHN J LOWNEY — DESIGN ENG.
DISC. ENG.
GERARD L BLENKLE — ENG. MGR.
APPROVALS

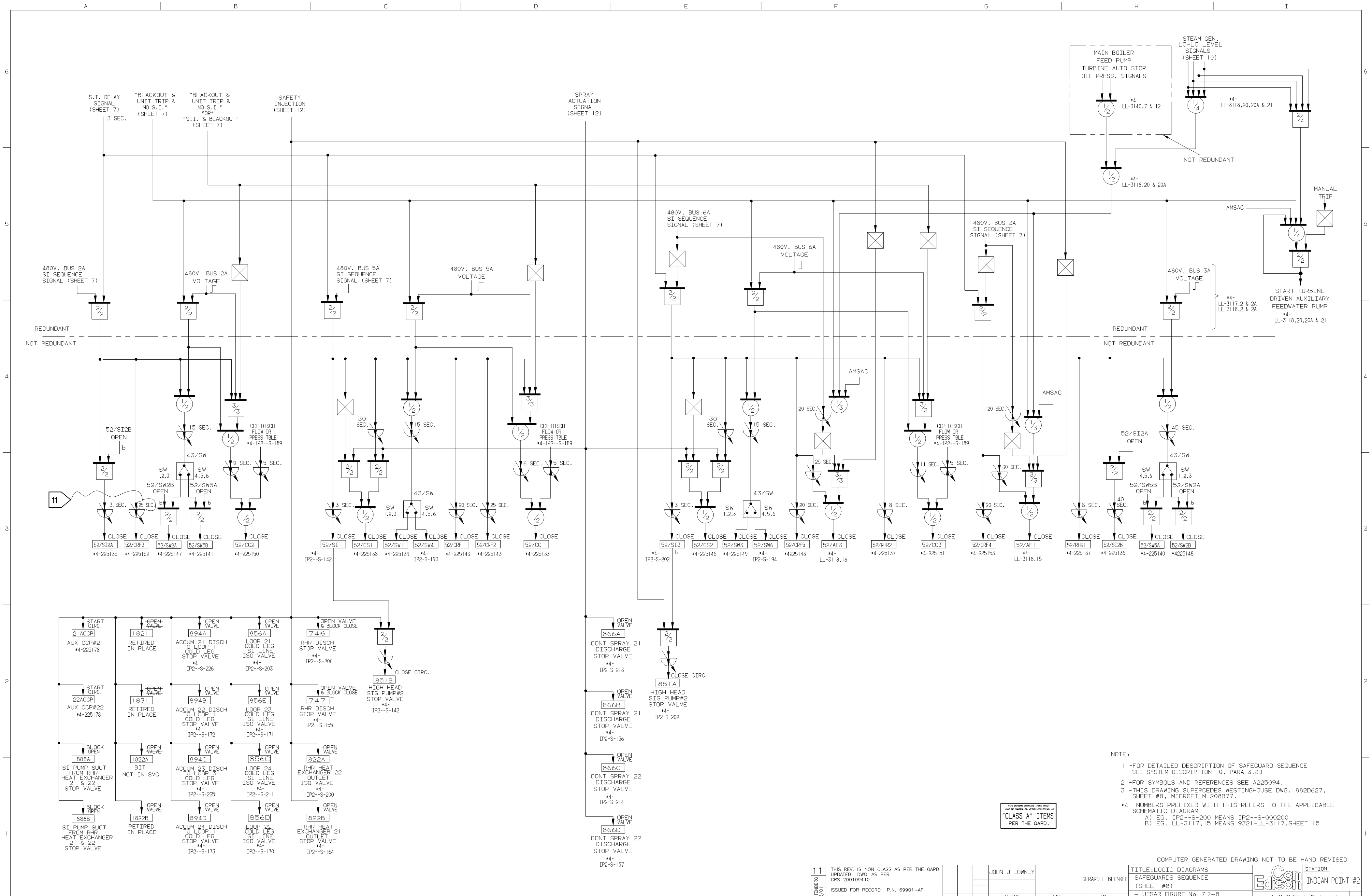
TITLE: LOGIC DIAGRAM
EMERGENCY GENERATOR STARTING
(SHEET #7)
- UFSAR FIGURE No. 7.2-7

DRAWN BY | SCALE NONE | REC'D

Con Edison

STATION: INDIAN POINT #2

DWG. A225100-05 DB



NOTE:

1 -FOR DETAILED DESCRIPTION OF SAFEGUARD SEQUENCE SEE SYSTEM DESCRIPTION 10, PARA 3.3D

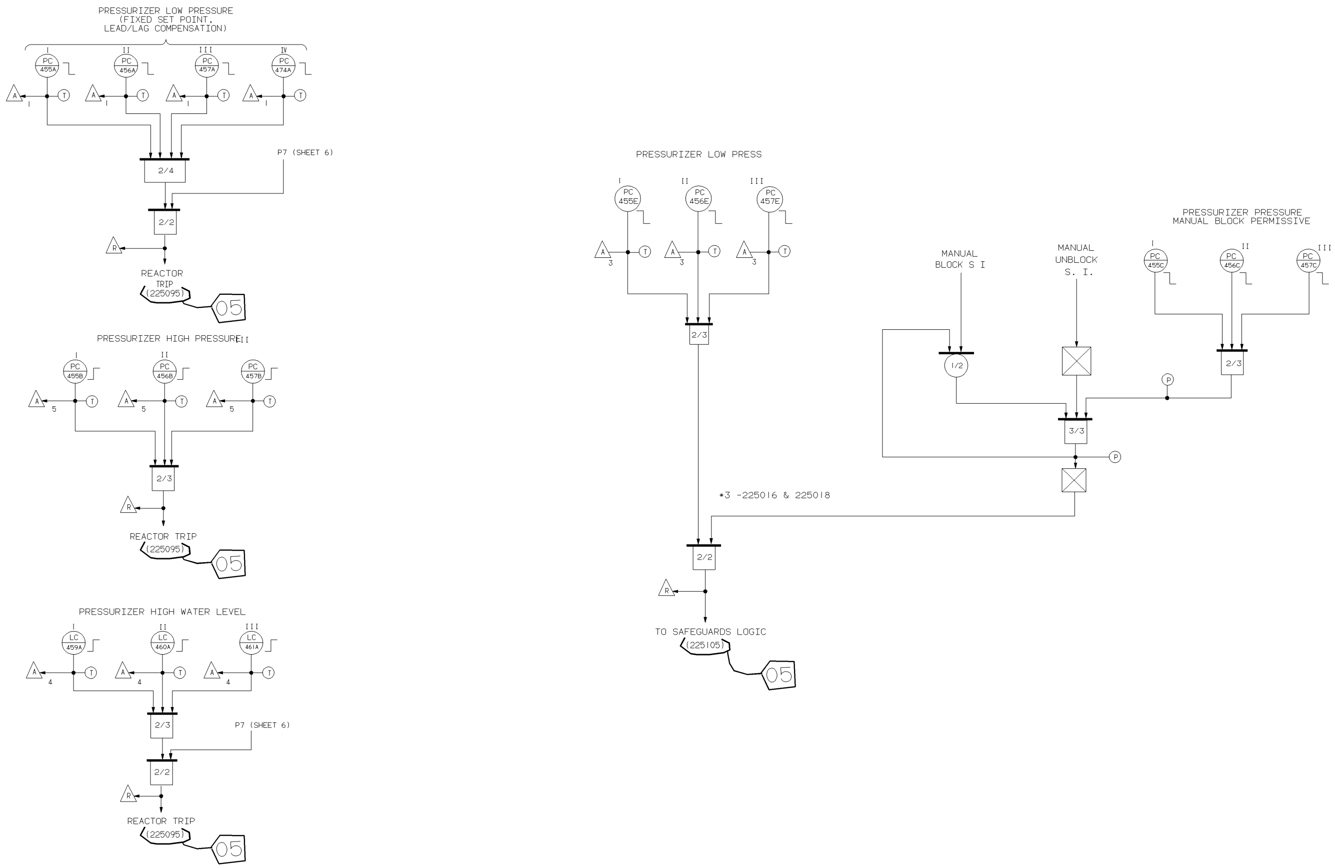
2 -FOR SYMBOLS AND REFERENCES SEE A225094.

3 -THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #8, MICROFILM 208B77.

*4 -NUMBERS PREFIXED WITH THIS REFERS TO THE APPLICABLE SCHEMATIC DIAGRAM
A) EG. IP2--S-200 MEANS IP2--S-000200
B) EG. LL-3117,15 MEANS 9321-LL-3117,SHEET 15

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

11	THIS REV. IS NON CLASS AS PER THE QAPD. UPDATED DWG. AS PER CRS 200109410. ISSUED FOR RECORD P.N. 69901-AF	M. ENTENBERG 10/22/01	ET/MPH 10/22/01		
JOHN J LOWNEY	GERARD L BLENKLE	TITLE: LOGIC DIAGRAMS SAFEGUARDS SEQUENCE (SHEET #8) — UFSAR FIGURE No. 7.2-8	Con Edison	STATION INDIAN POINT #2	
DATE / CKR. / SUPV. / REVIEW	DESIGN ENG / DISC. ENG. / ENG. MGR. / APPROVALS	DRAWN BY K.FOLEY	SCALE NONE	REC'D	DWG. NO. A225101-11 DB



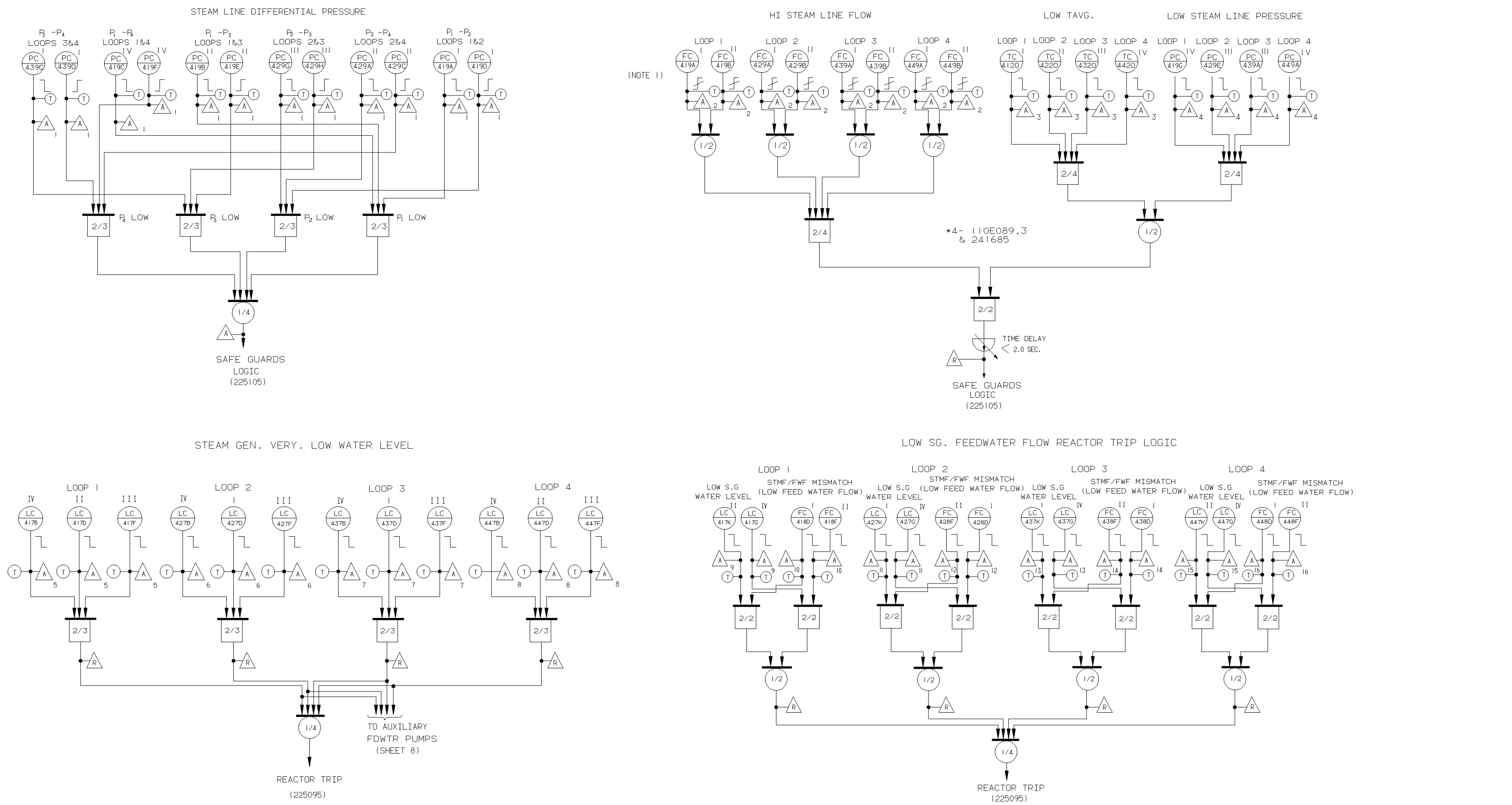
NOTES:

1 -FOR SYMBOLS AND REFERENCES SEE A225094.
2 -THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627. SHEET #9. MICROFILM 205B94.
•3 -NUMBERS PREFIXED WITH THIS REFERS TO THE APPLICABLE SCHEMATIC DIAGRAM

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLED WITHIN CON EDISON AS
"CLASS A" ITEMS
PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION							
PMD 5/11/99	THIS REV IS NON-CLASS AS PER CI-240-1 UPDATED DWG PER CRS199901224 & CRS199903752 PKG D-2412 RELEASED FOR RECORD P/N 69911-NP	SP	JOHN J LOWNEY		GERARD L BLENKLE	TITLE: LOGIC DIAGRAMS PRESSURIZER TRIP SIGNALS (SHEET #9) - UFSAR FIGURE No. 7.2-9	STATION INDIAN POINT #2
ENG.		DATE / CKR. / SUPV. REVIEW	DESIGN ENG	DISC. ENG.	ENG. MGR.	DRWN. BY / SCALE NONE / REC'D	DWG. NO. A225102-05 DH



NOTES:

1 -SETPOINTS OF STEAM FLOW BISTABLES ARE ADJUSTABLE AND SET BY TURBINE FIRST STAGE PRESSURE.

2 -FOR SYMBOLS AND REFERENCES SEE A225094.

3 -THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #10, MICROFILM 205B95.

*4 -NUMBERS PREFIXED WITH THIS REFERS TO THE APPLICABLE SCHEMATIC DIAGRAM

A) EG. 110E089.2 REFERS TO THE WH'SE SWD.SHEET #3

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLED WITHIN CON EDISON AS "CLASS A" ITEMS PER CI-240-1

08

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION	TQW 7/14/99	THIS REV IS NON-CLASS AS PER CI-240-1 UPDATED DWG PER CRS-199904906 RELEASED FOR RECORD P/N 69982-CD DT/TY

JOHN J LOWNEY — GERARD BLENKLE

DATE | CKR. | SUPV. | DESIGN ENG | DISC. ENG. | ENG. MGR. — REVIEW — APPROVALS

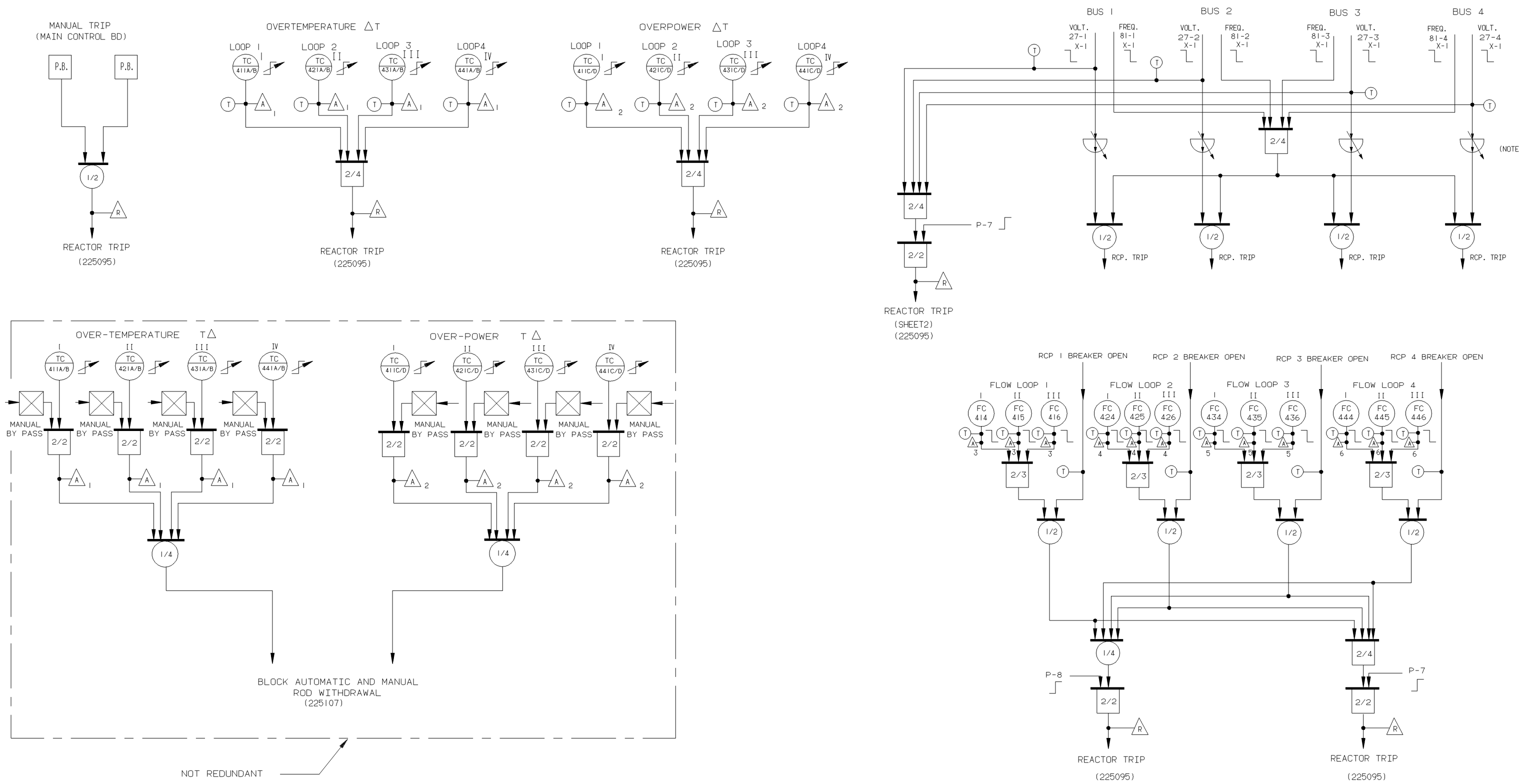
TITLE: LOGIC DIAGRAM STEAM GENERATOR TRIP SIGNALS (SHEET #10)

– UFSAR FIGURE No. 7.2-10

DRAWN BY | SCALE NONE | REC'D

Con Edison — STATION INDIAN POINT #2

DWG. NO. A225103-08 DB



THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLED WITHIN CON EDISON AS

"CLASS A" ITEMS
PER CI-240-1

NOTES:

1 -CIRCUITRY FOR RCP TRIP ON UNDERVOLTAGE PERTAINS TO BUS-CLEARING, IS NOT PART OF REACTOR PROTECTION SYSTEM, AND ITS NOT REDUNDANT.

2 -FOR SYMBOLS AND REFERENCES SEE A225094.

3 -THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #10, MICROFILM 207B97.

4 -FOR REACTOR PROTECTION SCHEMATIC SEE WHSE 110E073

5 -THE AUTOMATIC CONTROL ROD WITHDRAWAL FEATURE IN PLANT OPERATION HAS BEEN PHYSICALLY DISABLED, ALLOWING ONLY THE AUTOMATIC CONTROL ROD INSERTION MODE TO BE IN EFFECT WHEN ROD CONTROL IS IN AUTOMATIC.

06

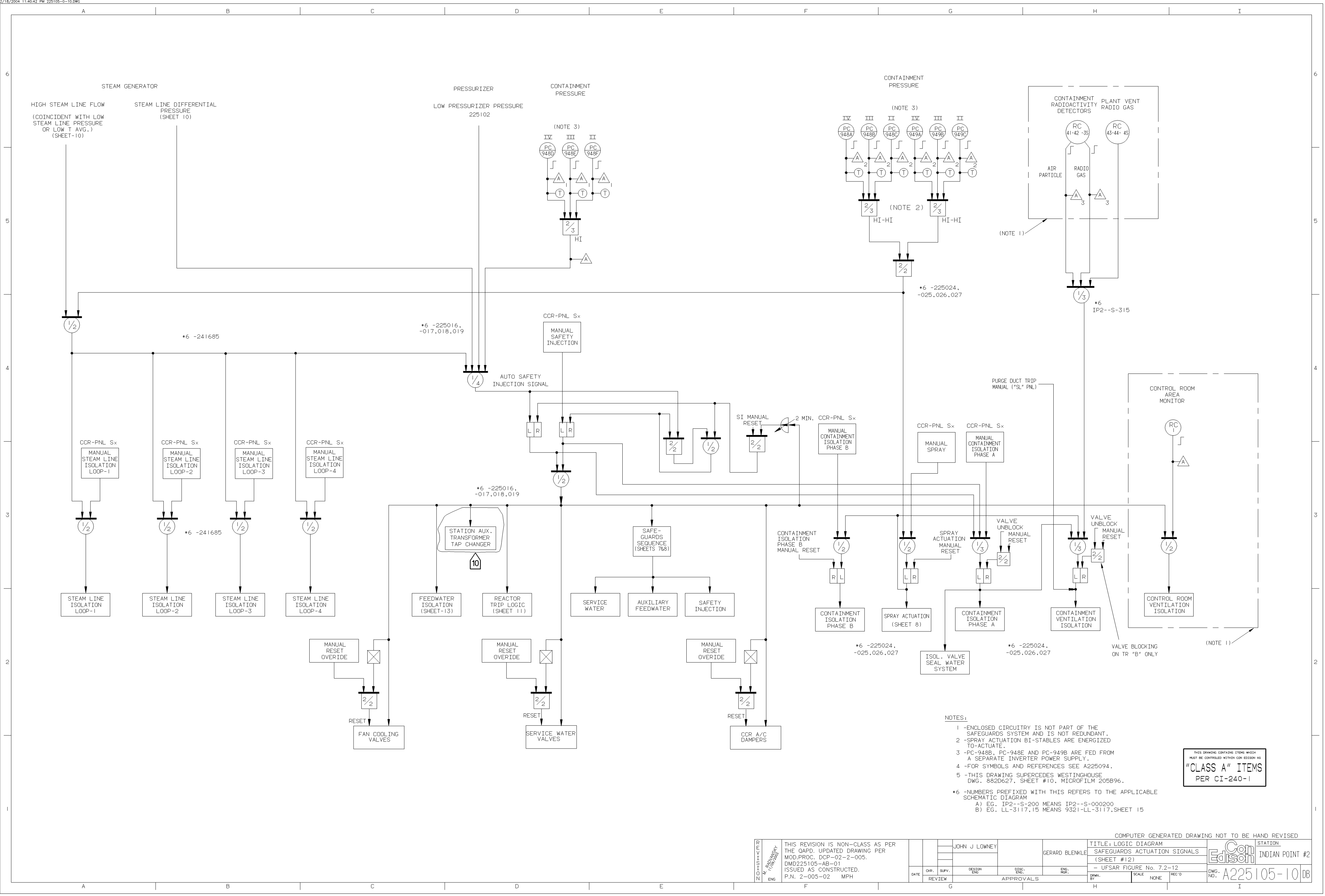
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION							
PW 12-19-01 ENG	THIS REVISION IS NON-CLASS PER THE QAPD, REVISE DRAWING PER CR# 200108050. RELEASED FOR RECORD. P/N 69901-AF CH 12-19-2001	12-19-2001		JOHN J LOWNEY		GERARD BLENKLE	TITLE: LOGIC DIAGRAM PRIMARY COOLANT SYSTEM TRIP SIGNALS & MANUAL TRIP (SHEET #11) - UFSAR FIGURE No. 7.2-11
		DATE	CKR. SUPV. REVIEW	DESIGN ENG	DISC. ENG.	ENG. MGR.	DRWN. BY / SCALE NONE / REC'D
				APPROVALS			

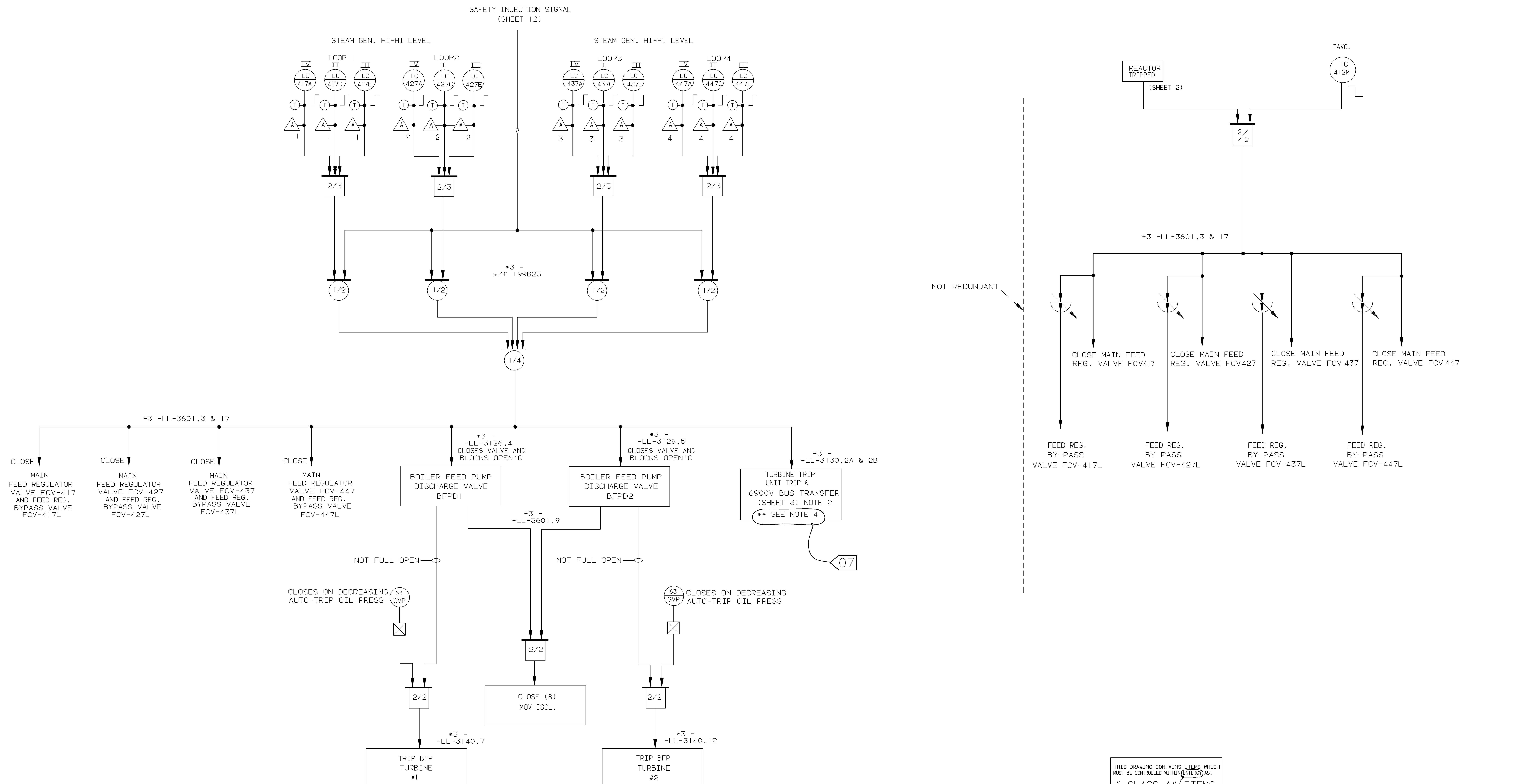
Con Edison

STATION: INDIAN POINT #2

DWG. NO. A225104-06 DB



2/18/2004 11:40:42 PM 225105-0-10.DWG
STEAM GENERATOR
HIGH STEAM LINE FLOW
(COINCIDENT WITH LOW STEAM LINE PRESSURE OR LOW T AVG.) (SHEET-10)
STEAM LINE DIFFERENTIAL PRESSURE (SHEET 10)
PRESSURIZER
LOW PRESSURIZER PRESSURE
225102
CONTAINMENT PRESSURE
(NOTE 3)
PC 948D
PC 948E
PC 948F
HI
CONTAINMENT PRESSURE
(NOTE 3)
PC 948A
PC 948B
PC 948C
PC 949A
PC 949B
PC 949C
(NOTE 2)
HI-HI
HI-HI
*6 -225024, -025,026,027
CONTAINMENT RADIOACTIVITY DETECTORS
PLANT VENT RADIO GAS
RC 41-42 -3S
RC 43-44- 4S
AIR PARTICLE
RADIO GAS
(NOTE 1)
*6 IP2--S-315
*6 -241685
*6 -225016, -017,018,019
AUTO SAFETY INJECTION SIGNAL
CCR-PNL Sx
MANUAL SAFETY INJECTION
SI MANUAL RESET
2 MIN.
CCR-PNL Sx
MANUAL CONTAINMENT ISOLATION PHASE B
CCR-PNL Sx
MANUAL SPRAY
CCR-PNL Sx
MANUAL CONTAINMENT ISOLATION PHASE A
PURGE DUCT TRIP MANUAL ("SL" PNL)
CONTROL ROOM AREA MONITOR
RC 1
CCR-PNL Sx
MANUAL STEAM LINE ISOLATION LOOP-1
CCR-PNL Sx
MANUAL STEAM LINE ISOLATION LOOP-2
CCR-PNL Sx
MANUAL STEAM LINE ISOLATION LOOP-3
CCR-PNL Sx
MANUAL STEAM LINE ISOLATION LOOP-4
*6 -241685
*6 -225016, -017,018,019
STATION AUX. TRANSFORMER TAP CHANGER
10
SAFE-GUARDS SEQUENCE (SHEETS 7&8)
CONTAINMENT ISOLATION PHASE B MANUAL RESET
SPRAY ACTUATION MANUAL RESET
VALVE UNBLOCK
MANUAL RESET
VALVE UNBLOCK
MANUAL RESET
STEAM LINE ISOLATION LOOP-1
STEAM LINE ISOLATION LOOP-2
STEAM LINE ISOLATION LOOP-3
STEAM LINE ISOLATION LOOP-4
FEEDWATER ISOLATION (SHEET-13)
REACTOR TRIP LOGIC (SHEET 11)
SERVICE WATER
AUXILIARY FEEDWATER
SAFETY INJECTION
CONTAINMENT ISOLATION PHASE B
SPRAY ACTUATION (SHEET 8)
CONTAINMENT ISOLATION PHASE A
CONTAINMENT VENTILATION ISOLATION
CONTROL ROOM VENTILATION ISOLATION
*6 -225024, -025,026,027
*6 -225024, -025,026,027
ISOL. VALVE SEAL WATER SYSTEM
VALVE BLOCKING ON TR "B" ONLY
(NOTE 1)
MANUAL RESET OVERIDE
RESET
FAN COOLING VALVES
MANUAL RESET OVERIDE
RESET
SERVICE WATER VALVES
MANUAL RESET OVERIDE
RESET
CCR A/C DAMPERS
NOTES:
1 -ENCLOSED CIRCUITRY IS NOT PART OF THE SAFEGUARDS SYSTEM AND IS NOT REDUNDANT.
2 -SPRAY ACTUATION BI-STABLES ARE ENERGIZED TO-ACTUATE.
3 -PC-948B, PC-948E AND PC-949B ARE FED FROM A SEPARATE INVERTER POWER SUPPLY.
4 -FOR SYMBOLS AND REFERENCES SEE A225094.
5 -THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #10, MICROFILM 205B96.
*6 -NUMBERS PREFIXED WITH THIS REFERS TO THE APPLICABLE SCHEMATIC DIAGRAM
A) EG. IP2--S-200 MEANS IP2--S-000200
B) EG. LL-3117,15 MEANS 9321-LL-3117,SHEET 15
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS
"CLASS A" ITEMS
PER CI-240-1
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
REVISION
THIS REVISION IS NON-CLASS AS PER THE QAPD. UPDATED DRAWING PER MOD.PROC. DCP-02-2-005. DMD225105-AB-01
ISSUED AS CONSTRUCTED.
P.N. 2-005-02 MPH
ENG
DATE
CHR.
SUPV.
REVIEW
JOHN J LOWNEY
DESIGN ENG
DISC. ENG.
GERARD BLENKLE
ENG. MGR.
APPROVALS
TITLE: LOGIC DIAGRAM
SAFEGUARDS ACTUATION SIGNALS
(SHEET #12)
- UFSAR FIGURE No. 7.2-12
DRAWN BY
SCALE NONE
REC'D
Con Edison
STATION
INDIAN POINT #2
DWG. NO. A225105-10
DB



THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN ENTERGY AS:

" CLASS A" ITEMS

PER THE QAPD

07

NOTES:

1 -FOR SYMBOLS AND REFERENCES SEE A225094.

2 -THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #10, MICROFILM 205B97.

*3 -NUMBERS PREFIXED WITH THIS REFERS TO THE APPLICABLE SCHEMATIC DIAGRAM
   A) EG. m/f REFERS TO MICROFILM NUMBER
   B) EG. LL-3117.15 MEANS 9321-LL-3117.SHEET 15

**4 -UNIT TRIP AND 6900V BUS TRANSFER ACTUATION DELAYED 30 SECONDS AFTER TURBINE TRIP

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION					
DES.	THIS REVISION IS NON-CLASS PER THE QAPD. UPDATED DWG. PER ER# IP2-04-18787 (CR-IP2-2004-00455). RELEASED FOR RECORD P/N 69901-AF A1/R.L.				
R.L. 05/03/04					
ENG.					

DATE	CKR.	SUPV.	DESIGN ENG.	DISC. ENG.	ENG. MGR.
			JOHN J LOWNEY		GERARD BLENKLE
	REVIEW		APPROVALS		

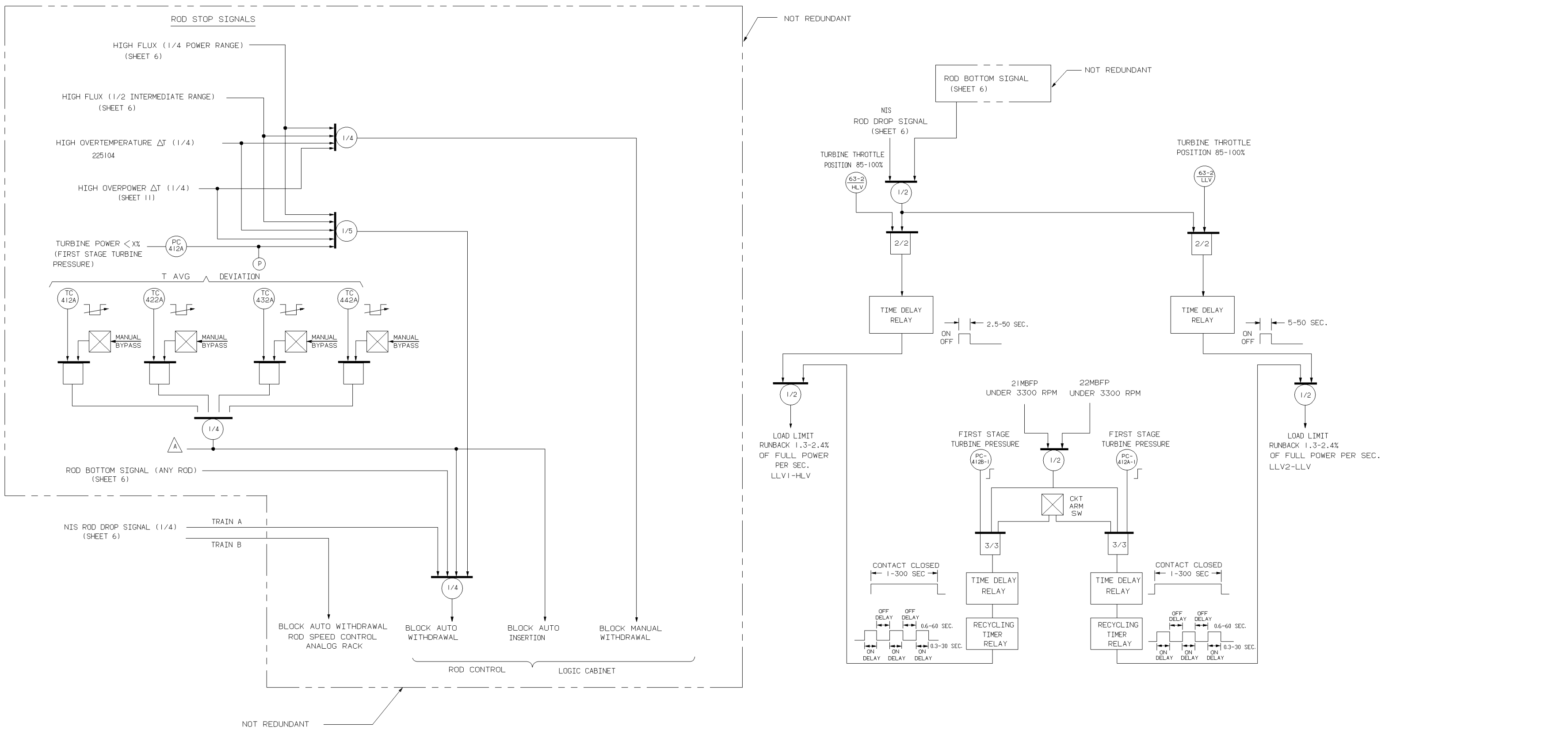
TITLE: LOGIC DIAGRAMS FEEDWATER ISOLATION.
(SHEET #13)
- UFSAR FIGURE No. 7.2-13

DRWN. BY | SCALE NONE | REC'D

Con Edison

STATION INDIAN POINT #2

DWG. NO. A225106-07 DB



NOTES:

1 -FOR SYMBOLS AND REFERENCES SEE A225094.

2 -THIS DRAWING SUPERCEDES WESTINGHOUSE DWG. 882D627, SHEET #10, MICROFILM 205B98.

3-THE AUTOMATIC CONTROL ROD WITHDRAWAL FEATURE IN PLANT OPERATION HAS BEEN PHYSICALLY DISABLED, ALLOWING ONLY THE AUTOMATIC CONTROL ROD INSERTION MODE TO BE IN EFFECT WHEN ROD CONTROL IS IN AUTOMATIC

09

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS

"CLASS A" ITEMS PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION	PW ENG.	THIS REV IS NON-CLASS AS PER THE QAPD UPDATED DWG PER CR# 200108050 RELEASED FOR RECORD P/N 69901-AF 12-19-2001	CH	12-19-2001

JOHN J LOWNEY		GERARD BLENKLE		
CHR. SUPV.	DESIGN ENG.	DISC. ENG.	ENG. MGR.	
REVIEW	APPROVALS			

TITLE: LOGIC DIAGRAM ROD STOPS & TURBINE LOADS CUTBACK. (SHEET #14)

– UFSAR FIGURE No. 7.2-14

DRAWN BY | SCALE NONE | REC'D

Con Edison

STATION INDIAN POINT #2

DWG. NO. A225107-09 DB

3/8/2004 5:06:48 PM 243311-0-2.dwg

REVISIONS

V.I. 4/18/99 02

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO INCLUDE UFSAR FIG. NO. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA 4/18/99

STRATUS ENGINEERING

AL	-	Alarm
Buf	-	Buffer
f	-	Special Function (such as a pressure compensation unit or lead/log compensation)
FC	-	Flow controller (off-on unless output signal is shown)
FI	-	Flow Indicator
FT	-	Flow Transmitter
Hi L	-	High Level
Hi LRT	-	High Level Reactor Trip
Hi PRT	-	High Pressure Reactor Trip
I/I	-	Isolation Current Repeater
ISOL	-	Isolation (other than I/I)
LC	-	Level Controller (off-on unless output signal is shown)
LI	-	Level Indicator
L-Low	-	Low Level
Lo L	-	Low Level
Lo Lo L	-	Low Low Level
Lo LRT	-	Low Level Reactor Trip
Lo Lo LRT	-	Low Low level Reactor Trip
Lo PRT	-	Low Pressure Reactor Trip
L_{ref}	-	Programmed Reference Level
LT	-	Level Transmitter
NC	-	Nuclear Flux Controller
NE	-	Nuclear Detector
NI	-	Nuclear Flux Indicator
NQ	-	Nuclear Power Supply
PC	-	Pressure controller (off-on unless output signal is shown)
PI	-	Pressure Indicator
P_{ref}	-	Programmed Reference Pressure
PS	-	Power Supply
PT	-	Pressure Transmitter
R/I	-	Resistance to Current Converter
S	-	Control channel transfer switch (used to maintain auto channel during test of the protection channel)
SI	-	Safety Injection
T	-	Built-in Test Point
TE	-	Temperature Element
TJ	-	Test Signal Insertion Jack
TP	-	Test Point
ΦU,L	-	Out of core upper or lower ion chamber flux signals

02

NI

STATION- INDIAN POINT 2

UFSAR FIGURE NO. 7.2-28

DRAWN BY REPRO CHECKED

SCALE NONE J.O. 32357-00

APPROVALS

CHIEF DESIGN ENG.

DE ENG. 9/9/85

ENG.

CONSOLIDATED EDISON CO. OF N.Y., INC.

DWG. NO. E 243311-02

RECORDED

57952

929D6 GEN ENG.

3/3/2004 8:00:56 PM 243312-0-1.dwg

REVISIONS

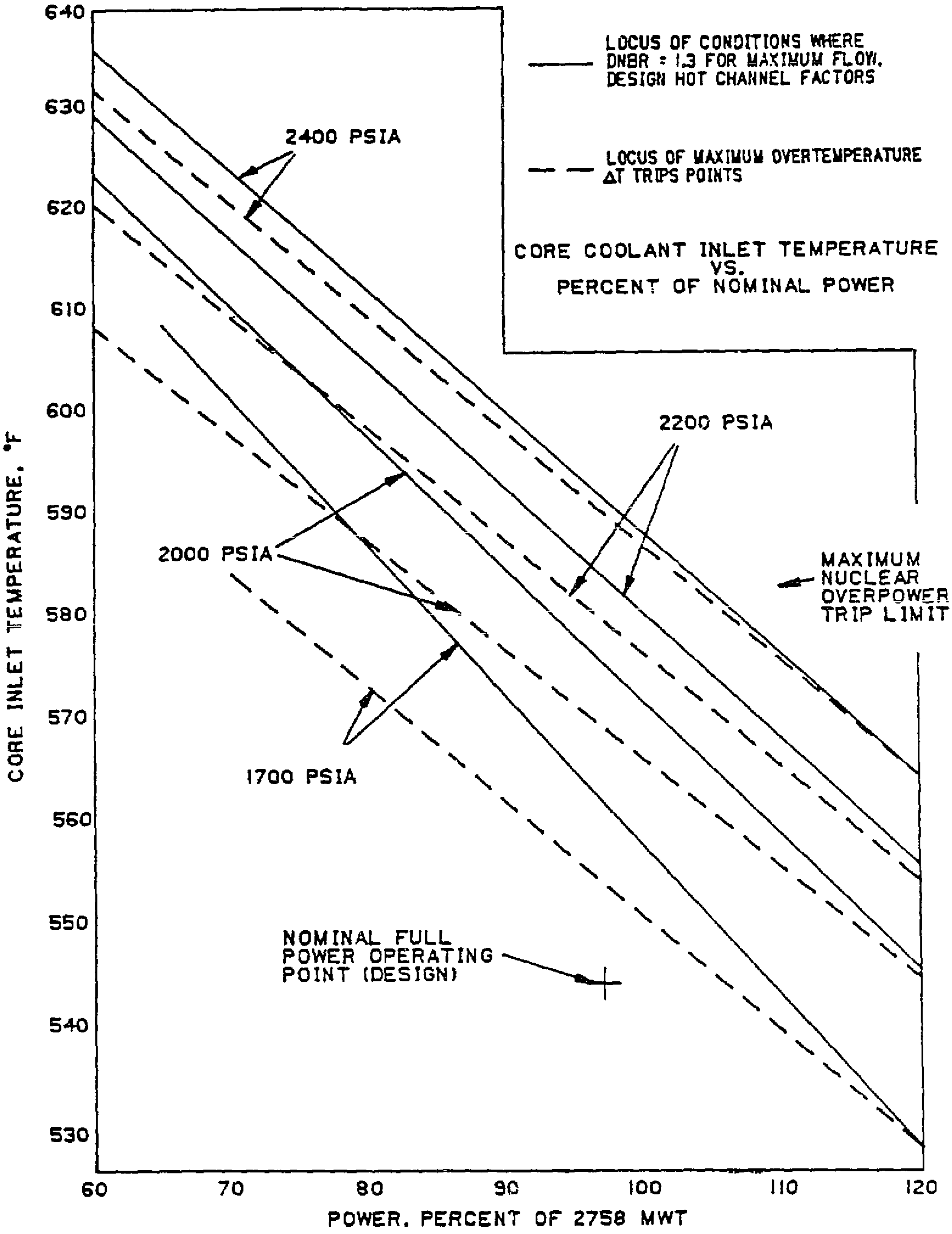
0

THIS REV. IS NON-CLASS AS PER CI-240-1 RELEASED FOR INFO ONLY PN 32357 4-24-85

V.I. 4/18/99 01

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO INCLUDE UFSAR FIG. NO. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA 4/18/99

STRATUS ENGINEERING



01

MI

STATION- INDIAN POINT 2 UFSAR FIGURE No. 7.2-19	APPROVALS: CHIEF DESIGN ENG.	CONSOLIDATED EDISON CO. OF N.Y., INC.
DRAWN BY REPRO CHECKED	ENG. G.L.B. 7/3/85	DWG. NO. E 243312-01
SCALE NONE J.O. 32357-00	DE ENG. 9/9/85	RECORDED

57952

929D6 GEN ENG.

3/3/2004 8:01:04 PM 243313-0-1.dwg

REVISIONS

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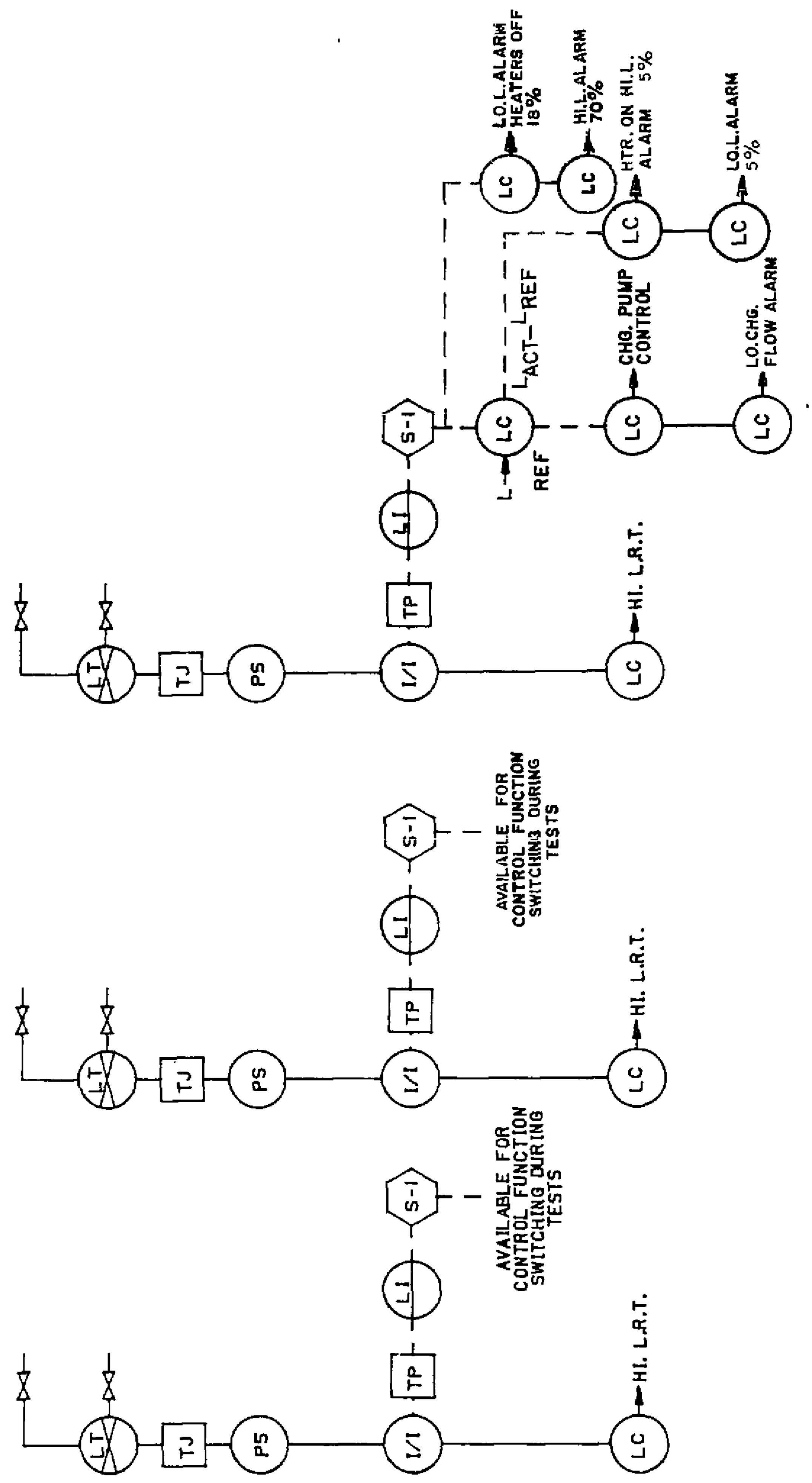
THIS REV. IS NON-CLASS AS PER CI-240-1 RELEASED FOR INFO ONLY PN 32357 4-24-85

V.I. 4/18/99 01

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO INCLUDE UFSAR FIG. NO. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA 4/18/99

STRATUS ENGINEERING



PRESSURIZER LEVEL CONTROL AND PROTECTION SYSTEM

MI

01

STATION- INDIAN POINT 2 (UFSAR FIGURE NO. 7.2-20)	APPROVALS	CHIEF DESIGN ENG.	CONSOLIDATED EDISON CO. OF N.Y., INC.
		ENG. [signature] 7/13/85	DWG. NO. E 243313-01
DRAWN BY REPRO CHECKED			
SCALE NONE J. O. 32357-00		ENG. [signature] 9/9/85	RECORDED

57952

929D6 GEN ENG.

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REVISIONS

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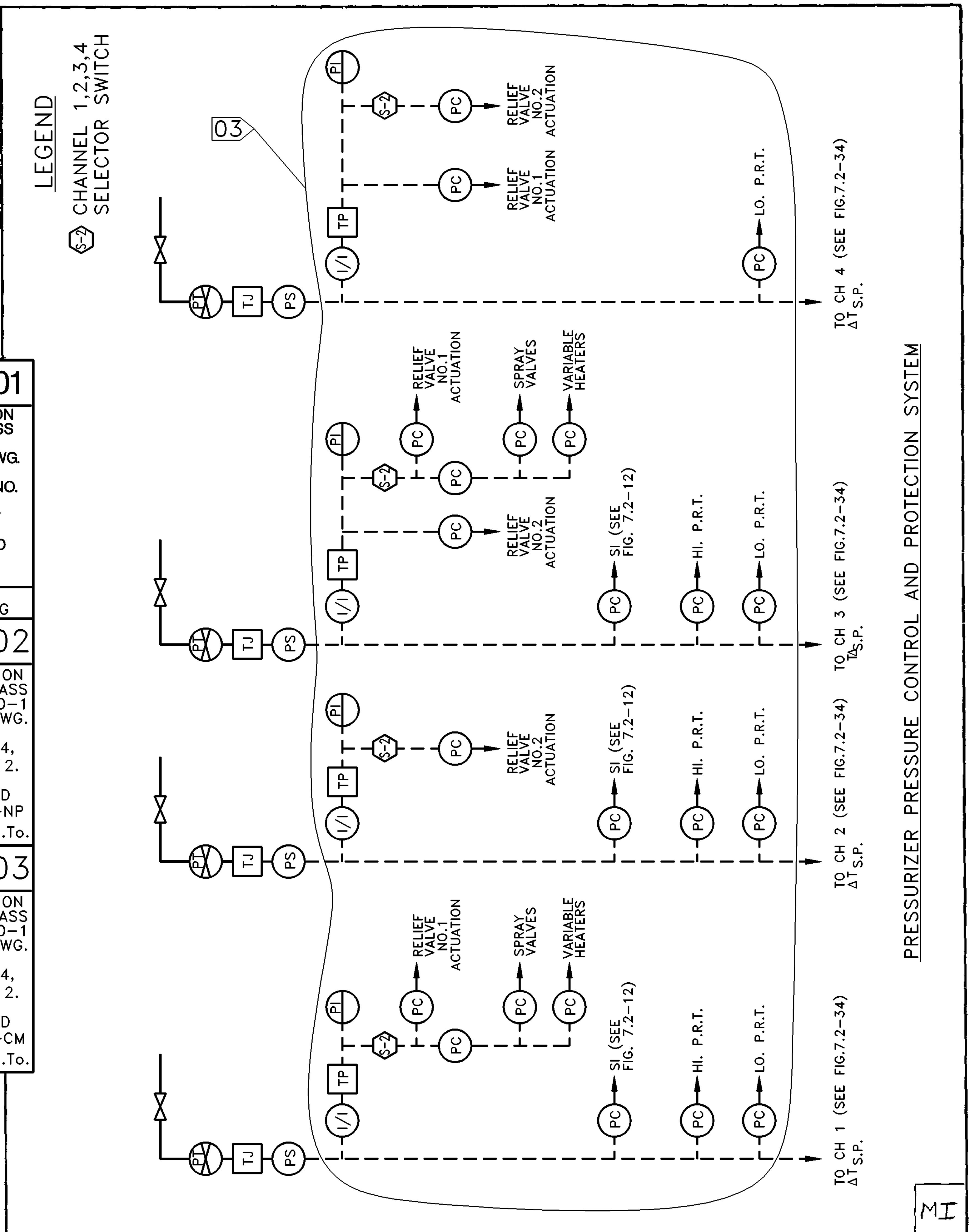
THIS REV. IS NON-CLASS AS PER CI-240-1 RELEASED FOR INFO ONLY PN32357 4-24-85	
V.I. 4/18/99	01
THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO INCLUDE UFSAR FIG. NO. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA 4/18/99	
STRATUS ENGINEERING	
S.MISILO 06-23-99	02
THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. PER CRS #199806134, FILE 0-2012. RELEASED FOR RECORD P.N.69911-NP G.To.	
S.MISILO 03-15-2000	03
THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. PER CRS #199806134, FILE 0-2012. RELEASED FOR RECORD P.N.69982-CM G.To.	



MI

STATION- INDIAN POINT 2 UFSAR FIGURE NO. 7.2-21	APPROVALS	CHIEF DESIGN ENG.	CONSOLIDATED EDISON CO. OF N.Y., INC.
		ENG. G.L. Bikle 7/1/85	**DWG. NO. E** 243314-03
DRAWN BY REPRO **CHECKED**			
SCALE NONE **J.O.** 32357-00		E ENG. R. Hellant 9/9/85	**RECORDED**

57952

929D8 GEN ENG.

REVISIONS

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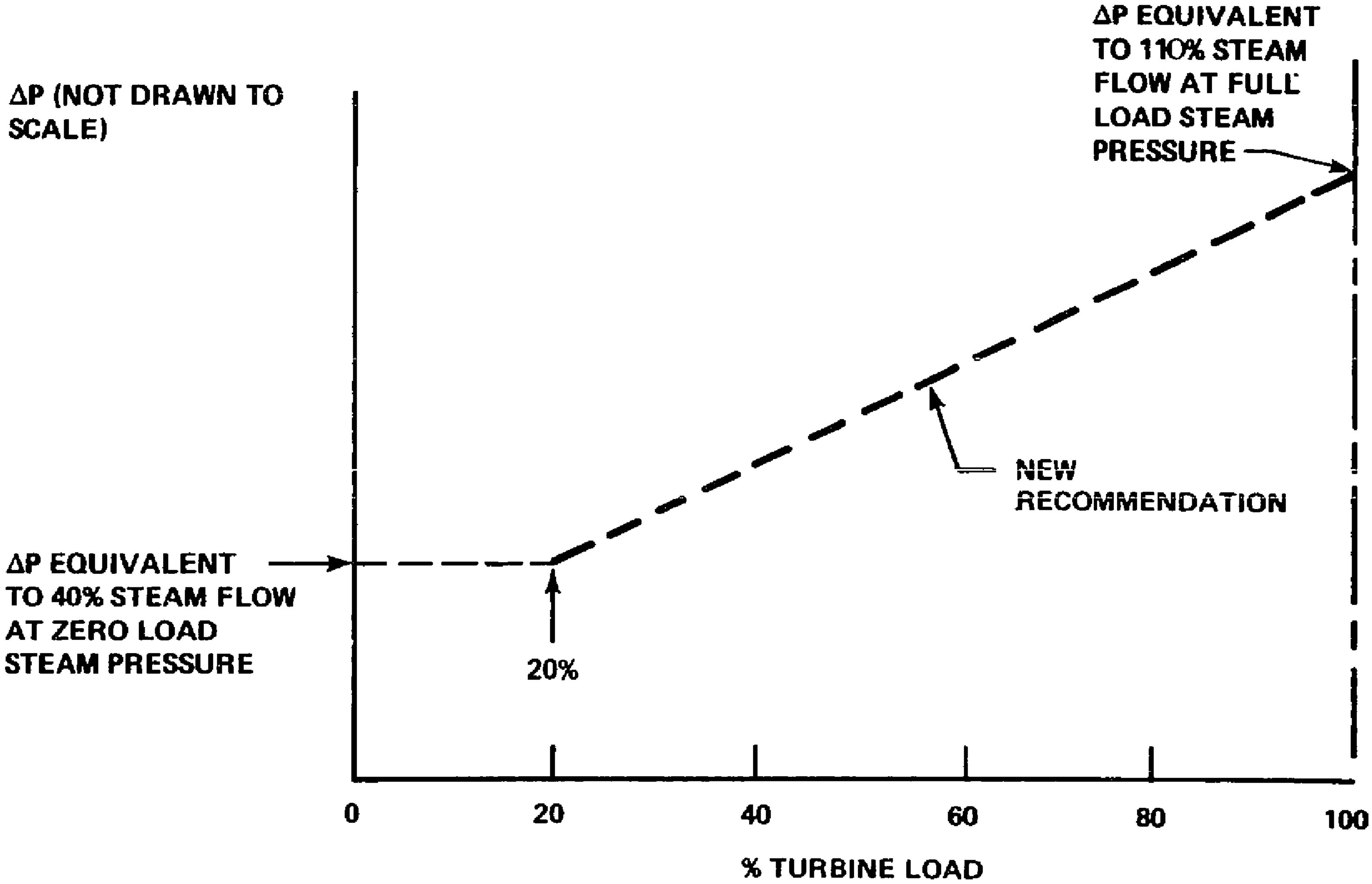
THIS REV. IS NON-CLASS AS PER CI-240-1 RELEASED FOR INFO ONLY PN 32357 4-24-85

V.I. 4/18/99 01

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO INCLUDE UFSAR FIG. NO. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA 4/18/99

STRATUS ENGINEERING



MI

01

STATION- INDIAN POINT 2

UFSAR FIGURE NO. 7.2-22

DRAWN BY REPRO CHECKED

SCALE NONE J.O. 32357-00

APPROVALS

CHIEF DESIGN ENG. 2/14/84

ENG. 3/13/85

DE ENG 9/9/85

CONSOLIDATED EDISON CO. OF N.Y., INC.

DWG. NO. E 243315-01

RECORDED

57952

929D6 GEN ENG.

REVISIONS

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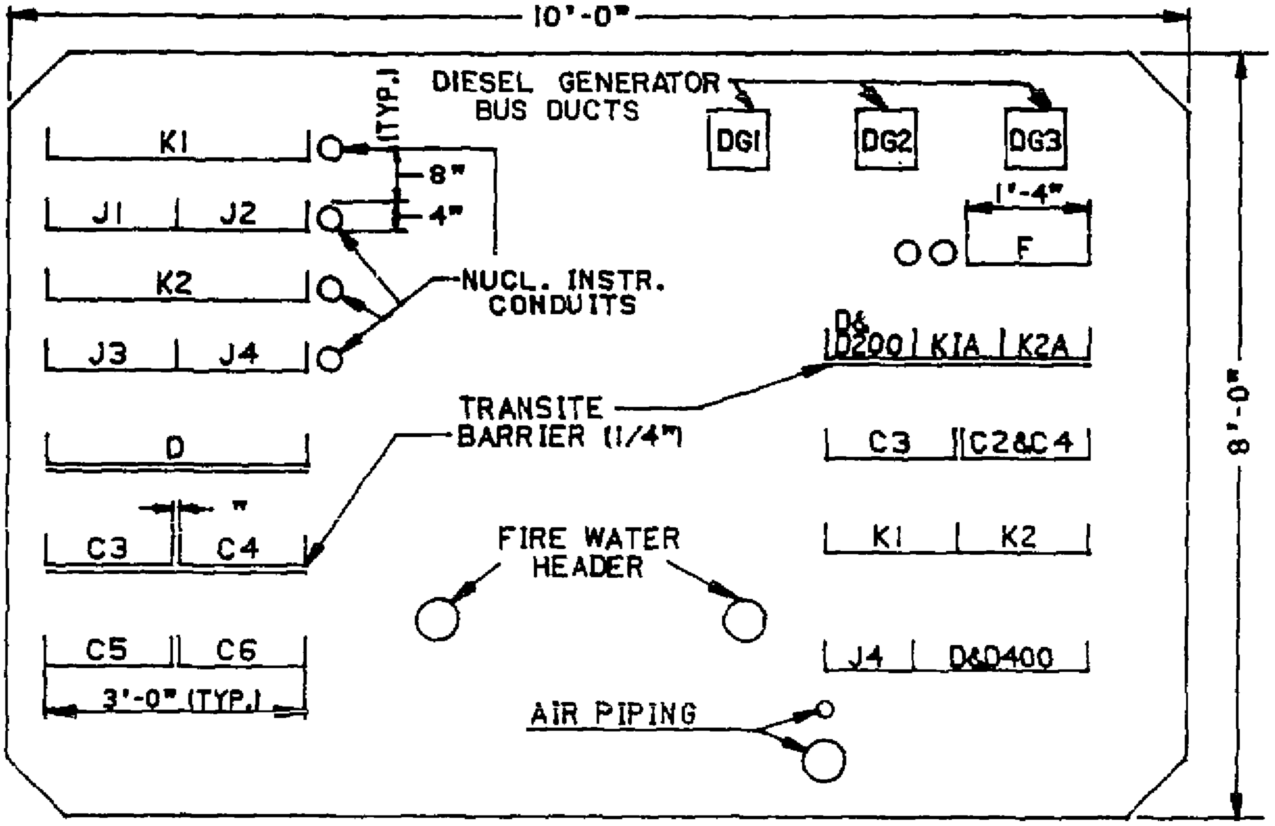
THIS REV. IS NON-CLASS AS PER CI-240-1 RELEASED FOR INFO ONLY PN 32357 4-24-85

V.I. 4/18/99 **01**

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO INCLUDE UFSAR FIG. NO. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA 4/18/99

STRATUS ENGINEERING



TYPICAL SECTION-CABLE TUNNEL

K1	CONTROL TRAY ONE CHANNEL (FOR VALVE CONTROL) ETC
J1-J2	2 INSTR TRAYS WITH BARRIERS-2 CHANNELS
K2	CONTROL TRAY ONE CHANNEL (FOR VALVE CONTROL) ETC
J3&J4	2 INSTR TRAYS WITH BARRIERS-2 CHANNELS
D	MAX #12 WIRE FOR SMALL POWER & ONE CONTROL CHANNEL
C4	(480 HEAVY POWER) CONT RECIRC FAN 21 SAF INJ PUMP 21 RECIRC PUMP 21
C3	(480 V HEAVY POWER) CONT RECIRC FAN 25 RES HT REM PUMP 22 SAF INJ PUMP 23 CONT RECIRC FAN 23
C6	(460 V HEAVY POWER) CONT RECIRC FAN 22 SAF INJ PUMP 22
C5	(480 V HEAVY POWER) RECIRC PUMP 22 RES HT REM PUMP 22 CONT RECIRC FAN 24
F	(1ST CHANNEL) DC SUPPLY (EMERG) DIESEL GEN CONT PNL 23 LTG & MOTOR FEEDERS
D & D200 - K1A-K2A	DIESEL GEN CONTROL 3 CHANNELS
C3	(480V HEAVY POWER) COMP CLG PUMP 23 MCC27 FEEDER MCC 26B FEEDER LTG SWGR TRANSF 22 CHARGING PUMP 22 CHARGING PUMP 23 CONT SPRAY PUMP 22
C2	(480V HEAVY POWER) DC EMER LTG FEEDER
C4	CONT SPRAY PUMP 21 COMP COOLING PUMP 21 COMP COOLING PUMP 22 MCC 26A FEEDER LTG SWGR TRANSF 23 CHARGING PUMP 21
K1-K2	CONTROL, 2 CHANNELS
J4	INSTR 1 CHANNEL
D&D400	MISC SMALL POWER & CONTROL 1 CHANNEL

01

MI

STATION- INDIAN POINT 2

UFSAR FIGURE NO. 7.2-24

DRAWN BY REPRO CHECKED

SCALE NONE J. O. 32357-00

APPROVALS

CHIEF DESIGN ENG. 3/14/?

ENG. 7/1/85

DE ENG. 9/9/85

CONSOLIDATED EDISON CO. OF N.Y., INC.

DWG. NO. E 243317-01

RECORDED

57952

929D6 GEN ENG.

3/9/2004 9:53:59 PM 243318-0-3.dwg

REVISIONS

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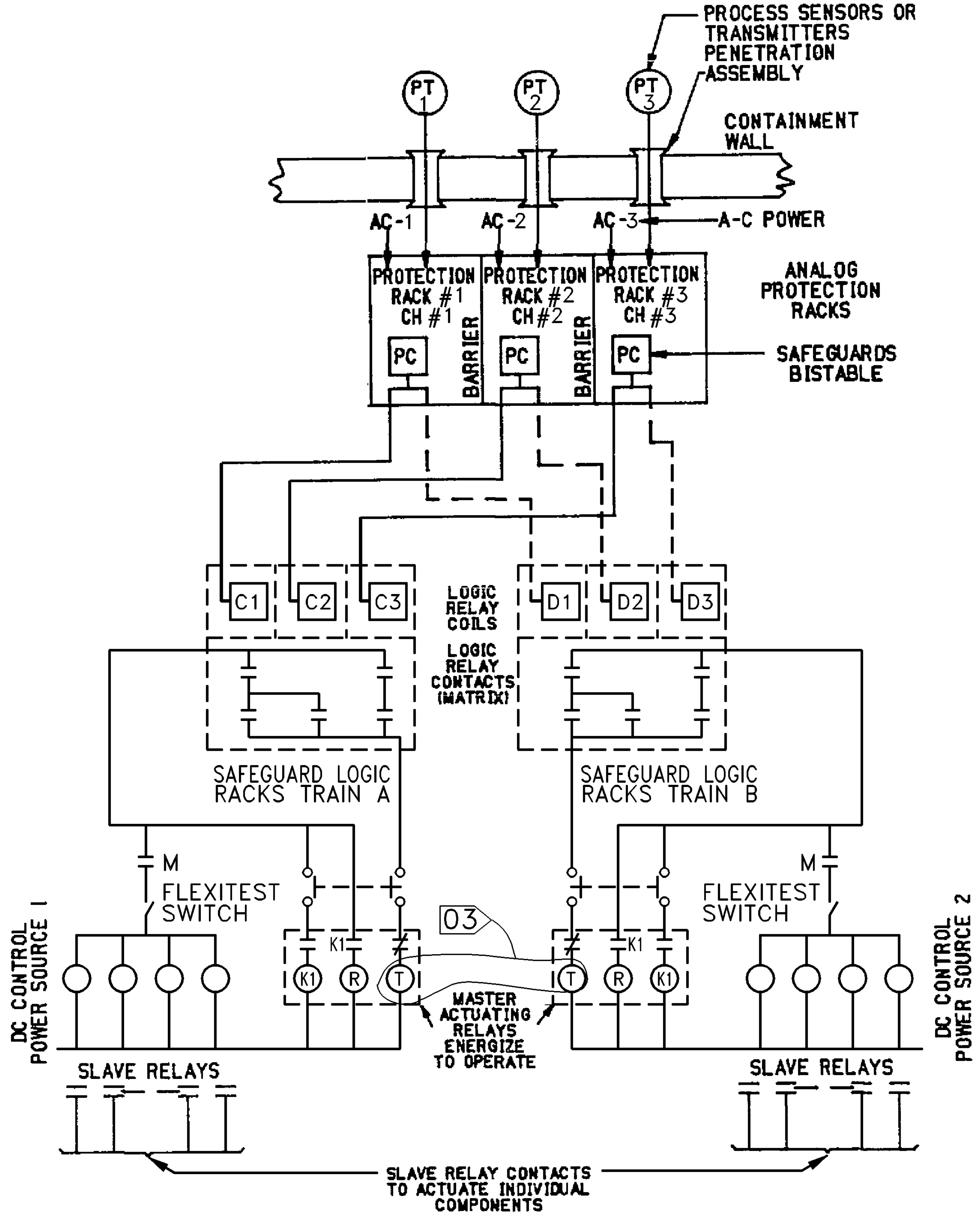
THIS REV. IS NON-CLASS AS PER CI-240-1 RELEASED FOR INFO ONLY PN 32357 4-24-85

V.JAYARAMAN 07-12-99 01

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. PER CRS #199806049, FILE 0-2014. RELEASED FOR RECORD P.N.69911-NP G.To.

V.JAYARAMAN 06/26/00 03

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. PER CRS #199800127 RELEASED FOR RECORD P.N.69982-CD AG/VJ



SAFEGUARD ACTUATION CIRCUITRY AND HARDWARE CHANNELIZATION

MI

STATION- INDIAN POINT 2

UFSAR FIGURE NO. 7.2-15

DRAWN BY REPRO CHECKED

SCALE NONE J. O. 32357-00

APPROVALS

CHIEF DESIGN ENG.

ENG. GTB 7/3/85

PE ENG. [signature] 9/9/85

CONSOLIDATED EDISON CO. OF N.Y., INC.

DWG. NO. E 243318-03

RECORDED

57952

929D6 GEN ENG.

3/8/2004 5:07:03 PM 243319-0-2.dwg

REVISIONS

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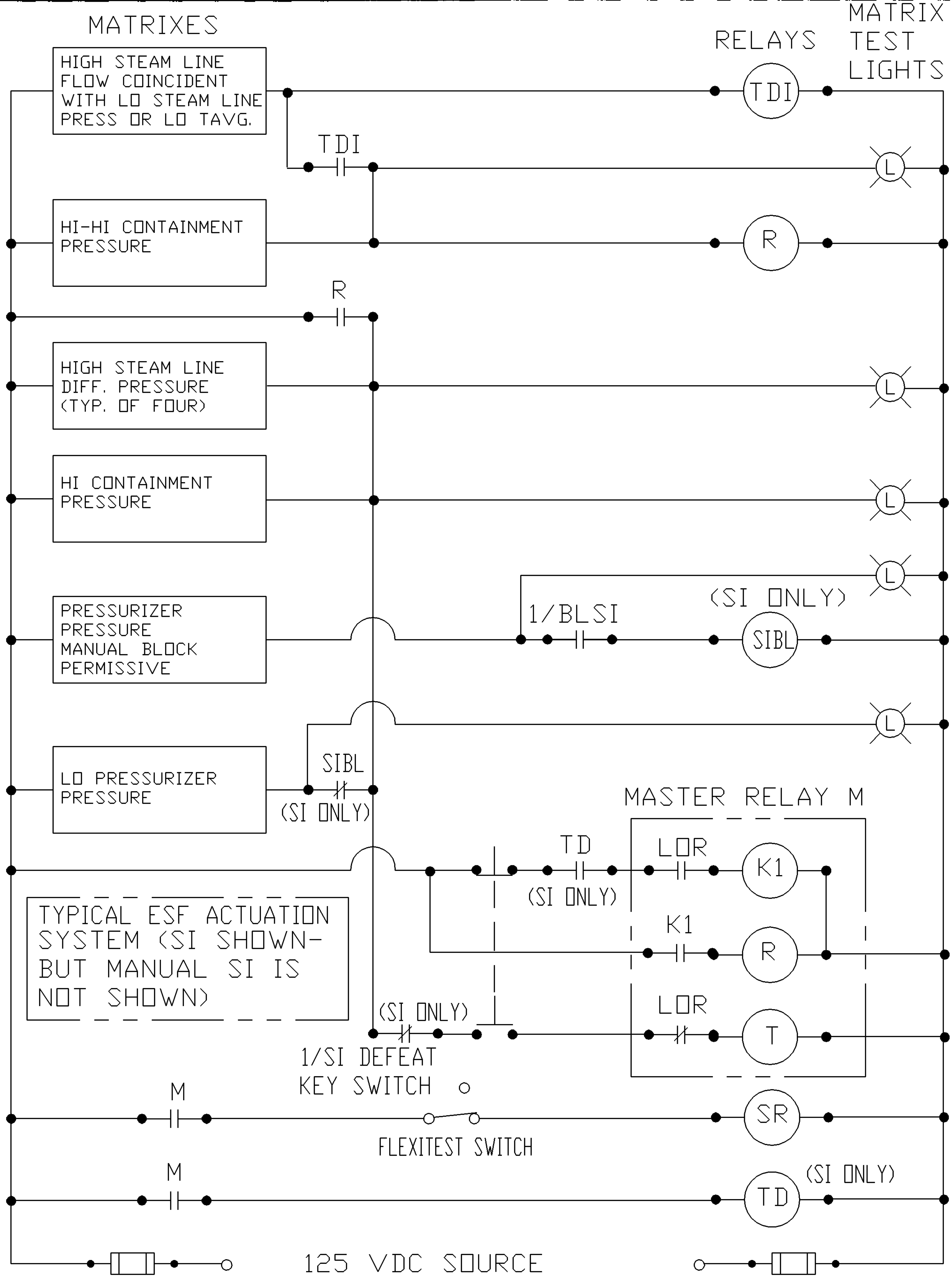

SIMPLIFIED DIAGRAM FOR OVERALL LOGIC RELAY TEST SCHEME

MI

STATION- INDIAN POINT 2 UFSAR FIGURE NO. 7.2-16	APPROVALS	CHIEF DESIGN. ENG.	**CONSOLIDATED EDISON CO. OF N.Y., INC.**
		ENG. G.J. Blahly 7/8/85	**DWG. NO. E** 243319-02
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V.INGRAVALLO 11/15/99	02

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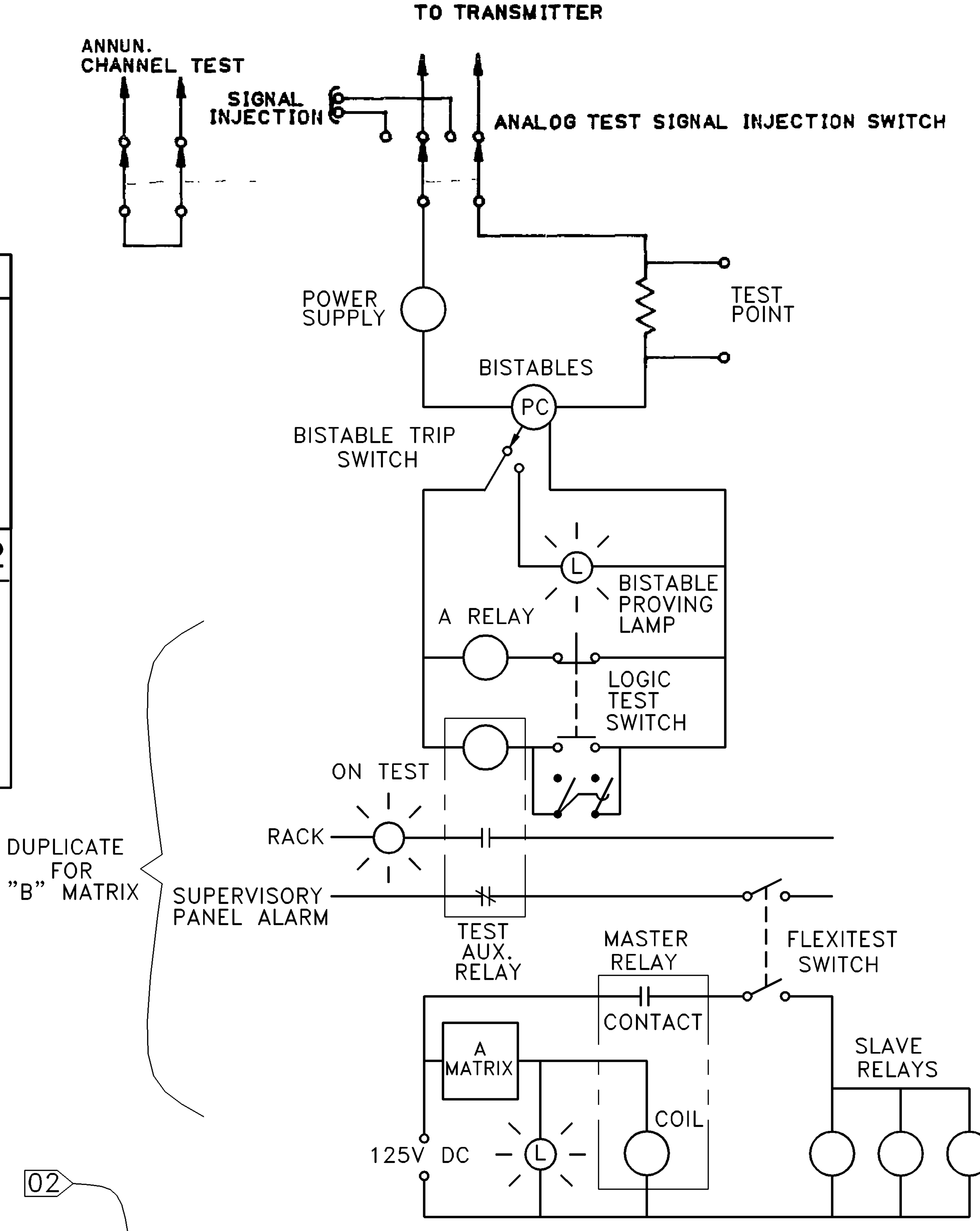

ANALOG AND LOGIC CHANNEL TESTING

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STATION- INDIAN POINT 2
UFSAR FIGURE NO. 7.2-17

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APPROVALS
CHIEF DESIGN ENG.
ENG.
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CONSOLIDATED EDISON CO. OF N.Y., INC.

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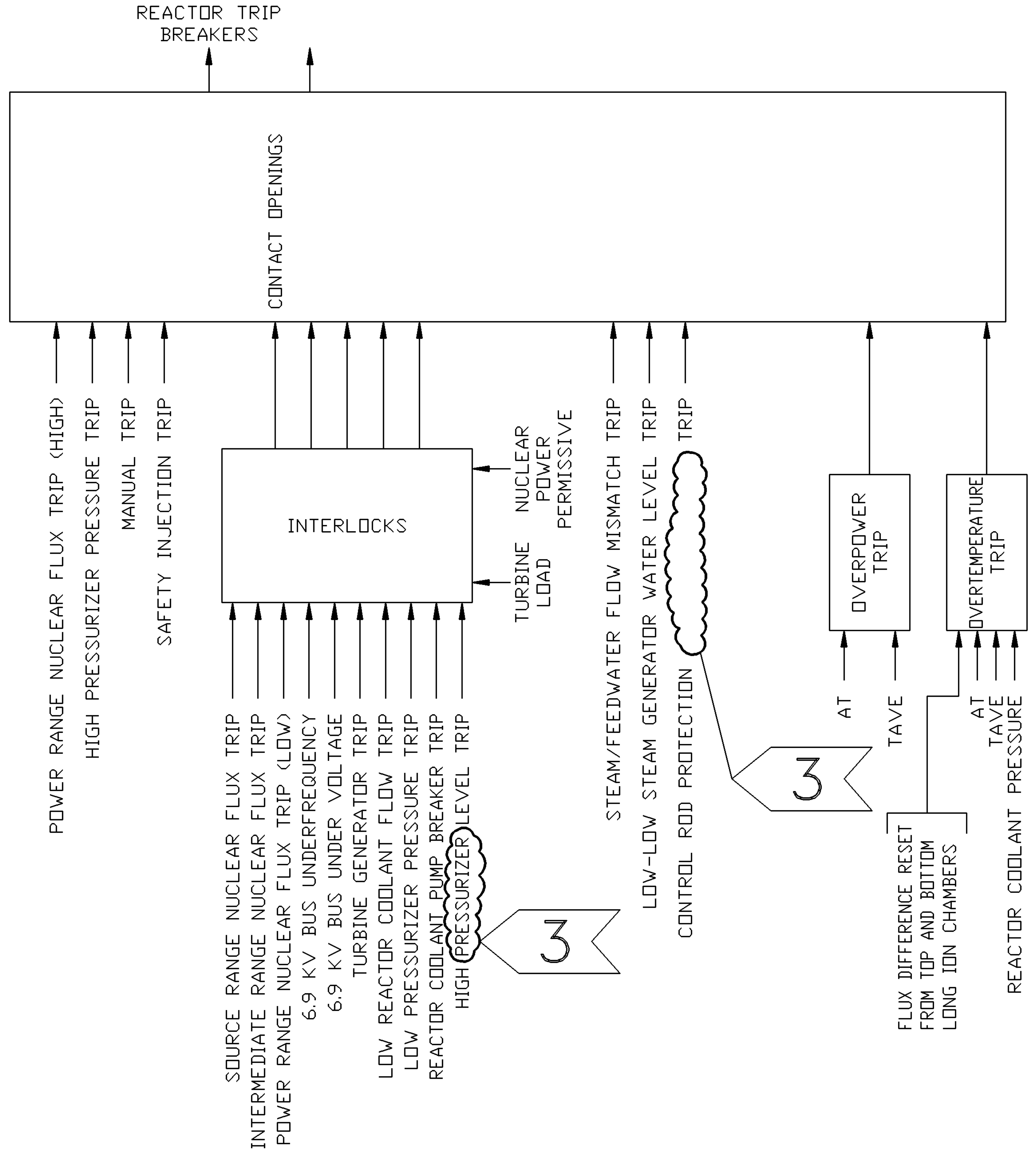

BLOCK DIAGRAM -
REACTOR PROTECTION SYSTEMS

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STATION- INDIAN POINT 2
UFSAR FIGURE NO. 7.2-18

DRAWN BY REPRO CHECKED

SCALE NONE J. O. 32357-00

APPROVALS

CHIEF DESIGN ENG. 4-4-84

ENG. 7/3/85

DE ENG. 9/9/85

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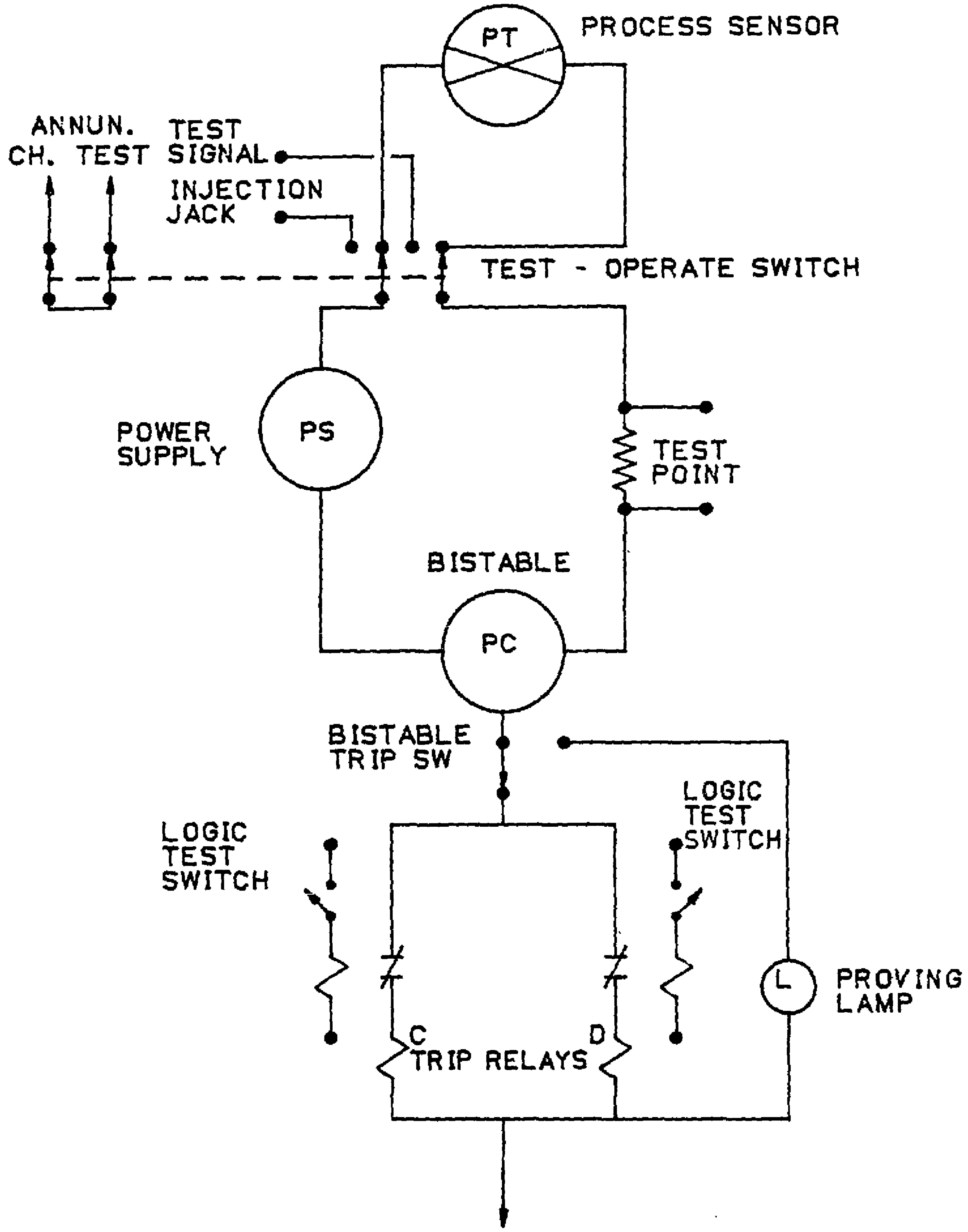

TYPICAL ANALOG CHANNEL TESTING ARRANGEMENT

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STRATUS ENGINEERING

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STATION- INDIAN POINT 2

UFSAR FIGURE NO. 7.2-25

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SCALE NONE J. O. 32357-00

APPROVALS

CHIEF DESIGN ENG. 2/14/89

ENG. 2/13/85

DE ENG. 9/9/85

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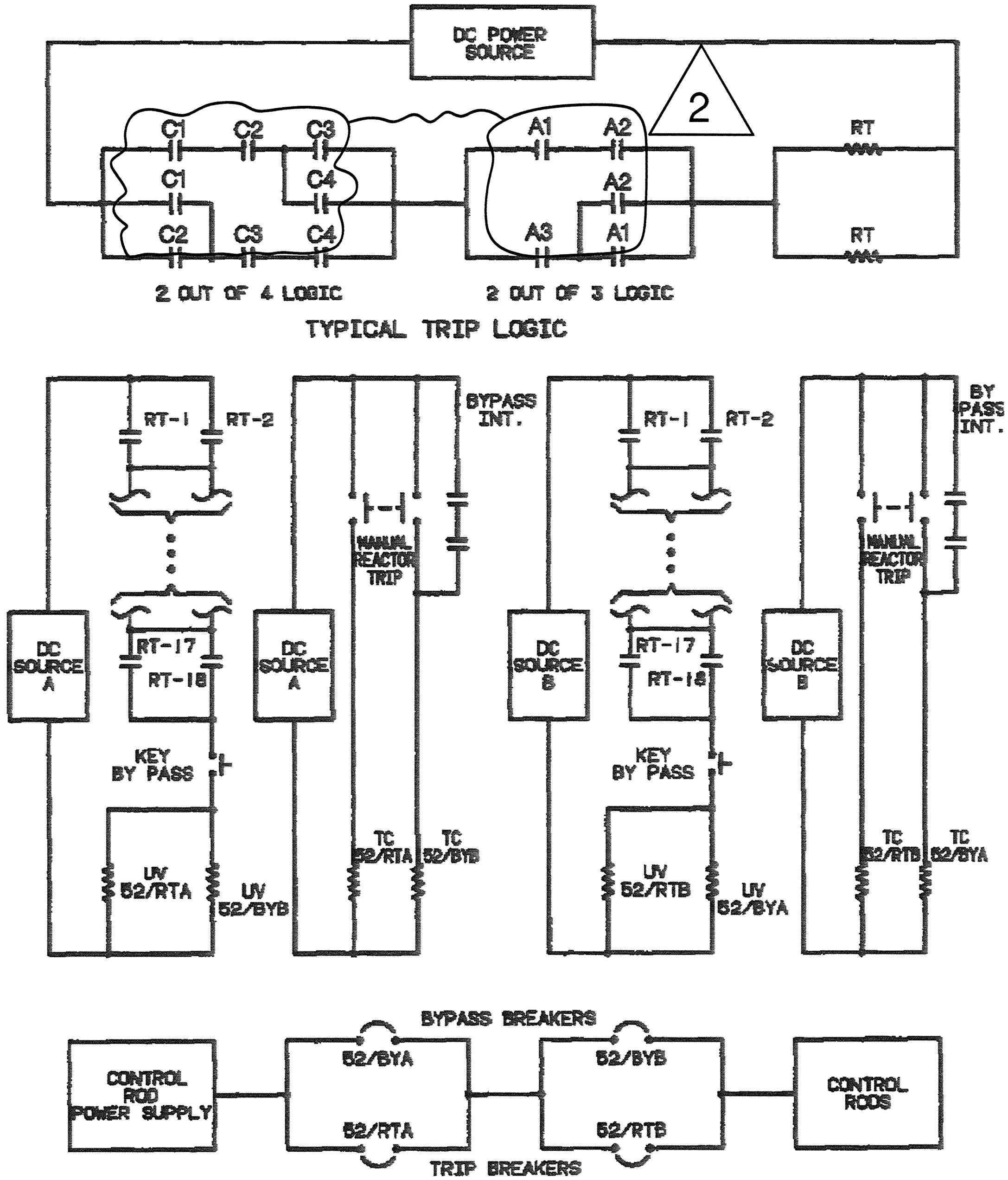
STRATUS ENGINEERING



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APPROVALS

CHIEF DESIGN ENG. 3/14/89

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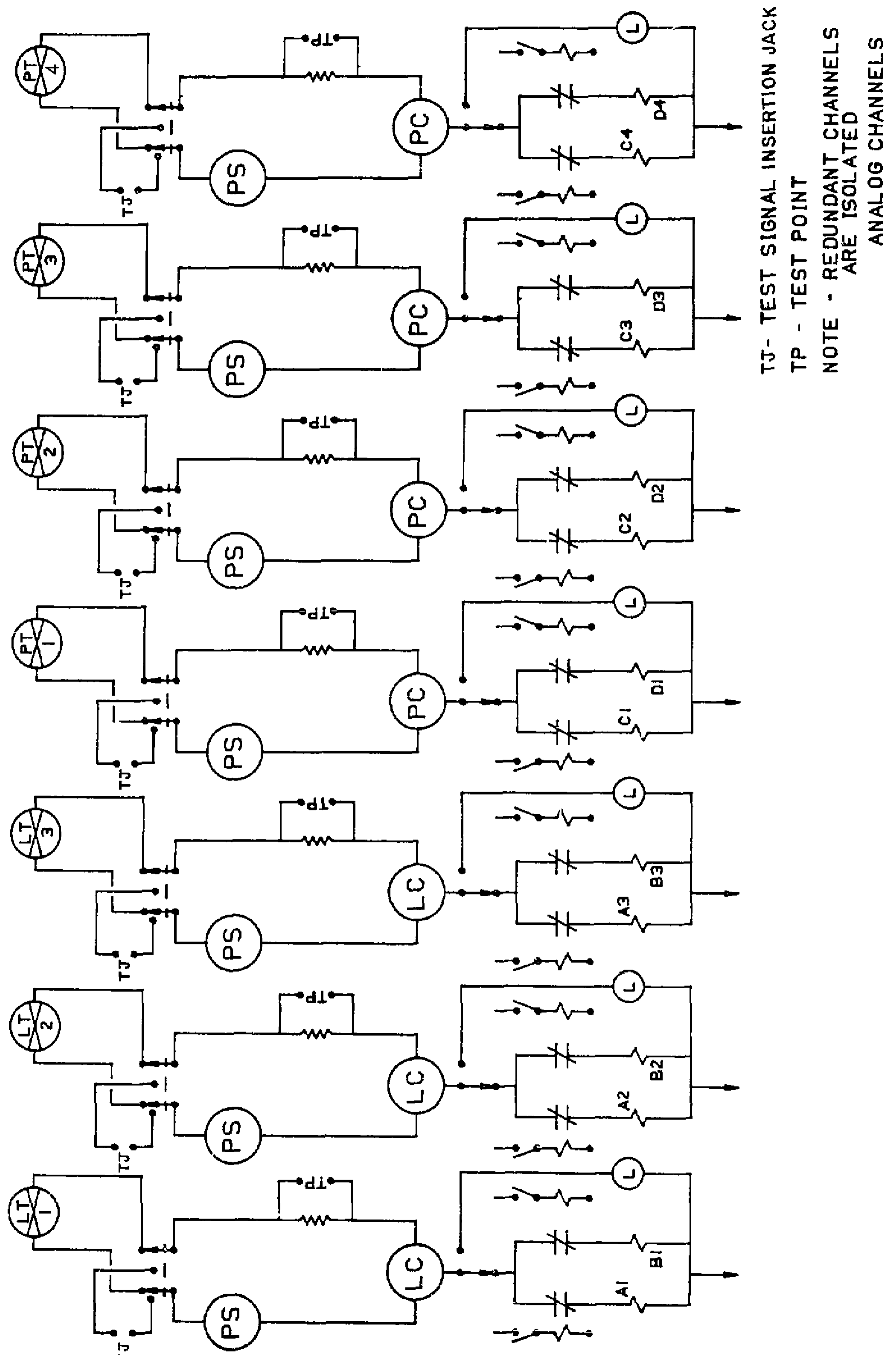
STRATUS ENGINEERING	



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STATION- INDIAN POINT 2 UFSAR FIGURE NO. 7.2-27	APPROVALS	CHIEF DESIGN ENG. 2/14/84	CONSOLIDATED EDISON CO. OF N.Y., INC.
DRAWN BY REPRO **CHECKED**		ENG. G. Blake 2/12/85	**DWG. NO. E** 243324-02
SCALE SCALE **J. O.** 32357-00		ENG. V. C. Hellman 9/1/85	**RECORDED**

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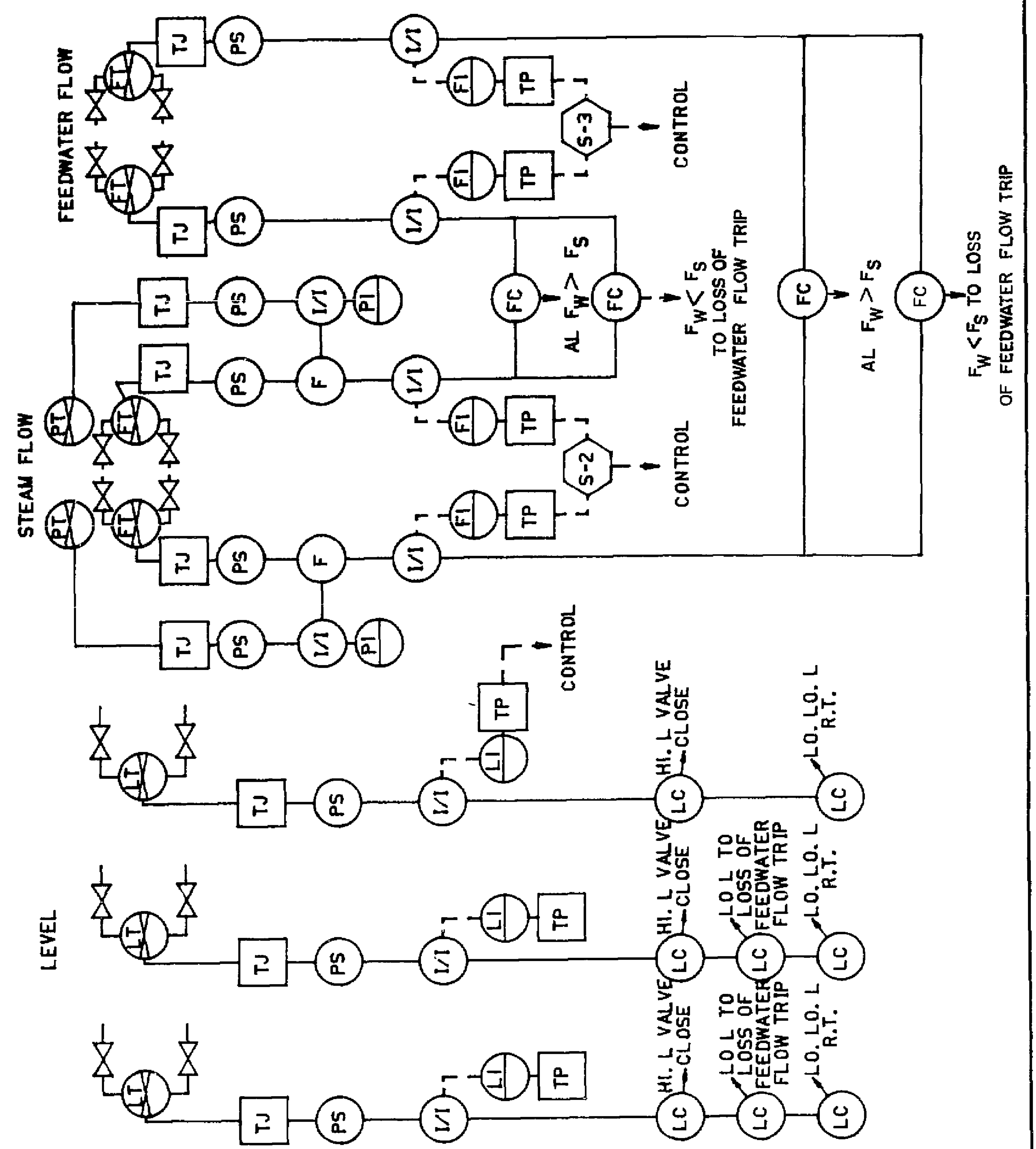
THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO INCLUDE UFSAR FIG. NO. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA 4/18/99

STRATUS ENGINEERING



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STATION- INDIAN POINT 2

UFSAR FIGURE NO. 7.2-32

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SCALE NONE | J.O. 32357-00

APPROVALS

CHIEF DESIGN ENG.

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CONSOLIDATED EDISON CO. OF N.Y., INC.

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CHAPTER 8
ELECTRICAL SYSTEMS

8.1 DESIGN BASES

The main generator supplies electrical power at 22-kV through an isolated-phase bus to two half-sized 20.3/345-kV main power transformers. Power required for station auxiliaries during normal operation is split between a 22/6.9-kV unit auxiliary transformer connected to the isolated phase bus and a 138/6.9-kV station auxiliary transformer. This practice provides significant diversity of normal supply power to the redundant safeguards power trains. Following any turbine trip when there are no electrical faults, which require tripping the generator from the network, the generator remains connected to the network for approximately 30 seconds. Upon generator trip, other than a generator over-frequency trip, auxiliaries fed from the unit transformer are "dead-fast" transferred to the station transformer. Provisions for standby (13.8-kV system) and emergency power (diesels) have been included to ensure further the continuity of electrical power for critical loads.

The function of the auxiliary electrical system is to provide reliable power to those auxiliaries required during any normal or emergency mode of plant operation.

Sufficient independence and isolation between the various sources of electrical power is provided in order to guard against concurrent loss of all auxiliary power.

8.1.1 Principal Design Criteria

8.1.1.1 Performance Standards

Criterion: Those systems and components of reactor facilities, which are essential to the prevention or to the mitigation of the consequences of nuclear accidents, which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (GDC 2)

All electrical systems and components vital to plant safety, including the emergency diesel generators, are seismic Class I and are designed so that their integrity is not impaired by the design-basis earthquake, certain wind storms, floods, or disturbances on the external electrical system. Power, control and instrument cabling, motors, and other electrical equipment required for operating the engineered safety features are suitably protected against the effects of a design-basis event or severe external environmental phenomena to ensure a high degree of confidence in their operability in the event that their use is required.

8.1.1.2 Emergency Power

Criterion: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single component. (GDC 39 and GDC 24)

Emergency power systems are provided with adequate independency, redundancy, capacity, and testability to supply the required engineered safety features and protection systems.

The plant is supplied with emergency power sources as follows:

1. Three independent emergency diesel generators, located in the Diesel Generator Building adjacent to the Primary Auxiliary Building, supply emergency power to the engineered safety features buses in the event of a loss of AC auxiliary power. There are no automatic bus ties associated with these buses. Each diesel generator is started automatically on a safety injection signal or upon the occurrence of an undervoltage condition on any vital 480-V switchgear bus. The system is sufficiently redundant such that any two diesels have adequate capacity to supply the engineered safety features for the design basis accident concurrent with a loss of offsite power. One diesel is adequate to provide power for a safe and orderly plant shutdown in the event of a loss-of-offsite electrical power.

2. Emergency power for vital instrumentation and control and for emergency lighting is supplied from the 125 VDC system via four independent DC channels. The station batteries supply emergency power to the instrumentation and control systems when their associated battery chargers are not available.

8.1.2 1980 Review of 10 CFR 50 Appendix A GDC 17 and GDC 18

Our August 11, 1980 response to the NRC's February 11, 1980 Confirmatory Order included a study of how the plant complied with 10 CFR 50 regulations in effect at that time. The following paragraphs provide a discussion of the extent to which the Indian Point Unit 2 design complies with Criteria 17 and 18 of 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

8.1.2.1 10 CFR 50 Appendix A General Design Criterion 17 - Electric Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

> Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that the core cooling, containment integrity, and other vital safety functions are maintained.
>
> Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

Independent alternate power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems.

The plant is supplied with normal, standby, and emergency power sources as follows:

1. The normal source of auxiliary power for 6.9-kV buses 1, 2, 3, and 4 during plant operation is the unit auxiliary transformer, which is connected to the main generator via the iso-phase bus.

2. The normal source of auxiliary power for 6.9-kV buses 5 and 6 and standby power required during plant startup, shutdown, and after reactor trip is the station auxiliary transformer, which is supplied from the Con Edison 138-kV system by either of two separate overhead lines from the Buchanan substation approximately 0.5 mile from the plant. Alternate feeds from the Buchanan 13.8-kV system are also available for immediate manual connection to the auxiliary buses.

3. Three diesel-generator sets supply emergency power to the engineered safety features buses in the event of a loss of AC auxiliary power. There are no automatic bus ties associated with these buses. The Station Blackout (SBO) / Appendix R emergency diesel-generator is installed in the Unit 1 Turbine Building and is used to supply power for Appendix R fires and a Station Blackout.

4. Power for vital instrumentation and controls and for emergency lighting is supplied from the four 125-V DC systems. The station batteries supply emergency power to the instrumentation and control systems when their associated battery chargers are not available.

The emergency diesel-generator sets are located in the Diesel Generator Building adjacent to the Primary Auxiliary Building and supply emergency power to separate 480-V switchgear buses. Each set will be started automatically on a safety injection signal or upon the occurrence of an undervoltage condition on any 480-V switchgear bus. Any two diesels have adequate capacity to supply the required engineered safety features for the design basis accident concurrent with a loss of offsite power. One diesel is adequate to provide power for a safe and orderly plant shutdown in the event of loss-of-offsite electrical power.

All electrical systems and components vital to plant safety, including the emergency diesel generators, are seismic Class I and are designed so that their integrity is not impaired by the design-basis earthquake, certain wind storms, floods, or disturbances on the external electrical system. Power, control and instrument cabling, motors, and other electrical equipment required for operating the engineered safety features are suitably protected against the effects of a design-basis event or severe external environmental phenomena to ensure a high degree of confidence in their operability in the event that their use is required.

The electrical system equipment is arranged so that no single contingency can inactivate enough safeguards equipment to jeopardize plant safety. The 480-V equipment is arranged on four buses (three power trains). Buses 2A and 3A are supplied by the same emergency diesel generator power supply. Buses 5A and 6A are each supplied by one of the remaining two emergency diesel generator power supplies. The 6.9-kV equipment is supplied from six buses.

The plant auxiliary equipment is arranged electrically so that redundant or similar equipment receive power from different sources. The charging pumps are supplied from 480-V buses 3A, 5A, and 6A. The six service water pumps and the five containment fans are similarly supplied from the four 480-V switchgear buses. The two service water pumps, one safety injection pump, and the emergency diesel associated with buses 2A and 3A can be connected to either bus 2A or 3A. Safeguards motor-operated valves are supplied from motor control centers 26A/26AA and 26B/26BB, which are supplied from buses 5A and 6A, respectively.

The 138-kV outside source of power and the 138-kV/6.9-kV station auxiliary transformer are adequate to run all of the plant auxiliary loads.

The bus arrangements specified for operation ensure that power is available to an adequate number of safeguards auxiliaries.

Two diesel generators have enough capacity to start and run a fully loaded set of engineered safeguards equipment. The safeguards equipment with any two of the three power trains can adequately cool the core for any loss-of-coolant incident and maintain the containment pressure within the design value.

The 125-V DC power supplies consist of four separate systems, each having its own battery, battery charger, and power panel. Under normal conditions, each battery charger supplies its DC loads, while maintaining its associated battery at full charge. The battery provides power to the DC loads when the battery charger is not available. DC control power for the 480-V ESF Switchgear and the emergency diesel generators is supplied via automatic transfer switches. Should normal battery voltage fall below a specified level, the associated transfer switch(es) transfer control power from the preferred source to the alternate source. This design eliminates any transfer of load between redundant DC systems 21 and 22, which power the reactor protection and safeguards logics and ensures that adequate DC power is available for starting the emergency diesel generators and for other emergency uses.

The plant turbine generator is the main source of 6.9-kV auxiliary electrical power during "online" plant operation. Power to the auxiliaries is supplied by a 22/6.9-kV two-winding unit auxiliary transformer that is connected to the isophase bus from the generator.

The 6.9-kV system is arranged as six buses. Under normal conditions, two buses (5 and 6) receive power from the 138-kV system via bus main breakers and the 138-6.9-kV station auxiliary transformer. Buses 1, 2, 3, and 4 receive power from the main generator via bus main breakers and the unit auxiliary transformer. Buses 1 and 2 can be tied to bus 5, and buses 3 and 4 can be tied to bus 6 via bus tie breakers when the turbine-generator is shutdown. Buses 2, 3, 5, and 6 each serve one of the four 6900-480-V station service transformers. Normal and offsite power to the 480-V switchgear buses is supplied through these station service transformers.

The 480-V system is arranged as four ESF switchgear buses. Each 480-V switchgear bus supplies several 480-V motor control center buses for power distribution throughout the station. The 480-V switchgear buses are supplied from the 6.9-kV buses as follows: 2A from 2, 3A from 3, 5A from 5, and 6A from 6. Tie breakers are provided between 480-V switchgear buses 2A and 3A, 2A and 5A, and 3A and 6A. These tie breakers are racked out under administrative control when the RCS temperature exceeds 350°F.

The required safeguards equipment circuits are supplied from the 480-V ESF switchgear buses. The normal source of power for buses 5A and 6A is the 138-kV system (via the station auxiliary transformer, 6.9-kV buses 5 and 6, and station service transformers); no transfer is required in the event of a unit trip. Buses 2A and 3A will receive power from the 138-kV system in the event of a unit trip via a "dead fast" transfer of buses 2 and 3 to buses 5 and 6, respectively.

One emergency diesel-generator set supplies emergency power to bus 5A, one to bus 6A, and the third to buses 2A and 3A. Each set will be started automatically on a safety injection signal (see Section 7.2) or upon undervoltage on any 480-V switchgear bus.

Power for the safeguards valve motors is supplied from four motor control centers (26A/26AA and 26B/26BB), which in turn are supplied from the 480-V ESF Switchgear. Motor Control Centers 26A and 26B are provided protection by 480-V circuit breakers. These circuit breakers are on different 480-V switchgear buses, and the bus associated with each circuit breaker has a dedicated emergency diesel generator MCC's 26AA and 26BB are supplied from MCC's 26A and 26B, respectively.

Two independent sources of DC control power are available to the breakers on each 480-V switchgear bus via automatic normal power seeking transfer switches. The preferred and alternate sources of DC control power for the breakers are detailed under Section 8.2.2.3.

Power for instrumentation and control is provided by four 118-V AC Instrument Supply Systems. Each system consists of one inverter, one manual bypass switch, two 118-V AC buses, and associated interconnections. The four inverters are dedicated, one to each system. Each inverter receives power from a different DC Power Panel (DC Power Panel 21 supplies Inverter 21. DC Power Panel 22 supplies Inverter 22, etc.) In the event an inverter, is taken out of service, a backup supply from the 480-V system is available to supply the 118-V AC loads. Failure of a single inverter or its static transfer to switch will not cause the loss of a basic protective system or prevent the actuation of the minimum safeguards devices.

Several sources of offsite power are available to Indian Point Unit 2. These consist of two 138-kV overhead supplies from the Buchanan 138-kV substation, and three separate underground feeders from the Buchanan 13.8-kV substation. The 13.8-kV line is rated 19.8 MVA at 13-kV. The 13.8/6.9-kV transformer is rated 20 MVA. The maximum engineered safety feature and safe shutdown loads are 9.2 MVA. No safety or emergency power is required from these sources for the retired Indian Point Unit 1.

The Buchanan 138-kV substation supply to Indian Point Unit 2 has two connections to the Millwood 138-kV substation, a connection to the Peekskill Refuse Burning Generating Station and a connection via auto-transformer to the Buchanan North 345-kV substation. The Indian Point Unit 2 345-kV connection to the system goes to the Buchanan North 345-kV substation, which has connections to Ramapo and Eastview 345-kV substations. System stability studies show that the system is stable for the loss of any generating unit including Indian Point Unit 2.

Each 138-kV overhead tie line can provide offsite power to Indian Point 2 via the station auxiliary transformer. The loss of this transformer would interrupt the 138-kV supply to the station. For this reason, an alternate 13.8/6.9-kV supply is provided.

An additional source of offsite power from the 13.8-kV distribution system at Buchanan is available to 6.9-kV buses 5 and 6 through supply breakers GT-25 and GT-26. The transfer from the normal to the reserve supply (or vice versa) must be accomplished manually.

Each of these circuits is designed to be available in sufficient time following a loss of all onsite AC power supplies and other offsite electric power circuits, to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. The 138-kV system is designed to be available instantaneously following a loss-of-coolant accident to ensure that core cooling, containment integrity, and other vital safety functions are maintained. This is accomplished by a "dead-fast" transfer scheme that uses stored energy breakers to transfer the auxiliaries on the four 6.9-kV buses supplied by the unit auxiliary transformer to the station auxiliary transformer, which is supplied from the 138-kV system. However, when buses 5 and 6 are supplied from the alternate 13.8-kV supply, the "dead fast" transfer scheme is defeated by manual action to protect the 13.8-kV-6.9-kV transformer.

The diversity and redundancy inherent in the combination of offsite electrical systems minimize the probability of losing electric power from any of the remaining sources as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of onsite power sources.

The electrical power sources and systems have been evaluated as meeting the requirements of 10 CFR 50.63 (the Station Blackout Rule) (References 3, 4, 5, 6, 7, 8 and 9).

The adequacy of the station electric distribution system voltages was reviewed (as requested by the NRC in Reference 1) for expected normal operating voltage ranges and potential degradations of both the offsite power system and the unit's main electrical generator. The offsite power sources were analyzed under the extremes of load and offsite voltage conditions and credited the automatic load tap changers. To protect safeguards equipment from degraded voltage conditions, which could impair their operation, separate sets of undervoltage relays on each 480-V ESF switchgear bus will alarm to alert the operator that voltage has fallen below approximately 94-percent on any bus and will trip the normal (offsite or main electrical generator) supply breakers to any bus if voltage remains below approximately 88-percent for 180 ± 30 sec. In addition, the 480-V supply breaker to the ESF Switchgear buses will trip upon sustained (10 ± 2 sec) degraded voltage conditions coincident with a safety injection signal. By Reference 2, the NRC concluded that the Indian Point Nuclear Station Unit 2 design is acceptable with respect to the adequacy of station electrical distribution system voltages.

8.1.2.2 10 CFR 50 Appendix A General Design Criterion 18 - Inspection and Testing of Electric Power Systems

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

At each refueling interval the 480-V emergency power system is tested to verify that it and vital equipment control systems will respond as designed. The test is initiated by simulating a loss of normal AC station service power.

Testing and surveillance of the station batteries is accomplished as follows:

1. Every month the voltage of each cell, the specific gravity and temperature of a pilot cell in each battery, and each battery voltage are measured and recorded.

2. Every three months the specific gravity of each cell, the temperature reading of every fifth cell, the height of electrolyte, and the amount of water added are measured and recorded. Also, an equalizing charge is applied if deemed necessary based on the recorded cell voltages and specific gravities.

3. Each time data are recorded, the new data are compared with the old to detect signs of abuse or deterioration.

4. At each refueling interval, each battery is subjected to a load test and a visual inspection of the plates.

Functional testing is performed in the automatic transfer switches that provide DC control power to the circuit breakers of 480-V Switchgear, Buses 2A, 3A, 5A, and 6A and the emergency diesel-generator control panels. This testing demonstrates that:

(a) Each automatic transfer switch will transfer from its preferred source to its alternate source when the preferred source is unavailable or its voltage falls below a predetermined value,

(b) The preferred and alternate sources of each transfer switch are available to supply DC control power to the breakers and for control of the emergency diesel-generators, and

(c) Each transfer switch will automatically transfer back to its preferred source when the voltage of the preferred source is re-established to an acceptable level.

The safety injection system is tested:

1. To verify that the various valves and pumps associated with the engineered safeguards system will respond and perform their required safety functions.

2. To ensure that each diesel generator will start automatically and assume the required load, within 60 sec after the initial start signal by simulating loss of all normal alternating current station service power supplies and simultaneously simulating a safety injection signal. This test is performed at each refueling interval.

3. To verify that the required bus load shedding takes place.

4. To verify the restoration of particular vital equipment to operation.

Environmental qualification of electrical equipment important to safety is addressed in Section 7.1.

REFERENCES FOR SECTION 8.1

1. Letter from William Gammill, U.S. Nuclear Regulatory Commission, to all Power Reactor Licensees (except Humboldt Bay), Subject: Adequacy of Station Electric Distribution Systems Voltages, dated August 8, 1979.

2. Letter from Steven A. Varga, U.S. Nuclear Regulatory Commission, to John D. O'Toole, Con Edison, Subject: Adequacy of Station Electric Distribution System Voltages, dated October 18, 1982.

3. Letter from Francis J. Williams, U.S. Nuclear Regulatory Commission, to Steven B. Bram, Con Edison, Subject: Supplemental Safety Evaluation of Indian Point Nuclear Generating Unit No. 2, Response to the Station Blackout Rule (TAC No. M68556), dated June 4, 1992.

4. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated April 14,1989.

5. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated March 27,1990.

6. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated October 22, 1993.

7. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated November 30,1993.

8. Letter from Francis J. Williams, U.S. Nuclear Regulatory Commission, to Stephen B. Bram, Con Edison, Subject: Safety Evaluation of the Indian Point Nuclear Generating Unit No.2, Response to the Station Blackout Rule (TAC No. M68556), dated November 21, 1991.

9. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated December 23, 1991.

8.2 ELECTRICAL SYSTEM DESIGN

8.2.1 Network Interconnections

Con Edison's external transmission system provides two basic functions for the nuclear generating station: (1) it provides auxiliary power as required for startup and normal shutdown and (2) it transmits the output power of the station.

Electrical energy generated at 22-kV is raised to 345-kV by the two main transformers. Power is delivered to the system via a 345-kV overhead tie line routed between the main transformers and the 345-kV North Ring Bus at Buchanan Substation. The North Ring Bus is configured with three circuit breakers rated 362-kV, 3000A, 40/63kA. Two of these breakers have synchronizing capability to connect the main generator to the system. The North Ring Bus is also connected to Ramapo and Eastview Substations via overhead transmission circuits and to the Buchanan 138-kV Substation via a 335/138-kV auto-transformer.

The electrical one-line diagram for the Indian Point Station is presented in Plant Drawing 250907 [Formerly UFSAR Figure 8.2-1]. Standby power is supplied to the station from the Buchanan 138-kV Substation, which has two connections to the Millwood 138-kV Substation, one connection to the Peekskill Refuse Burner, and one connection to the Buchanan 345-kV Substation via an auto-transformer. Several power flow paths exist to connect 13.8-kV buses through 13.8/6.9 kV autotransformers to Buses 1 and 6.

A single-line diagram showing the connections of the main generator to the power system grid and standby power source is shown in Plant Drawing 250907 [Formerly UFSAR Figure 8.2-2].

8.2.1.1 Reliability Assurance

Two external sources of standby power are available to Indian Point Unit 2. They are the 138-kV tie from the Buchanan 345-kV substation and the 138-kV Buchanan-Millwood ties. Loss of any of these sources will not affect the other. Substantial flexibility and alternate paths exist within each source.

The 138-kV supply from the Buchanan substation with its connections to the Con Edison 345-kV system provides a dependable source of station auxiliary power. Upon loss of 345/138-kV auto-transformer supply at Buchanan, two 138-kV ties are designed to provide additional auxiliary power from the Millwood 138-kV substation. A further guarantee of reliable auxiliary power, independent of transmission system connections, is provided by the SBO / Appendix R Diesel for the Appendix R fire or a loss of all AC (Station Blackout). The SBO / Appendix R Diesel, associated switchgear and breakers minimum operating requirements are specified in the Unit 2 Technical Requirements Manual (TRM). The minimum quantity of fuel for the SBO / Appendix R Diesel to operate 72 hours shall be available at all times the SBO / Appendix R Diesel is considered operable. Support systems for cooling include the City Water Storage Tank and the Service Water System (SWS) (first the city water and then a switch to the SWS). If these requirements cannot be met, then the diesel is considered inoperable and the TRM requirements are followed.

The fuel supply consists of two onsite 30,000-gal fuel oil tanks and a 200,000-gal storage tank located at the Buchanan substation site. A minimum amount of fuel is maintained available and dedicated for the SBO / Appendix R Diesel. This minimum fuel inventory ensures that the SBO / Appendix R Diesel will be capable of supplying the maximum electrical load for the Indian Point Unit 2 alternate safe shutdown power supply system (i.e., 1600kW) for at least 3 days. Commercial oil supplies and trucking facilities exist to ensure deliveries of additional fuel within one day's notice.

In the event of the loss of the Indian Point Unit 2 138-kV supply (the primary preferred offsite supply), the Indian Point Unit 2 13.8/6.9-kV supply is manually connected to 6.9-kV buses 5 and 6. The capacity of this supply is limited and is not capable of supplying full plant load. However, the 13.8-6.9-kV supply is capable of supplying the normal load on buses 5 and 6 and is also capable of supplying all 480-V safeguards and safe shutdown loads. The "dead-fast" transfer of 6.9-kV buses 1, 2, 3, and 4 is prevented by manual action when buses 5 and 6 are supplied from the 13.8/6.9-kV supply.

8.2.2 Station Distribution System

The auxiliary electrical system is designed to provide a simple arrangement of buses requiring a minimum of switching to restore power to a bus in the event that the normal supply is lost.

The basic components of the station electrical system are shown on the electrical one-line diagrams (See Plant Drawings 208377, 231592, 208088, 9321-3004, 249956, 9321-3005, 208507, 249955, 208241, 9321-3006, 248513, 208500, 208502, 208503, 9321-3008, and UFSAR Figure 8.2-4 [Formerly UFSAR Figures 8.2-3, and 8.2-5 through 8.2-16]), which include the main generator, the 345-kV, the 6.9-kV, the 480-V, the 118-V AC instrument, and the 125-V DC systems.

8.2.2.1 Unit Auxiliary, Station Auxiliary, and Station Service Transformers

The plant turbine generator is a main source of 6.9-kV auxiliary electrical power during "online" plant operation. Power to the auxiliaries on 6.9-kV Buses 1 thru 4 is supplied by a 22/6.9-kV two-winding unit auxiliary transformer that is connected to the main generator via the iso-phase bus. Power to the auxiliaries on 6.9-kV buses 5 and 6 during “on line” plant operation is supplied by a 13.8/6.9-kV two-winding station auxiliary transformer connected to an offsite supply. Power to the 480-V buses is supplied from four 6900/480-V, air-insulated, dry-type station service transformers.

These transformers were designed and constructed in accordance with ANSI C57.11, as the applicable standard of record at the time of fabrication. During engineered safeguards loading and operation, these transformers are loaded within their rating. Manufacturer shop tests of the transformers were conducted in accordance with the American Standard Test Code C 57.12.90. This series of tests consisted of the following:

1. Resistance measurements of all windings.
2. Ratio tests.
3. Polarity and phase relation tests.
4. No-load losses.
5. Exciting current.
6. Impedance and load loss.
7. Temperature test.

8. Applied potential tests.
9. Induced potential tests.

The normal source of power to buses 5 and 6 and auxiliary power required during plant startup, shutdown, and after a unit trip is supplied from the 138-kV switchyard. After a unit trip, the auxiliary loads on 6.9-kV Buses 1 through 4 are transferred from the unit auxiliary transformer to the station auxiliary transformer by automatic relay transfer scheme using stored energy breakers. The transfer is monitored by synchrocheck relays (Device 25). The 138-kV system is the normal supply for two of the three power trains of the auxiliary loads associated with plant engineered safeguards.

8.2.2.2 <u>6.9-kV System</u>

The 6.9-kV system is arranged as six buses. During normal plant operation, two buses (5 and 6) receive power from the 138-kV system by bus main breakers and the 138/6.9-kV station auxiliary transformer, while buses 1, 2, 3, and 4 receive power from the main generator by bus main breakers and the unit auxiliary transformer. On a generator trip, other than a generator over-frequency trip, a “dead-fast” transfer scheme ties buses 1 and 2 to bus 5, and bus 3 and 4 to bus 6, by bus tie breakers. In the case of a generator over-frequency trip, the transfer is blocked by an over-frequency transfer interrupt circuit provided for bus protection of out of phase transfer. Plant Drawing 225097 [Formerly UFSAR Figure 7.2-4] is the logic diagram of the transfer scheme. Buses 2, 3, 5, and 6 each serve one 6900/480-V station service transformer.

8.2.2.3 <u>480-Volt System</u>

The 480-V system arranged as ESF Switchgear buses 2A, 3A, 5A, and 6A and numerous motor control center buses. The 480-V switchgear buses are supplied from the 6.9-kV buses as follows: 2A from 2, 3A from 3, 5A from 5, and 6A from 6 (buses 2A and 3A are within the same power train). Tie breakers are provided between 480-V Switchgear buses 2A and 3A, 2A and 5A, and 3A and 6A.

The required safeguards equipment circuits are supplied from the 480-V Switchgear buses. The normal source of power for buses 5A and 6A is the 138-kV system (via the station auxiliary transformer, 6.9-kV buses 5 and 6, and station service transformers); since the normal source of power to these buses is not the main generator, no transfer is required in the event of a unit trip. Buses 2A and 3A are supplied from buses 5 and 6, respectively, via a "dead-fast" transfer of the 6.9-kV buses in the event of a unit trip.

One emergency diesel-generator set provides emergency power to bus 5A, one to 6A, and the other to buses 2A and 3A. Each set will automatically start on a safety injection signal or upon undervoltage on any 480-V switchgear bus.

Power for the safeguards valve motors is supplied from four motor control centers (MCC’s 26A, 26AA, 26B, and 26BB). Motor Control Centers 26A and 26B are supplied through separate circuit breakers on different 480-V switchgear buses. Each of these 480-V switchgear buses has a dedicated emergency diesel-generator set. Motor Control Centers 26AA and 26BB are sub fed from MCC’s 26A and 26B, respectively.

Loads required for safe shutdown and accident mitigation are supplied from the 480-V switchgear buses and from certain 480-V motor control centers. Other loads are segregated onto other motor control centers. In the event of loss-of-offsite power, loads are stripped from the 480-V buses, the diesel generators are started, and required loads are added in sequence, as described in section 8.2.3.4.

All four 480-V switchgear buses are safety-related and supply power to ESF systems and equipment. Therefore, two independent sources of DC control power are provided for control of 480-V breakers, protective circuits and other devices. This is accomplished by automatic transfer switches located near each switchgear. A transfer from the preferred source to the alternate source occurs when the voltage of the preferred source falls below a predetermined value (100-V DC), provided the voltage of the alternate source is above a predetermined value (112.5-V DC). When the preferred source is restored to 112.5-V DC or higher, the transfer switch will transfer back to the preferred source. With only one source energized, the transfer switch seeks the energized source. Lights indicate the available energized source. Thus, the DC supply for the protection and control of the ESF Switchgear is maintained in the event of a loss of one DC source.

The preferred and alternate sources of DC control power for the breakers are:

Transfer Switch	Associated Bus	Preferred Source	Alternate Source
EDD1	6A	DC PP #24	DC PP #22
EDD2	2A	DC PP #22	DC PP #24
EDD3	3A	DC PP #23	DC PP #21
EDD4	5A	DC PP #21	DC PP #23

8.2.2.4 125-V DC Systems

There are four separate safety-related 125-V DC systems serving the various DC loads throughout the station. Each system consists of one battery, one battery charger, one main power panel and one or more DC distribution panels (sub panels). The systems are similarly arranged, however equipment capacities are not necessarily the same.

Each battery charger is supplied from a different 480-V switchgear bus. Under normal and emergency conditions, the battery charger supplies the DC loads and float charges the battery. The battery provides power to the DC loads under the following conditions:

(a) When the load exceeds the capacity of the battery charger, such as during DC motor starting or simultaneous breaker operation.

(b) When the battery charger is not available, such as a battery charger failure or loss of input voltage.

Bus ties between the main power panels (DC Power Panel 21 and DC Power Panel 22) permit battery and battery charger maintenance.

8.2.2.5 118-V AC Instrument Supply Systems

There are four independent safety-related 118-V AC instrument supply systems serving the various instrumentation and control systems throughout the station. Each system consists of one solid-state inverter with an internal static transfer switch, one manual bypass switch and two 118-V AC instrument buses (See Plant Drawing 250970 [Formerly Figure 8.2-2] for system arrangement and connections to power sources). All four inverters are supplied from different 125-V DC power panels. Each inverter has an alternate input power source (120-V AC nominal), which is used to synchronize the inverter output to the auxiliary electrical system and to provide power to the vital 118-V AC loads in the unlikely event of an inverter failure. The alternate input power source to the inverters is provided by step-down transformers connected to the inverter's static transfer switch. These transformers are supplied from safety-related 480-V MCCs. These feeds are electrically separated from the feeds to the associated battery charger. In the event that an inverter or static transfer switch is out of service, each 118-V AC system has a manual transfer switch mounted in a separate enclosure that can bypass the static transfer switch and provide backup power from the step-down transformers directly to the 118-V AC buses. To ensure that a single failure of an emergency diesel-generator will not result in the unavailibility of more than one 118-V AC system, the normal and backup supplies for three of the instrument buses 21, 22, and 24 are unitized (i.e. fed from the associated emergency diesel-generator). Instrument bus 23 is fed from emergency diesel generators 21 and 22, providing diverse sources to prevent loss of this bus due to loss of a single emergency diesel-generator. Voltage drop calculations demonstrate that equipment supplied from Buses 21 and 21A are operable with the postulated minimum voltage at Inverter 21. This is typical of all instrument buses.

8.2.2.6 Evaluation of Layout and Load Distribution

Electrical distribution system equipment is located to minimize the exposure of vital circuits to physical damage as a result of accidents or natural phenomena. To a certain extent the Diesel-Generator Building is protected from tornados and major tornado generated major missiles because it is situated between large buildings as shown in the site plot plan (Plant Drawing 9321-1002 [Formerly UFSAR Figure 1.2-3]). The diesel-generator installation is considered redundant to other lines of power supply. As described in Section 8.1, there are alternate power supplies. In the case of a tornado, reliance is placed on power supply redundancy and not solely on the diesel installation.

Station Auxiliary, Unit Auxiliary, and the main transformers are located outdoors and are spaced to minimize their exposure to fire, water, and other physical damage.

Surge arresters are installed near the high-voltage terminals of the main and standby transformers to protect the windings from lightning and switching transients, which can cause transformers to fail. All oil-filled transformers are provided with automatic deluge systems to extinguish oil fires quickly and prevent the spread of fire.

The 6.9-kV buses are housed in two metal-clad switchgear units. The enclosures for switchgear 21 and 22 are located at elevation 15 ft in the turbine building. Each breaker is mounted in a separate compartment. Switchgear 21 and 22 have a solid top with cable penetrations and some openings on the side. The cable openings at the top are sealed to minimize bus exposure to fire, water, and other physical damage. An overcurrent condition on any of the 6.9-kV buses actuates the associated bus protection lockout relays, which isolate the bus by tripping and locking out both the normal supply breaker and the 6.9-kV tie breaker for that bus.

The 480-V buses are housed in two metal-enclosed switchgear units located at the 15-ft elevation of the Indian Point Unit 2 control building. The switchgear structure provides protection to minimize exposure from mechanical, fire, and water damage. Buses 5A and 2A are contained in switchgear enclosure 21; Buses 6A and 3A constitute switchgear enclosure 22. The switchgear contains the buses, the bus supply breakers, the tie breakers, the load (feeder) breakers, the station service transformers, and the potential transformers for synchronizing and under-voltage relay protection. The normal 480-V switchgear supply breakers 52/2A, 52/3A, 52/5A, and 52/6A are tripped under the following conditions:

1. Safety injection or unit trip, and loss of voltage (~46-percent) on bus 5A or 6A.
2. Actuation of manual trip pushbuttons on each breaker.
3. Actuation of control switches in the Central Control Room.
4. Actuation of control switches in the Diesel-Generator Building.
5. Individual breaker overcurrent protection.
6. Degraded voltage (~88-percent) for 180 ± 30 seconds on each respective bus.
7. Degraded voltage (~88-percent) coincident with a safety-injection signal for 10 ± 2 seconds.

The "short time" undervoltage relays provide input signals to the sequencing logic and emergency diesel generator start circuitry. Their setpoints (~46-percent) are designed to provide a fast trip response under complete loss-of-power ("dead bus") conditions.

The trip of the normal 480-V supply breakers to the safeguards buses upon sustained under voltage is actuated by two undervoltage relays (set at ~88-percent) on each bus. Two out of two logic will operate an Agastat timing relay (set at 180 ± 30 sec), which in turn trips its respective 480-V supply breaker. This function was added to provide additional protection to the safeguards loads against degraded-voltage conditions. Tripping the 480-V supply breakers to the safeguards buses, upon sustained degraded-voltage conditions coincident with a safety-injection signal for 10 ± 2 sec, protects the motors in addition to providing an alternate power supply to establish a correct voltage.

A separate category alarm and bullet lights in the central control room will alert the operator when any 480-V switchgear bus voltage falls to 94-percent. These may operate during load sequencing operations but they are primarily intended to alert the operator to sustained degraded voltages that result from problems on the offsite power system.

Remote manual and automatic control of the 480-V switchgear breakers and associated relays requires 125-V DC control power. Automatic transfer switches are provided to increase the reliability and availability of DC control power for operation of the 480-V switchgear under normal conditions and during safeguards actuation.

The original plant design provided for transfer between 125-V DC Systems 21 and 22 for each switchgear's DC control power. To improve the reliability of the system and eliminate any potential for transfer-related common-mode failures of DC systems 21 and 22, the transfer schemes were changed to utilize DC systems 23 and 24, which were added after the plant was commissioned. The NRC reviewed this plant change in their safety evaluation report dated 5/2/80, and determined that it met the requirements of Regulatory Guide 1.6 and was therefore acceptable (Reference 1). See Section 8.2.2.3 for the preferred and alternate sources of DC control power for the 480-V switchgear breakers.

Control power for the operation of equipment supplied from each 480-V switchgear bus is arranged to match the preferred and alternate sources of DC control power to the 480-V switchgear breakers. For example, for the equipment supplied from Switchgear Bus 2A, the preferred source of control power is 125-V DC System 22 and the alternate source of control power is 125-V DC System 24.

Four ASCO transfer switches, one per bus, provide DC control power to the 480-V switchgear. Each transfer switch is mounted in a separate enclosure near its respective switchgear breakers.

A similar improved design is provided for the DC control power supplies to the control panels associated with each of the three emergency diesel generators located in the diesel building. DC system 21 is the preferred source and DC System 23 is the alternate source for Diesel-Generator 21; DC System 23 is the preferred source and DC System 22 is the alternate source for Diesel-Generator 22; DC System 24 is the preferred source and DC System 22 is the alternate source for Diesel-Generator 23.

Each 480-V switchgear breaker, with the exception of the Rod Power Supply M-G Set input breakers (52/MG1, 52/MG2) and the reactor trip breakers (52/RTA, 52/RTB, 52/BYA, 52/BYB), is equipped with a Westinghouse "Amptector 1A" solid-state overcurrent trip unit to protect the auxiliary equipment supplied by the breaker (including cables) and the associated switchgear. The settings of the solid-state overcurrent trip unit are based on the supplied load. The solid-state trip unit is provided with an instantaneous and/or short-time setting(s) to protect against fault conditions, and long-time setting to protect against over-load conditions.
Each circuit breaker is tripped on overcurrent conditions (overload or short circuit) by the combined operations of three components:

1. Sensors
2. Amptector solid-state trip unit
3. Actuator

All necessary tripping energy (for a breaker trip on an overcurrent condition only) is derived from the load current flowing through the sensors; no separate power source is required. The tripping characteristics for a specific breaker rating, as established by the sensor rating, are determined by the continuously variable settings of the Amptector static trip unit. This unit supplies a pulse of tripping current (when preselected conditions of current magnitude and duration are exceeded) to the actuator, which produces a mechanical force to trip the breaker.

If an overcurrent condition occurs on one of the 480-V switchgear buses while the bus is supplied from the normal source, lockout relays trip (if required) and prevent the closing of the alternate supply breakers (diesels and bus ties) associated with the bus. These relays must be manually reset after the overcurrent condition is cleared to allow these breakers to close.

The 480-V motor control centers are located in the areas of electrical load concentration. In general, those associated with the turbine generator auxiliary system are located below the turbine generator operating floor level, and those associated with the nuclear steam supply system are located in the primary auxiliary building.

Nonsegregated, metal-enclosed 6.9-kV buses are used for all major bus runs where large blocks of current are carried. The routing of this metal-enclosed bus minimizes its exposure to fire, water, and other physical damage.

The original plant design philosophy maintains all 480VAC breaker controls for engineered safeguards equipment operational following the loss of a 125VDC bus / battery. In the original plant design, two batteries supported three trains of breaker controls by utilizing Battery 21 (Train A), Battery 22 (Train B), and dual inputs from Battery 21 and 22 routed together in a third routing channel to effectively create a Train C. To provide additional capacity, reliability and independence, Indian Point 2 subsequently installed two additional batteries, Battery 23 and Battery 24, which are independent of, and serve as "Swing buses" for the 480VAC breaker and emergency diesel generator controls (Battery 23 with Battery 21 and Battery 24 with Battery 22). This arrangement eliminates any transferring of loads between Batteries 21 and 22.

Train A loads are primarily supported by Diesel Generator 21 and Train B loads are primarily supported by Diesel Generator 23. Selected Train A and Train B loads are supplied from Diesel Generator 22. Train C loads are supported by Diesel Generator 22, with selected Diesel Generator 21 loads. Thus, each load group requires power from a minimum of two diesel generators to fully supply the load group.

The Indian Point Unit 2 cable raceway systems are divided into a maximum of four instrument, four small power & control and three heavy power channels. Where conditions warrant, small power & control and instrumentation cables utilize common raceway to efficiently service localized areas of the plant. For small power and control, a third train is provided.

The application and routing of control, instrumentation, and power cables minimize their exposure to damage from any source. All cables are designed using conservative margins with respect to their current carrying capacities, insulation properties, and mechanical construction. Cable insulation in the reactor building has sheathing selected to minimize the harmful effects of radiation, heat, and humidity. All cables are fire resistant.

The conductors of instrumentation cables are shielded to minimize induced voltages and twisted to minimize magnetic interference. Wire and cables related to engineered safeguards and reactor protection systems are routed and installed to maintain the integrity of their respective redundant channels and to protect them from physical damage.

Cable loading of trays and consequently heat dissipation of cable throughout the plant has been carefully studied and controlled to ensure that there is no overloading. The criteria for electrical loading were developed using IPCEA (now ICEA) Standard P-46-426, manufacturer recommendations, and good engineering practice.

Derating factors for cables in trays without maintained spacing are taken from Table VIII of the IPCEA publication. Derating factors for the maximum ambient temperature existing in any area of the plant are also taken from the IPCEA publication. These factors are applied against ampacities selected from appropriate tables in other portions of the standard.

For physical loading of trays, the following criteria are followed: for 6.9-kV power, one horizontal row of cables is allowed in a tray; for heavy power, two horizontal rows of cables are allowed; for medium power, small power & control or instrumentation, 70-percent of the cross-sectional area of a tray is the maximum fill, with the heavy power cables limited to two horizontal rows. During initial plant construction, a computer program monitored the loading and prevented the routing of anything greater than this amount.

For instrumentation cables, four basic channels are routed through the plant. These channels include cables for systems of 65-V or less. Cables assigned to these four channels are in their respective channels throughout the run.

Certain other cables such as thermocouple cable, public address system cable, and instrument power supplies are run in the four instrument channels.

Control cables are separated into two basic channels with a third channel provided as needed for redundant circuits. These groups of cables are set up for systems more than 65-V and less than 600-V and include multi-conductor control cable or other cable as required. Cables assigned to these two channels for separation are in their respective channels and are so designated from the beginning of the cable to the final termination. These cables include:

1. Motor-operated valves - two channels for the redundant valves.
2. Solenoid valves - two channels where required for redundant valves and safeguards. Otherwise not separated.
3. Detector drives - run in any channel as convenient.
4. Motor controls - except safeguards, run in any channel as convenient.
5. Small power cables - run in any channel as convenient.
6. Safeguard control cables - run in two channels as required.
7. Safeguard power cables - separated into sufficient channels to provide minimum functions, e.g., three channels are provided for the containment fan cooler motors.

In response to the NRC's February 11, 1980 Confirmatory Order, Consolidated Edison's August 11, 1980 letter to the NRC identified differences in cable raceway separation between Indian Point Units 2 and 3. Consolidated Edison determined, evaluated, and provided justification for each design difference between Indian Point Units 2 and 3 in submittals to the NRC (References 2, 3) demonstrating that a single failure would not preclude a safety function from being performed. The NRC reviewed these design differences and corresponding justifications and determined the Unit 2 design to be acceptable in their safety evaluation report (Reference 4).

Physical channeling is accomplished by either separate trays or trays with metal dividers and in some cases by separate conduit. The safeguard channeling and control train development, and cable tray separations are shown in Plant Drawings 208376 and 208761 [Formerly UFSAR Figures 8.2-17 and 8.2-18].

In general, redundant circuits are separated horizontally rather than vertically. When physical conditions prevent this, horizontal barriers (i.e., transite or sheet metal barriers) separate heavy power trays from redundant small power & control and instrument trays. To ensure that only fire retardant cables are used throughout the plant, a careful study of cable insulation systems was undertaken early in the design of the plant. Insulation systems that appeared to have superior flame retardant capability were selected and manufacturers were invited to submit cable samples for testing. An extensive flame testing program was conducted including ASTM vertical flame and Con Edison vertical flame and bonfire tests. A report summarizing the testing was prepared by Con Edison. These tests were used as one of the means of qualifying cables, and the specifications were written on the basis of the results.

The following tests were made to determine the flame retardant qualities of the covering and insulations of various types of cables for Indian Point Unit 2:

1. Standard Vertical Flame Test - made in accordance with ASTM-D-470-59T, "Tests for Rubber and Thermoplastic Insulated Wire and Cable."

2. Five-Minute Vertical Flame Test - made with cable held in vertical position and 1750°F flame applied for 5 min.

3. Bonfire Test - consisted of exposing bundles of three or six cables to flame produced by igniting transformer oil in a 12-in. pail for 5 min. The cable bundles were supported horizontally over the center of the pail with the lowest cable 3 in. above the top of the pail. The time required to ignite the cable and the time the cable continued to flame after the fire was extinguished were noted.

On the basis of these tests, cables were selected for the reactor containment vessel penetration. New cables are selected to conform with IEEE 383-1974.

The design and use of fire stops, seals and barriers to meet 10 CFR 50.48 criteria for the prevention of flame propagation where cable and cable trays pass through walls and floors is found in the document under separate cover entitled, "IP2 Fire Hazards Analysis."

In areas where missile protection could not be provided (such as near the reactor coolant system), redundant instrument impulse lines and cables are run by separate routes. These lines are kept as far apart as physically possible or are protected by heavy (0.24 in.) metal plates interposed where inherent missile protection could not be provided by spacing.

In 1989, the NRC approved changes to the design basis with respect to dynamic effects of postulated primary loop ruptures, as discussed in Section 4.1.2.4.

In those areas where the compressed instrument air system is near the essential 480-V switchgear, the following provisions have been incorporated to shield this essential switchgear and cabling from potential missiles or pipe whip:

1. The compressed instrument air lines in the vicinity of the switchgear are supported at the piping bends. This will resist any step loading of PA (which could occur in the event of an instantaneous circumferential rupture) without occurrence of a "plastic hinge." The possibility of pipe whip is eliminated.

2. A guard cover is supplied around the air compressor flywheel. This cover is designed to absorb the translational kinetic energy associated with a compressor flywheel missile.

3. A guard barrier is supplied adjacent to the compression chamber of the air compressor. This barrier is designed to absorb the kinetic energy associated with a compression chamber segment.

These provisions ensure that no missile or whipping pipe originating from postulated failures in the compressed instrument air system will strike the essential switchgear.

8.2.3 Emergency Power

8.2.3.1 Source Descriptions

The sources of offsite emergency power are: (1) the Con Edison 345-kV system and (2) Con Edison’s 138-kV system. The emergency diesel-generator sets provide three sources of onsite emergency power. Each set is an Alco Model 16-251-E engine coupled to a Westinghouse 900 rpm, 3-phase, 60-cycle, 480-V generator. The units have a capability of 1750 kW (continuous), 2300 kW for 1/2 hour in any 24 hour period, and 2100 kW for 2 hours in any 24 hour period. [Deleted]

Any two units, backups to the normal standby AC power supply, are capable of sequentially starting and supplying the power requirement of at least one complete set of safeguards equipment. The units are installed in a seismic Class I structure located near the Primary Auxiliary Building.

Each emergency diesel is automatically started by two redundant air motors, each unit having a complete 53-ft^3 air storage tank and compressor system powered by a 480-V motor. The piping and the electrical services are arranged so that manual transfer between units is possible. The capability exists to cross-connect a single EDG air compressor to more than one (1) EDG air receiver, via manual air tie valves. However, to ensure that the operability of two (2) of the three (3) EDGs is maintained for minimum safeguards in the event of a single failure, administrative controls are in-place to require an operator to be stationed within the EDG Building, whenever any of the starting air tie valves are opened. Each air receiver has sufficient storage for four normal starts. However, the diesel will consume only enough air for one automatic start during any particular power failure. Additionally, the engine control system is designed to shut down and lock out any engine that did not start during the initial try. The emergency units are capable of starting and load sequencing within 10 sec after the initial start signal. The units have the capability of being fully loaded within 30 sec after the start of load sequencing.

To ensure rapid start, the units are equipped with water jacket and lube-oil heating. A prelube pump circulates the oil when a unit is not running. The units are located in heated rooms.

Audible and visual alarms are located in the control room and in the diesel generator building. Alarms on the electrical annunciator panels in the control room are:

1. Diesel-generator trouble.
2. Diesel-generator oil storage tank low level.
3. 21 Diesel-Generator Trouble.
4. 22 Diesel-Generator Trouble.
5. 23 Diesel-Generator Trouble
6. Diesel-Generator Service Water Flow Low

The activation of the emergency diesel generator trouble alarm in the control room will be caused by the initiation of any of the following alarms in the diesel generator building:

1. Low oil pressure.
2. Differential fuel strainer, secondary.
3. Overcrank.
4. High differential lube-oil strainer.
5. High water temperature.
6. High differential pressure lube-oil filter.
7. High-high jacket water temperature.
8. Deleted.
9. Overspeed.
10. Overcurrent.
11. Low fuel oil level, day tank.
12. Reverse power.
13. Low start air pressure.

14. Exciter field shutdown.
15. High/Low lube-oil temperature.
16. High differential pressure primary filter.
17. Deleted.

The diesel-generator oil storage tank low level alarm will be energized on a low level in any one of the three fuel-oil storage tanks.

The alarms “21 Diesel-Generator Trouble”, “22 Diesel-Generator Trouble”, and “23 Diesel-Generator Trouble” located on Panel SG in the Central Control Room will be activated respectively by the following conditions at each EDG local control panel:

1. Loss of DC control power.
2. Engine control switch position (Off or Manual).
3. Breaker control switch position pulled-out [Note - the breaker control switch in the CCR will activate the “Safeguards Equipment Locked Open” alarm (Window 1-8 on Panel SB-1) in the CCR].
4. Engine stop solenoid energized.
5. Day tank level low, primary and backup fuel pump fails to start.
6. For 23 diesel-generator trouble only, loss of voltage on EDG 23 auxiliary load main feed.

There are six electrical contacts, each of which when activated will energize a diesel-generator lockout relay. This lockout relay will, in turn, cause a diesel to shut down if it is operating or will prevent the diesel from responding to an automatic emergency start signal. These contacts are activated by one of the following conditions:

1. Activation of the diesel emergency stop push-button in the diesel-generator building.

2. Activation of the overcurrent relay. A phase-to-phase fault or excessive loads on the diesel generator will operate this relay.

3. Activation of the reverse power relay.

4. Activation of the overcrank relay. If a diesel engine fails to attain speed within 13 sec, this relay will be energized.

5. Activation of the overspeed relay. When the mechanical governor senses 1070 rpm, this relay will be energized.

6. Activation of the low oil pressure relay. This relay is energized by the coincident sensing of lube-oil pressure below 60 psi by two of the three oil pressure switches for each diesel. An oil pressure timer is set to allow 20 sec to pass before tripping the diesel engine lockout relay. This circuit is designed to provide sufficient time for the oil pressure to build up following an engine start.

A safety injection signal will prevent the first three conditions from energizing the diesel engine lockout relay and tripping the diesel generator. Activation of any one of the latter three relays will cause a diesel to stop even when a safety injection signal is present. Shutdown permits corrective action to be taken before the engine is damaged, and the diesel generator can then be returned to normal operation. Once any of these six electrical contacts has been activated causing the diesel engine lockout relay to energize, the lockout relay must be manually reset locally before the diesel can be started.

8.2.3.2 Emergency Fuel Supply

Each of the three emergency diesel generators has its own 175-gal fuel-oil day tank plus an underground bulk storage supply tank and uses diesel oil Specification Number 2. Each day tank is located within the diesel-generator building and supplies its respective engine-mounted fuel-oil pump. The day tank is automatically filled during engine operation from its separate underground storage tank located outside adjacent to the diesel-generator building. Each storage tank has a capacity of 7700 gal and is provided with a motor-driven transfer pump mounted in a manhole opening above oil level. Each pump can be aligned to discharge into the common normal or emergency makeup line to all three diesel-generator fuel-oil day tanks. If a low level is detected in the day tank for diesel generator 21, transfer pump 21 will automatically start to refill the tank to approximately 158 gal. If pump 21 fails to refill the day tank, transfer pump 22 will receive an automatic starting signal as a backup to the primary pump. In a similar manner, transfer pump 22 receives an automatic starting signal on low level in the day tank for diesel 22 and is backed up by transfer pump 23. Transfer pump 23 starts on low level in the day tank for diesel generator 23 and is backed up by transfer pump 21.

Each diesel oil transfer pump stops automatically when 15.5-in. of oil remains in the associated underground tank which equates to a maximum of approximately 7000-gal of available fuel oil per tank. A minimum fuel storage of 19,000 gal (i.e., approximately 6340 gal per tank) is maintained in the three underground storage tanks.

The 19,000 gal of storage ensures that two diesels can operate for at least 73 hours at the maximum load profile permitted by the diesels' ratings. If one of the three storage tanks is not available, there is sufficient fuel oil to run two diesels at the maximum load profile for at least 45 hours. Similarly, if three diesels are available, there is sufficient fuel oil in the three storage tanks for at least 45 hours of operation at the maximum load profile. These values are based on the use of No. 2 diesel fuel oil at the lowest density of 6.87 lb/gal and engine fuel oil consumption rates based on operating at each load rating. For heavier oil, the time would be increased proportionally to the ratio of 6.87 lb/gal and the actual fuel density. An upper limit of 7.39 lb/gal is common for No. 2 diesel oil.

Additional fuel oil suitable for the diesel engines is stored on the site and at Buchanan substation. A minimum additional storage of 29,000 gal is maintained in the storage tanks dedicated for diesel-generator use. This storage is sufficient for operation of two diesels for at least 111 hours at the maximum load profile permitted by the diesels' ratings. As previously mentioned (Section 8.2.1), commercial oil supplies and trucking facilities exist to ensure deliveries on one day's notice.

The basis for the minimum total required fuel oil quantity of 48,000 gallons is to provide for operation of two diesel generators for 7 days. The specified minimum quantity of fuel oil is based on operation of two diesel generators for 7 days at the maximum load profile permitted by the diesel generator rating. Each diesel is rated for operation for 0.5 hours of operation out of any 24 hours at 2300 kW plus 2.0 hours of operation out of any 24 hours at 2100 kW with the remaining 21.5 hours of operation of any twenty four hours at 1750 kW. Operation of the diesel generators at the maximum load profile ratings bounds the postulated accident load profile. If one EDG storage tank or transfer pump is unavailable, the remaining tanks or pumps with the additional 29,000 gallons of fuel oil can operate two diesels at the maximum load profile permitted by the diesel generator rating for at least 160 hours.

8.2.3.3 Emergency Diesel Generator Separation

The emergency diesel generators are located in a sheet metal, steel-framed building immediately South of the Primary Auxiliary Building. The diesel generators are arranged parallel to each other on 13-ft centers, with approximately 10 ft of clear space between engine components. The engine foundations are surrounded by a 1 foot-high concrete curb containing sufficient volume to hold all the lube-oil or fuel released from a single engine in the event of an inadvertent spill or line break.

Diesel generator separation and fire protection features necessary to meet the criteria of 10 CFR 50.48 are described in the document under separate cover entitled, "IP2 Fire Hazards Analysis". A control panel, which contains relays and metering equipment for all three diesel generators is located on the west end of the building. The panels are compartmentalized with controls for each engine separated from each other. The compartmentalized design minimizes the potential spread of fire to other electrical components. A reinforced-concrete wall separates the diesel generators from the control panel.

Based on the engine manufacturer's case histories of engine failures, missile protection between machines is not considered necessary. Field case histories disclose a complete absence of damage to the engine environs as a result of engine component failure. Engine failures, usually the result of extreme operating conditions, can be classified as follows:

1. Stuck valve.

   A valve sticks open and is struck by the piston. The damaged valve, and possibly part of the piston, enters the exhaust manifold, damages the turbo-charger, and passes harmlessly up the stack. There is no record of a damaged piston generating a missile external to the engine.

2. Piston seizure.

   A piston seizure causes bending and eventual fracture of the connecting rod. All damaged parts remain inside the engine block.

3. Turbo-charger failure.

   A turbo-charger wheel fouls the casing as a result of overspeed or overheat. The robust double-walled casing contains all parts.

4. Engine overspeed.

   The engine's normal operating speed is 900 rpm. Overspeed trips shut off the fuel at each individual fuel injection pump. No cast iron is used in the engine block or base so even if the overspeed trip failed, the engine structure, which is not brittle by nature, would contain any fracture parts. Isolated cases of crank shaft fractures have not resulted in flying missiles.

5. Cylinder head failure.

   Cylinder heads are secured to the block by high-tensile studs. No cap gaskets are used between the head and cylinder liners. This prestressed design, which does not allow slackness to develop, has resulted in an assembly that has not had any incidents of heads flying off, even when failed pistons have pounded the heads. There are also cases on record of improperly timed engines resulting in excessively high firing pressures, over 2000 psi (normal pressure 1600 to 1700 psi), in which the heads have always remained intact.

Operating experience with the Alco engine indicates that internal missiles do not escape from the engine. Alco does not have any evidence of blades coming through the turbo casing. Valves from the engine have broken and been exhausted through the turbo and caused damage to the turbo, but are contained within the casing. There is no evidence of connecting rods escaping from the engine.

To generate any flying parts, the generator would have to be in an overspeed condition beyond what is normally possible with a diesel engine. The construction of the stator windings and stator barrel frame would have to be penetrated by a rotor part in order to escape. The rugged construction of each complements its ability to contain flying objects.

Since the engine has overspeed trips and would not operate much beyond this speed because the valves would hang up, it is concluded that the generator would never reach any critical speeds.

8.2.3.4 <u>Loading Description</u>

Each emergency diesel-generator unit is started on the occurrence of either of the following incidents:

1. Initiation of a safety-injection signal.
2. Undervoltage on any 480-V switchgear bus.

On safety injection or undervoltage on any bus, the engines run at idle and can be connected to deenergized buses by the operator from the control room. Upon blackout (loss of power to bus 5A or 6A) plus unit trip (with no SI), the emergency diesel-generators will be automatically connected to de-energized buses and sequentially loaded, but will continue to idle for live buses.

Upon the activation of a safety injection (SI) signal and blackout (loss of power to bus 5A or 6A) plus unit trip, automatic load sequencing is initiated as follows:

1. All 480-V switchgear feeder breakers, except those supplying motor control centers 26A/26AA, 26B/26BB, 26C, and 211 are tripped on undervoltage and all automatically operated non-safeguard feeder breakers are locked out. (Note – All engineered safeguards motors are supplied from the 480-V system.)

2. The emergency diesel generators are connected to their respective buses. [Note - An alarm (safeguards equipment locked open) will be energized in the Central Control Room if any control switch for the EDG breakers is in the "pull-out" position.]

3. Required engineered safeguards are sequentially started. The list of loads is shown in Table 8.2-2.

4. The operators may energize Motor Control Centers 24A, 27A, and 29A (which feed equipment required for safe shutdown and accident mitigation) and their loads as required.

In an August 11, 1980 response to the NRC's February 11, 1980 Confirmatory Order, Consolidated Edison determined and evaluated the design differences between Indian Point Units 2 and 3 for automatic starting and sequential loading of the emergency diesel generators (EDGs). Whereas the Unit 3 EDGs are automatically connected to supply the 480-V emergency busses on an undervoltage signal, the Unit 2 EDGs will only supply the 480-V emergency busses on a 480-V bus undervoltage signal coincident with a safety injection or a unit trip signal. Each EDG receives automatic starting and sequential loading signals from both control logic Trains. The additional coincidence logic does not preclude manual starting and loading of the EDGs by the operators, and in the absence of a safety injection or unit trip signal, the steam generator water inventory and the steam-driven auxiliary feedwater pump provide sufficient time for such operator action. Consolidated Edison presented each design difference and justification to the NRC (References 2, 3). The NRC reviewed these design differences and corresponding justifications and determined the Unit 2 design to be acceptable in their safety evaluation report (Reference 4).

Load sequencing for the emergency diesel generators during the safety-injection phase of a loss-of-coolant accident is described in References 5 and 6. The logic diagrams for the starting of the emergency diesel-generators and the safeguards sequence are presented in Plant Drawings 225100 and 225101 [Formerly UFSAR Figures 7.2-7 and 7.2-8].

The recirculation phase is initiated manually by control switches on the supervisory panel in the control room as described in Section 6.2.2.1.4.

Loading studies show that the loads on the emergency diesel generators are maintained within their ratings for large loss-of-coolant accidents (as described above), small-break loss-of-coolant accidents, steamline breaks, steam generator tube ruptures, and spurious safety-injection actuations.

Studies have also shown that, in the event of loss of both offsite and SBO / Appendix R Diesel power, one emergency diesel generator can provide adequate power to bring the plant to cold shutdown.

Tests performed on the emergency power system to verify proper response within the required time limit are detailed in the Technical Specifications. See Section 8.5, Tests and Inspections.

8.2.3.5 Batteries and Battery Chargers

Each of the four battery installations is composed of 58 individual lead-calcium storage cells connected to provide a nominal terminal voltage of 125-V DC. Each battery is fed from a separate charger and each charger is fed from a separate AC power panel. Each battery bus is equipped with a sensitive-type undervoltage relay, which provides alarm/indication of an undervoltage condition. Ground alarms are also provided on each board. Improved status indication of the battery chargers and the direct current system has been provided by segregating the battery charger alarms into four ground alarms and by providing four DC bus trouble alarms, which include an input for low battery terminal voltage. Loads on each battery are shown on Plant Drawings 208501 and 9321-3008 [Formerly UFSAR figures 8.2-15 and 8.2-16]. Loads on the 118-V vital alternating current instrument buses are shown on Plant Drawings 208502 and 208503 [Formerly UFSAR figures 8.2-13 and 8.2-14]. Each battery has been sized to carry its expected shutdown loads for a period of 2 hr following a plant trip and a loss of all AC power. All equipment supplied by the batteries are maintained operable with minimum expected voltages at the battery terminals during the 2 hrs. Each of the four battery chargers has been sized to recharge its own discharged battery within 15 hrs while carrying its normal load.

Seismic design considerations have been adequately included in the design of the battery racks. Stress analyses of these racks assumed worst case conditions of static and dynamic loads in the vertical, horizontal transverse, and horizontal longitudinal direction; stresses were all within allowable values.

8.2.3.6 Reliability Assurance

The electrical system equipment is arranged such that no single accident or incident can inactivate enough safeguards equipment to jeopardize plant safety. The 480-V equipment is arranged on four buses. The 6.9-kV equipment is supplied from six buses.

The plant auxiliary equipment is arranged electrically so that redundant items receive power from different sources. The charging pumps are supplied from 480-V buses 3A, 5A, and 6A. The six service water pumps and the five containment fans are divided among the four 480-V buses. Valves are supplied from motor control centers 26A/26AA and 26B/26BB, which are supplied from buses 5A and 6A, respectively.

The outside source of power is adequate to run all normal operating equipment. The 138/6.9-kV station auxiliary transformer can supply all the auxiliary loads.

The bus arrangements specified for operation ensure that power is available to an adequate number of safeguards auxiliaries.

Two diesel generators have enough capacity to start and run a fully loaded set of engineered safeguards equipment. These safeguards can adequately cool the core for any loss-of-coolant incident and maintain the containment pressure within the design value.

The power supplies to the diesel generators' auxiliary equipment are arranged so that each diesel generator will feed its own auxiliary equipment.

A total loss of DC feed to the switchgear and associated equipment will not cause a loss of offsite power through an inadvertent tripping of the Indian Point Unit 2 light and power supply circuit breakers, because DC is required to trip a breaker. Loss of DC feed to protective relaying will cause an alarm condition rather than initiation of a protective action. If necessary, the light and power circuit breakers in the Buchanan substation may be tripped manually at the breaker mechanisms.

Each independent battery installation is maintained under continuous charge by its associated self-regulating battery charger so that the batteries will always be at full charge in anticipation of a loss-of-ac-power incident. This ensures that adequate DC power will be available for starting and loading the emergency diesel generators and for other emergency uses.

The equipment arrangement in the Indian Point Unit 2 Central Control Room is discussed in Section 7.7.

REFERENCES FOR SECTION 8.2

1. Letter (with attachments) from S. A. Varga, NRC, to W. J. Cahill, Jr., Con Edison, Safety Evaluation Indian Point Unit 2 - Proposed Modification of the 125V DC Battery System, Dated May 2, 1980

2. Letter from William J. Cahill, Consolidated Edison, to Harold R. Denton, NRC, "Confirmatory Order", dated May 9, 1980

3. Letter from John D. O'Toole, Consolidated Edison, to Steven A. Varga, NRC, "Confirmatory Order", dated May 27, 1982

4. Letter from Steven A. Varga, NRC, to John D. O'Toole, Consolidated Edison, "Confirmatory Order", dated December 1, 1982.

5. "Emergency Diesel Generator Loading Study for Indian Point Unit 2," WCAP-12655 (Non-Proprietary Class 3), Rev. June 2002.

6. Letter from Westinghouse to Entergy, IPP-03-187, "EDG Load Study Reconciliation," November 13, 2003.

TABLE 8.2-1
Deleted

TABLE 8.2-2
Diesel Generator Loads

LOAD	D.G. 21 (BUS 5A)	D.G 22 (BUS 2A-3A)	D.G. 23 (BUS 6A)
1. Auxiliary component cooling pumps	1		1
2. Safety injection pumps	1	1	1
3. Residual heat removal pumps		1	1
4. Nuclear service water pumps	1	1	1
5. Containment air recirculation cooling fans	2	2	1
6. Auxiliary feedwater pumps		1	1
7. Spray pumps (if start signal present)	1		1

TABLES 8.2-3 & 8.2-4
Deleted

8.2 FIGURES

Figure No.	**Title**
Figure 8.2-1	Electrical One-Line Diagram, Replaced with Plant Drawing 250907

Figure 8.2-2	Electrical Power System Diagram, Replaced with Plant Drawing 250907
Figure 8.2-3	Main One-Line Diagram, Replaced with Plant Drawing 208377
Figure 8.2-4	345-KV Installation at Buchanan
Figure 8.2-5	6900-V One-Line Diagram, Replaced with Plant Drawing 231592
Figure 8.2-6	480-V One-Line Diagram, Replaced with Plant Drawing 208088
Figure 8.2-7	Single Line Diagram 480-V Motor Control Centers 21, 22, 23,25, 25A, Replaced with Plant Drawing 9321-3004
Figure 8.2-7a	Single Line Diagram - 480-V Motor Control Centers 24 and 24A, Replaced with Plant Drawing 249956
Figure 8.2-8	Single Line Diagram - 480-V Motor Control Centers 27 and 27A, Replaced with Plant Drawing 9321-3005
Figure 8.2-9	Single Line Diagram - 480-V Motor Control Centers 28 and 210, Replaced with Plant Drawing 208507
Figure 8.2-9a	Single Line Diagram - 480-V Motor Control Centers 29 and 29A, Replaced with Plant Drawing 249955
Figure 8.2-10	Single Line Diagram - 480-V Motor Control Centers 28A and 211, Replaced with Plant Drawing 208241
Figure 8.2-11	Single Line Diagram - 480-V Motor Control Centers 26A and 26B, Replaced with Plant Drawing 9321-3006
Figure 8.2-11a	Single Line Diagram - 480-V Motor Control Center 26C, Replaced with Plant Drawing 248513
Figure 8.2-12	Single Line Diagram - 480-V Motor Control Centers 26AA and 26BB and 120-V AC Panels No. 1 and 2, Replaced with Plant Drawing 208500
Figure 8.2-13	Single Line Diagram - 118-VAC Instrument Buses No. 21 thru 24, Replaced with Plant Drawing 208502
Figure 8.2-14	Single Line Diagram - 118-VAC Instrument Buses No. 21A thru 24A, Replaced with Plant Drawing 208503
Figure 8.2-15	Single Line Diagram - DC System Distribution Panels No. 21, 21A, 21B, 22, and 22A, Replaced with Plant Drawing 208501
Figure 8.2-16	Single Line Diagram - DC System Power Panels No. 21 thru 24, Replaced with Plant Drawing 9321-3008
Figure 8.2-17	Single Line Diagram of Unit Safeguard Channeling and Control Train Development, Replaced with Plant Drawing 208376
Figure 8.2-18	Cable Tray Separations, Functions, and Routing, Replaced with Plant Drawing 208761

8.3 ALTERNATE SHUTDOWN SYSTEM

The Indian Point Unit 2 alternate safe shutdown system provides the necessary functions to maintain the plant in a safe shutdown condition following a fire that damages the capability to power and control essential equipment from normal and emergency Indian Point Unit 2 sources.

In the unlikely event of a major fire or other external event affecting redundant cabling or equipment in certain areas, electrical power could be disrupted to safe shutdown components and systems. However, following the unlikely loss of normal and preferred alternate power, additional independent and separate power supplies from the Indian Point Unit 1 440-V switchgear are provided for a number of safe shutdown components.

An independent SBO / Appendix R diesel generator is provided to power the Unit 1 440-V switchgear in the unlikely event of loss of offsite power to Unit 1 switchgear. In addition, there is provision to cross-connect the Unit 3 SBO / Appendix R diesel generator to the Unit 2 alternate shutdown loads; and Unit 2 SBO / Appendix R diesel generator to Unit 3 alternate shutdown loads. The Indian Point Unit 2 SBO / Appendix R diesel generator set is manufactured by Cummins Power Generation with a rating of 2700 kW (Standby Rating), 13.8 kV, 3 Phase, 60 Hertz, 1800 RPM, for operation on diesel fuel. The output of the generator is connected to SBO / Appendix R 13.8 kV Switchgear bus via circuit breaker SBO / Alternate Safe Shutdown (ASS) located at diesel generator breaker switchgear. The SBO / Appendix R 13.8 kV Switchgear section has two (2) feeder circuit breakers, ASS and SBO high (SBOH). The ASS breaker feeds the existing Unit 1 13.8 kV L&P Bus Section 3 in order to provide power to ASS System loads. The SBOH breaker feeds a 13.8 kV – 6.9 kV, 3750 KVA SBO transformer, that in turn feeds the 6.9 kV section of the SBO / Appendix R Switchgear via circuit breaker SBO low (SBOL). This breaker then feeds power to the plant 6.9 kV electrical distribution system via breakers GT-25 and GT-26. In addition, there is provision to cross-connect the Unit 3 SBO / Appendix R diesel generator to the Unit 2 alternate shutdown loads; and Unit 2 SBO / Appendix R diesel generator to Unit 3 alternate shutdown loads.

The SBO / Appendix R diesel generator and associated switchgear, fuel supply and breakers shall be operable and tested in accordance with the TRM.

A detailed description of the alternate safe shutdown system including its functions, components, and operation is provided in the document under separate cover entitled, "IP2 10 CFR 50, Appendix R Safe-Shutdown Separation Analysis."

8.3 FIGURES

Figure No.	**Title**
Figure 8.3-1	Deleted

8.4 MINIMUM OPERATING CONDITIONS

The electrical system is designed such that no single contingency can inactivate enough safeguards equipment to jeopardize plant safety. The minimum operating conditions define those conditions of electrical power availability necessary (1) to provide for safe reactor operation and (2) to provide for the continuing availability of engineered safety features. The facility Technical Specifications, Section 3.8, include minimum operating conditions covering the following plant conditions:

1. Minimum electrical conditions for reactor criticality.
2. Minimum electrical conditions during power operation.

8.5 TESTS AND INSPECTIONS

Emergency Diesel generators are tested in accordance with technical specification requirements. The tests specified are designed to demonstrate that the emergency diesel generators will provide power for the operation of equipment. They also ensure that the emergency generator system controls and the control systems for safeguards equipment will function automatically in the event of a loss of all normal 480-V AC station service power.

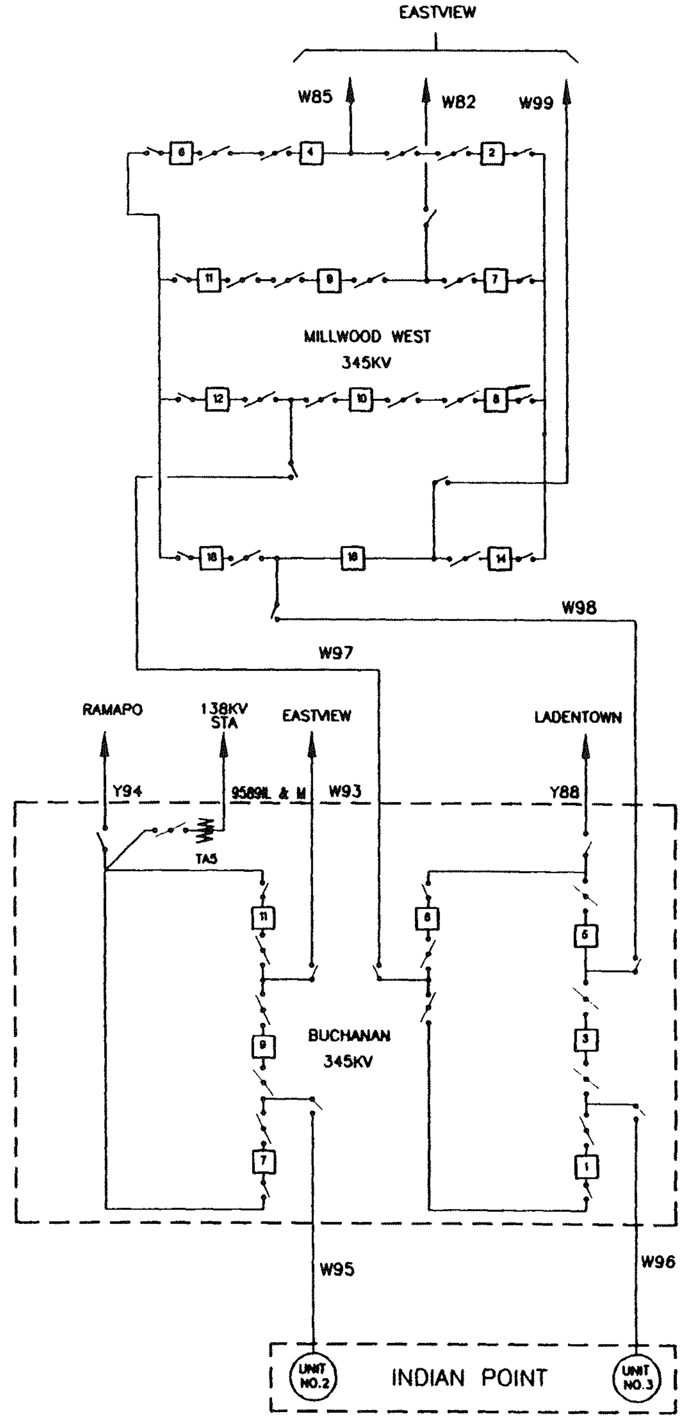
The testing frequency specified is often enough to identify and correct deficiencies in systems under test before they can result in a system failure. The fuel supply and starting circuits and controls are continuously monitored and any faults are alarm indicated. An abnormal condition in these systems would be signaled without having to place the emergency diesel generators on test.

The Emergency Diesel Generators will be inspected in accordance with a licensee controlled maintenance program. The maintenance program will require inspection in accordance with the manufacturer's recommendation for this class of standby service. Changes to the maintenance program will be controlled under 10 CFR 50.65

Station batteries will deteriorate with time, but precipitous failure is extremely unlikely. The surveillance specified is that which has been demonstrated over the years to provide an indication of a cell becoming unserviceable long before it fails. The periodic voltage and specific gravity measurements will ensure that the ampere-hour capability of the batteries is maintained.

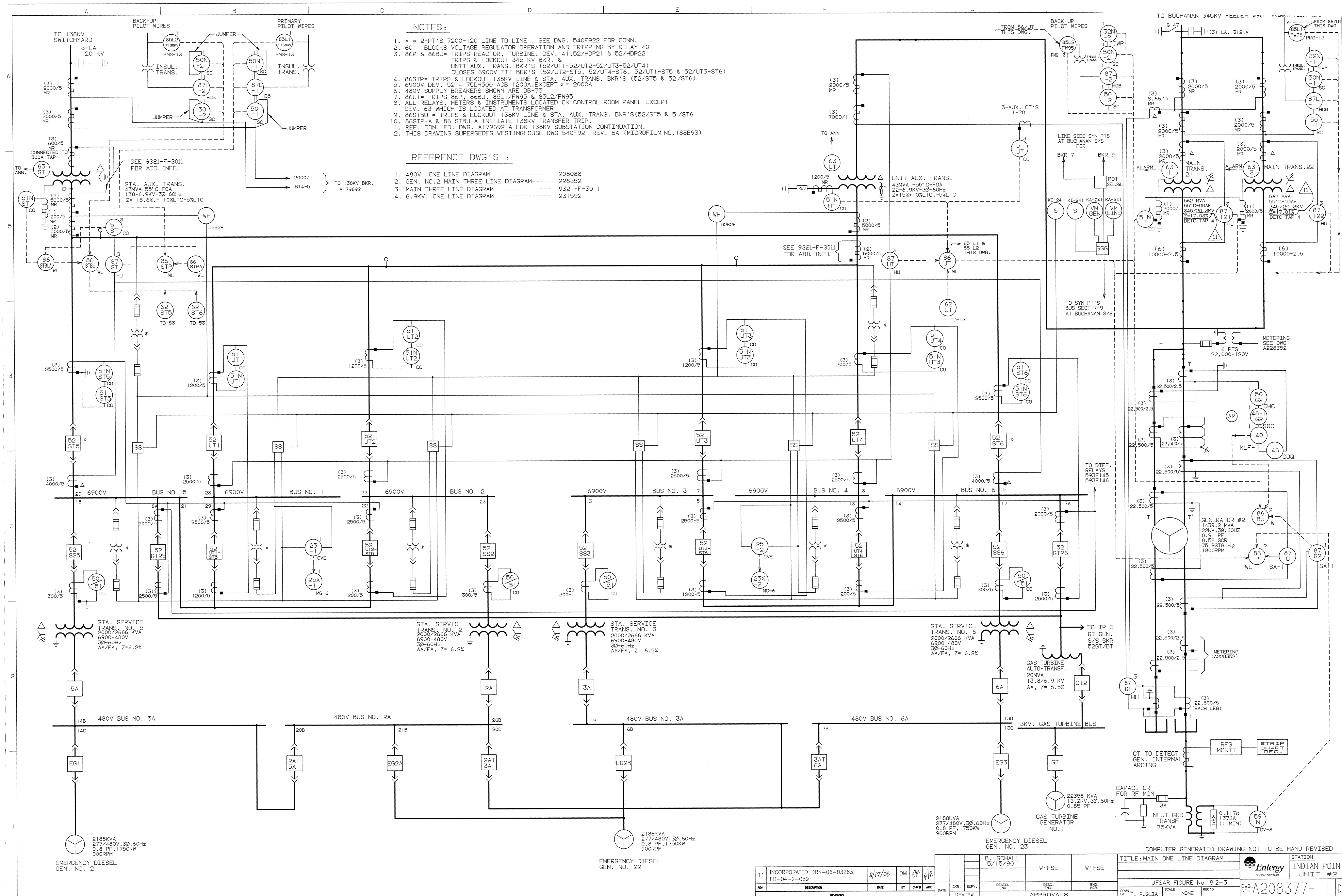
The ‘refueling interval’ load test for each battery, together with the visual inspection of the plates, will assure the continued integrity of the batteries. The batteries are of the type that can be visually inspected, and this method of assuring the continued integrity of the battery is proven standard power plant practice.

The SBO / Appendix R diesel and support systems shall be tested and have surveillances in accordance with the TRM. These tests and surveillances are designed to assure that the SBO / Appendix R diesel will be available to provide power for operation of equipment, if required.



INDIAN POINT UNIT No. 2	
UFSAR FIGURE 8.2-4 345KV INSTALLATION AT BUCHANAN	
MIC. No. 1999MC3885	REV. No. 17A

SPLICE BOX "2C"
138KV MILLWOOD SUBSTATION 96952
GAS TURBINE 2 28MVA
GAS TURBINE 3 19.2MVA
13W94 R&J
13W94M
BUCHANAN 13.8KV
BUCHANAN 345KV
NORTH RING
BUCHANAN 138KV
TRANSFORMER 3 138/13.8KV 46.7MVA
TRANSFORMER 2 138/13.8KV 35MVA
TRANSFORMER 1 138/13.8KV 35MVA
95891 L&M
TRANSFORMER TA5 345/138KV 234MVA
W93 EASTVIEW SUBSTATION 345 KV
Y94 RAMAPO SUBSTATION 345KV
95951/95093 PEEKSKILL REFUSE BURNING GEN STA. 138KV
96951 MILLWOOD SUBSTATION 138KV
33332 L&M
IP3 STA. AUX TRANS.
GAS TURBINE 1 22.3MVA
GAS TURBINE AUTO-TRANSFORMER 13.8/6.9KV 20MVA
SYN BUS WEST SECTION
SYN BUS EAST SECTION
MAIN TRANSFORMER 21 22/345KV 542MVA # 55 DEGREE C. RISE
MAIN TRANSFORMER 22 22/345KV 542MVA # 55 DEGREE C. RISE
GENERATOR 2 22KV, 1800RPM 1439.2MVA
UNIT AUX. TRANSFORMER 22/6.9 KV 43MVA # 55 DEGREE C. RISE
STATION AUX TRANSFORMER 138/6.9KV 43MVA # 55 DEGREE C. RISE
IP3 6.9KV BUS
IP3 APPENDIX "R" DIESEL
6.9KV BUS 5
6.9KV BUS 1
6.9KV BUS 2
6.9KV BUS 3
6.9KV BUS 4
6.9KV BUS 6
(2) 2000 KVA TRANSFORMERS 13.8KV-480/277V
NETWORK PROTECTORS
EMERGENCY DIESEL GENERATOR 21 1750KW
STATION SERVICE TRANSFORMER 5 6.9KV/480V 2.67 MVA
SUB.STA 21RW1 TRANSFORMER 6.9KV/480V 1250 KVA
STATION SERVICE TRANSFORMER 2 6.9KV/480V 2.67 MVA
EMERGENCY DIESEL GENERATOR 22 1750KW
STATION SERVICE TRANSFORMER 3 6.9KV/480V 2.67 MVA
SUB.STA 22RW3 TRANSFORMER 6.9KV/480V 1250 KVA
EMERGENCY DIESEL GENERATOR 23 1750KW
STATION SERVICE TRANSFORMER 6 6.9KV/480V 2.67 MVA
480V BUS 5A
480V BUS 2A
480V BUS 3A
480V BUS 6A
DWG.303257
IP3 480V BUS 2A
TRANSFORMER 21 480/120V 15KVA-1Ø
TRANSFORMER 23 480/120V 15KVA-1Ø
TRANSFORMER 1 480/208-120V 45KVA
TRANSFORMER 24 480/120V 15KVA-1Ø
TRANSFORMER 2 480/208-120V 45KVA
TRANSFORMER 22 480/120V 15KVA-1Ø
125VDC POWER PNL 21
125VDC POWER PNL 22
125VDC POWER PNL 23
125VDC POWER PNL 24
118VAC INST BUS 21
118VAC INST BUS 21A
118VAC INST BUS 22
118VAC INST BUS 22A
118VAC INST. BUS 23
118VAC INST. BUS 23A
118VAC INST BUS 24
118VAC INST BUS 24A
120VAC DIST. PNL 1
120VAC DIST. PNL 2
NOTES:
1. SEE REFERENCE DRAWINGS FOR ALL ADDITIONAL CONNECTIONS TO SWITCHGEAR AND CONTROL CENTERS
2. ---* DISTRIBUTION LOAD
MOLDED CASE SWITCH W CAT #RHFA-2100N
THIS SWITCH IS NOT TO BE USED TO OPEN ENERGIZED CIRCUIT
* STATED CAPACITY IS THE NOMINAL FOR 8 HOUR DISCHARGE TO 1.75 V PER CELL FINAL.
3. FOR MORE DETAILED VERSION REFERENCE DWGS. 141D186,141D187, AND 136D936
REFERENCE DRAWINGS:
480VAC SWITCHGEAR BUSES 1-LINE.........A208088
MAIN AC 1-LINE.........................A208377
118 VAC INSTRUMENTATION BUS 1-LINE.....A208502
6.9 KV 1-LINE..........................A231592
125 VDC POWER PANELS 1-LINE............9321-F-3008
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS:
CLASS A ITEMS PER CI-240-1
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
THIS REVISION IS NON-CLASS PER THE QAPD. UPDATED DRAWING PER CR-IP2-2002-11039
RELEASED FOR RECORD P/N 69901-AF 6/27/03 SL/VM
F. HOFFMAN
A.KAFFASHAN
G. BLENKLE 9/12/91
TITLE: ELECTRICAL DISTRIBUTION AND TRANSMISSION SYSTEM - UFSAR FIG. NO. 8.2-1 & 8.2-2
Con Edison
STATION INDIAN POINT
DRAWN BY BOWE/WATKINS
SCALE NONE
DWG. NO. A250907-21 DZ



NOTES:

1. * = 2-PT'S 7200-120 LINE TO LINE . SEE DWG. 540F922 FOR CONN.
2. 60 = BLOCKS VOLTAGE REGULATOR OPERATION AND TRIPPING BY RELAY 40
3. 86P & 86BU= TRIPS REACTOR, TURBINE, DEV. 41,52/HDP21 & 52/HDP22
   TRIPS & LOCKOUT 345 KV BKR. &
   UNIT AUX. TRANS. BKR'S (52/UT1-52/UT2-52/UT3-52/UT4)
   CLOSES 6900V TIE BKR'S (52/UT2-ST5, 52/UT4-ST6, 52/UT1-ST5 & 52/UT3-ST6)
4. 86STP= TRIPS & LOCKOUT 138KV LINE & STA. AUX. TRANS. BKR'S (52/ST5 & 52/ST6)
5. 6900V DEV. 52 = 75DH500 ACB 1200A,EXCEPT ∘ = 2000A
6. 480V SUPPLY BREAKERS SHOWN ARE DB-75
7. 86UT= TRIPS 86P, 86BU, 85L1/FW95 & 85L2/FW95
8. ALL RELAYS, METERS & INSTRUMENTS LOCATED ON CONTROL ROOM PANEL EXCEPT DEV. 63 WHICH IS LOCATED AT TRANSFORMER
9. 86STBU = TRIPS & LOCKOUT 138KV LINE & STA. AUX. TRANS. BKR'S(52/ST5 & 5 /ST6
10. 86STP-A & 86 STBU-A INITIATE 138KV TRANSFER TRIP.
11. REF. CON. ED. DWG. A179692-A FOR 138KV SUBSTATION CONTINUATION.
12. THIS DRAWING SUPERSEDES WESTINGHOUSE DWG 540F921 REV. 6A (MICROFILM NO.188B93)

REFERENCE DWG'S :

1. 480V. ONE LINE DIAGRAM ------------ 208088
2. GEN. NO.2 MAIN THREE LINE DIAGRAM------ 228352
3. MAIN THREE LINE DIAGRAM ------------- 9321-F-3011
4. 6.9KV. ONE LINE DIAGRAM ------------ 231592

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
11	INCORPORATED DRN-06-03263, ER-04-2-059	8/17/06	DM	[illegible]	N/A

REVISIONS

DATE	CKR.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.
			B. SCHALL 5/15/90	W'HSE	W'HSE
	REVIEW		APPROVALS		

TITLE: MAIN ONE LINE DIAGRAM

- UFSAR FIGURE No. 8.2-3

DRWN. BY T. PUGLIA | SCALE NONE | REC'D

Entergy Nuclear Northeast

STATION INDIAN POINT UNIT #2

DWG. NO. A208377-11 DZ

NOTES:

1. 52=75DH500 ACB 1200A SOLENOID; ●=2000A SOLENOID; *=1200A STORED ENERGY
2. 17 =LOCATED ON CONTROL ROOM PANEL
3. EQUIPMENT NOT MARKED LOCATED AT SWGR
4. 86UT1 TRIP & LOCKOUT BKR'S 52/UT1 & 52/UT1ST5
   86UT2 TRIP & LOCKOUT BKR'S 52/UT2 & 52/UT2ST5
   86UT3 TRIP & LOCKOUT BKR'S 52/UT3 & 52/UT3ST6
   86UT4 TRIP & LOCKOUT BKR'S 52/UT4 & 52/UT4ST6
   86ST5 TRIP & LOCKOUT BKR'S 52/ST5,52/UT1ST5,52/UT2ST5,52/GT25
   86ST6 TRIP & LOCKOUT BKR'S 52/ST6,52/UT3ST6,52/UT4ST6,52/GT26
   62UT1,62UT2,62UT3,62UT4,62ST5,62ST6,BKR.FAILURE TIMER
5. ALL BUSES- 6900V.,3Ø,60HZ.,1200A., EXCEPT AS NOTED.
6. THIS DRAWING SUPERSEDES W'HSE DWG.540F922.
7. FOR MORE DETAILED VERSION REFERENCE DWGS. 141D186, 141D187 AND 136D936 18

A RECORD OF THE ORIGINAL WITH INITIALS/SIGNATURES IS MAINTAINED IN CENTRAL ENGINEERING DOCUMENTATION FILE.

THE LAST PENCILED REVISION WAS 01

THE ORIGINAL TRACING FOR THIS DRAWING WAS PREPARED BY WESTINGHOUSE

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS

"CLASS A" ITEMS

PER QAPD

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION: V.MYERS 6/27/03 — THIS REV IS NON-CLASS AS PER QAPD; DES — UPDATED DWG AS PER CR-IP2-2002-11039 RELEASED FOR RECORD P/N 69901-AF SL/VM; ENG — 6/27/03

DATE 12/03/02 — REVIEW: CKR., SUPV. — APPROVALS: DESIGN ENG, DISC. ENG., ENG. MGR. — REPRODUCED, REPRODUCED, REPRODUCED

TITLE: 6900 VOLT AC ONE LINE DIAGRAM

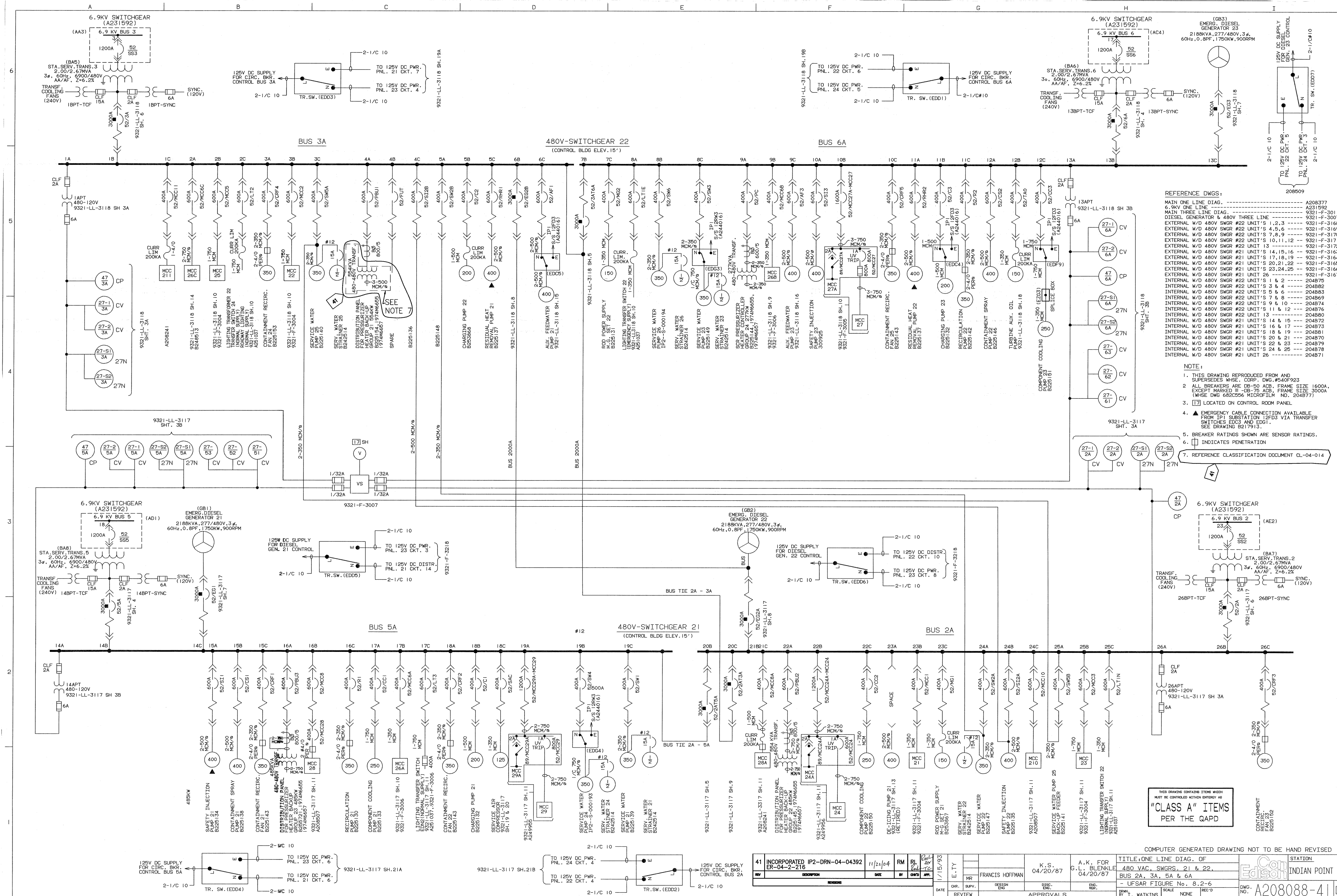
- UFSAR FIGURE No. 8.2-5

DRWN. BY A.K. SCALE NONE REC'D

Con Edison

STATION INDIAN POINT#2

DWG. NO. A231592-18 DZ



REFERENCE DWGS:

MAIN ONE LINE DIAG.	A208377
6.9KV ONE LINE	A231592
MAIN THREE LINE DIAG.	9321-F-3011
DIESEL GENERATOR & 480V THREE LINE	9321-F-3007
EXTERNAL W/D 480V SWGR #22 UNIT'S 1,2,3	9321-F-3168
EXTERNAL W/D 480V SWGR #22 UNIT'S 4,5,6	9321-F-3169
EXTERNAL W/D 480V SWGR #22 UNIT'S 7,8,9	9321-F-3170
EXTERNAL W/D 480V SWGR #22 UNIT'S 10,11,12	9321-F-3171
EXTERNAL W/D 480V SWGR #22 UNIT 13	9321-F-3172
EXTERNAL W/D 480V SWGR #21 UNIT'S 14,15,16	9321-F-3163
EXTERNAL W/D 480V SWGR #21 UNIT'S 17,18,19	9321-F-3164
EXTERNAL W/D 480V SWGR #21 UNIT'S 20,21,22	9321-F-3165
EXTERNAL W/D 480V SWGR #21 UNIT'S 23,24,25	9321-F-3166
EXTERNAL W/D 480V SWGR #21 UNIT 26	9321-F-3167
INTERNAL W/D 480V SWGR #22 UNIT'S 1 & 2	204B75
INTERNAL W/D 480V SWGR #22 UNIT'S 3 & 4	204B82
INTERNAL W/D 480V SWGR #22 UNIT'S 5 & 6	204B83
INTERNAL W/D 480V SWGR #22 UNIT'S 7 & 8	204B69
INTERNAL W/D 480V SWGR #22 UNIT'S 9 & 10	204B74
INTERNAL W/D 480V SWGR #22 UNIT'S 11 & 12	204B76
INTERNAL W/D 480V SWGR #22 UNIT 13	204B80
INTERNAL W/D 480V SWGR #21 UNIT'S 14 & 15	204B72
INTERNAL W/D 480V SWGR #21 UNIT'S 16 & 17	204B73
INTERNAL W/D 480V SWGR #21 UNIT'S 18 & 19	204B81
INTERNAL W/D 480V SWGR #21 UNIT'S 20 & 21	204B70
INTERNAL W/D 480V SWGR #21 UNIT'S 22 & 23	204B79
INTERNAL W/D 480V SWGR #21 UNIT'S 24 & 25	204B78
INTERNAL W/D 480V SWGR #21 UNIT 26	204B71

NOTE:

1. THIS DRAWING REPRODUCED FROM AND SUPERSEDES WHSE. CORP. DWG.#540F923
2. ALL BREAKERS ARE DB-50 ACB, FRAME SIZE 1600A, EXCEPT MARKED -DB-75 ACB, FRAME SIZE 3000A (WHSE DWG 682C556 MICROFILM NO. 204B77)
3. 17 LOCATED ON CONTROL ROOM PANEL
4. ▲ EMERGENCY CABLE CONNECTION AVAILABLE FROM IP1 SUBSTATION 12FD3 VIA TRANSFER SWITCHES EDC3 AND EDG1. SEE DRAWING B217913.
5. BREAKER RATINGS SHOWN ARE SENSOR RATINGS.
6. INDICATES PENETRATION
7. REFERENCE CLASSIFICATION DOCUMENT CL-04-014

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
41	INCORPORATED IP2-DRN-04-04392 ER-04-2-216	11/22/04	RM	RL	Rul for TC

REVISIONS

DATE	CKR.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.
1/15/93	E.TY	MR	FRANCIS HOFFMAN	K.S. 04/20/87	A.K. FOR G.L. BLENKLE 04/20/87

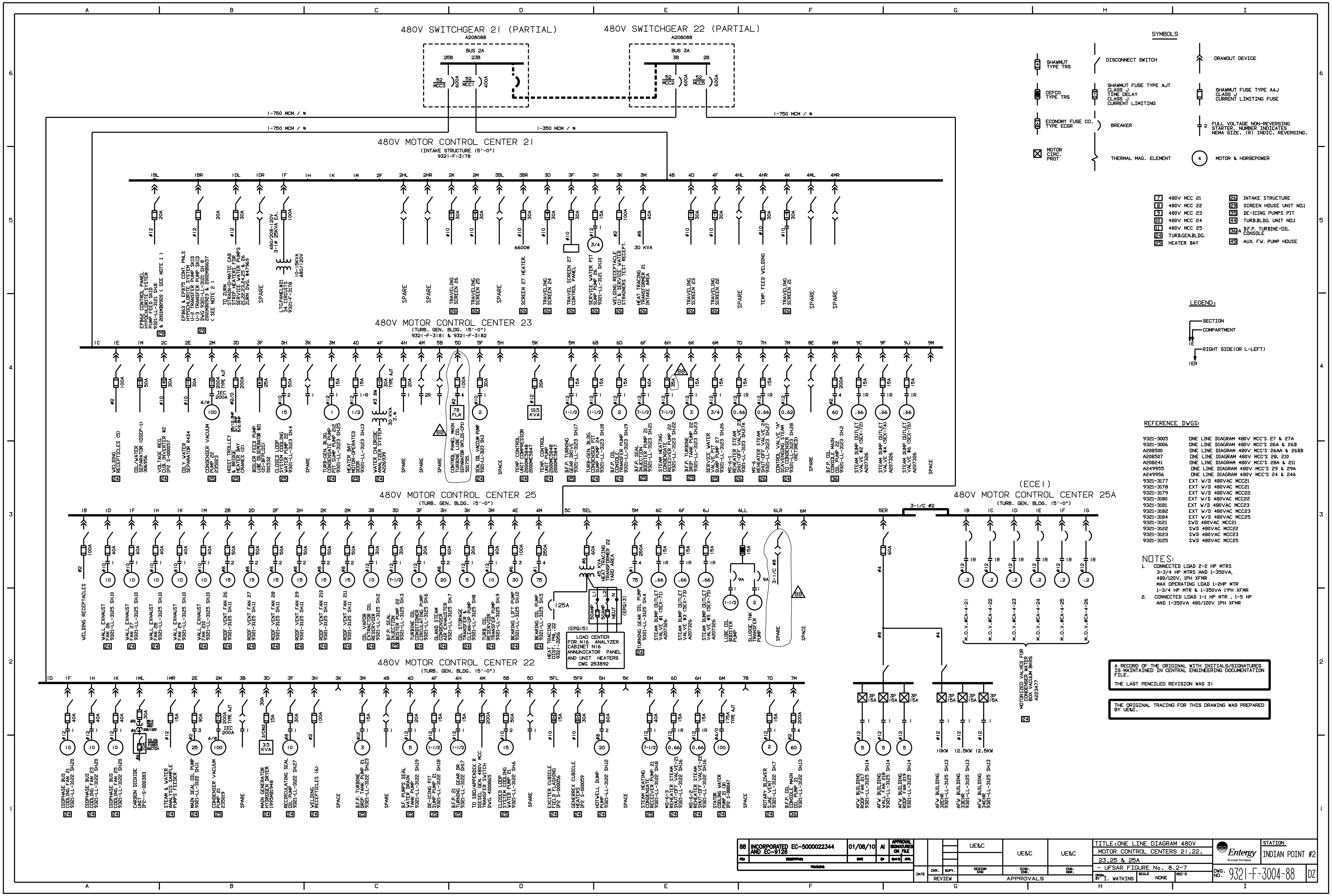
REVIEW — APPROVALS

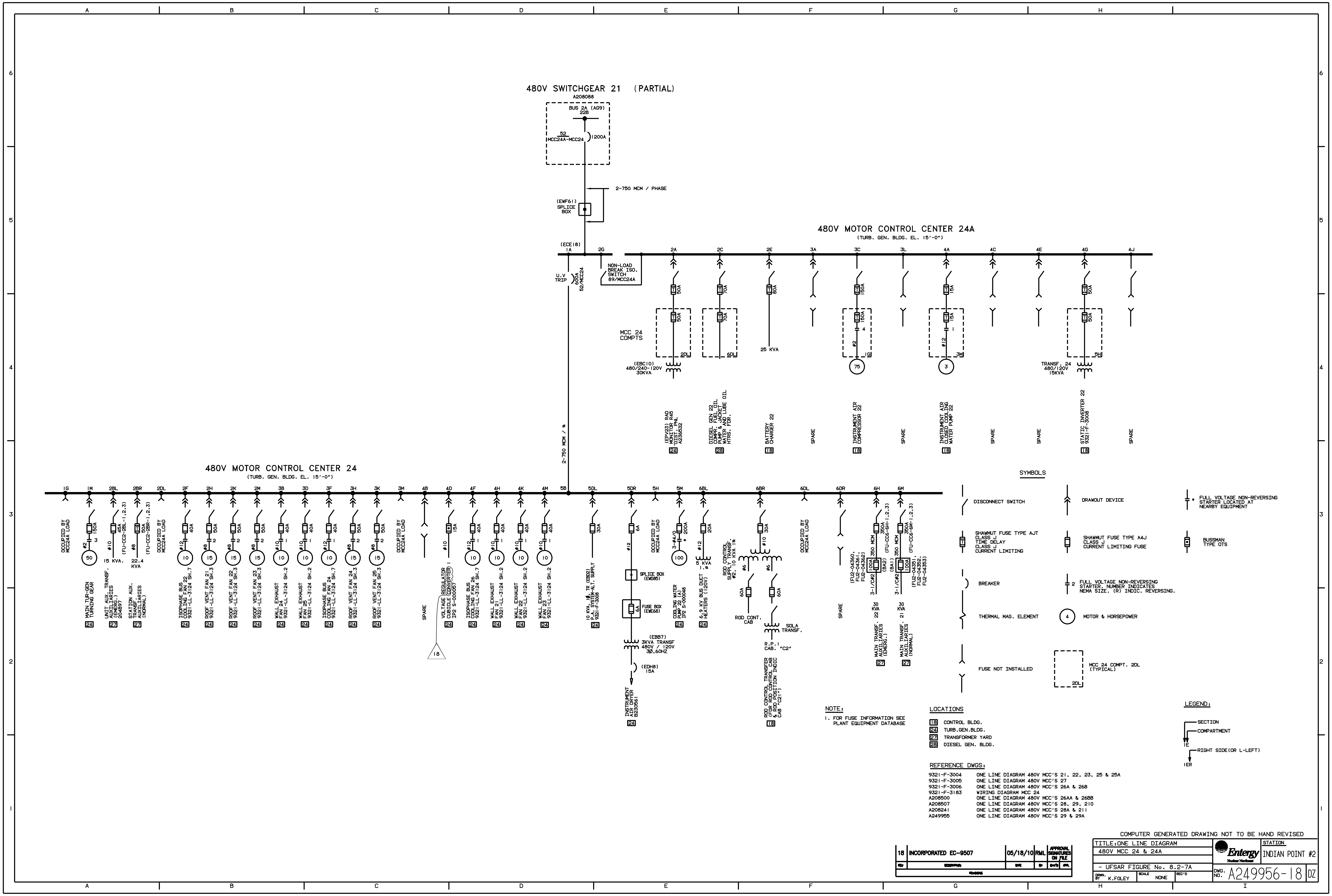
TITLE: ONE LINE DIAG. OF 480 VAC, SWGRS. 21 & 22, BUS 2A, 3A, 5A & 6A - UFSAR FIGURE No. 8.2-6

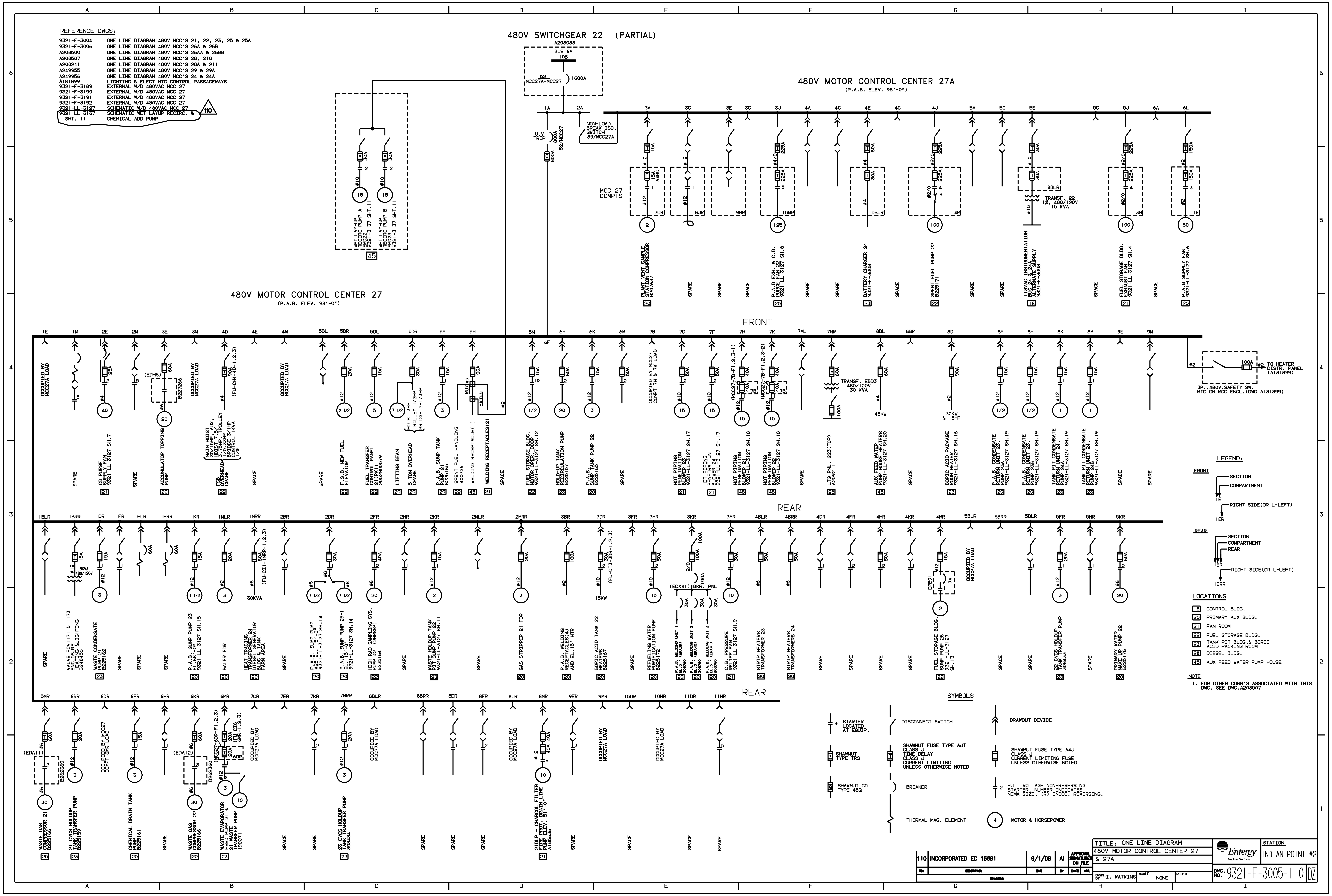
DRWN. BY I. WATKINS — SCALE NONE — REC'D

Con Edison — STATION: INDIAN POINT #2

DWG. NO. A208088-41 DZ


480V SWITCHGEAR 21 (PARTIAL)
A208088
480V SWITCHGEAR 22 (PARTIAL)
A208088
BUS 2A
BUS 3A
480V MOTOR CONTROL CENTER 21
(INTAKE STRUCTURE 15'-0")
9321-F-3178
480V MOTOR CONTROL CENTER 23
(TURB. GEN. BLDG. 15'-0")
9321-F-3181 & 9321-F-3182
480V MOTOR CONTROL CENTER 25
(TURB. GEN. BLDG. 15'-0")
(ECE1)
480V MOTOR CONTROL CENTER 25A
(TURB. GEN. BLDG. 15'-0")
480V MOTOR CONTROL CENTER 22
(TURB. GEN. BLDG. 15'-0")
SYMBOLS
SHAWMUT TYPE TRS
DISCONNECT SWITCH
DRAWOUT DEVICE
CEFCO TYPE TRS
SHAWMUT FUSE TYPE AJT CLASS J TIME DELAY CLASS J CURRENT LIMITING
SHAWMUT FUSE TYPE A4J CLASS J CURRENT LIMITING FUSE
ECONOMY FUSE CO. TYPE ECSR
BREAKER
FULL VOLTAGE NON-REVERSING STARTER. NUMBER INDICATES NEMA SIZE. (R) INDIC. REVERSING.
MOTOR CIRC. PROT
THERMAL MAG. ELEMENT
MOTOR & HORSEPOWER
7 480V MCC 21
8 480V MCC 22
9 480V MCC 23
10 480V MCC 24
11 480V MCC 25
24 TURB.GEN.BLDG.
36 HEATER BAY
26 INTAKE STRUCTURE
SCREEN HOUSE UNIT NO.1
DE-ICING PUMPS PIT
TURB.BLDG. UNIT NO.1
B.F.P. TURBINE-OIL CONSOLE
45 AUX. FW. PUMP HOUSE
LEGEND:
SECTION
COMPARTMENT
RIGHT SIDE(OR L-LEFT)
REFERENCE DWGS:
9321-3005 ONE LINE DIAGRAM 480V MCC'S 27 & 27A
9321-3006 ONE LINE DIAGRAM 480V MCC'S 26A & 26B
A208500 ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507 ONE LINE DIAGRAM 480V MCC'S 28, 210
A208241 ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955 ONE LINE DIAGRAM 480V MCC'S 29 & 29A
A249956 ONE LINE DIAGRAM 480V MCC'S 24 & 24A
9321-3177 EXT W/D 480VAC MCC21
9321-3178 EXT W/D 480VAC MCC21
9321-3179 EXT W/D 480VAC MCC22
9321-3180 EXT W/D 480VAC MCC22
9321-3181 EXT W/D 480VAC MCC23
9321-3182 EXT W/D 480VAC MCC23
9321-3184 EXT W/D 480VAC MCC25
9321-3121 SWD 480VAC MCC21
9321-3122 SWD 480VAC MCC22
9321-3123 SWD 480VAC MCC23
9321-3125 SWD 480VAC MCC25
NOTES:
1. CONNECTED LOAD 2-2 HP MTRS 3-3/4 HP MTRS AND 1-350VA, 480/120V, 1PH XFMR MAX OPERATING LOAD 1-2HP MTR 1-3/4 HP MTR & 1-350VA 1PH XFMR
2. CONNECTED LOAD 1-1 HP MTR , 1-5 HP AND 1-350VA 480/120V 1PH XFMR
A RECORD OF THE ORIGINAL WITH INITIALS/SIGNATURES IS MAINTAINED IN CENTRAL ENGINEERING DOCUMENTATION FILE.
THE LAST PENCILED REVISION WAS 31
THE ORIGINAL TRACING FOR THIS DRAWING WAS PREPARED BY UE&C.
LOAD CENTER FOR N16 ANALYZER CABINET N16 ANNUNICATOR PANEL AND UNIT HEATERS DWG 253892
MOTORIZED VALVES FOR CONDENSER WATER BOX VACUUM BKRS A223477
88 INCORPORATED EC-5000022344 AND EC-9126 01/08/10 AI
APPROVAL SIGNATURES ON FILE
UE&C
UE&C
UE&C
DESIGN ENG
DISC. ENG.
ENG. MGR.
DATE
CKR.
SUPV.
REVIEW
APPROVALS
TITLE: ONE LINE DIAGRAM 480V MOTOR CONTROL CENTERS 21,22, 23,25 & 25A - UFSAR FIGURE No. 8.2-7
DRWN. BY I. WATKINS
SCALE NONE
REC'D
Entergy Nuclear Northeast
STATION INDIAN POINT #2
DWG. NO. 9321-F-3004-88
DZ


480V SWITCHGEAR 21 (PARTIAL)
A208088
BUS 2A (AG9)
22B
52
MCC24A-MCC24
1200A
2-750 MCM / PHASE
(EWF61)
SPLICE
BOX
480V MOTOR CONTROL CENTER 24A
(TURB. GEN. BLDG. EL. 15'-0")
(ECE18)
1A
2G
NON-LOAD
BREAK ISO.
SWITCH
89/MCC24A
U.V
TRIP
600A
52/MCC24
MCC 24
COMPTS
(EBC10)
480/240-120V
30KVA
25 KVA
TRANSF. 24
480/120V
15KVA
(EDV23) RAD MONITOR R45 DIST. PNL A235532
DIESEL GEN 22 COMPR. FUEL OIL JACKET PUMP & LUBE OIL WATER AND HTRS. FDR.
BATTERY CHARGER 22
SPARE
INSTRUMENT AIR COMPRESSOR 22
INSTRUMENT AIR CLOSED COOLING WATER PUMP 22
STATIC INVERTER 22 9321-F-3008
2-750 MCM / ø
480V MOTOR CONTROL CENTER 24
(TURB. GEN. BLDG. EL. 15'-0")
OCCUPIED BY MCC24A LOAD
MAIN TUR-GEN TURNING GEAR
15 KVA.
UNIT AUX. TRANSF. AUXILIARIES (EMERG.) 204897
22.4 KVA
STATION AUX. TRANSF. AUXILIARIES (NORMAL)
ISOPHASE BUS COOLING FAN 22 9321-LL-3124 SH.7
ROOF VENT FAN 21 9321-LL-3124 SH.3
ROOF VENT FAN 22 9321-LL-3124 SH.3
ROOF VENT FAN 23 9321-LL-3124 SH.3
WALL EXHAUST FAN 24 9321-LL-3124 SH.2
WALL EXHAUST FAN 25 9321-LL-3124 SH.2
ISOPHASE BUS COOLING FAN 21 9321-LL-3124 SH.7
ROOF VENT FAN 24 9321-LL-3124 SH.3
ROOF VENT FAN 25 9321-LL-3124 SH.3
SPARE
VOLTAGE REGULATOR CUBICLE (EXCITER) IP2 S-000057
ISOPHASE BUS COOLING FAN 26 9321-LL-3124 SH.7
WALL EXHAUST FAN 21 9321-LL-3124 SH.2
WALL EXHAUST FAN 22 9321-LL-3124 SH.2
WALL EXHAUST FAN 23 9321-LL-3124 SH.2
10 KVA, 1ø, TR (EB02) P.A. SYSTEM-ALT. SUPPLY 9321-F-3008
SPLICE BOX (EWB85)
FUSE BOX (EWE68)
(EBB7)
3KVA TRANSF
480V / 120V
3Ø,60HZ
(EDH8)
15A
INSTRUMENT AIR DRYER B230561
COOLING WATER PUMP 22 (A) IP2 S-000048
5 KVA
6.9 KV BUS DUCT HEATERS (120V)
ROD CONTROL SUPPLY TRANSF. #2, 10 KVA 1ø
ROD CONT. CAB
SOLA TRANSF.
R.P.I. CAB. "C2"
ROD CONTROL TRANSFER (FOR ROD CONTROL CAB & ROD POSITION INDIC CAB "C2(?)")
MAIN TRANSF. 22 AUXILIARIES (EMERG.)
MAIN TRANSF. 21 AUXILIARIES (NORMAL)
SYMBOLS
DISCONNECT SWITCH
DRAWOUT DEVICE
FULL VOLTAGE NON-REVERSING STARTER LOCATED AT NEARBY EQUIPMENT
SHAWMUT FUSE TYPE AJT CLASS J TIME DELAY CLASS J CURRENT LIMITING
SHAWMUT FUSE TYPE A4J CLASS J CURRENT LIMITING FUSE
BUSSMAN TYPE OTS
BREAKER
FULL VOLTAGE NON-REVERSING STARTER. NUMBER INDICATES NEMA SIZE. (R) INDIC. REVERSING.
THERMAL MAG. ELEMENT
MOTOR & HORSEPOWER
FUSE NOT INSTALLED
MCC 24 COMPT. 2DL (TYPICAL)
NOTE:
1. FOR FUSE INFORMATION SEE PLANT EQUIPMENT DATABASE
LOCATIONS
18 CONTROL BLDG.
24 TURB.GEN.BLDG.
27 TRANSFORMER YARD
28 DIESEL GEN. BLDG.
LEGEND:
SECTION
COMPARTMENT
RIGHT SIDE(OR L-LEFT)
REFERENCE DWGS.
9321-F-3004 ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3005 ONE LINE DIAGRAM 480V MCC'S 27
9321-F-3006 ONE LINE DIAGRAM 480V MCC'S 26A & 26B
9321-F-3183 WIRING DIAGRAM MCC 24
A208500 ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507 ONE LINE DIAGRAM 480V MCC'S 28, 29, 210
A208241 ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955 ONE LINE DIAGRAM 480V MCC'S 29 & 29A
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
18 INCORPORATED EC-9507 05/18/10 RML
APPROVAL SIGNATURES ON FILE
TITLE: ONE LINE DIAGRAM
480V MCC 24 & 24A
- UFSAR FIGURE No. 8.2-7A
DRWN. BY K.FOLEY
SCALE NONE
Entergy
STATION
INDIAN POINT #2
DWG. NO. A249956-18 DZ


REFERENCE DWGS:
9321-F-3004 ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3006 ONE LINE DIAGRAM 480V MCC'S 26A & 26B
A208500 ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507 ONE LINE DIAGRAM 480V MCC'S 28, 210
A208241 ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955 ONE LINE DIAGRAM 480V MCC'S 29 & 29A
A249956 ONE LINE DIAGRAM 480V MCC'S 24 & 24A
A181899 LIGHTING & ELECT HTG CONTROL PASSAGEWAYS
9321-F-3189 EXTERNAL W/D 480VAC MCC 27
9321-F-3190 EXTERNAL W/D 480VAC MCC 27
9321-F-3191 EXTERNAL W/D 480VAC MCC 27
9321-F-3192 EXTERNAL W/D 480VAC MCC 27
9321-LL-3127 SCHEMATIC W/D 480VAC MCC 27
9321-LL-3137- SHT. 11 SCHEMATIC WET LAYUP RECIRC. & CHEMICAL ADD PUMP
110
480V SWITCHGEAR 22 (PARTIAL)
A208088
BUS 6A
480V MOTOR CONTROL CENTER 27A
(P.A.B. ELEV. 98'-0")
480V MOTOR CONTROL CENTER 27
(P.A.B. ELEV. 98'-0")
FRONT
REAR
REAR
LEGEND:
FRONT
SECTION
COMPARTMENT
RIGHT SIDE(OR L-LEFT)
REAR
SECTION
COMPARTMENT
REAR
RIGHT SIDE(OR L-LEFT)
LOCATIONS
CONTROL BLDG.
PRIMARY AUX BLDG.
FAN ROOM
FUEL STORAGE BLDG.
TANK PIT BLDG.& BORIC ACID PACKING ROOM
DIESEL BLDG.
AUX FEED WATER PUMP HOUSE
NOTE
1. FOR OTHER CONN'S ASSOCIATED WITH THIS DWG. SEE DWG.A208507
SYMBOLS
STARTER LOCATED AT EQUIP.
DISCONNECT SWITCH
DRAWOUT DEVICE
SHAWMUT TYPE TRS
SHAWMUT FUSE TYPE AJT CLASS J TIME DELAY CLASS J CURRENT LIMITING UNLESS OTHERWISE NOTED
SHAWMUT FUSE TYPE A4J CLASS J CURRENT LIMITING FUSE UNLESS OTHERWISE NOTED
SHAWMUT CO TYPE 4BQ
BREAKER
FULL VOLTAGE NON-REVERSING STARTER. NUMBER INDICATES NEMA SIZE. (R) INDIC. REVERSING.
THERMAL MAG. ELEMENT
MOTOR & HORSEPOWER
110 INCORPORATED EC 16691 9/1/09 AI APPROVAL SIGNATURES ON FILE
TITLE: ONE LINE DIAGRAM
480V MOTOR CONTROL CENTER 27
& 27A
DRWN. BY I. WATKINS
SCALE NONE
REC'D
Entergy
Nuclear Northeast
STATION
INDIAN POINT #2
DWG. NO. 9321-F-3005-110
DZ

REFERENCE DWGS.

9321-F-3004	ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3005	ONE LINE DIAGRAM 480V MCC'S 27 & 27A
9321-F-3006	ONE LINE DIAGRAM 480V MCC'S 26A & 26B
A208500	ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208241	ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955	ONE LINE DIAGRAM 480V MCC'S 29 & 29A
A249956	ONE LINE DIAGRAM 480V MCC'S 24 & 24A
9321-F-3193	EXTERNAL CONN'S 480V MCC 28
9321-F-3175, 3176	EXTERNAL CONN'S 480V MCC 210
9321-LL-3128	SCHEM. W/D CONN'S 480V MCC 28
9321-LL-3120	SCHEM. W/D CONN'S 480V MCC 210

NOTES

- * LOCATED ADJACENT TO MCC 28
- *1 TERMINAL BLOCKS IN BOX "XF1"
- *2 PLUG AND RECEPTACLE

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
39	INCORPORATED DRN-06-01547, TE 06-000711	5/18/06	DM		

REVISIONS

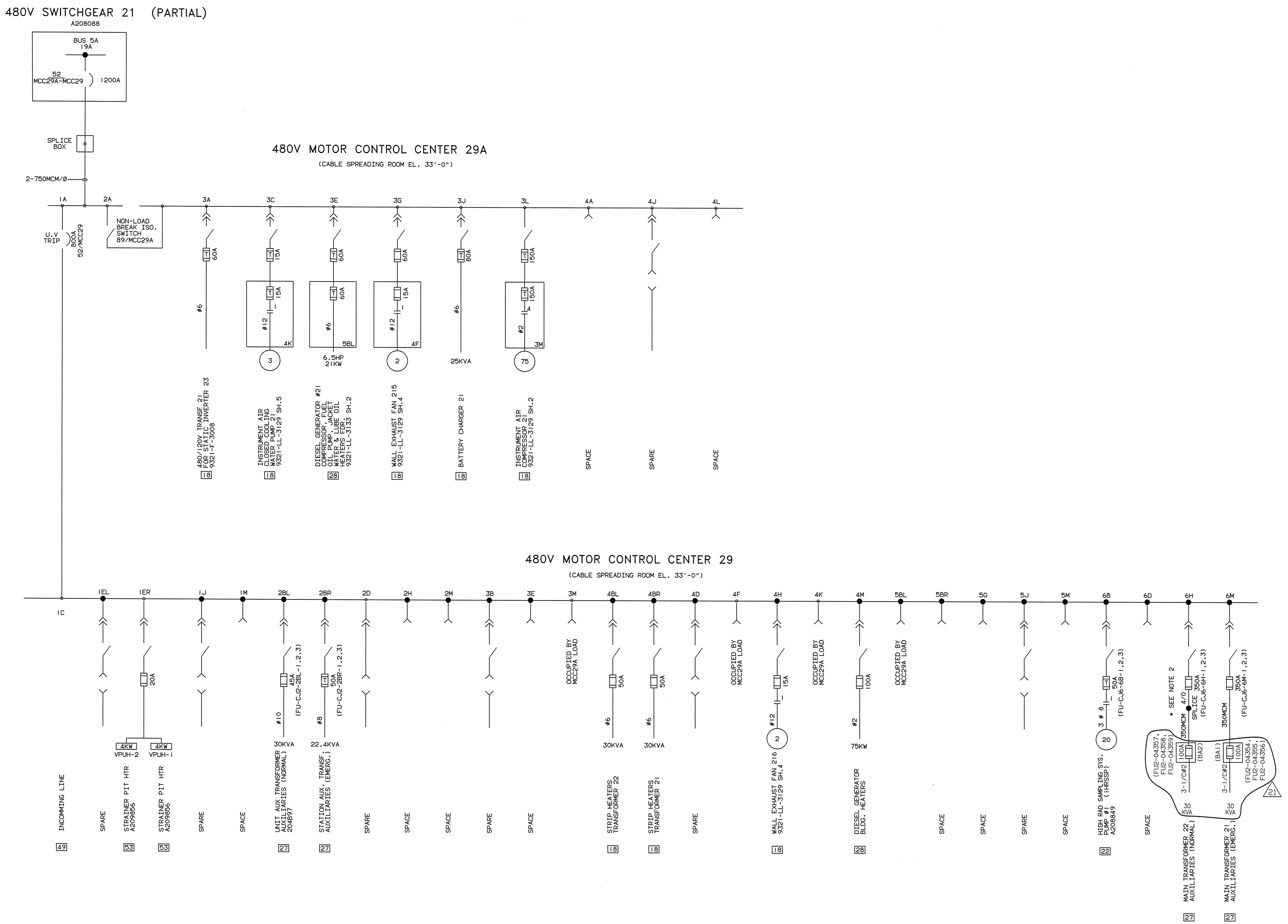
TITLE: ONE LINE DIAGRAM, 480 VAC MCC'S 28 & 210
- UFSAR FIGURE No. 8.2-9

Entergy Nuclear Northeast

STATION: INDIAN POINT #2

DRWN. BY: IW/TH | SCALE: NONE

DWG. NO. A208507-39 DZ



SYMBOLS

- DISCONNECT SWITCH
- DRAWOUT DEVICE
- SHAWMUT FUSE TYPE AJT CLASS J TIME DELAY CLASS J CURRENT LIMITING
- SHAWMUT FUSE TYPE A4J CLASS J CURRENT LIMITING FUSE
- BREAKER
- FULL VOLTAGE NON-REVERSING STARTER. NUMBER INDICATES NEMA SIZE. (R) INDIC. REVERSING.
- THERMAL MAG. ELEMENT
- MOTOR & HORSEPOWER
- FUSE NOT INSTALLED

LOCATIONS

- 18 CONTROL BLDG.
- 27 TRANSF. YARD
- 28 DIESEL BLDG.
- 49 480V MCC 29
- 53 SERVICE WATER VALVE PIT
- 22 FUEL STORAGE BLDG.

LEGEND:

FRONT — SECTION — COMPARTMENT — RIGHT SIDE(OR L-LEFT)

IE

IER

REFERENCE DWGS:

9321-F-3004	ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3005	ONE LINE DIAGRAM 480V MCC'S 27 & 27A
9321-F-3006	ONE LINE DIAGRAM 480V MCC'S 26A & 26B
A208500	ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507	ONE LINE DIAGRAM 480V MCC'S 28, 210
A208241	ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249956	ONE LINE DIAGRAM 480V MCC'S 24 & 24A
9321-F-3194	EXTERNAL W/D 480V MCC29
9321-LL-3129	SCHEMATIC W/D 480V MCC29

NOTES:

1. THIS DWG. SUPERSEDES IN PART CON EDISON (A208507)
2. FUTURE EXPANSION OF CIRCUIT 6H OF MCC29 IS LIMITED BY 200AMP DISCONNECT SWITCH
3. FOR FUSE INFORMATION SEE PLANT EQUIPMENT DATABASE

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
21	INCORPORATED DRN-06-00527, ER-04-2-059	5/17/06	GH		N/A

REVISIONS

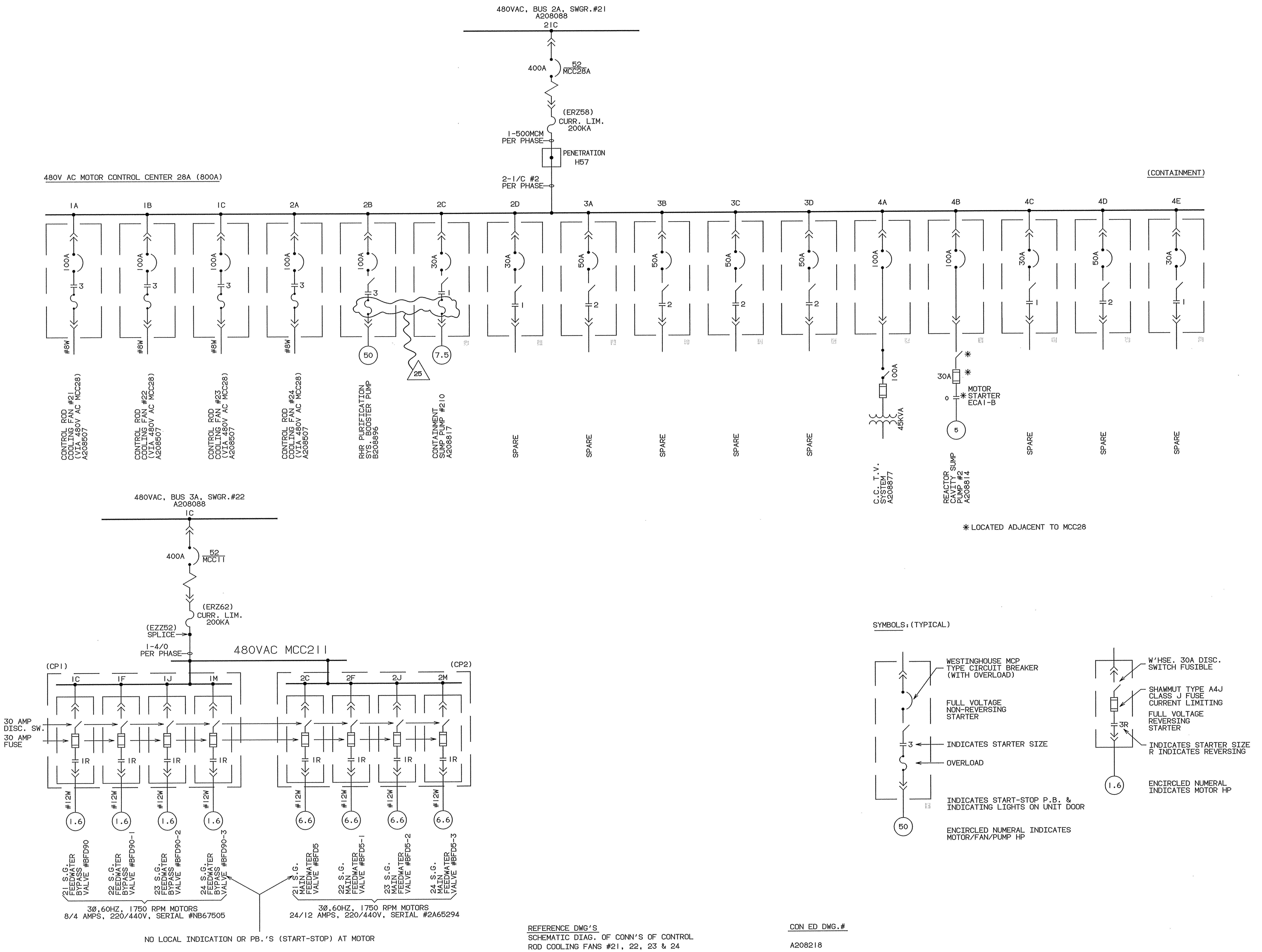
TITLE: ONE LINE DIAGRAM, 480V AC MCC 29 & 29A

- UFSAR FIGURE No. 8.2-9A

DRWN. BY K.FOLEY — SCALE NONE — REC'D

Entergy Nuclear Northeast — STATION INDIAN POINT #2

DWG. NO. A249955-21



REFERENCE DWG'S	CON ED DWG.#
SCHEMATIC DIAG. OF CONN'S OF CONTROL ROD COOLING FANS #21, 22, 23 & 24	A208218
DIAG. OF INT. CONN'S OF STARTERS & PHYSICAL LAYOUT & ELECTRICAL SPEC'S OF 480VAC MCC 28A	A208217
ONE LINE DIAG. OF 480VAC, 3 PHASE, 60HZ. POWER SUPPLY	A208088
DIAGRAM OF EXTERNAL CONN'S OF 480V MCC# 28A	A208216
	U.E.&C. DWG.#
FEEDWATER SYSTEM BY-PASS VALVES (SHTS. #2,6,15) AND SCHEMATIC W/D OF CONN'S FOR MCC211 (SHTS. #9 THRU 9G)	9321-LL-3601
SCHEMATIC DIAG. OF 480V SWITCHGEAR #21 (SHTS. #3,11)	9321-LL-3117

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
25	INCORPORATED DRN-06-00542 ER-IP2-06-10796	3/13/06	JS	RLL	N/A

REVISIONS

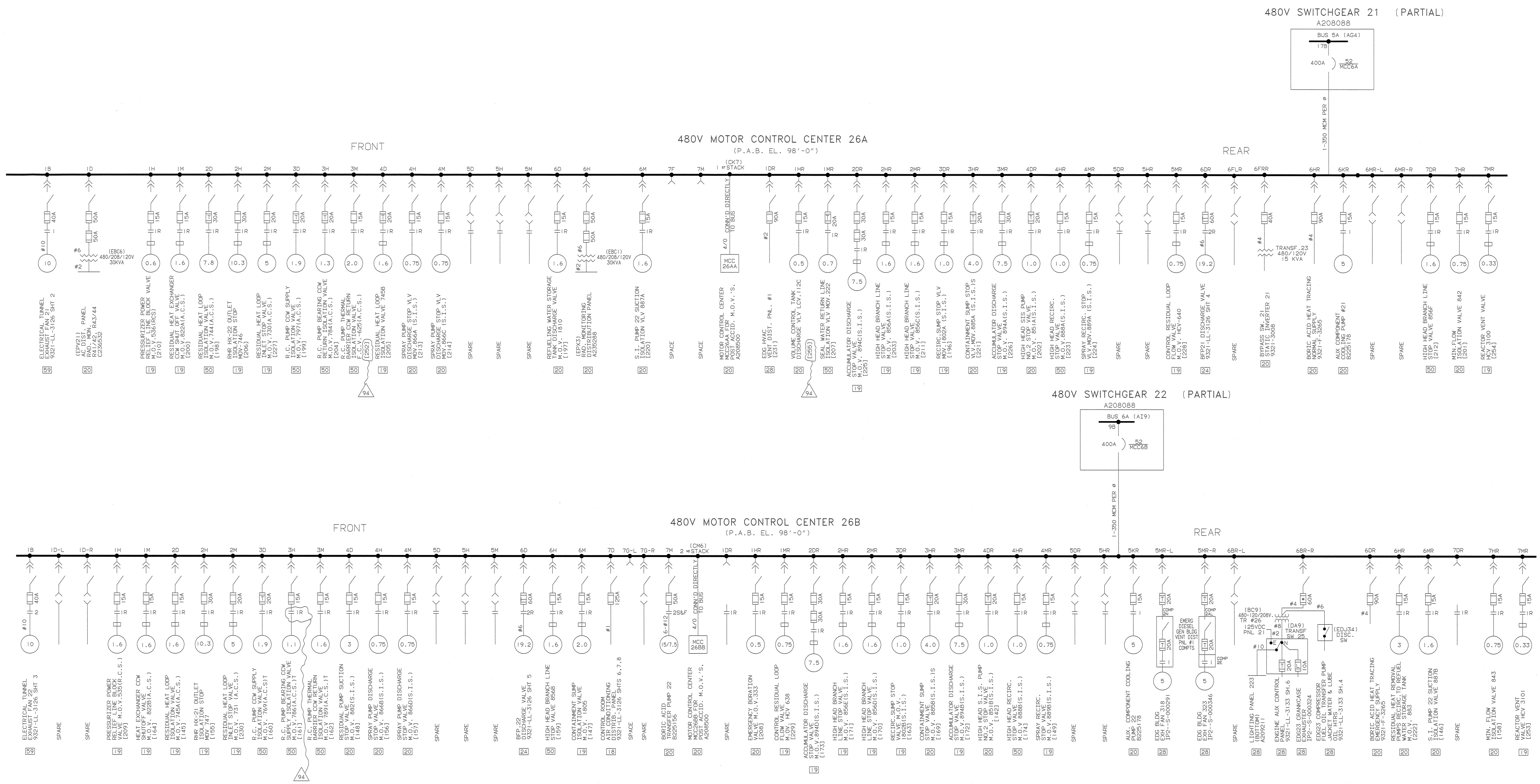
TITLE: SINGLE LINE DIA OF 480 VAC MCC 28A AND 211 - UFSAR FIGURE No. 8.2-10

DRWN. BY: I. WATKINS SCALE: NONE

Entergy Nuclear Northeast

STATION: INDIAN POINT #2

DWG. NO. A208241-25 DZ



SYMBOLS

DISCONNECT SWITCH	DRAWOUT DEVICE
SHAWMUT TYPE TRS	
SHAWMUT FUSE TYPE AJT CLASS J TIME DELAY CURRENT LIMITING FUSE	SHAWMUT FUSE TYPE A4J CLASS J CURRENT LIMITING FUSE
BUSSMAN TYPE LPN-RK	
BREAKER	2 FULL VOLTAGE NON-REVERSING STARTER. NUMBER INDICATES NEMA SIZE. (R) INDIC. REVERSING. (S&F) INDICATE SLOW & FAST.
THERMAL MAG. ELEMENT	4 MOTOR & HORSEPOWER

S SAFETY INJECTION SIGNAL
T TRIP OR CLOSE ON HIGH CONTAINMENT PRESSURE
SIS SAFETY INJECTION SYSTEM
ACS AUXILIARY COOLANT SYSTEM
RCS REACTOR COOLANT SYSTEM

17 CONTROL ROOM PANEL
18 CONTROL BUILDING
19 CONTAINMENT BUILDING
20 PRIMARY AUX. BUILDING
24 TURBINE GENERATOR BUILDING
26 INTAKE STRUCTURE
28 DIESEL GENERATOR BUILDING
50 PENETRATION TUNNEL
59 ELECTRICAL TUNNEL

NOTES:

1. PANELS ARE TYPE NEB
2. ALL FEEDERS SHALL BE #12 UNLESS OTHERWISE INDICATED
3. ALL REFERENCES TO DWG. NUMBERS IN [ ] REPRESENT THE SCHEMATIC WIRING DIAGRAM (SWD#).

REFERENCE DWGS:

9321-F-3004	ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3005	ONE LINE DIAGRAM 480V MCC 27
A208500	ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507	ONE LINE DIAGRAM 480V MCC'S 28, 210
A208241	ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955	ONE LINE DIAGRAM 480V MCC'S 29 & 29A
A249956	ONE LINE DIAGRAM 480V MCC'S 24 & 24A
9321-F-3185	EXTERNAL WIRING DIAGRAM MCC 26A
9321-F-3186	EXTERNAL WIRING DIAGRAM MCC 26A
9321-F-3187	EXTERNAL WIRING DIAGRAM MCC 26B
9321-F-3188	EXTERNAL WIRING DIAGRAM MCC 26B
9321-F-3208	EXTERNAL WIRING DIAGRAM MCC'S 26A & 26B
9321-LL-3126	SCHEMATIC WIRING DIAGRAM MCC'S 26A & 26B

LEGEND:

FRONT
SECTION
COMPARTMENT
IE
RIGHT SIDE(OR L-LEFT)
IE-R

REAR
SECTION
COMPARTMENT
REAR
IER
RIGHT SIDE(OR L-LEFT)
IER-R

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
94	INCORPORATED DRN-06-00345 ER IP2-05-27301	1/24/06	JS	Rul	N/A

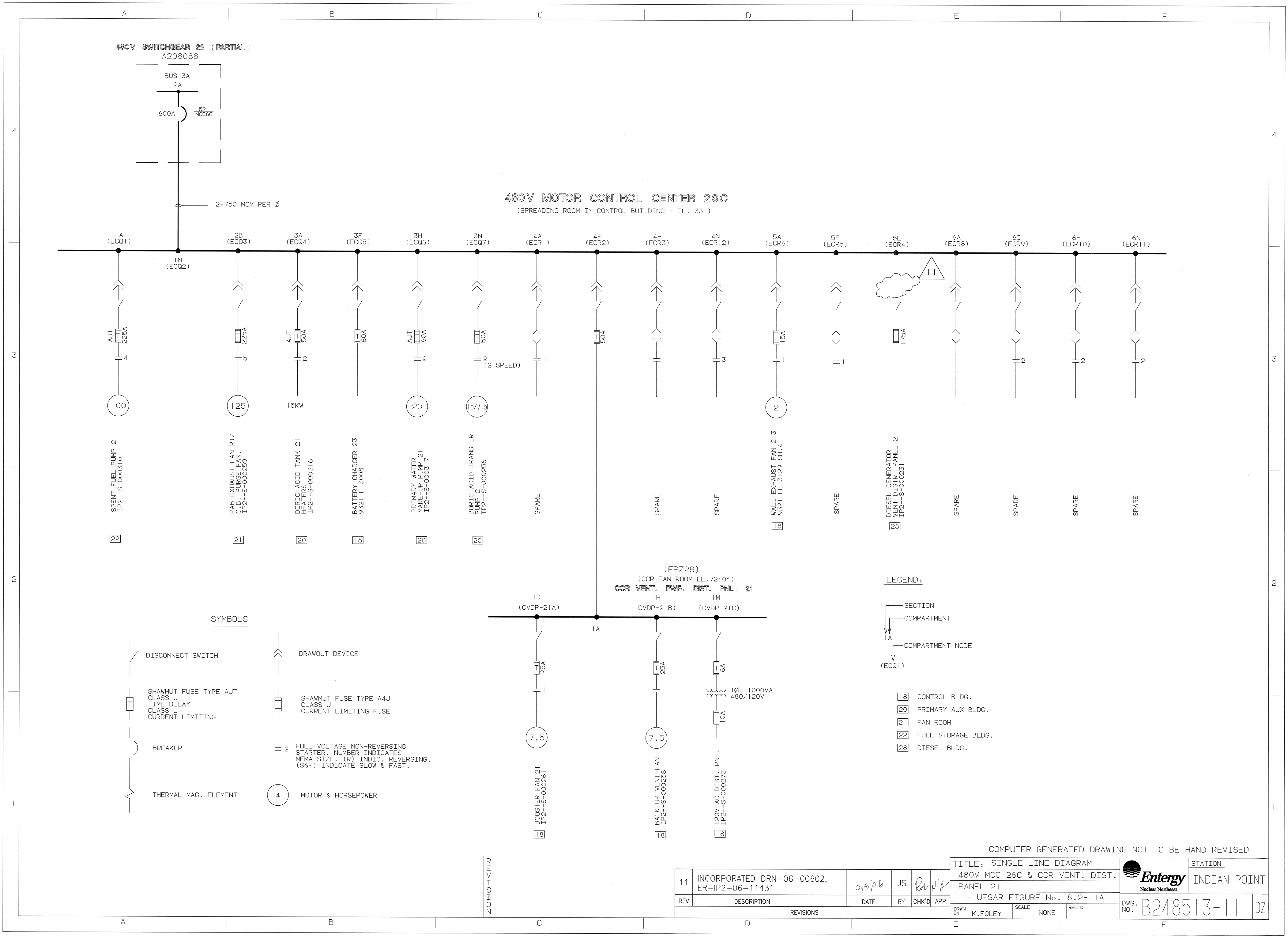
REVISIONS

INDIAN POINT ENERGY CENTER – UNIT 2

SINGLE LINE DIAGRAM
480V MCC 26A AND 26B

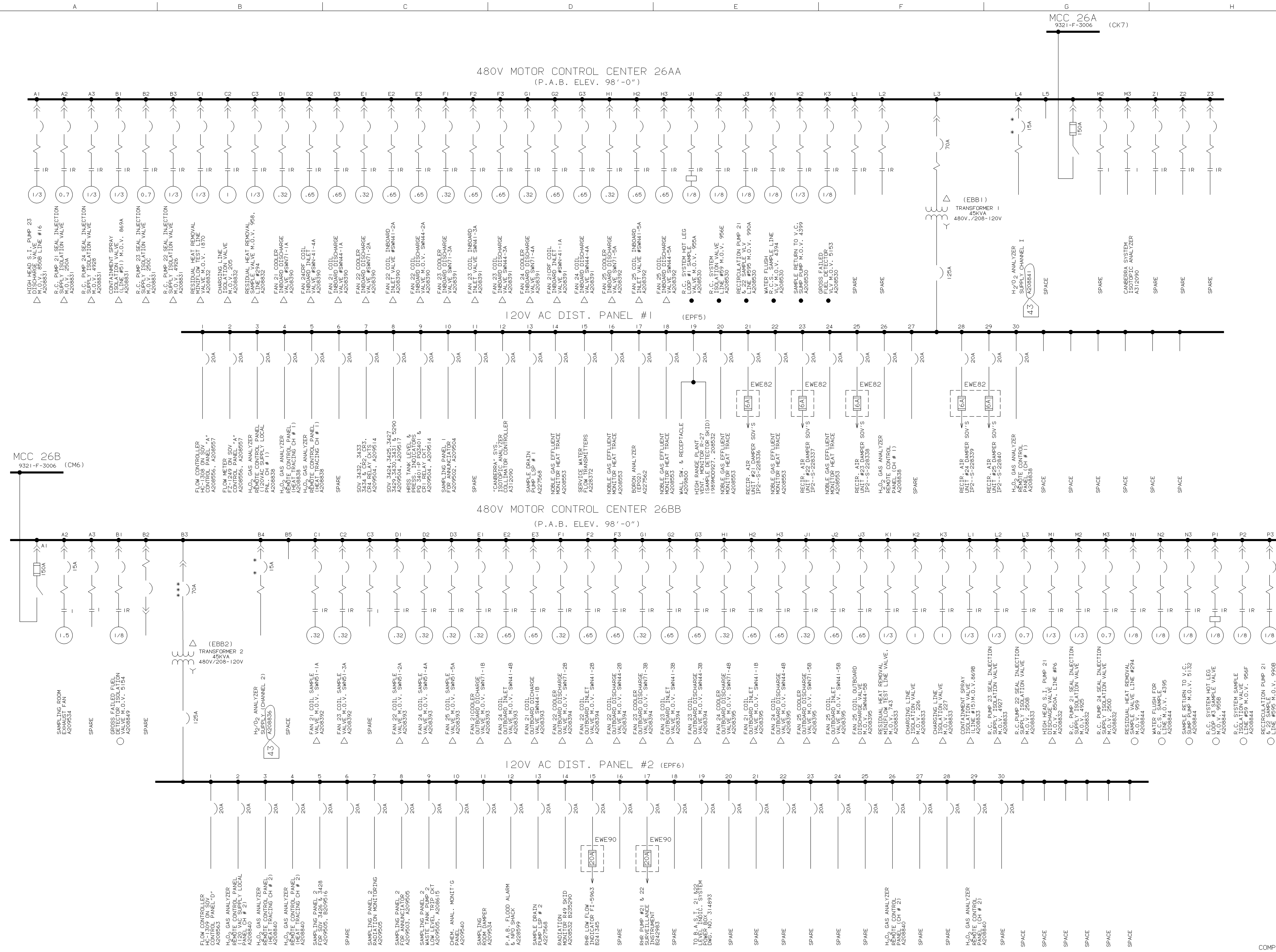
Entergy
Nuclear Northeast

DWG NO. 9321-F-3006-94 DZ
SCALE
SHEET



480V SWITCHGEAR 22 (PARTIAL)
A208088
BUS 3A
2A
600A
52/MCC6C
2-750 MCM PER Ø
480V MOTOR CONTROL CENTER 26C
(SPREADING ROOM IN CONTROL BUILDING - EL. 33')
1A (ECQ1)
1N (ECQ2)
2B (ECQ3)
3A (ECQ4)
3F (ECQ5)
3H (ECQ6)
3N (ECQ7)
4A (ECR1)
4F (ECR2)
4H (ECR3)
4N (ECR12)
5A (ECR6)
5F (ECR5)
5L (ECR4)
6A (ECR8)
6C (ECR9)
6H (ECR10)
6N (ECR11)
11
AJT 225A
4
100
SPENT FUEL PUMP 21
IP2--S-000310
22
225A
5
125
PAB EXHAUST FAN 21/
C.B. PURGE FAN.
IP2--S-000259
21
AJT 50A
2
15KW
BORIC ACID TANK 21
HEATERS
IP2--S-000316
20
60A
BATTERY CHARGER 23
9321-F-3008
18
AJT 60A
2
20
PRIMARY WATER
MAKE-UP PUMP 21
IP2--S-000317
20
50A
2 (2 SPEED)
15/7.5
BORIC ACID TRANSFER
PUMP 21
IP2--S-000256
20
1
SPARE
50A
1
SPARE
3
SPARE
15A
1
2
WALL EXHAUST FAN 213
9321-LL-3129 SH.4
18
1
SPARE
175A
DIESEL GENERATOR
VENT DISTR. PANEL 2
IP2--S-000231
28
SPARE
2
SPARE
2
SPARE
2
SPARE
(EPZ28)
(CCR FAN ROOM EL.72'0")
CCR VENT. PWR. DIST. PNL. 21
1D (CVDP-21A)
1A
1H CVDP-21B)
1M (CVDP-21C)
25A
1
7.5
BOOSTER FAN 21
IP2--S-000261
18
25A
7.5
BACK-UP VENT FAN
IP2--S-000258
18
6A
1Ø, 1000VA
480/120V
10A
120V AC DIST. PNL.
IP2--S-000273
18
SYMBOLS
DISCONNECT SWITCH
DRAWOUT DEVICE
SHAWMUT FUSE TYPE AJT
CLASS J
TIME DELAY
CLASS J
CURRENT LIMITING
SHAWMUT FUSE TYPE A4J
CLASS J
CURRENT LIMITING FUSE
BREAKER
2
FULL VOLTAGE NON-REVERSING
STARTER. NUMBER INDICATES
NEMA SIZE. (R) INDIC. REVERSING.
(S&F) INDICATE SLOW & FAST.
THERMAL MAG. ELEMENT
4
MOTOR & HORSEPOWER
LEGEND:
SECTION
COMPARTMENT
1A
COMPARTMENT NODE
(ECQ1)
18 CONTROL BLDG.
20 PRIMARY AUX BLDG.
21 FAN ROOM
22 FUEL STORAGE BLDG.
28 DIESEL BLDG.
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
REVISION
11 | INCORPORATED DRN-06-00602, ER-IP2-06-11431 | 2/8/06 | JS
REV | DESCRIPTION | DATE | BY | CHK'D | APP.
REVISIONS
TITLE: SINGLE LINE DIAGRAM
480V MCC 26C & CCR VENT. DIST.
PANEL 21
- UFSAR FIGURE No. 8.2-11A
DRWN. BY K.FOLEY
SCALE NONE
REC'D
Entergy
Nuclear Northeast
STATION
INDIAN POINT
DWG. NO. B248513-11
DZ

2/20/2004 11:49:34 PM 208500-43.DWG



SYMBOLS

- DRAWOUT CIRC.BKR STARTER TYPE UNIT
- ALL CIRC. BKR'S ARE MOLDED CASE TYPE SEE NOTE 1
- THERMAL OVERLOAD
- FULL VOLTAGE NON-REVERSING STARTER NUMERAL INDICATES SIZE (R-INDICATES REVERSING)
- CONTAINMENT PENETRATION
- ENCIRCLED NUMERALS INDICATE MOTOR HORSEPOWER

△ — INDICATES M.O.V. TO BE PADLOCKED, WITH CONTROL SW. (CLOSE-OPEN) AND 2 INDIC. LTS.(GREEN-RED) FOR EACH ONE.

● — INDICATES CONTROL FROM SAMPLING PNL.#1 DWG.#A209502

○ — INDICATES CONTROL FROM SAMPLING PNL.#2 DWG.#A209503

* — CIRC. BKR,KLOCKNER-MOELLER TYPE NZM H9-250 6

** — CIRC. BKR,KLOCKNER-MOELLER TYPE NZM H6-63

*** — CIRC. BKR,KLOCKNER-MOELLER TYPE NZM H6-100

NOTES:

1. ALL CIRC. BKRS IN MCC26AA & MCC26BB ARE: KLOCKNER-MOLLER TYPE NZB6B-63 (63 AMPS) EXCEPT AS NOTED OTHERWISE. FOR BREAKER SETTINGS SEE REF. DWG'S 256927, & 255880 BELOW

REFERENCE DWG:

9321-F-3006	ONE LINE DIAGRAM 480V MCC'S 26A & 26B
208523	MCC 26AA EXTERNAL W/D
208524	MCC 26AA EXTERNAL W/D
208525	MCC 26BB EXTERNAL W/D
208526	MCC 26BB EXTERNAL W/D
208532	120VAC DIST. PNL'S 1&2 EXTERNAL W/D
208397	MCC 26AA & MCC 26BB EXTERNAL W/D
256927	M.O.V INFO. -1995 REFUEL OUTAGE
255880	M.O.V. INFOMATION

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN ENTERGY AS:
"CLASS A" ITEMS
PER THE QAPD

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION	ENG		DATE	CKR.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.
	V.MYERS 10/28/03	THIS REVISION IS NON CLASS AS PER THE QAPD. UPDATED DRAWING PER CR-IP2-2003-06244. RELEASED FOR RECORD P.N. 69901-AF AI/VM			MR	F.HOFFMAN 3/3/87	A.KAFFASHAN	G.BLENKLE

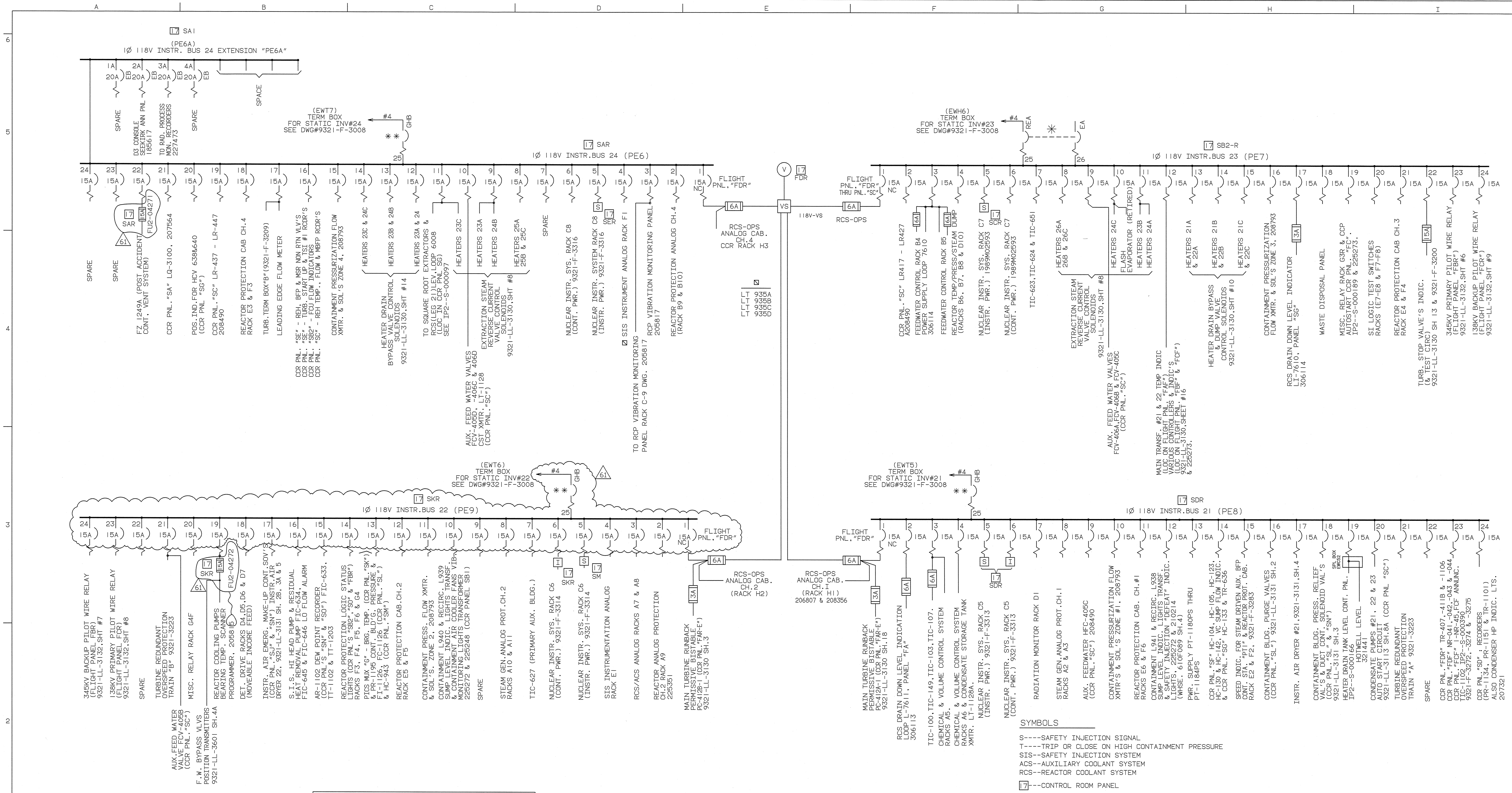
REVIEW — APPROVALS

TITLE: ONE LINE DIAG FOR 480V AC; MCC 26AA AND MCC 26BB & 120V AC DIST. PANEL 1 & 2. - UFSAR FIGURE No. 8.2-12

DRWN. BY IW/TH | SCALE NONE | REC'D

Con Edison | STATION: INDIAN POINT #2

DWG. NO. A208500-43 DZ



FOR ADDITIONAL LOAD INFO
REGARDING THESE INSTR. BUSSES
SEE THE FOLLOWING DWGS:
INSTR BUS #21-- 263980
INSTR BUS #22-- 263981
INSTR BUS #23-- 263982
INSTR.BUS #24-- 263983

NOTES:

1. FOR INSTRUMENT BUSES 21, 22 & 24 ALL 15A MOLDED CASE CIRCUIT BREAKER CUTLER-HAMMER TYPE GHB
2. FOR INSTRUMENT BUS 23 ALL 15A MOLDED CASE CIRCUIT BREAKER WESTINGHOUSE TYPE REA.

REFERENCE DWG.

ONE LINE DIAGRAM 480VAC MCC 21, 22, 23, 25 & 25A---DWG.#9321-F-3004
ONE LINE DIAGRAM 480VAC MCC 27 & 27A---------------DWG.#9321-F-3005
ONE LINE DIAGRAM 480VAC MCC 26A & 26B--------------DWG.#9321-F-3006

W/D 118VAC INSTRUMENT BUS PANELS 21 & 22-----------DWG.#9321-F-3199
W/D 118VAC INSTRUMENT BUS PANELS 23 & 24-----------DWG.#9321-F-3200
GENERAL ARRANGEMENT OF BKR PANEL BOARD 21 & 24 DWG.# 2004MD1129

SYMBOLS

S----SAFETY INJECTION SIGNAL
T----TRIP OR CLOSE ON HIGH CONTAINMENT PRESSURE
SIS--SAFETY INJECTION SYSTEM
ACS--AUXILIARY COOLANT SYSTEM
RCS--REACTOR COOLANT SYSTEM

17---CONTROL ROOM PANEL

*---MAIN BKR'S ARE "AB" TYPE 100A-1POLE AND ARE MECHANICALLY INTERLOCKED SO THAT ONLY ONE BKR CAN BE CLOSED

**---MAIN BKR IS CUTLER-HAMMER TYPE GHB 100A-1 POLE

PANELS ARE TYPE NEB

FOR OTHER SYMBOLS SEE CON ED DWG 225113

I 17 SM — SHIELDED SQUARE D ISOLATION TRANSFORMER 120-120V 1Ø 1KVA — LOCATION — PNL.DESIGNATION

S 17 SDR — SOLATRON-LINE VOLTAGE REGULATOR 120-120V, 1Ø, 1KVA — LOCATION — PNL.DESIGNATION

FOR OTHER CONNS.& EQUIPT. ON THIS PNL.SEE DWG#. 9321-F-3006

FOR SCHEM.INFO.OF 118VAC INST.BUSES#21A,22A,23A & 24A SEE DWG#A208503

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REV	DESCRIPTION	DATE	BY	CHK'D	APP
61	INCORPORATED DRN-05-03452, ER-05-2-067 AND DRN-05-04042, ER-05-2-064	5/4/06	DM		N/A

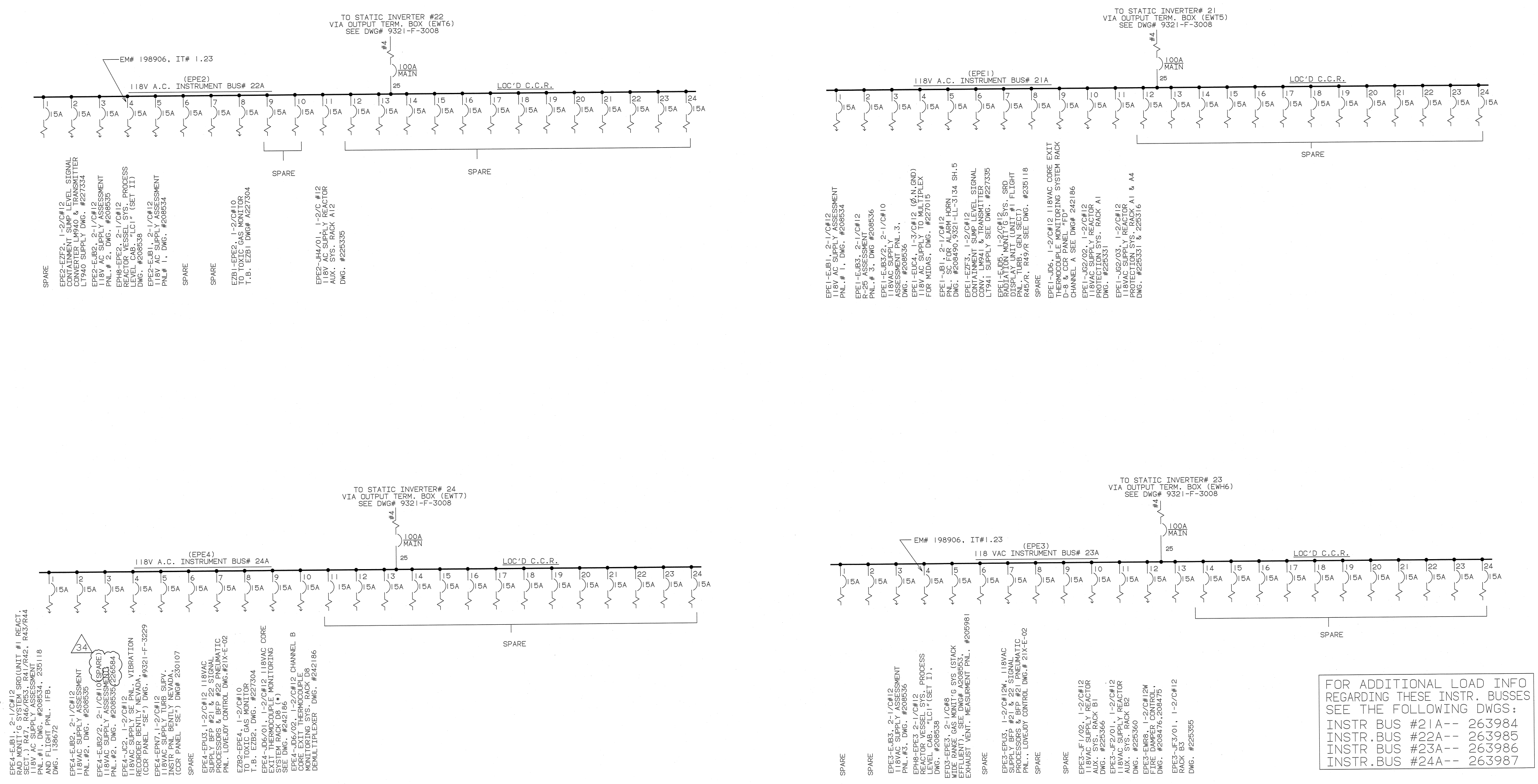
TITLE: SINGLE LINE DIAGRAM 118 VAC. 1 PHASE INST. BUSSES NO. 21,22,23 AND 24 - UFSAR FIGURE No. 8.2-13

DRAWN BY J. WATKINS | SCALE NONE

Entergy

STATION INDIAN POINT #2

DWG. NO. A208502-61 DZ



(*) CONTINUED FROM CIRCUIT #9 ABOVE
JD6-JA4/02 TO T-SAT (CH.B) NR46, NR47, PR403, TR433 PANEL FDF, DWG. 9321-F-3274

FOR ADDITIONAL LOAD INFO REGARDING THESE INSTR. BUSSES SEE THE FOLLOWING DWGS:

INSTR BUS #21A-- 263984
INSTR.BUS #22A-- 263985
INSTR.BUS #23A-- 263986
INSTR.BUS #24A-- 263987

REFERENCE DWGS.:

SINGLE LINE DIAG. D-C SYSTEM _ _ _ _ _ _ _ _ _ _9321-F-3008
D/C FOR INSTR. BUSES 21A, 22A, 23A& 24A _ _ _ _ _ _ _ _208504

NOTES:

1- FOR SCHEM. INFO. OF 118V AC INSTR. BUSES# 21,22,23&24 SEE DWG. #208502

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
34	INCORPORATED DRN-06-01615 ER-04-2-234	6/21/06	RML	GHH	N/A

REVISIONS

DATE	REVIEW CKR.	REVIEW SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.
04/13/88	CP	BS	FRANCIS HOFFMAN 12/08/87	K.S. 04/20/87	A.K. FOR G.L. BLENKLE 04/20/87

APPROVALS

TITLE: SCHEM DIA OF 118 VAC INST BUSES 21A,22A,23A AND 24A (LOCATED IN CCR) - UFSAR FIGURE No. 8.2-14

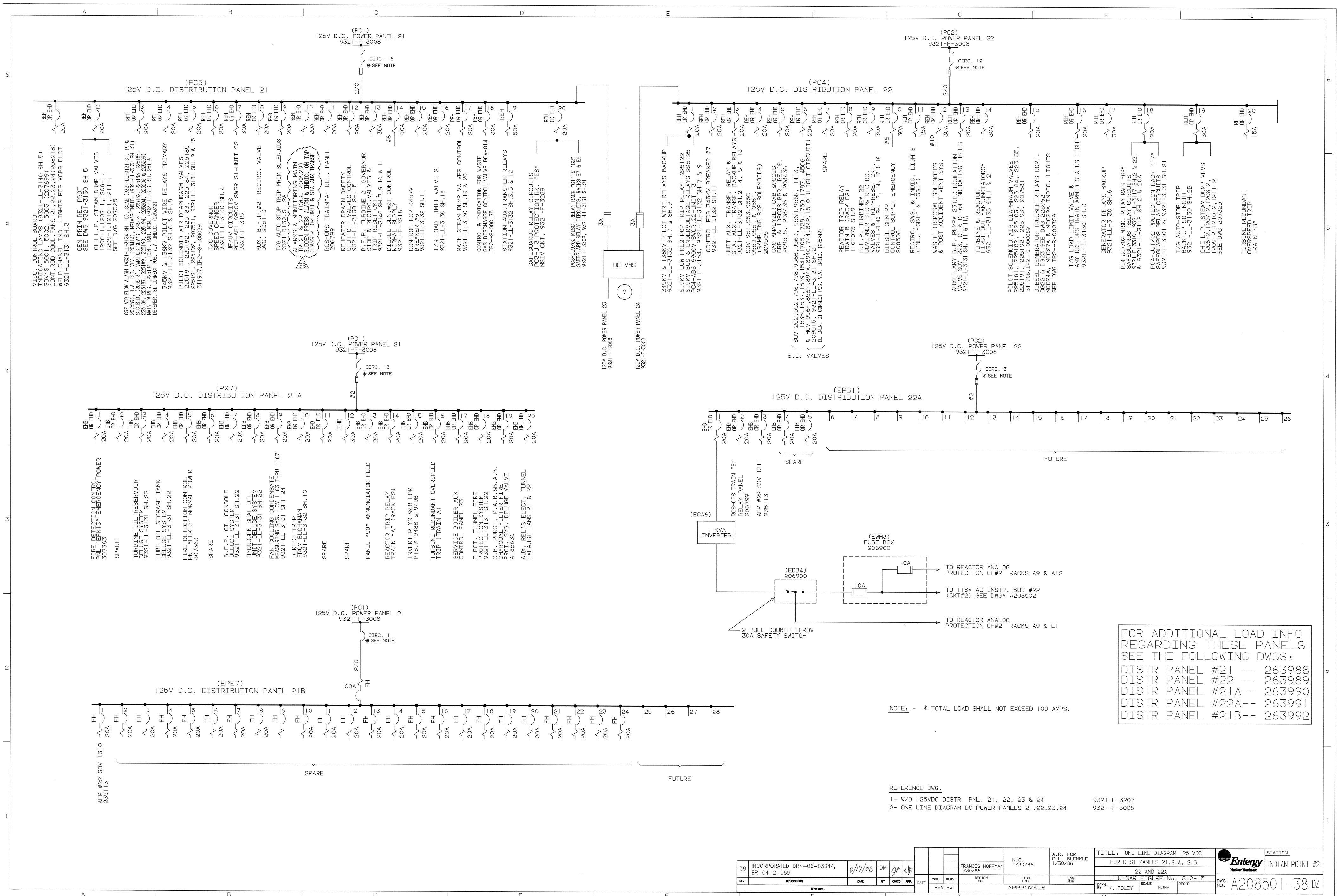
MOD.PROC.OR SPEC.

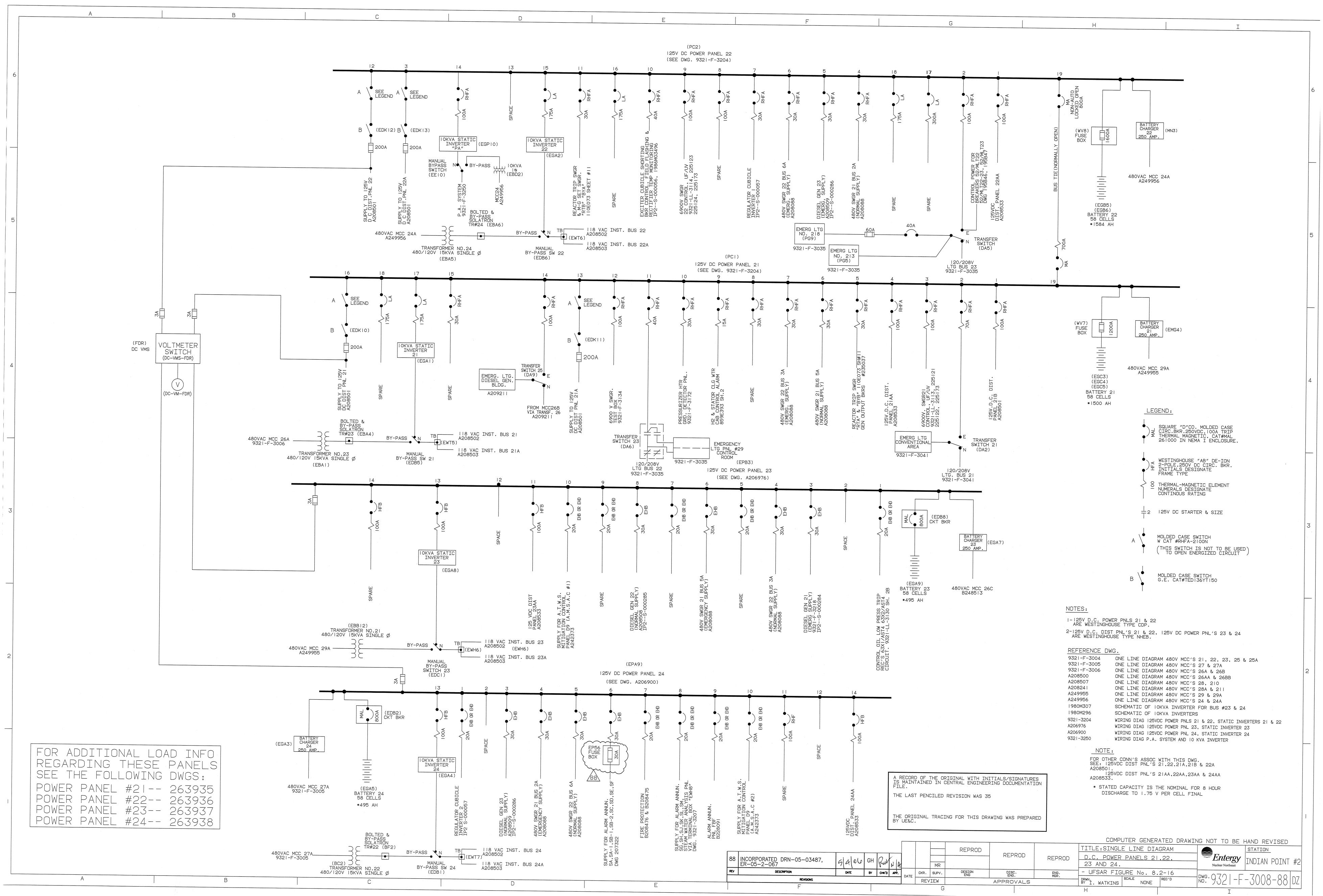
DRWN. BY I. WATKINS | SCALE NONE | REC'D

Entergy Nuclear Northeast

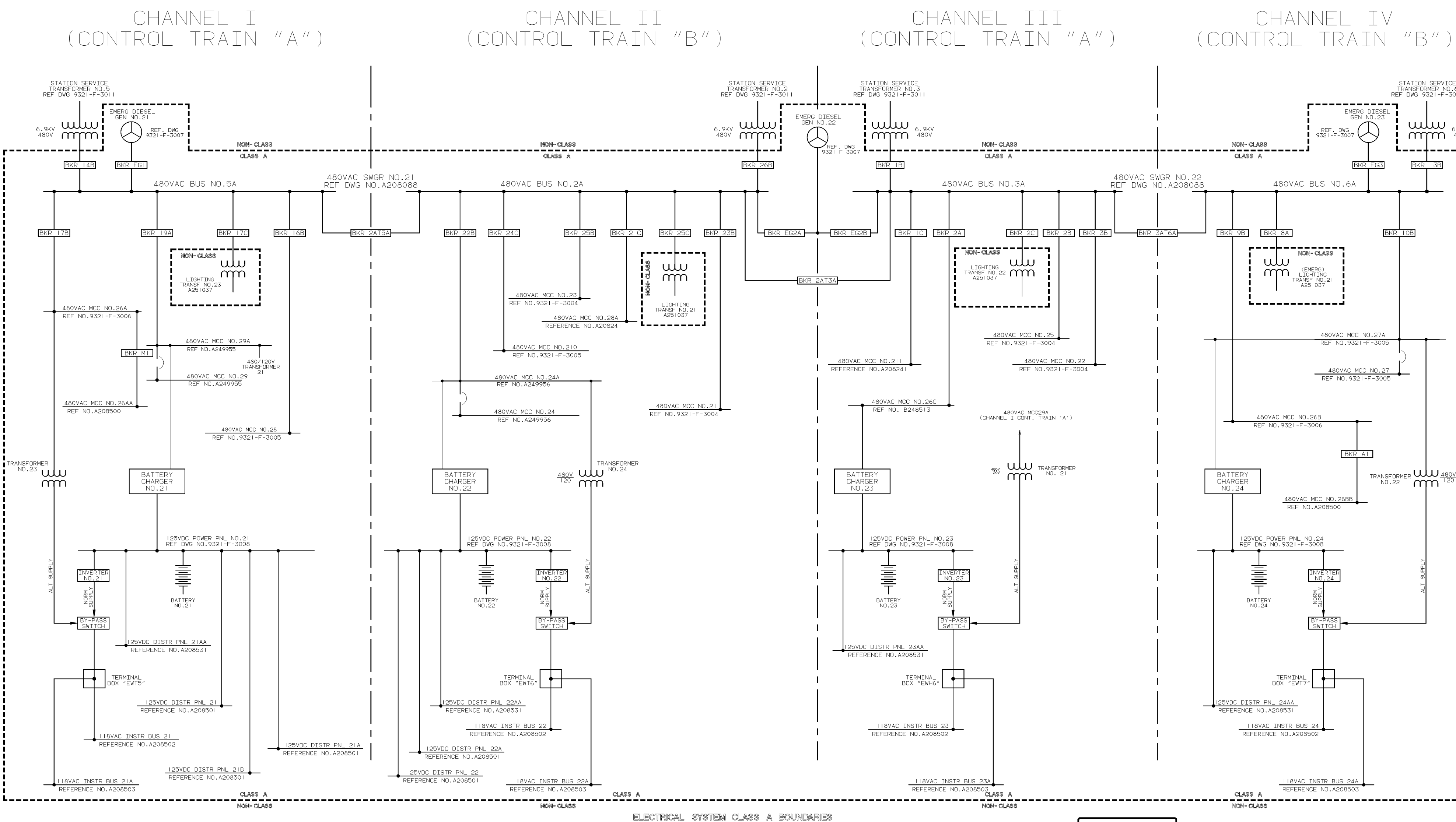
STATION INDIAN POINT #2

DWG. NO. A208503-34 DZ


(PC1)
125V D.C. POWER PANEL 21
9321-F-3008
CIRC. 16
* SEE NOTE
(PC3)
125V D.C. DISTRIBUTION PANEL 21
(PC2)
125V D.C. POWER PANEL 22
9321-F-3008
CIRC. 12
* SEE NOTE
(PC4)
125V D.C. DISTRIBUTION PANEL 22
DC VMS
125V D.C. POWER PANEL 23 9321-F-3008
125V D.C. POWER PANEL 24 9321-F-3008
S.I. VALVES
(PC1)
125V D.C. POWER PANEL 21
9321-F-3008
CIRC. 13
* SEE NOTE
(PX7)
125V D.C. DISTRIBUTION PANEL 21A
(PC2)
125V D.C. POWER PANEL 22
9321-F-3008
CIRC. 3
* SEE NOTE
(EPB1)
125V D.C. DISTRIBUTION PANEL 22A
SPARE
FUTURE
(EGA6)
1 KVA INVERTER
(EWH3)
FUSE BOX
206900
(EDB4)
206900
TO REACTOR ANALOG PROTECTION CH#2 RACKS A9 & A12
TO 118V AC INSTR. BUS #22 (CKT#2) SEE DWG# A208502
TO REACTOR ANALOG PROTECTION CH#2 RACKS A9 & E1
2 POLE DOUBLE THROW 30A SAFETY SWITCH
(PC1)
125V D.C. POWER PANEL 21
9321-F-3008
CIRC. 1
* SEE NOTE
(EPE7)
125V D.C. DISTRIBUTION PANEL 21B
AFP #22 SOV 1310 235113
SPARE
FUTURE
FOR ADDITIONAL LOAD INFO
REGARDING THESE PANELS
SEE THE FOLLOWING DWGS:
DISTR PANEL #21 -- 263988
DISTR PANEL #22 -- 263989
DISTR PANEL #21A-- 263990
DISTR PANEL #22A-- 263991
DISTR PANEL #21B-- 263992
NOTE: - * TOTAL LOAD SHALL NOT EXCEED 100 AMPS.
REFERENCE DWG.
1- W/D 125VDC DISTR. PNL. 21, 22, 23 & 24 9321-F-3207
2- ONE LINE DIAGRAM DC POWER PANELS 21,22,23,24 9321-F-3008
38 INCORPORATED DRN-06-03344, ER-04-2-059 8/17/06 DM
REV DESCRIPTION DATE BY CHK'D APP.
REVISIONS
FRANCIS HOFFMAN 1/30/86
K.S. 1/30/86
A.K. FOR G.L. BLENKLE 1/30/86
REVIEW APPROVALS
TITLE: ONE LINE DIAGRAM 125 VDC FOR DIST PANELS 21,21A, 21B 22 AND 22A
- UFSAR FIGURE No. 8.2-15
DRWN. BY K. FOLEY SCALE NONE
Entergy
STATION INDIAN POINT #2
DWG. NO. A208501-38 DZ


(PC2)
125V DC POWER PANEL 22
(SEE DWG. 9321-F-3204)
(PC1)
125V DC POWER PANEL 21
(SEE DWG. 9321-F-3204)
(EP83)
125V DC POWER PANEL 23
(SEE DWG. A206976)
(EPA9)
125V DC POWER PANEL 24
(SEE DWG. A206900)
VOLTMETER SWITCH (DC-VMS-FDR)
FOR ADDITIONAL LOAD INFO REGARDING THESE PANELS SEE THE FOLLOWING DWGS:
POWER PANEL #21-- 263935
POWER PANEL #22-- 263936
POWER PANEL #23-- 263937
POWER PANEL #24-- 263938
LEGEND:
SQUARE "D"CO. MOLDED CASE CIRC.BKR.250VDC,100A TRIP THERMAL MAGNETIC. CAT#MAL 261000 IN NEMA I ENCLOSURE.
WESTINGHOUSE "AB" DE-ION 2-POLE,250V DC CIRC. BKR. INITIALS DESIGNATE FRAME TYPE
THERMAL-MAGNETIC ELEMENT NUMERALS DESIGNATE CONTINOUS RATING
125V DC STARTER & SIZE
MOLDED CASE SWITCH W CAT #RHFA-2100N (THIS SWITCH IS NOT TO BE USED TO OPEN ENERGIZED CIRCUIT)
MOLDED CASE SWITCH G.E. CAT#TED136YT150
NOTES:
1-125V D.C. POWER PNLS 21 & 22 ARE WESTINGHOUSE TYPE CDP.
2-125V D.C. DIST PNL'S 21 & 22, 125V DC POWER PNL'S 23 & 24 ARE WESTINGHOUSE TYPE NHEB.
REFERENCE DWG.
9321-F-3004 ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3005 ONE LINE DIAGRAM 480V MCC'S 27 & 27A
9321-F-3006 ONE LINE DIAGRAM 480V MCC'S 26A & 26B
A208500 ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507 ONE LINE DIAGRAM 480V MCC'S 28, 210
A208241 ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955 ONE LINE DIAGRAM 480V MCC'S 29 & 29A
A249956 ONE LINE DIAGRAM 480V MCC'S 24 & 24A
1980M307 SCHEMATIC OF 10KVA INVERTER FOR BUS #23 & 24
1980M296 SCHEMATIC OF 10KVA INVERTERS
9321-3204 WIRING DIAG 125VDC POWER PNLS 21 & 22, STATIC INVERTERS 21 & 22
A206976 WIRING DIAG 125VDC POWER PNL 23, STATIC INVERTER 23
A206900 WIRING DIAG 125VDC POWER PNL 24, STATIC INVERTER 24
9321-3250 WIRING DIAG P.A. SYSTEM AND 10 KVA INVERTER
NOTE:
FOR OTHER CONN'S ASSOC WITH THIS DWG. SEE: 125VDC DIST PNL'S 21,22,21A,21B & 22A A208501.
125VDC DIST PNL'S 21AA,22AA,23AA & 24AA A208533.
* STATED CAPACITY IS THE NOMINAL FOR 8 HOUR DISCHARGE TO 1.75 V PER CELL FINAL
A RECORD OF THE ORIGINAL WITH INITIALS/SIGNATURES IS MAINTAINED IN CENTRAL ENGINEERING DOCUMENTATION FILE.
THE LAST PENCILED REVISION WAS 35
THE ORIGINAL TRACING FOR THIS DRAWING WAS PREPARED BY UE&C.
88 INCORPORATED DRN-05-03487, ER-05-2-067
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
TITLE: SINGLE LINE DIAGRAM D.C. POWER PANELS 21,22, 23 AND 24.
- UFSAR FIGURE No. 8.2-16
DRAWN BY I. WATKINS
SCALE NONE
Entergy
STATION INDIAN POINT #2
DWG. NO. 9321-F-3008-88
REPROD
APPROVALS
REVIEW

2/18/2004 10:14:58 PM 208376-0-11.dwg



ELECTRICAL SYSTEM CLASS A BOUNDARIES

NOTE

THIS DWG IS INTENDED TO SHOW "SAFEGUARD CHANNELING AND CONTROL TRAIN DEVELOPMENT" ONLY. FOR MORE INFORMATION CONCERNING SPECIFIC BKR POSITION, SIZING AND EQUIPMENT RATING SEE REFERENCE DWG AS INDICATED.

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS:
CLASS A ITEMS
PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION
J.H. 05/22/01 DES — THIS REVISION IS NON-CLASS PER THE QAPD. REVISED DRAWING PER CRS #200104889
M.E. 05/22/01 ENG — P/N 69901-AF J.H./L.L. 05/18/01
STRATUS ENGINEERING

DATE | CHK. | SUPV. | DESIGN ENG: J. LOWNEY 10/01/80 | DISC. ENG.: P.DUGGAN 10/07/80 | ENG. MGR.: ROBERT SAYA 10/07/80
REVIEW — APPROVALS

TITLE: SINGLE LINE DIAG OF UNIT SAFEGUARD CHANNELING AND CONTROL TRAIN DEVELOPMENT. - UFSAR FIGURE No. 8.2-17

11

Con Edison — STATION: INDIAN POINT

DRAWN BY: I. WATKINS | SCALE: NONE | 11/24/80 | DWG. NO. A208376-11 | DD

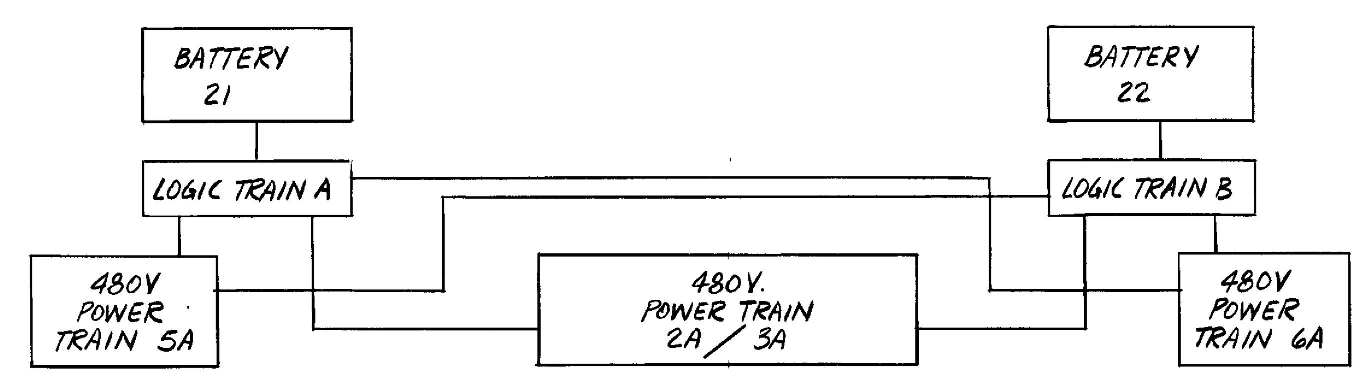
CHANNEL / CONTROL / TRAIN POWER TRAIN SEPARATION DESIGNATIONS	FUNCTION	PHYSICAL ROUTING DESIGNATIONS (SEE NOTE 5)
I (RED) II (WHITE) III (BLUE) IV (YELLOW)	120 VOLT A.C. INSTRUMENT BUS FEEDS AND ANALOG & DIGITAL SIGNAL OUTPUTS ASSOCIATED WITH 120 VOLT A.C. INSTRUMENT BUSES 21, 22, 23 & 24 RESPECTIVELY	J1, J2, J3, J4 — FOR PROTECTION SYSTEM CIRCUITRY CHANNEL / ROUTING ASSOCIATIONS ARE FIXED (I IN J1, II IN J2, ETC.) SPECIFIC EXCEPTIONS (e.g. A CHANNEL I CIRCUIT ROUTED IN A J2, J3 OR J4 TRAY) MUST BE APPROVED BY E.E. AND WILL ONLY BE PERMITTED FOR NON-SAFETY (NON-IE) FUNCTIONS. ALL PORTIONS OF A PARTICULAR INSTRUMENT LOOP SHALL BE ROUTED IN THE SAME CHANNEL.
CONTROL TRAIN A (RED) CONTROL TRAIN B (WHITE)	125 VOLT D.C. CONTROL AND SMALL POWER FEEDS ASSOCIATED WITH 125 VOLT D.C. BATTERIES 21 AND 22 RESPECTIVELY ✱ ✱ IN THE ORIGINAL PLANT DESIGN ONLY TWO BATTERIES (BATTERIES 21 & 22) EXISTED AND REDUNDANT (TRAIN A AND TRAIN B) CONTROL SIGNALS ARE SENT TO EQUIPMENT IN EACH POWER TRAIN. THIS PERMITS THE 3RD POWER TRAIN ASSOCIATED WITH 480 VOLT BUSES 2A AND 3A TO MEET SINGLE FAILURE CRITERIA	K1 Δ K2 Δ Δ A THIRD D ROUTING EXISTS FOR SELECTED CIRCUITS REQUIRING 3 TRAIN SEPARATION
480 VOLT M.C.C. POWER TRAIN 5A AND ASSOCIATED 120 VOLT A.C. (M.C.C. CONTROL TRANSFORMER) SMALL POWER & CONTROL CIRCUITS (RED)	480 V. M.C.C. POWER & CONTROL	K1 SEE NOTES #1 & 4 — FIXED ASSOCIATION (i.e. 5A IN K1) FOR ALL IE CIRCUITS. SPECIFIC EXCEPTIONS (e.g. A NON IE M.C.C. POWER OR CONTROL FEED FROM BUS 5A ROUTED IN K2 MUST BE APPROVED BY E.E.
480 VOLT M.C.C. POWER TRAIN 6A (YELLOW)	" " " " "	K2 SEE NOTES #1 & 4
480 VOLT M.C.C. POWER TRAIN 2A (WHITE)	" " " " "	VARIOUS "D" CHANNELS SEE NOTES #1 & 4
480 VOLT M.C.C. POWER TRAIN 3A (BLUE)	" " " " "	VARIOUS "D" CHANNELS SEE NOTES #1 & 4
CONTROL TRAIN C (BLUE)	125 VOLT D.C. CONTROL AND SMALL POWER FEEDS ASSOCIATED WITH 125 VOLT D.C. BATTERY 23 (ADDED AFTER PLANT START-UP)	K3D AND VARIOUS "D" CHANNELS SEE NOTES #1 & 4
CONTROL TRAIN D (YELLOW)	125 VOLT D.C. CONTROL AND SMALL POWER FEEDS ASSOCIATED WITH 125 VOLT D.C. BATTERY 24 (ADDED AFTER PLANT START-UP)	SEE NOTES #1 & 4
HEAVY POWER BUS 5A (RED) (480 VOLT & BUS 6A (YELLOW) 125 VOLT D.C.) BUS 2A (WHITE) BUS 3A (BLUE)	480 VOLT HEAVY POWER & 125 VOLT HEAVY POWER ASSOCIATED WITH 480V BUS 5A/BATTERY 21, 480 VOLT BUSES 2A & 3A / BATTERY 22 AND 480 VOLT BUS 6A RESPECTIVELY	C4 (ASSOCIATED WITH BUS 5A) C3 (ASSOCIATED WITH BUS 6A) C6 (ASSOCIATED WITH BUS 2A) C5 (ASSOCIATED WITH BUS 3A) SEE NOTE #4
D.C. CONTROL FEEDS FOR DIESELS	SPECIAL ROUTINGS ASSOCIATED WITH D.C. CONTROL FEEDS FOR DIESELS 21, 22 & 23 RESPECTIVELY THROUGH THE CONTROL TUNNEL	F(21) DC FEED FROM BATTERY 21 F(22) " " " " 22 F(23) " " " " 23 F(24) " " " " 24

NOTES:

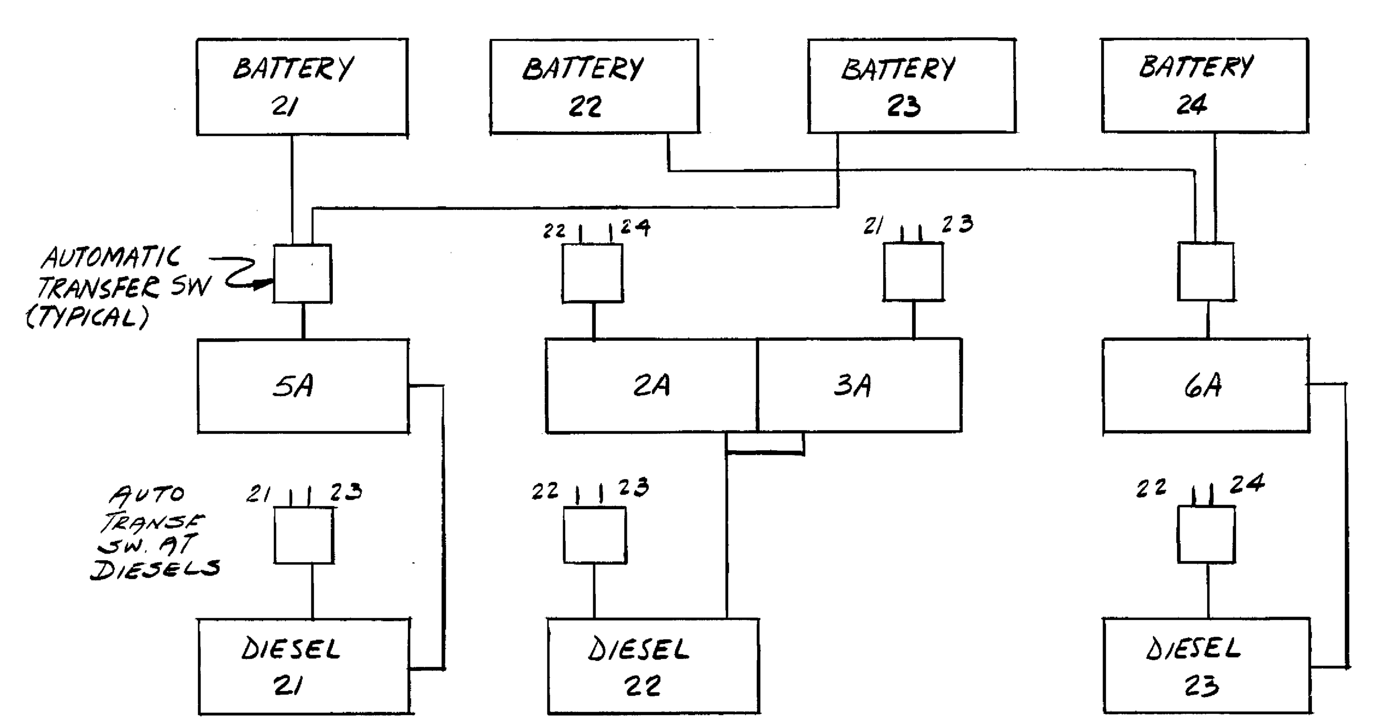
1. K1 AND K2 ARE THE KEY BASIC 480 VOLT SMALL POWER AND 120 VOLT M.C.C. ROUTING DESIGNATIONS. THESE DESIGNATIONS HAVE BEEN FURTHER EXPANDED IN THE RACEWAY SYSTEM TO PROVIDE ADDITIONAL ROUTING OF FUNCTIONAL INFORMATION

ROUTINGS ADAPTABLE WITH K1 480/120 VAC EXCEPT AS NOTED	ROUTING ASSOCIATED WITH K2D BATTERY 22	ROUTING ASSOCIATED WITH K3D BATTERY 23	ROUTINGS ADAPTABLE WITH K2	ROUTING OR FUNCTIONS
K1 (RED)	—	— ▲	K2 (YELLOW)	GENERAL DESIGNATIONS USED IN MOST AREAS OF THE PLANT AND FOR MOST FUNCTIONS ▲ D-D400 - EXISTS FOR THIRD TRAIN SEPARATION IN ORIGINAL PLANT DESIGN
K1A (RED)	—	— ✱	K2A (YELLOW)	ROUTING BETWEEN DIESEL AND CONTROL BUILDING ✱ D-D200 - EXISTS FOR THREE TRAIN SEPARATION IN ORIGINAL PLANT DESIGN
K1B (RED)	—	—	K2B (YELLOW)	ROUTING BETWEEN P.A.B. & CONTAINMENT FOR MCC 26A & M.C.C. 26B
K1AA (RED)	—	—	K2BB (YELLOW)	POWER AND CONTROL ASSOCIATED WITH MOTOR CONTROL CENTERS 26AA AND 26BB RESPECTIVELY WHICH WERE ADDED AS PART OF "THREE MILE ISLAND" PLANT MODIFICATIONS
125 V DC K1 LOGIC & CONTROL K1D POWER (RED)	125 V DC K2 LOGIC & CONTROL K2D POWER (WHITE)	125 V DC. K1 LOGIC ONLY K3D (BLUE)	125 V DC K2 LOGIC ONLY K4D (YELLOW)	BATTERY 21 & 22 LOGIC SIGNALS AND CONTROL POWER (K1 & K2) RESPECTIVELY AND NEW ROUTINGS FOR 125 VOLT D.C. BATTERIES 21 THROUGH 24 RESPECTIVELY FOR CIRCUITS WHICH WERE ADDED AS PART OF "THREE MILE ISLAND" PLANT MODIFICATIONS SEE NOTES 3 & 4

2. "CIRCUIT TYPE" DESIGNATIONS ARE USED TO FUNCTIONALLY DESCRIBE THE PURPOSE OF A CIRCUIT. THESE ARE PURELY FUNCTIONAL DESCRIPTIONS AND SHOULD NOT BE CONFUSED WITH PHYSICAL ROUTING DESIGNATIONS. LIST TABLE OR CIRCUIT TYPE DESIGNATIONS - FROM CABLE SCHEDULE



480 VOLT SYSTEM CHANNELIZATION OF LOGIC SIGNALS



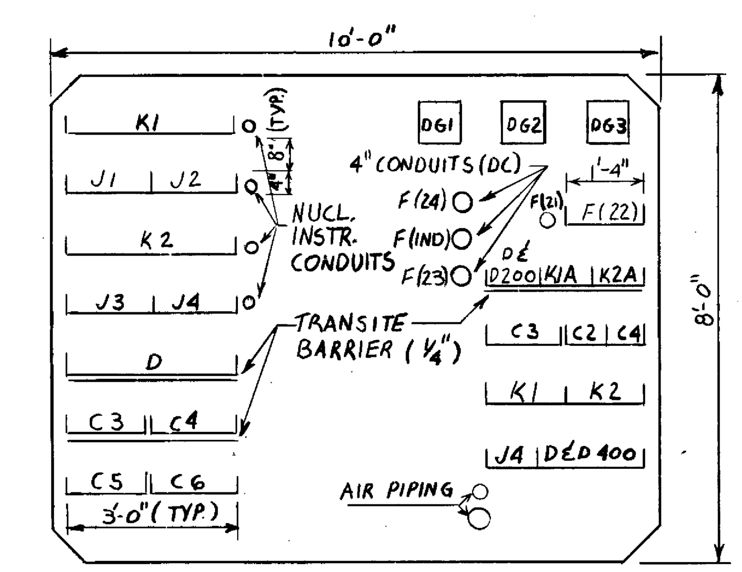
480 VOLT SYSTEM CHANNELIZATION OF D.C. CONTROL POWER

NOTES CONTINUED:

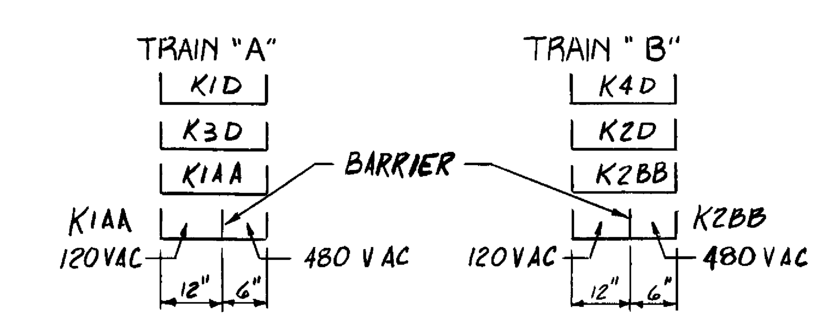
4. IN THE ORIGINAL PLANT DESIGN SEPARATION WAS SET UP ON A CIRCUIT BY CIRCUIT BASIS RATHER THAN A "UNITIZED" FIXED "BUS TO ROUTING CHANNEL" ASSOCIATION (e.g. C1 ≡ BUS 5A) SINGLE FAILURE IS MET FOR THESE CASES BECAUSE OF THE FLEXIBILITY OF REDUNDANT TRAIN A AND B LOGIC AND CONTROL SIGNALS TO EACH BUS (i.e. LOSS OF ONE TRAY MAY FAIL A CONTAINMENT SPRAY PUMP ON ONE BUS AND AN SI PUMP ON ANOTHER BUS BUT CONTROL FROM ONE OR THE TWO D.C. SYSTEMS WILL STILL BE AVAILABLE TO BOTH BUSES. IN ALL FUTURE MODIFICATIONS THE "UNITIZED" BUS / ROUTING ASSOCIATIONS AS SHOWN ON THE TABLE ARE PREFERRED. EXCEPTIONS WILL BE PERMITTED FOR NON-IE EQUIPMENT WHERE NECESSARY TO MAINTAIN THE ORIGINAL PLANT CRITERIA OF MINIMIZING PHYSICAL CROSSOVERS IN THE CABLE RACE-WAY SYSTEM.

5. AS ESTABLISHED BY THE ORIGINAL PLANT DESIGN CRITERIA AND SUBSEQUENT MODIFICATIONS ALL NON CLASS IE CIRCUITS (POWER, CONTROL AND INSTRUMENTATION) WERE ROUTED IN TRAYS OR CONDUITS CONVENIENT TO THE TERMINATION POINTS. THIS WAS ACCOMPLISHED BY ROUTING CABLE IN ANY SAFTEY GRADE CHANNELS AND AS SUCH TREATED AS AN "ASSOCIATED CIRCUIT". THEREFORE NO "TRAY HOPPING" WAS PERMITTED AND ONCE A NON IE CIRCUIT WAS ASSIGNED TO A SAFEGUARD ROUTING CHANNEL IT MUST HAVE REMAINED IN THAT CHANNEL THROUGHOUT THE WHOLE RUN.

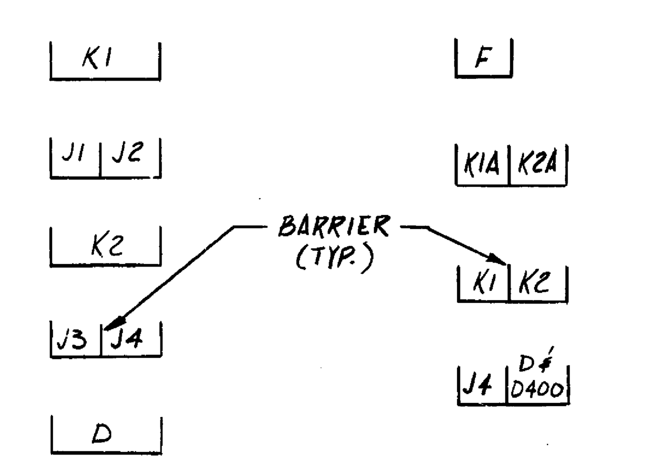
6. ALL CABLES IN RACEWAYS SHALL MEET THE LATEST CON EDISON SPECIFICATION EO-13 AND BE QUALIFIED TO IEEE 383. COMMERCIAL GRADE CABLE AND IMC CONDUIT IS ONLY PERMITTED FOR LIGHTING, RECEPTACLES, AND OTHER SERVICES NOT ASSOCIATED WITH PLANT PROCESS SYSTEMS (M.O. BUILDING, TSC, RESPIRATOR FACILITY, PLANT OFFICES ETC.). ALL TERMINAL BLOCKS INSTALLED SHALL BE QUALIFIED TO IEEE 323 AND 344 TO ASSURE THEIR AVAILABILITY FOR FUTURE CLASS "A"/CLASS "IE" TERMINATIONS.



TYPICAL SECTION CABLE TUNNEL



TYPICAL SECTION ON EL. 98'-0" RA.B.



TYPICAL SECTION CABLE SPREADING ROOM

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS:
"CLASS A" ITEMS
PER CI-240-1

Con Edison clean energy

REVISIONS

0 — THIS REV. IS CLASS A AS PER CI-240-1 MOD. PROC. ESG 80-2-21 RELEASED FOR INFORMATION P.N. 90049-50 2/4/81
1 — THIS REV. IS CLASS "A" AS PER CI-240-1. ADDED NOTE #6 MOD. PROC. ESG 80-2-21 REL. FOR INFO. P/N 90049-50
2 — THIS REVISION IS CLASS "A" PER CI 240-1 UPDATED DWG TO SHOW WORK OF REV "0" & 1 MOD. PROC. #ESG-80-2-21 RELEASED FOR AS CONSTRUCTED P.N. 90049-50 6-8-84
03 — V1 4/18/99 THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DRAWING TO INCLUDE UFSAR FIGURE No. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA/4/18/99
STRATUS ENGINEERING

A 208761-3

CONSOLIDATED EDISON CO. OF NEW YORK, INC.

STATION LOCATION: INDIAN POINT

CABLE TRAY SEPARATION FUNCTIONS & ROUTING DESIGNATIONS - OUTLINE - UFSAR FIGURE No. 8.2-18

SCALE NONE — DRAWN P. SCHNURER — 2-4-81
90049-50 — CHECKED JAC

APPROVALS: GENERAL ENGINEERING; MECHANICAL ENGINEERING; CIVIL ENGINEERING; ELECTRICAL ENGINEERING; GAS & STEAM OPERATIONS; PRODUCTION

EG

INDIAN POINT — CABLE TRAY SEPARATION FUNCTIONS & ROUTING — A 208761

CHAPTER 9
AUXILIARY AND EMERGENCY SYSTEMS

9.0 INTRODUCTION

The auxiliary and emergency systems are supporting systems required to ensure the safe operation or servicing of the reactor coolant system (detailed in Chapter 4).

In some cases the dependable operation of several systems is required to protect the reactor coolant system by controlling system conditions within specified operating limits. Certain systems are required to operate under emergency conditions.

This section considers systems in which component malfunctions, inadvertent interruptions of system operation, or a partial system failure may lead to a hazardous or unsafe condition. The extent of information provided for each system is proportional to the relative contribution of, or reliance placed upon, each system with respect to the overall plant operational safety.

The following systems are considered under this category:

<u>Chemical and Volume Control System</u>

This system provides for boron injection, chemical additions for corrosion control, reactor coolant cleanup and degasification, reactor coolant makeup, reprocessing of primary letdown from the reactor coolant system, and reactor coolant pump seal-water injection.

<u>Auxiliary Coolant System</u>

This system provides for transferring heat from the reactor coolant during shutdown, stored spent fuel, and other components to the service water system and consists of the following three loops:

1. The residual heat removal loop removes residual and sensible heat from the core and reduces the temperature of the reactor coolant system during the second phase of plant cooldown.

2. The spent fuel pit loop removes decay heat from the spent fuel pit.

3. The component cooling loop removes residual and sensible heat from the reactor coolant system via the residual heat removal loop during plant shutdown, cools the spent fuel pit water and the letdown flow to the chemical and volume control system during power operation and provides cooling to dissipate waste heat from various primary and safety-related plant components.

<u>Sampling System</u>

This system provides the equipment necessary to obtain liquid and gaseous samples from the reactor plant systems.

<u>Facility Service Systems</u>

These systems include fire protection, service water, and auxiliary building ventilation.

Reactor Components Handling System

This system provides for handling fuel assemblies, control rod assemblies, core structural components, and material irradiation specimens.

Equipment and Decontamination Processes

These procedures provide for the removal of radioactive deposits from system surfaces.

Primary Auxiliary Building Ventilation System

This system maintains ambient operation temperatures and provides purging of the auxiliary building to the plant vent.

Control Room Ventilation System

This system maintains the required environment in the control room.

9.1 GENERAL DESIGN CRITERIA

9.1.1 Applicable Criteria

The criteria, which apply primarily to other systems discussed in other sections are listed and cross-referenced because details of directly related systems and equipment are given in this section. Those criteria, which are specific to one of the auxiliary and emergency systems are listed and discussed in the appropriate system design-basis section.

9.1.2 Related Criteria

9.1.2.1 Reactivity Control System Malfunction

Criterion: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (GDC 31)

As described in Chapter 7 and justified in Chapter 14, the reactor protection systems are designed to limit reactivity transients to maintain DNBR at or above the applicable safety analysis DNBR limit due to any single malfunction in the deboration controls.

9.1.2.2 Engineered Safety Features Performance Capability

Criterion: Engineered safety features such as the emergency core cooling system and the containment heat removal system shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public. (GDC 41)

Each of the auxiliary cooling systems, which serves an emergency function provides sufficient capability in the emergency operational mode to accommodate any single failure of an active component and still function in a manner to avoid undue risk to the health and safety of the public.

9.1.2.3 Containment Heat Removal Systems

Criterion: Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure this system shall perform its required function, assuming failure of any single active component. (GDC 52)

Each of the auxiliary cooling systems that serves an emergency function to prevent exceeding containment design pressure, provides sufficient capability in the emergency operational mode to accommodate any single failure of an active component and still perform its required function.

9.2 CHEMICAL AND VOLUME CONTROL SYSTEM

The chemical and volume control system (1) adjusts the concentration of boric acid for nuclear reactivity control, (2) maintains the proper water inventory in the reactor coolant system, (3) provides the required seal water flow for the reactor coolant pump shaft seals, (4) maintains the proper concentration of corrosion inhibiting chemicals in the reactor coolant, and (5) maintains the reactor coolant and corrosion product activities within design levels. The system is also used to fill and hydrostatically test the reactor coolant system.

This system has provisions for supplying the following chemicals:

1. Chemicals to regenerate the deborating demineralizers.
2. Hydrogen to the volume control tank.
3. Nitrogen as required for purging the volume control tank.
4. Hydrazine and lithium hydroxide, as required, via the chemical mixing tank to the charging pumps suction.

During normal plant operation, reactor coolant letdown from the intermediate leg of loop 21 flows through the shell side of the regenerative heat exchanger where its temperature is reduced by transferring heat to the charging fluid. The coolant then flows through a letdown orifice, which regulates flow and reduces the coolant pressure. The cooled, low-pressure water leaves the reactor containment and enters the primary auxiliary building where it undergoes a second temperature reduction in the tube side of the nonregenerative heat exchanger followed by a second pressure reduction by the low-pressure letdown valve (this valve essentially controls backpressure on the orifices and prevents flashing there). After passing through one of the mixed-bed demineralizers, where ionic impurities are removed, the fluid flows through the reactor coolant filter, and enters the volume control tank through a spray nozzle.

The coolant flows from the volume control tank to the charging pumps that raise the pressure above that in the reactor coolant system. The high-pressure water flows from the primary auxiliary building to the reactor containment along two parallel paths. One path returns directly to the reactor coolant system through the tube side of the regenerative heat exchanger to the cold leg of loop 21. The second path injects water into the seals of the reactor coolant pumps. A portion of this seal-water is injected into the reactor coolant system through the reactor coolant pumps labyrinth seals. The remainder of this seal-water flow returns to the volume control tank through the seal-water filter and the seal-water heat exchanger.

Concentrated boric acid, used for chemical shim or shutdown operations, is mixed in the batching tank. A transfer pump is used to transfer the batch to the boric acid storage tanks, which maintain a large inventory of concentrated boric acid solution. Small quantities of boric acid solution are metered from the discharge of the operating boric acid transfer pump for mixing with primary water in the blender to provide makeup for normal leakage or for increasing the boron concentration in the reactor coolant system.

A chemical mixing tank (primary auxiliary building - 98-ft elevation) is provided to supply small quantities of hydrazine and lithium hydroxide to the charging pump suction. However, this will generally be accomplished through the letdown relief valve exhaust line. This line has a sample header in the sampling room into which the chemicals can be added.

Equipment for processing reactor coolant for reuse of boric acid and reactor makeup water is no longer used and has been partially removed.

9.2.1 Design Bases

9.2.1.1 Redundancy of Reactivity Control

Criterion: Two independent reactivity control systems, preferably of different principles, shall be provided. (GDC 27)

In addition to the reactivity control achieved by the rod cluster control as detailed in Chapter 7, reactivity control is provided by the chemical and volume control system, which regulates the concentration of boric acid solution neutron absorber in the reactor coolant system. The system is designed to prevent, under anticipated system malfunction, uncontrolled or inadvertent reactivity changes, which might cause system parameters to exceed design limits.

9.2.1.2 Reactivity Hold-Down Capability

Criterion: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (GDC 30)

Normal reactivity shutdown capability is provided by control rods, with boric acid injection used to compensate for the long term xenon decay transient and for plant cooldown. Any time that the plant is at power, the quantity of boric acid retained in the boric acid tanks and ready for injection will always exceed that quantity required for the normal cold shutdown. This quantity will always exceed the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The boric acid solution is transferred from the boric acid tanks by boric acid pumps to the suction of the charging pumps, which inject boric acid into the reactor coolant. Any charging pump and boric acid transfer pump can be operated from diesel-generator power on loss-of-offsite power. Boric acid can be injected by one charging pump and one boric acid transfer pump to shut the reactor down even with no rods inserted. Additional boric acid can be injected to compensate for xenon decay although xenon decay below the equilibrium operating level will not begin until approximately 12-15 hr after shutdown. Additional boric acid is employed if it is desired to bring the reactor to cold shutdown conditions. In addition, borated makeup water can be supplied to the primary system from the refueling water storage tank in the event that availability of the boric acid transfer pumps is lost.

On the basis of the above, the injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters, which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

9.2.1.3 Reactivity Hot Shutdown Capability

Criterion: The reactivity control system provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition. (GDC 28)

The reactivity control systems provided are capable of making and holding the core subcritical from any hot standby or hot operating condition, including those resulting from power changes. The maximum excess reactivity expected for the core occurs for the cold, clean condition at the beginning-of-life of the initial core. The full length rod cluster control assemblies are divided into two categories comprising a control group and shutdown groups.

The control group, used in combination with chemical shim provides control of the reactivity changes of the core throughout the life of the core at power conditions. This group of rod cluster control assemblies is used to compensate for short-term reactivity changes at power that might be produced due to variations in reactor power requirements or in coolant temperature. The chemical shim control is used to compensate for the more slowly occurring changes in reactivity throughout core life such as those due to fuel depletion and fission product buildup and decay.

9.2.1.4 Reactivity Shutdown Capability

Criterion: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (GDC 29)

The reactor core, together with the reactor control protection system is designed so that the minimum allowable DNBR remains at or above the applicable safety analysis DNBR limit and there is no fuel melting during normal operation including anticipated transients.

The shutdown groups of rod cluster control assemblies are provided to supplement the control group of rod cluster control assemblies to make the reactor at least 1-percent subcritical (k_{eff} = 0.99) following trip from any credible operating condition to the hot, zero power condition assuming the most reactive rod cluster control assembly remains in the fully withdrawn position.

Sufficient shutdown capability is also provided to maintain the core subcritical for the most severe anticipated cooldown transient associated with a single active failure, e.g., accidental opening of a steam bypass or relief valve. This is achieved with a combination of control rods and automatic boron addition via the safety injection system with the most reactive rod assumed to be fully withdrawn. Manually controlled boric acid addition is used to maintain the shutdown margin for the long-term conditions of xenon decay and plant cooldown.

9.2.1.5 Codes and Classifications

All pressure retaining components (or compartments of components), which are exposed to reactor coolant comply with the code requirements as shown in Table 9.2-1.

The tube side on both the regenerative and excess letdown heat exchangers are designed as ASME III, Class C. This designation is based on the applicable codes at the time of construction and on the following considerations: (1) each exchanger is connected to the primary coolant system by a 3 inch line (Regenerative Heat Exchanger) or a 1 inch line (Excess Letdown Heat Exchanger), and (2) each is located inside the reactor containment. Contaminated primary coolant escaping from the primary coolant system during a break in one of these lines is confined to the reactor containment building and no public hazard results as discussed in Section 14.3.

9.2.2 System Design and Operation

The chemical and volume control system, shown in Plant Drawings 9321-2736, 208168, and 9321-2737 [Formerly UFSAR Figures 9.2-1 (Sheets 1 through 3)] provides a means for injection of control poison in the form of boric acid solution, chemical additions for corrosion control, and reactor coolant cleanup and degasification. This system also adds makeup water to the reactor coolant system, reprocesses water letdown from the reactor coolant system, and provides seal water injection to the reactor coolant pump seals.

Overpressure protective devices are provided for system components whose design pressure and temperature are less than the reactor coolant system design limits.

System discharges from overpressure protective devices (safety valves) and system leakages are directed to closed systems. Effluents removed from such closed systems are monitored and discharged under controlled conditions. System design enables post-operational testing to applicable code test pressures. Testing is based upon requirements set forth in ASME Section XI, as discussed in Section 1.12.

During plant operation, reactor coolant is removed from the reactor coolant loop cold leg through the letdown line located on the suction side of the pump and is returned to the cold leg of the same loop on the discharge side of the pump via a charging line. An alternate charging connection is provided to the hot leg of another loop. [TEMP MOD] EC-20987 installed a blocking device on valve 204A for one complete operating cycle. Therefore this alternative flow path will not be available from 2R19 to 2R20. An excess letdown line is also provided.

Each of the connections to the reactor coolant system has an isolation valve located close to the loop piping. In addition, a check valve is located downstream of each charging line isolation valve. For the alternate charging line, blocking the isolation valve (204A) just upstream of the check valve closed eliminates the need for the check valve to actuate closed. Reactor coolant entering the chemical and volume control system flows through the shell side of the regenerative heat exchanger where its temperature is reduced. The coolant then flows through a letdown orifice, which reduces the coolant pressure. The cooled, low-pressure water leaves the reactor containment and enters the auxiliary building where it undergoes a second temperature reduction in the tube side of the nonregenerative heat exchanger followed by a second pressure reduction by the low-pressure letdown valve. After passing through one of the mixed-bed demineralizers, where ionic impurities are removed, coolant flows through the reactor coolant filter and enters the volume control tank though a spray nozzle.

Hydrogen is automatically supplied, as determined by pressure control, to the vapor space in the volume control tank, which is predominantly hydrogen and water vapor. The hydrogen within this tank is, in turn, the supply source to the reactor coolant. Fission gases are periodically removed from the system by venting the volume control tank to the waste disposal system prior to a cold or refueling shutdown.

From the volume control tanks the coolant flows to the charging pumps, which raise the pressure above that in the reactor coolant system. The coolant then enters the containment, passes through the tube side of the regenerative heat exchanger, and is returned to the reactor coolant system.

The cation bed demineralizer, located downstream of the mixed-bed demineralizers, is used intermittently to control cesium activity in the coolant and also to remove excess lithium, which is formed from the B^{10} (n,α) Li^7 reaction.

Boric acid is dissolved in hot water in the batching tank. The lower portion of the batching tank is jacketed to permit heating of the batching tank solution with low-pressure steam. A transfer pump is used to transfer the batch to the boric acid storage tank. During boric acid transfer from the batching tank when the reactor is critical the receiving storage tank is not aligned to the boric acid filter. The receiving storage tank is sampled after boric acid transfer is completed and before it is placed in service. Small quantities of boric acid solution are metered from the discharge of an operating boric acid transfer pump for blending with makeup water as makeup for normal leakage or for increasing the reactor coolant boron concentration during normal operation. Electric immersion heaters maintain the temperature of the boric acid tank solution high enough to prevent precipitation.

During plant startup, normal operation, load reductions, and shutdowns, liquid effluents containing boric acid flow from the reactor coolant system through the letdown line and are collected in the holdup tanks. As liquid enters the holdup tanks, the nitrogen cover gas is displaced to the gas decay tanks in the waste disposal system through the waste vent header. The concentration of boric acid in the holdup tanks varies throughout core life from the refueling concentration to essentially zero at the end of the core cycle. A recirculation pump is provided to transfer liquid from one holdup tank to another.

Liquid effluent in the holdup tanks is processed by demineralization or as radwaste.

The deborating demineralizers can be used intermittently to remove boron from the reactor coolant near the end of the core life. When the deborating demineralizers are in operation, the letdown stream passes from the mixed-bed demineralizers and then through the deborating demineralizers and into the volume control tank after passing through the reactor coolant filter.

During plant cooldown when the residual heat removal loop is operating and the letdown orifices are not in service, a flow path is provided to remove corrosion impurities and fission products. A portion of the flow leaving the residual heat exchangers passes through the nonregenerative heat exchanger, mixed-bed demineralizers, reactor coolant filter and volume control tank. The fluid is then pumped, via the charging pump, through the tube side of the regenerative heat exchanger into the reactor coolant system. A booster pump is also provided in the crosstie.

The pump and associated piping provide an additional capacity to provide reactor coolant system purification in a more timely manner.

9.2.2.1 Design Parameters

Tables 9.2-2, 9.2-3, and 9.2-4 list the system design requirements for individual system components, and reactor coolant equilibrium activity concentration. Table 9.2-5 supplements Table 9.2-4.

Reactor Coolant Activity Concentration

The parameters used in the calculation of the reactor coolant fission product inventory, including pertinent information concerning the expected coolant cleanup flow rate and demineralizer effectiveness, are presented in Table 9.2-5. The results of the calculations are presented in Table 9.2-4. In these calculations the defective fuel rods are assumed to be present at initial core loading and are uniformly distributed throughout the core through the use of fission product escape rate coefficients.

The fission product activity in the reactor coolant during operation with small cladding defects. [*Note - Fuel rods containing pinholes or fine cracks.*] In 1-percent of the fuel rods is computed using the following differential equations:

For parent nuclides in the coolant:

$$\frac{dN_{wi}}{dt} = D\nu_i N_{C_i} - \left(\lambda_i + R\eta_i + \frac{B'}{B_o - tB'}\right)N_{wi}$$

for daughter nuclides in the coolant:

$$\frac{dN_{wj}}{dt} = D\nu_j N_{C_j} - \left(\lambda_j + R\eta_j + \frac{B'}{B_o - tB'}\right)N_{Wj} + \lambda_i N_{Wi}$$

where:

N = population of nuclide
D = fraction of fuel rods having defective cladding
R = purfication flow, coolant system volumes per sec
B_o = initial boron concentration, ppm
B' = boron concentration reduction rate by feed and bleed, ppm per sec
η = removal efficiency of purification cycle for nuclide
λ = radioactive decay constant
ν = escape rate coefficient for diffusion into coolant
Subscript C refers to core
Subscript w refers to coolant
Subscript i refers to parent nuclide
Subscript j refers to daughter nuclide

Tritium is produced in the reactor from ternary fission in the fuel, irradiation of boron in the burnable poison rods and irradiation of boron, lithium, and deuterium in the coolant. The deuterium contribution is less than 0.1 Ci per year and may be neglected. The parameters used in the calculation of tritium production rate are presented in Table 9.2-6.

9.2.2.2 Reactor Makeup Control

The reactor makeup control consists of a group of instruments arranged to provide a manually preselected makeup composition to the charging pump suction header or the volume control tank. The makeup control functions to maintain desired operating fluid inventory in the volume control tank and to adjust reactor coolant boron concentration for reactivity and shim control.

Makeup for normal plant leakage is regulated by the reactor makeup control, which is set by the operator, to blend water from the primary water storage tank with concentrated boric acid to match the reactor coolant boron concentration.

The makeup system also provides concentrated boric acid or primary water to change the boric acid concentration in the reactor coolant system. To maintain the reactor coolant volume constant, an equal amount of reactor coolant at existing reactor coolant boric acid concentration is letdown to the holdup tanks. Should the letdown line be out of service during operation, sufficient volume exists in the pressurizer to accept the amount of boric acid necessary to achieve cold shutdown.

Makeup water to the reactor coolant system is provided by the chemical and volume control system from the following sources:

1. The primary water storage tank, which provides water for dilution when the reactor coolant boron concentration is to be reduced.

2. The boric acid tanks, which supply concentrated boric acid solution when reactor coolant boron concentration is to be increased.

3. The refueling water storage tank, which supplies borated water for emergency makeup.

4. The chemical mixing tank, which is used to inject small quantities of solution when additions of hydrazine or pH control chemical are necessary.

The reactor makeup control is operated from the control room by manually preselecting makeup composition to the charging pump suction header or the volume control tank in order to adjust the reactor coolant boron concentration for reactivity control. Makeup is provided to maintain the desired operating fluid inventory in the reactor coolant system. The operator can stop the makeup operation at any time in any operating mode by placing the Makeup Control switch to “STOP”.

One primary water makeup pump and one boric acid transfer pump are normally aligned for operation on demand from the reactor makeup control system.

A portion of the high pressure charging flow is injected into the reactor coolant pumps between the thermal barrier and the shaft seal so that the seals are not exposed to high-temperature reactor coolant. Part of the flow is the shaft seal leakage flow and the remainder enters the reactor coolant system through a labyrinth seal on the pump shaft. Part of the shaft seal injection flow cools the lower radial bearing and part passes through the seals and is cooled in the seal water heat exchanger, filtered, and returned to the volume control tank.

An alternate source of flow for reactor coolant pump seal injection is provided, at the charging pump makeup header. It splits into four separate feed lines, one for each pump. Refer to Plant Drawing 9321-2736 [Formerly UFSAR Figure 9.2-1 (Sheet 1)].

Seal water injection to the reactor coolant system requires a continuous letdown of reactor coolant to maintain the desired inventory. In addition, bleed and feed of reactor coolant are required for removal of impurities and adjustment of boric acid in the reactor coolant.

9.2.2.2.1 Automatic Makeup

The automatic makeup mode of operation of the reactor makeup control provides boric acid solution preset to match the boron concentration in the reactor coolant system. The automatic makeup compensates for minor leakage of reactor coolant without causing significant changes in the coolant boron concentration.

Under normal plant operating conditions, the Makeup Mode Selector switch and makeup stop valves are set in the "AUTO" position and the Makeup Control switch in the "START" position. At a preset low-level in the volume control tank, the automatic makeup control action is initiated as follows:

- Starts both primary water makeup pumps (if not already running)
- Starts both boric acid transfer pumps (if not already running)
- Opens the concentrated boric acid control valve (FCV-110A)
- Opens the boric acid blender to charging pumps discharge control valve (FCV-110B)
- Opens the primary water makeup control valve (FCV-111A)

The flow controllers then blend the makeup stream according to the preset concentration. Makeup addition to the charging pump suction header causes the water level in the volume control tank to rise. At a preset high-level in the volume control tank, the automatic makeup control action is ceased.

If the level in the volume control tank continues to decrease to a preset low-low level, the volume control tank outlet is isolated and the refueling water storage tank is aligned for RCS makeup as follows:

- Opens the RWST makeup to charging pumps suction stop valve (LCV-112B)
- Closes the volume control tank level control valve (LCV-112C)

9.2.2.2.2 Dilution

The dilution mode of operation permits the addition of a preselected quantity of primary water makeup at a preselected flow rate to the reactor coolant system. To prepare for dilution, the operator sets the Makeup Mode Selector switch to "DILUTE", the primary water makeup flow controller setpoint to the desired flow rate, and the primary water makeup batch integrator to the desired quantity. Placing the Makeup Control switch to “START” initiates the dilution control action as follows:

- Starts both primary water makeup pumps
- Opens the primary water makeup control valve (FCV-111A)
- Opens the boric acid blender discharge control valve (FCV-111B)

Makeup water is added to the volume control tank and then goes to the charging pump suction header. If the primary water makeup flow deviates from the preset flow rate, an alarm indicates the deviation. Excessive rise of the volume control tank water level is prevented by automatic actuation (by the tank level controller) of a three-way diversion valve, which routes the reactor coolant letdown flow to the holdup tanks. When the preset quantity of primary water makeup has been added, the dilution control action is ceased.

9.2.2.2.3 Boration

The boration mode of operation permits the addition of a preselected quantity of concentrated boric acid solution at a preselected flow rate to the reactor coolant system. To prepare for boration, the operator sets the Makeup Mode Selector switch to "BORATE", the concentrated boric acid flow controller setpoint to the desired flow rate, and the concentrated boric acid batch integrator to the desired quantity. Placing the Makeup Control switch to “START” initiates the boration control action as follows:

- Starts both boric acid transfer pumps
- Opens the concentrated boric acid control valve (FCV-110A)
- Opens the boric acid blender to charging pumps discharge control valve (FCV-110B)

The concentrated boric acid is added to the charging pump suction header. If the concentrated boric acid solution flow deviates from the preset flow rate, an alarm indicates the deviation. The total quantity added in most cases is so small that it has only a minor effect on the volume control tank level. When the preset quantity of concentrated boric acid solution has been added, the boration control action is ceased.

The capability to add boron to the reactor coolant is sufficient, using the normal makeup system, so that no limitation, due to boration, is imposed on the rate for cooldown of the reactor upon shutdown.

9.2.2.2.4 Alarm Functions

The reactor makeup control is provided with alarm functions to call the operator's attention to the following conditions:

1. Deviation of primary water makeup flow rate from the control setpoint.
2. Deviation of concentrated boric acid flow rate from the control setpoint.
3. Low-level (makeup initiation point) in the volume control tank when the reactor makeup control selector is not set for the automatic or manual makeup control mode.
4. Low-Low Level in the Volume Control Tank.

Concentrated boric acid is injected into the reactor coolant system by means of the charging pumps, which take suction from the boric acid storage tanks via the boric acid transfer pumps. The refueling water storage tank is also available to the charging pumps for injection of 2400 ppm borated water. Each operation is considered in turn:

1. Concentrated boric acid can be delivered to the suction of the charging pumps using the following paths; flow and tank level indications are available to the operator as needed for these operations (refer to Plant Drawing 9321-2736 [Formerly UFSAR Figure 9.2-1, Sheet 1)]:

a. Through the blender and valve FCV-110B; for this operation the operator has flow indication available.

b. Through path with manual valve 293; for this operation the operator has flow indication available.

c. In the event that neither flow paths (a) nor (b) are available, the operator would use the emergency boration path through valve MOV-333.

d. Refueling water storage tank is available to the charging pumps by closing LCV-112C and opening LCV-112B.

2. The charging pumps can deliver boric acid into the reactor coolant system via the following paths:

a. Normal charging line via flow meter FT-128.

b. Seal water supply line to the reactor pumps while bypassing the seal injection filters. If this path is used, flow indicators are available.

Facilities are provided to enable primary coolant samples to be taken from the following points:

- Pressurizer steam space
- Pressurizer liquid space
- Loop 1 hot leg, reactor coolant system
- Loop 3 hot leg, reactor coolant system
- Upstream of demineralizers (chemical and volume control system)
- Downstream of demineralizers (chemical and volume control system)

The Technical Specifications for the plant require a boron content analysis to support shutdown margin determination. Samples would normally be taken from either the loop 1 hot leg or the loop 3 hot leg for routine analysis; the sample will be analyzed for boron concentration. It is important to note, however, that the main indicator to the operator during power operation as to the requirement for boration or dilution is control rod position (see Section 14.1.5).

During startup and refueling, the main indicator to the operator of abnormal conditions is the nuclear instrumentation system source range detectors. Abnormal dilution conditions are discussed in Section 14.1.5. As for power operation, it is considered that frequent boron analysis of the primary coolant is not essential for safe operation.

For a cold shutdown, the operator borates the system prior to the start of cooldown. Boration is indicated by the flow indicators in the boric acid transfer pump discharge line. The prime indicator that sufficient boron has been added to the system is inventory from the boric acid storage tanks and reactor coolant system sample analysis.

9.2.2.3 Charging Pump Control

Three positive displacement variable speed drive charging pumps are used to supply charging flow to the reactor coolant system.

The speed of each pump can be controlled manually or automatically. During normal operation, only one charging pump is expected to be operating and the speed is modulated in accordance with pressurizer level. During load changes the pressurizer level setpoint is varied automatically to compensate partially for the expansion or contraction of the reactor coolant associated with the T_{avg} changes. T_{avg} compensates for power changes by varying the pressurizer level setpoints in conjunction with pressurizer level for charging pump control. The level setpoints are varied depending on the power level.

If the pressurizer level increases, the speed of the pump decreases, likewise if the level decreases, the speed increases. If the charging pump on automatic control is unable to maintain the required charging rate, then a pressurizer low level alarm actuates and a second charging pump may be manually started. The speed of the second pump is manually regulated. If the speed of the charging pump on automatic control does not decrease and the second charging pump is operating at maximum speed, the third charging pump can be started and its speed manually regulated. If the speed of the charging pump on automatic control decreases to its minimum value, an alarm is actuated and the speed of the pumps on manual control is reduced.

9.2.2.4 Components

A summary of principal component data is given in Table 9.2-3.

9.2.2.4.1 Regenerative Heat Exchanger (containment elevation 46-ft)

The regenerative heat exchanger is designed to recover heat from the letdown flow by reheating the charging flow, to eliminate reactivity effects due to insertion of cold water, and to reduce thermal shock on the charging line penetrations to the reactor coolant loop piping.

The coolant enters the shell side of the regenerative heat exchanger (U-tube multiple pass heat exchanger) where its temperature is reduced by transferring heat to the charging flow. In order to prevent flashing, this temperature should never be allowed to exceed the saturation temperature of the letdown steam at the pressure prevailing downstream of the letdown orifices. A resistance temperature detector on the outlet of the heat exchanger provides temperature indication in the control room and a high- temperature alarm.

The unit is made of austenitic stainless steel and is of all-welded construction. The exchanger is designed to withstand 2000 step changes in shell-side fluid temperature from 100°F to 560°F during the design life of the unit.

9.2.2.4.2 First Stage Letdown Orifices and Control Valves (containment elevation 46-ft)

Three letdown orifices are provided to admit a predetermined coolant flow to the letdown stream and reduce to letdown pressure. They consist of two 75-gpm and one 45-gpm orifices. Normally a 75-gpm orifice is in service. The 45-gpm orifice combined with the 75-gpm orifice results in a letdown flow of 120 gpm, which is a maximum for the chemical and volume control system (greater flow will result in channeling and hence inefficient operation in the demineralizers). The second 75-gpm orifice allows for even less flow restriction for letdown during operations when the system pressure is low (excess letdown and residual heat removal connections can also be used to maintain flow during times of low system pressure). This last orifice also provides a redundant backup for the first 75-gpm orifice. The selected orifice is placed in service from the control room by remote operation of its respective letdown flow control valve. These lights and switches are located on the flight panel in the central control room. An additional switch for the three valves labeled "close-remote," is provided on the containment isolation supervisory panel in the central control room. The three letdown flow control valves will close automatically on a phase A containment isolation signal. The switch on the containment isolation panel will allow the closing of these valves manually if required. Valve position is indicated on the isolation panel by dual-colored windows. Valve position for normal plant operations and valve position for containment isolation are provided.

Orifice selection is controlled from the central control room or primary auxiliary building. Indications are also provided at this location when the valves are open. The primary auxiliary building switches will be used to control the rate of letdown when the control room is not available. The letdown inlet stop valve to the regenerative heat exchanger may also be controlled locally in the primary auxiliary building. When these switches are in use, either in the close or open position, all control from the central control room will be lost. This will be indicated in the central control room by the actuation of a category alarm (control transferred to local) and the loss of all indicating lights associated with these valves.

9.2.2.4.3 Letdown Relief Valve

Relief valve No. 203 is provided to protect the piping downstream of the letdown flow control valves and up to the low-pressure letdown valve, PCV-135. Thus, this piping will be protected in the event that the letdown flow control valves fail in the open position allowing pressure to increase up to system pressure. The relief valve is set at 600 psig or below and discharges to the pressurizer relief tank. An orifice installed just up-stream of the relief valve provides sufficient differential pressure to prevent over-cycling of the valve. A resistance temperature detector is provided on the relief valve discharge piping. This temperature is indicated in the control room and a high-temperature alarm will indicate that the relief valve is leaking or has lifted.

9.2.2.4.4 Nonregenerative (letdown) Heat Exchanger (primary auxiliary building elevation 98-ft)

The letdown stream enters the tube side of the nonregenerative heat exchanger. In passing through these U-tubes, it is cooled by the multipass flow of component cooling water in the shell side of the heat exchanger.

Temperature and pressure control of the letdown flow is accomplished automatically by means of sensors located downstream of the heat exchanger. All surfaces in contact with the reactor coolant are austenitic stainless steel, and the shell is carbon steel.

9.2.2.4.5 Demineralizers (primary auxiliary building elevation 59-ft)

All the demineralizers in this system have similar piping connections. Water enters the demineralizer at the top and flows past an impingement baffle, which prevents channels being cut in the resin bed by the water stream. After passing through the resin, the water flows through a screen and exits through the water outlet connection. This screen prevents loss of resin through the water outlet connection. In order to allow resin replacement, a resin fill and a resin discharge connection are provided on the top and bottom of the demineralizer, respectively. A vent connection, located on the top of the demineralizer, is used during resin replacement and/or regeneration and backwashing operations. The vent screen will prevent loss of resin through this connection.

Sampling connections are provided on the common inlet line to the demineralizers and on the common outlet line from the demineralizers to check on the performance of the demineralizers. When impurities begin to leak through the resin bed the demineralizer is considered exhausted. At this point it is necessary to replace or regenerate the spent resin. Regeneration will be done only with anion demineralizers; the resin beds of the cation and mixed-bed units will be replaced when depleted. (The deborating and boric acid evaporator condensate demineralizer are the only anion beds in the system.) Current procedures use only the resin replacement option.

9.2.2.4.5.1 Mixed-Bed Demineralizers

Two flushable mixed-bed demineralizers maintain reactor coolant purity by removing fission and corrosion products. The resin bed is designed to reduce the concentration of ionic isotopes in the purification stream, except for cesium, tritium, and molybdenum, by a minimum factor of 10.

Each demineralizer is sized to accommodate the maximum letdown flow. One demineralizer serves as a standby unit for use if the operating demineralizer becomes exhausted during operation.

The demineralizer vessels are made of austenitic stainless steel and are provided with suitable connections to facilitate resin replacement when required. The vessels are equipped with a resin retention screen.

9.2.2.4.5.2 Cation Bed Demineralizer

A flushable cation resin bed in the hydrogen form is located downstream of the mixed-bed demineralizers and is used intermittently to control the concentration of lithium-7, which builds up in the coolant from the $B^{10}(n,\alpha)\ Li^{7}$ reaction. The demineralizer would be used intermittently to control cesium.

The demineralizer is made of austenitic stainless steel and is provided with suitable connections to facilitate resin replacement when required. The vessel is equipped with a resin retention screen.

9.2.2.4.5.3 Chemical Control Demineralizers

There are two anion demineralizers located downstream of the cation bed demineralizer, which can be used to remove boric acid from the reactor coolant system fluid. The anion deborating demineralizers are primarily used to remove boron from the reactor coolant system near the end of a core cycle, but can be used at any time.

Each anion deborating demineralizer is sized to remove the quantity of boric acid that must be removed from the reactor coolant system to maintain full power operation near the end of core life should the holdup tanks be full.

With a change in resin, either one of the two anion demineralizers could be reconfigured as a cation bed lithium control demineralizer. Either one would then be capable of removing lithium from the Reactor Coolant System, as does the normal cation bed demineralizer.

Facilities are provided for regeneration. When regeneration is no longer feasible, the resin is flushed to the spent resin storage tank.

9.2.2.4.6 Resin Fill Tank

The resin fill tank is used to charge fresh resin to the demineralizers. The line from the conical bottom of the tank is fitted with a dump valve and may be connected to any one of the demineralizer fill lines. The demineralized water and resin slurry can be sluiced into the demineralizer by opening the dump valve. The tank is made of austenitic stainless steel. An additional valve at the resin fill tank is installed to reduce the need for personnel to go to the ion exchange gallery each time new resin is added, thereby reducing radiation exposure.

9.2.2.4.7 Reactor Coolant Filter (Primary Auxiliary Building elevation 98-ft)

The reactor coolant filter will remove any resin fines or particulates larger than 25 microns. A range of smaller filter micron sizes are used in accordance with industry practice to reduce reactor coolant radiation activity and, consequently, reduce personnel exposure.

When the local pressure indicators before and after the filter indicate excessive pressure drop or when the filter develops high radiation fields, the disposable filter element will be replaced. Vent and drain connections are provided for the replacement operation. The vessel is made of austenitic stainless steel.

9.2.2.4.8 Volume Control Tank

The volume control tank collects the reactor coolant surge volume resulting from a change from zero power to full power that is not accommodated by the pressurizer. It also receives the excess coolant release caused by the deadband in the reactor control temperature instrumentation. A cover of hydrogen gas is maintained in the volume control tank to control the hydrogen concentration in the reactor coolant system.

A spray nozzle is located inside the tank on the inlet line from the reactor coolant filter. This spray nozzle provides intimate contact to equilibrate the gas and liquid phases. A remotely-operated vent valve discharging to the waste disposal system permits removal of gaseous fission products, which are stripped from the reactor coolant and collected in this tank. The volume control tank also acts as a head tank for the charging pumps and a reservoir for the leakage from the reactor coolant pump controlled leakage seal. The tank is constructed of austenitic stainless steel. A bypass line, with hand-operated valve, is installed to enable water to be pumped from the holdup tanks to the volume control tank to allow faster filling of the primary system following a shutdown.

9.2.2.4.9 Charging Pumps

Three charging pumps inject coolant into the reactor coolant system. The pumps are the variable speed positive displacement type, and all parts in contact with the reactor coolant are fabricated of austenitic stainless steel or other material of adequate corrosion resistance. These pumps have mechanical packing followed by a leakoff to collect reactor coolant before it can leak to the outside atmosphere. Pump leakage is piped to the drain header for disposal. The pump design prevents lubricating oil from contaminating the charging flow, and the integral discharge valves act as check valves.

Each pump is designed to provide the normal charging flow and the reactor coolant pump seal water supply during normal seal leakage. Each pump is designed to provide flow against a pressure equal to the sum of the reactor coolant system normal maximum pressure (existing when the pressurizer power-operated relief valve is operating) and the piping, valve and equipment pressure losses at the charging flows. During normal operation, 8 gpm seal injection enters each reactor coolant pump in the thermal barrier region where the flow splits, with 3 gpm flowing upward through the controlled leakage seal package and returning to the chemical and volume control system. The remaining 5 gpm passes through the thermal barrier heat exchanger and into the reactor coolant system where it constitutes a portion of the reactor coolant system water makeup. In the event that normal seal cooling is lost, the component cooling water system provides adequate seal cooling by supplying flow to the thermal barrier heat exchanger.

Seal injection flow is indicated locally and in the central control room.

An alternate power supply is provided for one of the charging pumps from the 13.8-kV normal offsite power through Unit 1 switchgear. If normal offsite power is not available, this pump can be energized using the SBO / Appendix R diesel.

Any one of the three charging pumps can be used to hydrotest the reactor coolant system.

A low-pressure tank (dampener) is installed in the suction line, and a high-pressure tank is installed in the discharge line on each charging pump in order to eliminate pulsation that could potentially cause cavitation at the charging pump suction or root weld cracks on the discharge piping.

9.2.2.4.10 Chemical Mixing Tank

The primary use of the stainless steel chemical mixing tank is to prepare caustic solutions for pH control and hydrazine for oxygen scavenging. The capacity of the chemical mixing tank is more than sufficient to prepare a solution of pH control chemical for the reactor coolant system.

9.2.2.4.11 Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools reactor coolant letdown flow if letdown through the normal letdown path is blocked. The letdown stream flows through the tube side and component cooling water is circulated through the shell side. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel. All tube joints are welded. The unit is designed to withstand 2000 step changes in the tube fluid temperature from 80^{o}F to the cold-leg temperature.

9.2.2.4.12 Seal-Water Heat Exchanger

The seal-water heat exchanger removes heat from two sources; reactor coolant pump seal-water returning to the volume control tank and reactor coolant discharge from the excess letdown heat exchanger. Reactor coolant flows through the tubes and component cooling water is circulated through the shell side. The tubes are welded to the tube sheet. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

The unit is designed to cool the excess letdown flow and the seal water flow to the temperature normally maintained in the volume control tank if all the reactor coolant pump seals are leaking at the maximum design leakage rate.

9.2.2.4.13 Seal-Water Filter

The filter collects particulates larger than 25 μ from the reactor coolant pump seal-water return and from the excess letdown heat exchanger flow. The filter is designed to pass the sum of the excess letdown flow and the maximum design leakage from the reactor coolant pump floating ring seals. The vessel is constructed of austenitic stainless steel and is provided with connections for draining and venting. Disposable synthetic filter elements are used.

9.2.2.4.14 Seal-Water Injection Filters

Two filters are provided in parallel, each sized for the injection flow. They collect particulates larger than 5 μ from the water supplied to the reactor coolant pump seals.

A seal injection filter is also provided for the alternate seal injection path.

9.2.2.4.15 Boric Acid Filter

The boric acid filter collects particulates larger than 25 μ from the boric acid solution being pumped to the charging pump suction line. The filter is designed to pass the design flow of two boric acid pumps operating simultaneously. The vessel is constructed of austenitic stainless steel and the filter elements are disposable synthetic cartridges. Provisions are available for venting and draining the filter.

9.2.2.4.16 Boric Acid Storage Tanks

The boric acid storage tanks are sized to store sufficient boric acid solution for refueling and enough boric acid solution for a cold shutdown shortly after full power operation is achieved. In addition, sufficient boric acid solution is available for cold shutdown if the most reactive rod cluster control is not inserted. The requirements for the volume of boric acid in the tanks are contained in the Technical Requirements Manual.

The concentration of boric acid solution in storage is maintained within Technical Requirements Manual limits. Periodic manual sampling and corrective actions are taken, if necessary, to ensure that these limits are maintained. Therefore, measured quantities of boric acid solution can be delivered to the reactor coolant to control the chemical poison concentration. A combination overflow and breather vent connection has a water loop seal to minimize vapor discharge during storage of the solution. The tank is constructed of austenitic stainless steel.

Each tank is provided with a low-level alarm. It is, however, optional whether the operator chooses to operate normally above the low-level alarm in both tanks. Each tank is instrumented for level indication. Indication of level is provided locally and on supervisory panel "SF" in the control room. The low-level condition is audibly annunciated in the control room.

9.2.2.4.17 Boric Acid Storage Tank Heaters

Each boric acid tank has two 100-percent capacity electric heaters, which are connected in parallel and controlled from a single controller and a single temperature sensing controller and a single temperature sensing device and are powered by a single source. The heaters maintain the boric acid solution temperature above the minimum required by the Technical Requirements Manual.

9.2.2.4.18 Batching Tank

The batching tank is used to provide makeup to the boric acid storage tanks. The tank manway is provided with a removable screen to prevent entry of foreign particles. In addition, the tank is provided with an agitator to improve mixing during batching operations. The tank is constructed of austenitic stainless steel. The tank is provided with a steam jacket for heating the boric acid solution. Original plant design also used the tank for sodium hydroxide addition for postaccident pH control inside containment. Current plant design uses sodium tetraborate for pH control. The sodium tetraborate is stored in baskets inside containment as described in Section 6.3.2.2.12.

9.2.2.4.19 Boric Acid Transfer Pumps

Two 100-percent capacity pumps are used to circulate or transfer chemical solutions. Redundancy is thus provided for the pumps to permit maintenance during operation of the plant. The pumps circulate boric acid solution through the boric acid storage tanks and inject boric acid into the charging pump suction header.

Although one pump is normally used for boric acid batching and transfer and the other for boric acid injection, either pump may function as standby for the other. The design capacity of each pump is equal to the normal letdown flow rate. The design head is sufficient, considering line and valve losses, to deliver rated flow to the charging pump suction header when volume control tank pressure is at the maximum operating value (relief valve setting). All parts in contact with the solutions are austenitic stainless steel or other adequate corrosion-resistant material.

The transfer pumps are operated either automatically or manually from the main control room or from a local control center. The reactor makeup control operates one of the pumps automatically when boric acid solution is required for makeup or boration.

9.2.2.4.20 Boric Acid Blender

The boric acid blender promotes thorough mixing of boric acid solution and reactor makeup water from the reactor coolant makeup circuit. The blender consists of a conventional pipe fitted with a perforated tube insert. All material is austenitic stainless steel. The blender decreases the pipe length required to homogenize the mixture for taking a representative local sample.

9.2.2.4.21 Valves

Valves that perform a modulating function are equipped with either two sets of packing and an intermediate leakoff connection that discharges to the waste disposal system or a standard stuffing box suitable for the specified service. All other valves have stem leakage control. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage. Basic material of construction is stainless steel for all valves except the batching tank steam jacket valves which are carbon steel.

Isolation valves are provided at all connections to the reactor coolant system. Lines entering the reactor containment also have check valves inside the containment to prevent reverse flow from the containment. Relief valves are provided for lines and components that might be pressurized above design pressure by improper operation or component malfunction. Pressure relief for the tube side of the regenerative heat exchanger is provided by the auxiliary spray line lift check valve, which is designed to open when pressure under the seat exceeds reactor coolant pressure by 200 psi.

9.2.2.4.22 Piping

All chemical and volume control system piping handling radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing. Piping, valves, equipment and line-mounted instrumentation, which normally contain concentrated boric acid solution, are heated by electrical tracing to ensure solubility of the boric acid.

9.2.2.4.23 Electrical Heat Tracing

Piping containing concentrated boric acid is provided with double circuit (one circuit redundant) electrical heat tracing in conjunction with insulation to maintain the concentrated solution above the precipitation temperature.
Alarms are provided.

Exceptions are as follows:

1. Lines, which may transport concentrated boric acid but are subsequently flushed with reactor coolant or other liquid of low boric acid concentration during normal operation.
2. The boric acid storage tanks, which are provided with immersion heaters.
3. The batching tank, which is provided with a steam jacket.
4. The concentrates holding tank, which is provided with an immersion heater.
5. The boric acid transfer pumps, which are provided with strip heaters in enclosures.

Emergency power is supplied to the heat tracing circuits and electric heaters on loss of offsite power.

Each individual pipe tracing circuit has a local control cabinet containing operating, testing, and alarm devices.

Failure of the operating circuit will result in a decrease in pipe temperature and will alarm in the control room. Test and connection of the redundant circuit can be readily accomplished. Likewise, failure of any operating device in the local control cabinet will result in alarm.

9.2.2.5 Recycle Process

Boron is no longer recycled, consequently some components of the boron recycle system are no longer used, some have been removed (evaporator 22, gas stripper 22 and ion exchanger filter 22) and some (Boron Monitoring Tanks and pumps) have been retired and their inlet and outlet piping cut and capped. Heaters, pumps and level and temperature instrumentation associated with the monitor tanks have been disconnected. Reactor coolant system effluents collected in the holdup tanks are either processed through demineralizers or sent to the radwaste system for processing. The originally supplied gas stripper feed pumps have been replaced by holdup tank transfer pumps, which are used to transfer water to waste collection tanks in Unit 1.

9.2.2.5.1 Purpose

The original purpose of the recycle portion of the chemical and volume control system is to accept and process all effluents, which could be readily reused as makeup to the reactor coolant system. Boron is no longer recycled, but portions of the boron recycle system are used to collect effluents and transfer them to the waste disposal system. Effluents are initially collected in the chemical and volume control system holdup tanks. Prior to the holdup tanks, particularly if the reactor is operating with defective fuel, the letdown from the reactor coolant system is passed through the mixed-bed demineralizers. Both forms of resin remove fission products and corrosion products. As fluid enters the holdup tanks, released gases (hydrogen and fission gases) mix with the nitrogen cover gas and are eventually drawn off to the waste gas system.

Three CVCS holdup tank transfer pumps take suction from the holdup tanks and pump the fluid through the evaporator feed ion exchangers where lithium and fission products (primarily cesium isotopes) are removed. The resin is a hydrogen form cation resin. Two ion exchangers are employed in series. Series operation is recommended to ensure prevention of breakthrough of cesium in the event of evaporation with 1-percent fuel defects. From the feed ion exchangers, the fluid is returned to the holdup tanks. The CVCS holdup tank transfer pumps are also used to transfer the holdup tank contents to the waste disposal system.

A holdup tank low pressure interlock will trip the CVCS holdup tank transfer pumps upon low pressure in the holdup tank. This interlock reduces the potential for creating a negative pressure condition in the holdup tanks during drain down of the tank.

During operation of the recycle process, samples can be taken at various positions through the system to assess the performance of the individual system components. Local samples may be obtained before and after the evaporator feed ion exchangers.

9.2.2.5.2 Holdup Tanks

Three holdup tanks contain radioactive liquid, which enters the tank from the letdown line. The liquid is released from the reactor coolant system during startup, shutdowns, load changes and from boron dilution to compensate for burnup. The contents of one tank are normally being processed while another tank is being filled. The third tank is normally kept empty to provide additional storage capacity when needed.

The total liquid storage sizing basis for the holdup tanks is given in Table 9.2-3. The tanks are constructed of austenitic stainless steel.

9.2.2.5.3 Holdup Tank Recirculation Pump

The recirculation pump is used to mix the contents of a holdup tank and to transfer the contents of a holdup tank to another.

A holdup tank low pressure interlock will trip the holdup tank recirculation pump upon low pressure in the holdup tank. This interlock reduces the potential for creating a negative pressure condition.

The wetted surface of this pump is constructed of austenitic stainless steel.

9.2.2.5.4 Holdup Tank Transfer Pump

The three holdup tank transfer pumps originally supplied feed to the gas stripper boric acid evaporator trains from a holdup tank. They now are used to transfer water to waste collection tanks in unit 1. These centrifugal pumps are constructed of austenitic stainless steel.

9.2.2.5.5 Evaporator Feed (Cation) Ion Exchangers

Four cation flushable demineralizers remove cations (primarily cesium and lithium) from the holdup tank effluent. The demineralizer vessels are constructed of austenitic stainless steel and contain a resin retention screen.

9.2.2.5.6 Ion Exchanger Filters

These filters were originally provided to collect resin fines and particulates larger than 25 microns from the cation ion exchanger. They are no longer used. Filter 21 has been retired in place and filter 22 has been removed.

9.2.2.5.7 Gas Stripper Equipment

Two gas strippers were originally provided to remove nitrogen, hydrogen, and fission gases from the evaporator feed. They are no longer used. Gas stripper 21 has been retired in place and gas stripper 22 has been removed.

9.2.2.5.8 Boric Acid Evaporator Equipment

Two boric acid evaporators were originally provided to concentrate boric acid for reuse in the reactor coolant system. They are no longer used. Evaporator 21 has been retired in place and evaporator 22 has been removed.

9.2.2.5.9 Evaporator Condensate Demineralizers

Two anion demineralizers were originally provided to remove any boric acid contained in the evaporator condensate. These demineralizers are valved out of service and no longer used.

9.2.2.5.10 Condensate Filters

The filters were originally provided to collect resin fines and particulates larger than 25 microns from the boric acid evaporator condensate streams. These filters are no longer used.

9.2.2.5.11 Monitor Tanks

The monitor tanks have been retired in place.

9.2.2.5.12 Monitor Tank Pumps

The monitor tank pumps have been retired in place.

9.2.2.5.13 Primary Water Storage Tank

A single 165,000-gal primary water storage tank is provided to store the demineralized water used by the primary water makeup system shown in Plant Drawing9321-2724 [Formerly UFSAR Figure 9.2-2]. The storage tank is constructed of type 304 stainless steel.

Chemical addition to the tank, if required, can be accomplished via a 3-in. blind flange connection located near the top of the tank, directly off the pressure-vacuum relief valve. This connection can be used to correct the reactor coolant system water chemistry. A local sample point is provided on the bottom of the tank in addition to a tank drain and a loop seal overflow. This loop seal will prevent the entrance of air. To ensure that this loop seal is filled with water a valved line is provided from the tank drain to the loop seal.

Besides these lines into the primary water storage tank, there are also two feeds. One comes from the monitor tank pumps, which have been retired in place, and the second comes from the primary water makeup pump recirculation. Lines carrying heating steam to and from the tank also enter it near its bottom. All of these connections and lines entering the tank are heat traced to prevent them from freezing. A large inspection port is provided on the side of the tank.

9.2.2.5.13.1 Primary Water Storage Tank Level Measurement

Level in the tank is measured and indicated locally and in the central control room. In addition, high level and low level are alarmed in the central control room.

9.2.2.5.13.2 Primary Water Storage Tank Temperature Control

Temperature in the tank is indicated locally. An additional temperature measurement is made at the tank, on the suction line to the makeup pumps.

The temperature element will sense a representative fluid temperature. This temperature measurement is used to control steam flow to the coils located at the bottom of the storage tank. The steam coils will maintain the water in the storage tank at a sufficiently high temperature to prevent freezing of the tank contents and large temperature changes in the primary water supplied to the shaft seals of the reactor coolant pumps by means of the blender. The walls of the tank are insulated and all lines connected to the tank and exposed to the environment are electrically heat traced to prevent freezing.

In addition, the external instrument cabinet is heated and weatherproofed to help ensure a controlled temperature for the tank level instrumentation. Low temperature alarms alert the operator of any instrument heat trace failure or low temperatures in the instrument enclosure.

9.2.2.5.14 Primary Water Makeup Pumps

Two primary water makeup pumps are provided and normally take their suction from the primary water storage tank. The pumps are constructed of type 316 austenitic stainless steel. Each can supply 150 gpm of water at a total dynamic head of 210-ft.

Control of both pumps is provided from the central control room. No local control of the pump is provided.

Normally one pump will be selected to run continuously; the second will be in auto. A limited flow recirculation line is provided and remains open in case makeup water is not required at a given time anywhere in the plant. An orifice in this line limits the recirculation flow.

In addition to manual operation, these pumps are also automatically controlled by the chemical and volume control system. In the event that automatic makeup to or dilution of the reactor coolant system is required, the makeup control system will send a start signal to both primary water pumps. The pump in operation will continue to run and the second pump, if in auto, will start. When this automatic start signal is removed, the pumps will return to their original operating condition. When makeup is required, the water follows the path to the boric acid blender. In the event the pressure in the supply line to the blender falls, indicating insufficient water supply, an alarm will be annunciated in the central control room. Each pump is also provided with a discharge pressure gauge. Operation of the pumps without a suction head is prevented.

9.2.2.5.15 Concentrates Filter

A disposable synthetic cartridge-type filter was provided in the original design to remove particulates larger than 25 microns from the evaporator concentrates. This filter is no longer used and has been retired in place.

9.2.2.5.16 Concentrates Holding Tank

The concentrates holding tank was provided in the original design to hold the production of concentrates from one batch of boric acid evaporator operation. The tank is no longer used and has been retired in place.

9.2.2.5.17 Concentrates Holding Tank Transfer Pumps

Two holding tank transfer pumps were provided in the original design to discharge boric acid solution from the concentrates holding tank to the boric acid storage tanks. These pumps are no longer used and have been retired in place.

9.2.3 System Design Evaluation

9.2.3.1 Availability and Reliability

A high degree of functional reliability is ensured in this system by providing standby components where performance is vital to safety and by ensuring fail safe response to the most probable mode of failure. Special provisions include duplicate heat tracing with alarm protection of lines, valves, and components normally containing concentrated boric acid.

The system has three high pressure charging pumps, each capable of supplying the normal reactor coolant pump seal and makeup flow.

The electrical equipment of the chemical and volume control system is arranged so that multiple items receive their power form various 480-V buses (see Chapter 8). Each of the three charging pumps is powered from a separate 480-V bus. The two boric acid transfer pumps are also powered from separate 480-V buses. One charging pump and one boric acid transfer pump are capable of meeting cold shutdown requirements shortly after full power operation. In cases of loss of offsite power, a charging pump and a boric acid transfer pump can be placed on the emergency diesels, if necessary.

9.2.3.2 Control of Tritium

The chemical and volume control system is used to control the concentration of tritium in the reactor coolant system. Essentially all of the tritium is in chemical combination with oxygen as form of water. Therefore, any leakage of coolant to the containment atmosphere carries tritium in the same proportion as it exists in the coolant. Thus, the level of tritium in the containment atmosphere, when it is sealed from outside air ventilation, is a function of tritium level in the reactor coolant, the cooling water temperature at the cooling coils, which determines the dewpoint temperature of the air, and the presence of leakage other than reactor coolant as a source of moisture in the containment air.

There are two major considerations with regard to the presence of tritium:

1. Possible plant personnel hazard during access to the containment. Leakage of reactor coolant during operation with a closed containment causes an accumulation of tritium in the containment atmosphere. It is desirable to limit the accumulation to allow containment access.

2. Possible public hazard due to release of tritium to the environment.

Neither of these considerations is limiting in this plant.

The concentration of tritium in the reactor coolant is maintained at a level, which precludes personnel hazard during access to the containment. This is achieved by diverting the letdown flow to the Chemical and Volume Control System for processing via the Waste Disposal System.

The Annual Effluent and Waste Disposal Report shows that tritium released to the environment in this manner is well below 10 CFR 20 limits and thus no public hazard would result.

9.2.3.3 Leakage Prevention

Quality control of the material and the installation of the chemical and volume control valves and piping that are designated for radioactive service, is provided in order to eliminate leakage to the atmosphere. The components designated for radioactive service are provided with welded connections to prevent leakage to the atmosphere. However, flanged connections are provided in each charging pump suction and discharge, on each boric acid pump suction and discharge, on the relief valves inlet and outlet, on three-way valves, and on the flow meters to permit removal for maintenance.

The positive displacement charging pumps stuffing boxes are provided with leakoffs to collect reactor coolant before it can leak to the atmosphere. All valves, with the exception of the control valves discussed below, which are larger than 2-in. and which are designated for radioactive service at an operating fluid temperature above 212°F, are provided with a stuffing box and capped lantern leakoff connections. Leakage to the atmosphere is essentially zero for these valves. All control valves are either provided with a stuffing box and leakoff connections, a standard stuffing box suitable for the specified service, or are totally enclosed. Leakage to the atmosphere is essentially zero for these valves.

Diaphragm valves are provided where the operating pressure and the operating temperature permit the use of these valves. Leakage to the atmosphere is essentially zero for these valves.

9.2.3.4 Incident Control

The letdown line and the reactor coolant pumps seal water return line penetrate the reactor containment. The letdown line contains air-operated valves inside the reactor containment and two air-operated valves outside the reactor containment, which are automatically closed by the containment isolation signal.

The reactor coolant pumps seal water return line contains one motor-operated isolation valve outside the reactor containment, which is automatically closed by the containment isolation signal.

The four seal water injection lines to the reactor coolant pumps and the normal charging line are inflow lines penetrating the reactor containment. Each line contains at least one check valve inside the reactor containment to provide isolation of the reactor containment should a break occur in these lines outside the reactor containment.

9.2.3.5 Malfunction Analysis

To evaluate system safety, failures or malfunctions were assumed concurrent with a loss-of-coolant and the consequences analyzed and presented in Table 9.2-7. As a result of this evaluation, it is concluded that proper consideration has been given to safety in the design of the system.

If a rupture were to take place between the reactor coolant loop and the first isolation valve or check valve, this incident would lead to an uncontrolled loss of reactor coolant. The analysis of loss-of-coolant accidents is discussed in Section 14.3.

Should a rupture occur in the chemical and volume control system outside the containment, or at any point beyond the first check valve or remotely operated isolation valve, actuation of the valve would limit the release of coolant and ensure continued functioning of the normal means of heat dissipation from the core. For the alternate charging line, blocking the isolation valve (204A) just upstream of the check valve closed eliminates the need for the check valve to actuate closed. For the general case of rupture outside the containment, the largest source of radioactive fluid subject to release is the contents of the volume control tank. The consequences of such a release are considered in Section 14.2.

When the reactor is subcritical (i.e., during cold or hot shutdown, refueling, and approach to criticality), the relative reactivity status (neutron source multiplication) is continuously monitored and indicated by the nuclear instrumentation source range detectors, counters and count rate indicators. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate, is slow enough to give ample time to start a corrective action (boron dilution stop and/or emergency boron injection) to prevent the core from becoming critical. The maximum dilution rate is based on the abnormal condition of three charging pumps operating at full speed delivering unborated makeup water to the reactor coolant system at a particular time during refueling when the boron concentration is at the maximum value and the water volume in the system is at a minimum. This analysis is referred to as the Boron Dilution Event analysis and is discussed in Section 14.1.5.

At least two separate and independent flow paths are available for reactor coolant boration, i.e., either the charging line, or the reactor coolant pumps labyrinths. The malfunction or failure of one component will not result in the inability to borate the reactor coolant system. An alternate supply path is always available for emergency boration of the reactor coolant. As a backup to the boration system, the operator can align the refueling water storage tank outlet to the suction of the charging pumps. A third method involves depressurization of the primary system, if necessary, and the use of the safety injection pumps.

On loss of seal injection water to the reactor coolant pump seals, seal water flow may be reestablished by manually starting a standby charging pump. Even if the seal water injection flow is not reestablished, the plant can be operated since the thermal barrier cooler has sufficient capacity to cool the reactor coolant flow, which pass through the thermal barrier cooler and seal leakoff from the pump volute.

9.2.3.6 Galvanic Corrosion

The only types of materials, which are in contact with each other in borated water are stainless steels, Inconel, Stellite valve materials, and zircaloy fuel element cladding. These materials exhibit only and insignificant degree of galvanic corrosion when coupled to each other. As can be seen from tests, the effects of galvanic corrosion are insignificant to systems containing borated water.

Boration during normal operation to compensate for power changes will be indicated to the operator from two sources: (1) the control rod movement, and (2) the flow indicators in the boric acid transfer pump discharge line.

When the emergency boration path is used, two indications to the operator are available. The charging line flow indicator will indicate boric acid flow since the charging pump suction is aligned to the boric acid transfer pump suction for this mode of operation. The change in boric acid storage tank level is another indication of boric acid injection.

9.2.4 Minimum Operating Conditions

Minimum operating conditions are specified in the Technical Requirements Manual.

9.2.5 Tests and Inspections

The minimum frequencies for testing, calibrating and/or checking instrument channels for the chemical and volume control system are specified in the Technical Requirements Manual.

TABLE 9.2-1
Chemical and Volume Control System Code Requirements

Component	Code
Regenerative heat exchanger	ASME III,[1] Class C
Nonregenerative heat exchanger	ASME III, Class C, tube side, ASME VIII, shell side
Mixed-bed demineralizers	ASME III, Class C
Reactor coolant filter	ASME III, Class C
Volume control tank	ASME III, Class C
Seal water heat exchanger	ASME III, Class C, tube side, ASME VIII, shell side
Excess letdown heat exchanger	ASME III, Class C, tube side, ASME VIII, shell side
Chemical mixing tank	ASME VIII
Deborating demineralizers	ASME III, Class C
Cation bed demineralizers	ASME III, Class C
Seal injection filters (normal seal injection path)	ASME III, Class C
Seal water injection filter (alternate seal injection path)	ASME III Class 2
Seal water filter	ASME III, Class C
Holdup tanks	ASME III, Class C
Boric acid filter	ASME III, Class C
Gas stripper package (Note 3)	ASME III, Class C
Boric acid evaporator package (Note 3)	ASME III, Class C
Evaporator condensate demineralizers (Note 4)	ASME III, Class C
Concentrates filter (Note 4)	ASME III, Class C
Evaporator feed (Cation) ion exchanger	ASME III, Class C
Ion exchanger filter (Note 3)	ASME III, Class C
Condensate filter (Note 4)	ASME III, Class C
Piping and valves	USAS B31.1[2]

Notes:
1. ASME III – American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.
2. USAS B31.1 – Code for Pressure Piping, and special nuclear cases where applicable.
3. Unit 21 is no longer used, Unit 22 has been physically removed.
4. No longer used.

TABLE 9.2-2
Chemical and Volume Control System Letdown Requirements[1]

Plant design life, years	40
Normal seal water supply flow rate, gpm	32
Normal seal water return flow rate, gpm	12
Normal letdown flow rate, gpm	75
Maximum letdown flow rate, gpm	120
Normal charging pump flow (one pump), gpm	87
Normal seal injection flow to reactor coolant pumps, gpm	32
Normal charging line flow, gpm	55

Notes:
1. Volumetric flow rates in gpm are based on 127°F and 15 psig.

TABLE 9.2-3 (Sheet 1 of 2)
Chemical and Volume Control System Principal Component Design Data Summary

	Quantity	Heat Transfer, Btu/hr	Design Letdown Flow, 1b/hr	Letdown, ΔT °F	Design Pressure, psig, Shell/Tube	Design Temperature, °F, Shell/Tube
Heat exchangers						
Regenerative	1	10.28×10^6	37,050	257	2,485/2,735	650/650
Non-regenerative (Letdown)	1	14.8×10^6	59,700	253	150/600	250/400
Seal water	1	2.17×10^6	126,756	17	150/150	250/250
Excess letdown	1	4.75×10^6	12,400	360	150/2,485	250/650

	Quantity	Type	Capacity, gpm	Head, ft or psi	Design Pressure, psig	Design Temperature, °F
Pumps						
Charging	3	Pos. Displ.	98	2,500 psi	3,200	250
Boric acid Transfer	2	Centrifugal	75	235-ft	150	250
Holdup tank recirculation	1	Centrifugal	500	100-ft	75	200
Primary water makeup	2	Centrifugal	150	210-ft	150	Ambient
Monitor tank (Retired in place)						
Concentrates holding tank transfer (Retired in place)						
Holdup Tank Transfer Pump 22	1	Centrifugal	25	63-ft	150	200
Holdup Tank Transfer Pump 21 & 23	2	Centrifugal	25	63-ft	150	200

TABLE 9.2-3 (Sheet 2 of 2)
Chemical and Volume Control System Principal Component Design Data Summary

	Quantity	Type	Volume	Design pressure, psig	Design Temperature, °F
Tanks					
Volume control	1	Vertical	400-ft^3 [1]	75/15	250
Charging pump	3	Vertical	-	75	250
Stabilizer separator	3	Spherical	-	2735	250
Pulsation dampener					
Boric acid	2	Vertical	7,000 gal [1]	atmos.	250
Chemical mixing	1	Vertical	5.0 gal [1]	150	200
Batching	1	Jacket Btm.	400 gal [1]	atmos.	250
Holdup	3	Horizontal	8106-ft^3 [1]	15	200
Primary water storage	1	Vertical	165,000 gal	atmos.	150
Concentrates holding (Retired in Place)					
Monitor (Retired in Place)					
Resin fill	1	Open	8-ft^3 [1]	-	200

	Quantity	Type	Resin Volume, ft3	Flow, gpm	Design Pressure, psig	Design Temperature, °F
Demineralizers						
Mixed-bed	2	Flushable	30	120	200	250
Cation bed	1	Flushable	12.0	42	200	250
Evaporator feed	4	Flushable	12.0	12.5	200	250
Evaporator condensate	2	Flushable	12.0	12.5	200	250
Deborating	2	Flushable	30	120	200	250

Notes:

1. Net Internal Volume

TABLE 9.2-4
Reactor Coolant System Activities
(576°F)

Activation Products	uCi/g
Mn-54	1.60E-03
Cr-51	5.50E-03
Mn-56	2.00E-02
Fe-55	2.00E-03
Fe-59	5.20E-04
Co-58	1.56E-02
Co-60	1.98E-03

Non-Volatile Fission Products (Continuous Full Power Operation)

	uCi/g		uCi/g		uCi/g		uCi/g
Br-83	9.90E-02	Rb-86	4.55E-02	Tc-99m	7.62E-01	Ba-137m	2.48E+00
Br-84	4.86E-02	Rb-88	4.36E+00	Ru-103	6.42E-04	Ba-140	4.36E-03
Br-85	5.67E-03	Rb-89	2.00E-01	Rh-103m	6.38E-04	La-140	1.46E-03
I-127 (a)	1.53E-10	Sr-89	4.37E-03	Ru-106	3.30E-04	Ce-141	6.56E-04
I-129	8.48E-08	Sr-90	2.85E-04	Rh-106	3.30E-04	Ce-143	5.24E-04
I-130	7.08E-02	Sr-91	5.78E-03	Ag-110m	4.89E-03	Pr-143	6.37E-04
I-131	2.90E+00	Sr-92	1.28E-03	Te-125m	1.15E-03	Ce-144	4.92E-04
I-132	3.02E+00	Y-90	8.09E-05	Te-127m	3.83E-03	Pr-144	4.92E-04
I-133	4.65E+00	Y-91m	3.12E-03	Te-127	1.57E-02		
I-134	6.52E-01	Y-91	5.77E-04	Te-129m	1.16E-02		
I-135	2.57E+00	Y-92	1.12E-03	Te-129	1.50E-02		
Cs-134	5.14E+00	Y-93	3.86E-04	Te-131m	2.63E-02		
Cs-136	5.35E+00	Zr-95	6.55E-04	Te-131	1.42E-02		
Cs-137	2.62E+00	Nb-95	6.56E-04	Te-132	3.14E-01		
Cs-138	1.06E+00	Mo-99	8.22E-01	Te-134	3.13E-02		

Gaseous Fission Products

	uCi/g
Kr-83m	4.67E-01
Kr-85m	1.85E+00
Kr-85	1.36E+01
Kr-87	1.22E+00
Kr-88	3.49E+00
Kr-89	9.90E-02
Xe-131m	3.18E+00
Xe-133m	3.61E+00
Xe-133	2.57E+02
Xe-135m	5.55E-01
Xe-135	8.94E+00
Xe-137	1.93E-01
Xe-138	6.94E-01

TABLE 9.2-5
Parameters Used in the Calculation of Reactor Coolant Fission Product Activities

1.	Core thermal power, MWt	3280.3
2.	Fraction of fuel containing clad defects	0.01
3.	Reactor coolant liquid volume, ft^3	10,620
4.	Reactor coolant average temperature, °F	573
5.	Purification flow rate (normal), gpm	75
6.	Effective cation demineralizer flow, gpm	7
7.	Volume control tank volumes	
	a. Vapor, ft^3	270
	b. Liquid, ft^3	130
8.	Fission product escape rate coefficients:	
	a. Noble gas isotopes, sec^{-1}	6.5×10^{-8}
	b. Br, I and Cs isotopes, sec^{-1}	1.3×10^{-8}
	c. Te isotopes, sec^{-1}	1.0×10^{-9}
	d. Mo, Te, and Ag isotopes, sec^{-1}	2.0×10^{-9}
	e. Sr and Ba isotopes, sec^{-1}	1.0×10^{-11}
	f. Y, Zr, Nb, Ru, Rh, La, Ce and Pr isotopes, sec^{-1}	1.6×10^{-12}
9.	Mixed-bed demineralizer decontamination factors:	
	a. Noble gases and Cs-134, 136, and 137	1.0
	b. All other isotopes	10.0
10.	Cation bed demineralizer decontamination factor for Cs-134, 137, and Rb-86	10.0
11.	Volume control tank noble gas stripping fraction (closed system):	

Isotope	Stripping Fraction
Kr-83m	7.9×10^{-1}
Kr-85	7.5×10^{-5}
Kr-85m	6.1×10^{-1}
Kr-87	8.5×10^{-1}
Kr-88	7.1×10^{-1}
Kr-89	9.9×10^{-1}
Xe-131m	1.7×10^{-2}
Xe-133	3.9×10^{-2}
Xe-133m	8.8×10^{-2}
Xe-135	3.6×10^{-1}
Xe-135m	9.5×10^{-1}
Xe-137	9.9×10^{-1}
Xe-138	9.6×10^{-1}

TABLE 9.2-6 (Sheet 1 of 2)
Tritium Production in the Reactor Coolant

BASIC ASSUMPTIONS

Plant Parameters:

1. Core thermal power, MWt	3216
2. Coolant water volume, ft^3	12,600
3. Core volume, ft^3	1,152.5
4. Core volume fraction	
a. UO_2	0.3023
b. Zr + SS	0.1035
c. H_20	0.5942
5. Plant full power operating times	
a. Initial cycle	78 wk (18 months)
b. Equilibrium cycle	49 wk (11.3 months)
6. Boron concentrations (Peak hot full power equilibrium Xe)	
a. Initial cycle, ppm	890
b. Equilibrium cycle, ppm	825
7. Burnable poison boron content (total - all rods), kg	18.1
8. Fraction of tritium in core (ternary fission + burnable boron) diffusing through cladding	0.30_1
9. Ternary fission yield, atoms/fission	8×10^{-5}
10. Nuclear cross-sections and neutron fluxes	
B^{10} (n,2α) T σ ; mb	(nv; n/cm^2 - sec)
1 MeV $\leq$ E $\leq$ 5 MeV = 31.95 (Spectrum weighted)	5.04×10^{13}
E > 5 MeV = 75	7.4×10^{12}
Li^7 (n, nα) T (99.9-percent purity Li^7)	
3 MeV $\leq$ E $\leq$ 6 MeV = 39.1 (Spectrum weighted)	2.14×10^{13}
E > 6 MeV = 0.4	2.76×10^{12}
Li^6 (n, α) T (99.9-percent purity Li^7)	
σ = 675 barns;	2.14×10^{13}
11. Cooling water flow: 7.5×10^5 gpm = 15×10^{14} cm^3/yr	

TABLE 9.2-6 (sheet 2 of 2)
Tritium production in the Reactor Coolant

CALCULATIONS (per year)

	Initial Cycle	Equilibrium Cycle
A. Tritium from core (curies)		
1. Ternary fission	11,450	11,450
2. B^{10} (n, 2α) T (in poison rods)	800	NA
3. B^{10} (n, α) Li^7 (n, nα) T (in poison rods)	1,500	NA
4. Release fraction (0.30)		
5. Total release to coolant	4,125	3,440
B. Tritium from coolant (curies)		
1. B^{10} (n, 2α) T	1,130	780
2. Li^7 (n, nα) T (limit 2.2 ppm Li)	8.8	8.8
3. Li^6 (n, α) T (purity of Li^7 = 99.9-percent)	8.8	8.8
4. Release fraction (1.0)		
5. Total release to coolant	1,147.6	797.6
C. Total tritium in coolant (curies)	5,273	4.238

Notes:

1. The assumption that 30-percent of the ternary produced tritium diffuses into the coolant is based on the analysis made of fuel retention in the Saxton and the Yankee stainless-clad fuel. This analysis indicated that the fuel retained 68-percent of the tritium produced in the fuel. Although data is not currently available on zircaloy-clad fuel operating at the specific power anticipated for these reactors, it is reasonably certain that a significant portion of the tritium released by the fuel will not diffuse through the zircaloy possibly because of the formation of zirconium tritide. Shipping port data indicates that less than 1-percent of ternary tritium produced is released to the coolant. Although this data cannot be used directly, it does indicate that zircaloy will reduce tritium diffusion.

TABLE 9.2-7
Malfunction Analysis of Chemical and Volume Control System

Component	Failure	Comments and Consequences
Letdown line	Rupture in the line inside the reactor containment	The remote air-operated valve located near the main coolant loop is closed on low pressurizer level to prevent supplementary loss of coolant through the letdown line rupture. The containment isolation valves in the letdown line outside the reactor containment and also the orifice block valves are automatically closed by the containment isolation signal initiated by the concurrent loss-of-coolant accident. The closure of that valve prevents any leakage of the reactor containment atmosphere outside the reactor containment.
Normal and alternate charging lines	See above	The check valve (210B) in the normal charging line or the air operated isolation valve (204A) just upstream of the check valve (210A) in the alternate charging line located near the main coolant loops prevent supplementary loss of coolant through the rupture. The check valves located at the boundary of the reactor containment prevent any leakage of the reactor containment atmosphere outside the reactor containment.
Seal water return line	See above	The motor-operated isolation valve located outside the containment is manually closed or is automatically closed by the containment isolation signal initiated by the concurrent loss-of-coolant accident. The closure of that valve prevents any leakage of the reactor containment atmosphere outside the reactor containment.

9.2 FIGURES

Figure No.	**Title**
Figure 9.2-1 Sh. 1	Chemical and Volume Control System - Flow Diagram, Sheet 1, Replaced with Plant Drawing 9321-2736
Figure 9.2-1 Sh. 2	Chemical and Volume Control System - Flow Diagram, Sheet 2, Replaced with Plant Drawing 208168
Figure 9.2-1 Sh. 3	Chemical and Volume Control System - Flow Diagram, Sheet 3, Replaced with Plant Drawing 9321-2737

Figure 9.2-1 Sh. 4	Chemical and Volume Control System - Flow Diagram, Sheet 4, Replaced with Plant Drawing 235309
Figure 9.2-2	Primary Water Makeup System - Flow Diagram, Replaced with Plant Drawing 9321-2724

9.3 AUXILIARY COOLANT SYSTEM

9.3.1 Design Basis

The auxiliary coolant system consists of three loops as shown in Plant Drawings 227781, 9321-2720, and 251783 [Formerly UFSAR Figure 9.3-1, Sheets 1, 2, and 3] the component cooling loop, the residual heat removal loop, and the spent fuel pit cooling loop.

9.3.1.1 Performance Objectives

9.3.1.1.1 Component Cooling Loop

The component cooling loop is designed to remove residual and sensible heat from the reactor coolant system via the residual heat removal loop during plant shutdown, cool the letdown flow to the chemical and volume control system during power operation, and to provide cooling to dissipate waste heat from various primary plant components. It also provides cooling for engineered safeguards and safe shutdown components.

Active loop components, which are relied upon to perform the cooling function are redundant. Redundancy of components in the process cooling loop does not degrade the reliability of any system, which the process loop serves.

The loop design provides for detection of radioactivity entering the loop from reactor coolant source and also provides means for isolation.

9.3.1.1.2 Residual Heat Removal Loop

The residual heat removal loop is designed to remove residual and sensible heat from the core and reduce the temperature of the reactor coolant system during the second phase of plant cooldown. During the first phase of cool-down, the temperature of the reactor coolant system is reduced by transferring heat from the reactor coolant system to the steam and power conversion system.

The loop design provides means to detect radioactivity migration to the ultimate heat sink environment and includes provisions, which permit adequate action for continued core cooling, when required, in the event radioactivity limits are exceeded.

The loop design precludes any significant reduction in the overall design reactor shutdown margin when the loop is brought into operation for decay heat removal or for emergency core cooling by recirculation.

The loop design includes provisions to enable periodic hydrostatic testing to applicable code test pressures.

Loop components, whose design pressure and temperature are less than the reactor coolant system design limits, are provided with overpressure protective devices and redundant isolation means.

9.3.1.1.3 Spent Fuel Pit Cooling Loop

The spent fuel pit cooling loop is designed to remove from the spent fuel pit the heat generated by stored spent fuel elements.

The loop design consists of two pumps, a heat exchanger, a filter, a demineralizer, piping, and associated valves and instrumentation. Alternate cooling capability can be made available under anticipated malfunctions or failures (expected fault conditions).

Loop piping is so arranged that the failure of any pipeline does not drain the spent fuel pit below the top of the stored fuel elements.

The thermal design basis for the loop provides for all fuel pool rack locations to be filled at the end of a full core discharge.

9.3.1.2 Design Characteristics

9.3.1.2.1 Component Cooling Loop

Normally one pump and two component heat exchangers are operated to provide cooling water for the components located in the auxiliary building and the reactor containment building. At elevated CCW supply temperatures two pumps may be required. The water is normally supplied to all components being cooled even though one of the components may be out of service.

Cooling is provided by at least one component cooling pump during the recirculation phase of a loss-of-coolant accident. The cooling of the recirculation pump motors is supported by the operation of at least one auxiliary component cooling water pump during the recirculation phase of a LOCA.

Makeup water is taken from the primary water treatment plant, as required, and delivered to the surge tank. A backup source of water is provided from the primary water makeup transfer pumps.

The operation of the loop is monitored with the following instrumentation:

1. A pressure indicator on the line between the component cooling pumps and the component cooling heat exchangers.
2. A temperature indicator, flow indicator, and radiation monitor in the outlet line from the heat exchangers.
3. A temperature indicator on the main inlet line to the component cooling pumps.

9.3.1.2.2 Residual Heat Removal Loop

Two pumps and two residual heat exchangers perform the decay heat cooling functions for the reactor unit. After the reactor coolant system temperature and pressure have been reduced to approximately 350°F and below 365 psig (the upper limit to prevent RHR system overpressurization), respectively, decay heat cooling is initiated by aligning pumps to take suction from the reactor outlet line and discharge through the heat exchangers into the reactor inlet line. The normal plant cooldown times to cold shutdown and refueling entry conditions using 95°F Service Water are given in table 9.3-3. If only one pump and one heat exchanger are available, reduction of reactor coolant temperature is accomplished at a lower rate.

The equipment used for decay heat cooling is also used for emergency core cooling during loss-of-coolant accident conditions. This is described in Chapter 6.

9.3.1.2.3 Spent Fuel Pit Cooling Loop

The spent fuel pit contains spent fuel discharged from the reactor over its operating life. Spent fuel cooling loop performance has been analyzed for operation at a core power level of 102% of 3216 MWt and at service water temperatures up to 95°F. When a refueling load of approximately 88 freshly discharged assemblies (plus previously discharged assembles) are present, the pump and spent fuel heat exchanger will handle the load and maintain a bulk pit water temperature less than 140°F. When a full core of 193 assemblies is freshly discharged, the bulk pit water temperature is maintained below 180°F.

Two criteria must be met before spent fuel can be discharged to the spent fuel pit:

1. In accordance with Technical Requirements Manual Section 3.9.A, spent fuel can not be discharged to the spent fuel pit until at least 84 hours after shutdown to satisfy the assumptions of the spent fuel handling accident analysis as discussed in Section 14.2.1.

2. An additional delay time limit prior to spent fuel discharge is administratively controlled by operating procedures to ensure that the total spent fuel heat load is within the capacity of the spent fuel cooling loop to satisfy the bulk pit water temperature limits discussed above. This is a variable time limit primarily dependant upon service water temperature, and cooling capacity without supplemental cooling.

9.3.1.3 Codes and Classifications

All piping and components of the auxiliary coolant system are designed to the applicable codes and standards listed in Table 9.3-1. The component cooling loop water contains a corrosion inhibitor to protect the carbon steel piping. Austenitic stainless steel piping is used in the remaining piping systems that contain borated water without a corrosion inhibitor.

9.3.2 System Design and Operation

9.3.2.1 Component Cooling Loop

Component cooling is provided for the following heat sources:

1. Residual heat exchangers (auxiliary coolant system).
2. Reactor coolant pumps (reactor coolant system).
3. Nonregenerative heat exchanger (chemical and volume control system).
4. Excess letdown heat exchanger (chemical and volume control system).
5. Seal-water heat exchanger (chemical and volume control system).
6. Sample heat exchangers (sampling system).
7. Waste gas compressors (waste disposal system).
8. Reactor vessel support pads.

9. Residual heat removal pumps (auxiliary coolant system).
10. Safety injection pumps (safety injection system).
11. Recirculation pump motors (safety injection system).
12. Spent fuel pit heat exchanger (auxiliary coolant system).
13. Charging pumps (chemical and volume control system), fluid drive coolers and crankcase.

At the reactor coolant pump, component cooling water removes heat from the bearing oil and the thermal barrier. Since the heat is transferred from the component cooling water to the service water, the component cooling loop serves as an intermediate system between the reactor coolant pump and service water cooling system. This double barrier arrangement reduces the probability of leakage of high pressure, potentially radioactive coolant directly to the service water system. The component cooling loop is monitored for radioactivity by a radiation monitor that samples the component cooling pump discharge downstream of the component cooling heat exchangers.

During normal full power operation, one component cooling pump and two component cooling heat exchangers accommodate the heat removal loads. Two CCW pumps are in stand-by and both heat exchangers are utilized. At elevated CCW supply temperatures two CCW pumps may be required. Three pumps and two heat exchangers can be used to remove the residual and sensible heat during plant shutdown. If one of the pumps or one of the heat exchangers is not operative, safe shutdown of the plant is not affected; however, the time for cooldown is extended. The surge tank accommodates expansion, contraction and inleakage of water, and ensures a continuous component cooling water supply until a leaking cooling line can be isolated. Makeup to the surge tank is provided from the primary water makeup system. The surge tank is normally vented to the atmosphere. In the unlikely event that the radiation level in the component cooling loop reaches a preset level above the normal background, the radiation monitor in the component cooling loop annunciates in the control room and closes a valve in the surge tank vent line. Parameters for components in the component cooling loop are presented in Table 9.3-2.

9.3.2.2 <u>Residual Heat Removal Loop</u>

The residual heat removal loop consists of heat exchangers, pumps, piping, and the necessary valves and instrumentation. During plant shutdown, coolant flows from the reactor coolant system to the residual heat removal pumps, through the tube side of the residual heat exchangers and back to the reactor coolant system. The inlet line to the residual heat removal loop starts at the hot leg of one reactor coolant loop and the return line connects to the safety injection system piping. The residual heat exchangers are also used to cool the water during the latter phase of safety injection system operation. These duties are defined in Section 6.2. The heat loads are transferred by the residual heat exchangers to the component cooling water.

During plant shutdown, the cooldown rate of the reactor coolant is controlled by regulating the flow through the tube side of the residual heat exchangers. Two remote motor-operated control valves downstream of the residual heat exchangers are used to control flow.

Instrumentation has been provided in the control room to monitor RHR and reactor coolant system level when the system is cooled and depressurized. These instruments are provided to monitor level during draindown to assure decay heat removal capability. A channel with an intermediate range of 240 inches measures differential pressure between the top of the pressurizer and the bottom of the hot leg. A wide range channel, capable of monitoring level from the bottom of the hot leg to top of the pressurizer, measures the pressures at those two points using redundant pressure transducer pairs. This wide range channel also has an optional third transducer pair, which may be installed on the reactor head vent line to monitor reactor water level during certain evolutions. Another level channel with a differential pressure sensor can also be used to monitor RCS level. A narrow range level channel using an ultrasonic transducer monitors level in hot leg 21. Wide and narrow range instrumentation is also provided to measure RHR system flow. Monitors are provided for RHR pump suction pressure and discharge pressure. RHR temperature sensors are located at the common discharge header of the RHR pumps and RHR Heat Exchanger outlet line. RCS temperature is monitored by core exit thermocouples whenever the reactor head and the instrumentation interface assembly are in place. The RHR pump monitors, along with the narrow range level and flow instrumentation assists the operators in avoiding air entrainment in the RHR pump suction line during periods when the reactor is shut down and water level has been lowered.

Remotely-operated, double valving is provided to isolate the residual heat removal loop from the reactor coolant system. When reactor coolant system pressure exceeds the design pressure of the residual heat removal loop, interlocks between the reactor coolant system wide range pressure channels and the residual heat removal inlet valves prevent the valves from opening. A remotely-operated normally closed valve and two check valves isolate each line to the reactor coolant system cold legs from the residual heat removal loop during power operation. Parameters for components in the residual heat removal loop are presented in Table 9.3-3.

9.3.2.3 Spent Fuel Pit Cooling Loop

The spent fuel pit cooling loop removes residual heat from fuel placed in the pit for long term storage. The loop can safely accommodate the heat load from all of the assemblies for which there is storage space available.

The spent fuel pit is located outside the reactor containment and is not affected by any loss-of-coolant accident in the containment. During refueling the water in the pit is connected to that in the refueling canal by the fuel transfer tube. Only a very small amount of interchange of water occurs as fuel assemblies are transferred.

The spent fuel pit cooling loop consists of two pumps, a heat exchanger, filter, demineralizer, piping and associated valves and instrumentation. One of the pumps draws water from the pit, circulates it through the heat exchanger and returns it to the pit. Component cooling water cools the heat exchanger. Redundancy of this equipment is not required because of the large heat capacity of the pit and the slow heatup rate.

The clarity and purity of the spent fuel pit water is maintained by passing approximately 5-percent of the loop flow through a filter and demineralizer. The spent fuel pit pump suction line, which is used to draw water from the pit, penetrates the spent fuel pit wall above the fuel assemblies. The penetration location prevents loss of water as a result of a possible suction line rupture.

A separate pump is used to circulate refueling water storage tank water through the same demineralizer and filter for purification.

Parameters for components in the spent fuel cooling loop are presented in Table 9.3-4.

9.3.2.4 Component Cooling Loop Components

9.3.2.4.1 Component Cooling Heat Exchangers

The two component cooling heat exchangers are of the shell and straight tube type. Service water circulates through the tubes while component cooling water circulates through the shell side. Parameters are presented in Table 9.3-2.

9.3.2.4.2 Component Cooling Pumps

The three component cooling pumps, which circulate component cooling water through the component cooling loop are horizontal, centrifugal units. The original pumps have casings made from cast iron (ASTM 48) based on the corrosion-erosion resistance and the ability to obtain sound castings. The material thickness indicates the high quality casting practice and the ability to withstand mechanical damage and, as such, is substantially overdesigned from a stress level standpoint. Carbon steel casing material (ASTM A216) has been evaluated and approved for replacement pumps. Parameters are presented in Table 9.3-2.

9.3.2.4.3 Auxiliary Cooling Water Pumps

The component cooling pumps do not run during the injection phase of a loss of coolant accident with loss of offsite power. The CCW circulating water pumps provide cooling for the high head safety injection pumps during this situation. These pumps are connected to the motor shaft of each safety injection pump and cool the pump bearings / seals when the safety injection pumps operate. The heat is absorbed by the thermal inertia of the component cooling water system.

The auxiliary component cooling water pumps start on a Safety Injection signals and can operate during injection phase with or without Loss-Of-Offsite-Power (LOOP) by being automatically loaded onto the Emergency Diesel Generators (EDG). Their originally intended function was to provide adequate cooling flow to the recirculation pump motor coolers for both the injection and recirculation phase of the accident. An evaluation had concluded that during the injection phase when the recirculation pumps are not operating, the recirculation pump motors were qualified by testing to withstand the post-LOCA environment with no dedicated cooling. However, during the recirculation phase the function of the auxiliary component cooling water pumps is credited to ensure sufficient cooling flow to the motor coolers is available.

Both the auxiliary component cooling water pumps and the CCW circulating water pumps are discussed in further detail in Section 6.2.

9.3.2.4.4 Component Cooling Surge Tank

The component cooling surge tank, which accommodates changes in component cooling water volume is constructed of carbon steel. Parameters are presented in Table 9.3-2. In addition to piping connections, the tank has a flanged opening at the top for the addition of the chemical corrosion inhibitor to the component cooling loop.

9.3.2.4.5 Component Cooling Valves

The valves used in the component cooling loop are standard commercial valves constructed of carbon steel with bronze or stainless steel trim. Since the component cooling water is not normally radioactive, special features to prevent leakage to the atmosphere are not provided.

Self-actuated spring-loaded relief valves are provided for lines and components that could be pressurized beyond their design pressure by improper operation or malfunction.

9.3.2.4.6 Component Cooling Piping

All component cooling loop piping is carbon steel with welded joints and connections except at components, which might need to be removed for maintenance. The piping has been evaluated for the most limiting component cooling water temperatures under loss of coolant accident conditions and found to be acceptable

9.3.2.5 Residual Heat Removal Loop Components

9.3.2.5.1 Residual Heat Exchangers

The two residual heat exchangers located within the containment are of the shell and U-tube type with the tubes welded to the tube sheet. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell side. The tubes and other surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

9.3.2.5.2 Residual Heat Removal Pumps

The two residual heat removal pumps are vertical, centrifugal units with special seals to prevent reactor coolant leakage to the atmosphere. All pump parts in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material. Cooling water is provided from the component cooling water system via flexible stainless steel hose.

9.3.2.5.3 Residual Heat Removal Valves

The valves used in the residual heat removal loop are constructed of austenitic stainless steel or equivalent corrosion resistant material. Stop valves are provided to isolate equipment for maintenance. Throttle valves are provided for remote and manual control of the residual heat exchanger tube side flow. Check valves prevent reverse flow through the residual heat removal pumps.

Two remotely-operated series stop valves at the inlet with a pressure interlock isolate the residual heat removal loop from the reactor coolant system. In addition the residual heat removal loop is isolated from the reactor coolant system by two series check valves and a remotely operated stop valve on the outlet lines. As depicted in Plant Drawing 227781 [Formerly UFSAR Figure 9.3-1, Sheet 1], overpressure protection in the residual heat removal loop is provided by a relief valve. Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the waste disposal system.

Manually-operated valves have backseats to facilitate repacking and to limit the stem leakage when the valves are open.

9.3.2.5.4 Residual Heat Removal Piping

All residual heat removal loop piping is austenitic stainless steel. The piping is welded with flanged connections at the pumps and at valve 741A.

9.3.2.5.5 Low Pressure Purification System

The system is used to clean reactor coolant water when the primary system is depressurized during an outage. The system has a 100-gpm canned purification pump, a line that bypasses the volume control tank and charging pumps of the chemical and volume control system and associated valves as shown in Plant Drawing 208168 [Formerly UFSAR Figure 9.2-1, sheet 2]. The system is designed for 600 psi operation.

9.3.2.6 Spent Fuel Pit Loop Components

9.3.2.6.1 Spent Fuel Pit Heat Exchanger

The spent fuel pit heat exchanger is of the shell and U-tube type with the tubes welded to the tube sheet. Component cooling water circulates through the shell, and spent fuel pit water circulates through the tubes. The tubes are austenitic stainless steel and the shell is carbon steel.

9.3.2.6.2 Spent Fuel Pit Pumps

One of two spent fuel pit pumps circulates water in the spent fuel pit cooling loop. The second pump is on standby. All wetted surfaces of the pumps are austenitic stainless steel, or equivalent corrosion resistant material. The pumps are operated manually from a local station.

9.3.2.6.3 Refueling Water Purification Pump

When it is required to clean up the refueling water storage tank water, the refueling water purification pump circulates water in a loop between the refueling water storage tank and the spent fuel pit demineralizer and filter. All wetted surfaces of the pump are austenitic stainless steel. The pump is operated manually from a local station.

9.3.2.6.4 Spent Fuel Pit Filter

The spent fuel pit filter removes particulate matter larger than 5 μ from the spent fuel pit water. The filter cartridge is synthetic fiber and the vessel shell is austenitic stainless steel.

9.3.2.6.5 Spent Fuel Pit Strainer

A stainless steel strainer is located at the inlet of the spent fuel pit loop suction line for removal of relatively large particles, which might otherwise clog the spent fuel pit demineralizer.

9.3.2.6.6 Spent Fuel Pit Demineralizer

The demineralizer is sized to pass 5-percent of the loop circulation flow, to provide adequate purification of the fuel pit water for unrestricted access to the working area, and to maintain optical clarity. In addition, it is used for purification of the refueling water storage tank water.

9.3.2.6.7 Spent Fuel Pit Skimmer [Deleted]

9.3.2.6.8 Spent Fuel Pit Valves

Manual stop valves are used to isolate equipment and lines, and manual throttle valves provide flow control. Valves in contact with spent fuel pit water are austenitic stainless steel or equivalent corrosion resistant material.

9.3.2.6.9 Spent Fuel Pit Piping

All piping in contact with spent fuel pit water is austenitic stainless steel. The piping is welded except where flanged connections are used at the pump, heat exchanger, and filter to facilitate maintenance.

9.3.3 System Evaluation

System performance has been evaluated for service water temperatures up to 95°F for normal operating modes, loss of offsite power and loss of coolant accident conditions.

9.3.3.1 Availability And Reliability

9.3.3.1.1 Component Cooling Loop

For component cooling of the reactor coolant pumps, the excess letdown heat exchanger and the residual heat exchangers inside the containment, most of the piping, valves, and instrumentation are located outside the primary system concrete shield at an elevation above the water level in the bottom of the containment at postaccident conditions. (The exceptions are the cooling lines for the reactor coolant pumps and reactor supports, which can be secured following the accident.) In this location the systems in the containment are protected against credible missiles and from being flooded during postaccident operations. Also, this location provides shielding, which allows for maintenance and inspections to be performed during power operation.

Outside the containment, the residual heat removal pumps, the spent fuel heat exchanger, the component cooling pumps and heat exchangers and associated valves, piping and instrumentation are maintainable and inspectable during power operation. Replacement of one pump or one heat exchanger is practicable while the other units are in service. The wetted surfaces of the component cooling loop are fabricated from carbon steel. The component cooling water contains a corrosion inhibitor to protect the carbon steel. Welded joints and connections are used except where flanged closures are employed to facilitate maintenance. The entire system is seismic Class I and is housed in structures of the same classification. The components are designed to the codes given in Table 9.3-1 and the design pressures given in Table 9.3-2. In addition, the components are not subjected to any high pressures or stresses. Hence, a rupture or failure of the system is very unlikely.

In the event of a loss-of-offsite power, the plant emergency diesel generators are immediately started and the component cooling water pumps are automatically loaded (in sequence) onto the emergency buses and started. Component cooling water to the reactor coolant pump thermal barrier heat exchanger is thus automatically restored to provide reactor coolant pump seal cooling and prevent seal failure for at least a 2-hr period following a loss-of-offsite power.

An alternate power supply is also provided for one of the component cooling water pumps from the 13.8-kV normal offsite power through Unit 1 switchgear. If normal offsite power is not available, this pump can be energized using the SBO / Appendix R diesel. During the recirculation phase following a loss-of-coolant accident, one of the three component cooling water pumps is required to deliver flow to the shell side of one of the residual heat exchangers.

9.3.3.1.2 Residual Heat Removal Loop

Two pumps and two heat exchangers are utilized to remove residual and sensible heat during plant cooldown. If one of the pumps and/or one of the heat exchangers is not operable, safe operation is governed by Technical Specifications and safe shutdown of the plant is not affected; however, the time for cooldown is extended. The function of this equipment following a loss-of-coolant accident is discussed in Section 6.2.

Alternate power can be supplied to one residual heat removal pump from the 13.8-kV normal outside power through Unit 1 switchgear.

The time to cool down using the alternate safe shutdown components (1 RHR pump and heat exchanger, 1 component cooling pump, and 1 service water pump supplying flow to non-essential header) has been determined[1 & 2]. Conditions assumed were an initial core power of 102% of 3216 MW and service water temperature of 95°F. The analysis shows that the RCS can be brought to the cold shutdown mode (temperature less than 200°F) within 72 hours.

9.3.3.1.3 Spent Fuel Pit Cooling Loop

This manually controlled loop may be shut down safely for time periods, as shown in Section 9.3.3.2.3, for maintenance or replacement of malfunctioning components.

9.3.3.2 Leakage Provisions

9.3.3.2.1 Component Cooling Loop

Water leakage from piping, valves, and equipment in the system inside the containment is not considered to be generally detrimental unless the leakage exceeds the makeup capability. With respect to water leakage from piping, valves, and equipment outside the containment, welded construction is used where possible to minimize the possibility of leakage. The component cooling water could become contaminated with radioactive water due to a leak in any heat exchanger tube in the chemical and volume control, the sampling, or the auxiliary coolant systems, or a leak in the thermal barrier cooling coil for the reactor coolant pumps.

Tube or coil leaks in components being cooled would be detected during normal plant operations by the leak detection system described in Sections 4.2.7 and 6.7. Such leaks are also detected at any time by a radiation monitor that samples the component cooling pump discharge downstream of the component cooling heat exchangers.

Leakage from the component cooling loop can be detected by a falling level in the component cooling surge tank. The rate of water level fall and the area of the water surface in the tank permit determination of the leakage rate. To assure accurate determinations, the operator would check that temperatures are stable.

The component, which is leaking can be located by sequential isolation or inspection of equipment in the loop. If the leak is in one of the component cooling water heat exchangers it can be isolated and repaired within the limitations of the Technical Specifications. Overall leakage within the containment is limited to the value given in the Technical Specifications.

Should a large tube-side to shell-side leak develop in a residual heat exchanger, the water level in the component cooling surge tank would rise, and the operator would be alerted by a high water alarm. The atmospheric vent on the tank is automatically closed in the event of high radiation level in the component cooling loop. If the leaking residual heat exchanger is not isolated from the component cooling loop before the inflow completely fills the surge tank, the relief valve on the surge tank lifts. The discharge of this relief valve is routed to the auxiliary building waste holdup tank.

The severance of a cooling line serving an individual reactor coolant pump cooler would result in substantial leakage of component cooling water. However, the piping is small as compared to piping located in the missile-protected area of the containment. Therefore, the water stored in the surge tank after a low level alarm together with makeup flow provides ample time for the closure of the valves external to the containment to isolate the leak before cooling is lost to the essential components in the component cooling loop.

The relief valves on the component cooling water lines downstream from each reactor coolant pump protect the downstream piping and thermal barrier cooling coils from overpressure should cooling water be isolated to the thermal barrier coil when the reactor coolant pumps are still operating. The valves set pressure equals the design pressure of the reactor coolant system.

The relief valves on the cooling water lines downstream from the sample, excess letdown, seal water, nonregenerative, spent fuel pit, and residual heat exchangers are sized to relieve the volumetric expansion occurring if the exchanger shell side is isolated when cool, and high temperature coolant flows through the tube side. The set pressure equals the design pressure of the shell side of the heat exchangers.

The relief valve on the component cooling surge tank is sized to relieve the maximum flow rate of water, which enters the surge tank following a rupture of a reactor coolant pump thermal barrier cooling coil. The set pressure will allow the component cooling system to be a closed system under accident conditions, even at 100-percent of containment design pressure. The over-pressurization incident, which results from a passive failure of a reactor coolant pump seal cooling coil coincident with the failure of the high flow cutoff valve would result in a maximum component cooling water pressure of 185 psig. This pressure is allowed in the component cooling water system in accordance with its design code of B31.1, 1967 edition, par 102.2.4(2), addressing permissible variation and allowable stress value for a limited time.

9.3.3.2.2 Residual Heat Removal Loop

During reactor operation all equipment of the residual heat removal loop is idle and the associated isolation valves are closed. During the loss-of-coolant accident condition, water from the containment recirculation sump is recirculated through a loop inside the containment using the recirculation pumps and the residual heat exchangers. The residual heat removal pumps (which are located outside of the containment) serve as backup to the internal recirculation pumps.

Each of the two residual heat removal pumps is located in a shielded compartment with a floor drain. Piping conveys the drain water to a common sump. Two redundant sump pumps, each capable of handling the less than 50 gpm flow, which would result from the failure of a residual heat removal pump seal, discharge to the waste holdup tank.

The original design of the RHR and HHSI Pump seals incorporated a disaster bushing that would limit the flow to 50 GPM if the seal faces were severely damaged. For Generic Letter 2004-02 compliance, an analysis determined the wear of these disaster bushings if debris laden fluid passed through a failed seal. The potentially abrasive nature of the fluid can wear non-metallic disaster bushings over time, whereby the flow out past the damaged seal could eventually exceed 50 GPM. However, this effect is not immediate and as before, actions would be taken to isolate the pump before the 50 GPM flow rate is reached. The Chesterton seal, an alternate type to the original seal, was tested to demonstrate that severely damaged seal faces would result in a flow rate of less than 50 GPM past the seal. Both the original seal designs and later Chesterton model seals are acceptable and may be used in the HHSI and RHR pumps.

9.3.3.2.3 Spent Fuel Pit Cooling Loop

Whenever a leaking fuel assembly is transferred from the fuel transfer canal to the spent fuel storage pool, a small quantity of fission products may enter the spent fuel cooling water. A bypass purification loop is provided for removing these fission products and other contaminants from the water.

The probability of inadvertently draining the water from the cooling loop of the spent fuel pit is exceedingly low. The only mode would be from such actions as opening a valve on the cooling line and leaving it open when the pump is operating. In the unlikely event of the cooling loop of the spent fuel pit being drained, the spent fuel storage pit itself cannot be drained and no spent fuel is uncovered since the spent fuel pit cooling connections enter near the top of the pit. With no heat removal the time for the spent fuel pit water to rise from 180°F to 212°F with a full core in storage is at least 1.8 hr. Makeup water can be supplied within this time from the primary water storage tank, the refueling water storage tank and/or the fire protection system. The maximum required makeup rate for boiloff is 62 gpm (for a full core). Spent fuel pit temperature and level instrumentation would warn the operator of an impending loss of cooling. A local flow indicator is available to support operation of the Spent Fuel Pit Pumps.

9.3.3.3 Incident Control

9.3.3.3.1 Component Cooling Loop

In the unlikely event of a pipe severance in the component cooling loop, backup is provided for postaccident heat removal by the containment fan coolers. Pipe severance is a passive failure and is assumed to occur 24 hours or greater after event initiation.

Should the break occur outside the containment the leak could either be isolated by valving or the broken line could be repaired, depending on the location in the loop at which the break occurred.

Once the leak is isolated or the break has been repaired, makeup water is supplied from the reactor makeup water tank by one of the primary makeup water pumps. If the loop drains completely before the leakage is stopped, it can be refilled by a primary makeup water pump in less than 2 hr.

If the break occurs inside the containment on a cooling water line to a reactor coolant pump, the leak can be isolated. Each of the cooling water supply lines to the reactor coolant pumps contains a check valve inside and a common remotely operated valve outside the containment wall.

Each return line (combined oil coolers and combined thermal barrier coolers) has a common remotely operated valve outside the containment wall. The cooling water supply line to the excess letdown heat exchanger contains a check valve inside the containment wall and both supply and return lines have automatically isolated valves outside the containment wall. Should the break occur inside containment and the leak can not be isolated the residual heat removal pumps and safety injection pumps, if required, are employed to recirculate uncooled spilled water to the core that is removed from the core by boiling off of the water to the containment with the fan coolers being used to condense the resulting steam.

Flow indication is provided on the component cooling return lines from the safety injection and residual heat removal pumps. Each of the component cooling supply lines to the residual heat exchangers has a normally closed remotely-operated valve. If one of the valves fails to open upon a safety injection signal, the valve, which does open supplies a heat exchanger with sufficient cooling to remove the heat load during long term postaccident recirculation.

The portion of the component cooling loop located outside the containment is considered to be a part of the reactor building isolation barrier.

Except for the normally closed makeup line the primary water and city water emergency cooling lines, and equipment vent and drain lines, there are no direct connections between the cooling water and other systems. The primary water make-up and SIS/RHR Emergency Cooling Lines have manual valves that are normally closed unless required for their design function or testing. The city water emergency cooling line contains two normally closed isolation valves with an open tell-tale connection between them. The tell-tale prevents the potential contamination of a potable water source with component cooling water corrosion inhibitor chemicals. The equipment vent and drain lines outside the containment have manual valves, which are normally closed unless the equipment is being vented or drained for maintenance or repair operations.

9.3.3.3.2 Residual Heat Removal Loop

The residual heat removal loop is connected to the reactor outlet line on the suction side and to the reactor inlet line on the discharge side. On the suction side the connection is through two electric motor-operated gate valves in series with both valves independently interlocked with reactor coolant system pressure. On the discharge side the connection is through two check valves in series with an electric motor-operated gate valve. All of these are closed whenever the reactor is in the operating condition.

9.3.3.3.3 Spent Fuel Pit Cooling Loop

The most serious failure of this loop is complete loss-of-water in the storage pool. To protect against this possibility, the spent fuel storage pool cooling connections enter near the water level so that the pool cannot be either gravity drained or inadvertently drained. For this same reason care is also exercised in the design and installation of the fuel transfer tube. The water in the spent fuel pit below the cooling loop connections could be removed by using a portable pump.

Instrumentation is provided that will activate an alarm in the control room if the level in the spent fuel pit is at a preset level deviation above or below normal. Operators normally observe the level in the pool on a regular basis.

9.3.3.4 Malfunction Analysis

A failure analysis of pumps, heat exchangers and valves is presented in Table 9.3-5.

9.3.4 Minimum Operating Conditions

Minimum operating conditions for the auxiliary coolant system are specified in the Technical Specifications.

9.3.5 Tests and Inspections

Tests and inspections of the auxiliary coolant system are specified in the Technical Specifications.

The portion of the Residual Heat Removal System that is outside of containment, and not tested in accordance with Technical Specifications, shall be tested at least once each 24 months either by use in normal operation or by hydrostatically testing at 350 psig. The piping, between the residual heat removal pump suction and the containment isolation valves in the residual heat removal pump suction line from the containment sump, shall be hydrostatically tested once each 24 months at no less than 100 psig. Visual inspection of the system components shall be performed during these tests and any significant leakage shall be measured by collection and weighing or by another equivalent method. Repairs or isolation shall be made as required to maintain leakage from the Residual Heat Removal System components located outside of the containment per Technical Specification 5.5.2.

REFERENCES FOR SECTION 9.3

1. Letter (with attachment, WCAP-12312) from S. Bram, Con Edison, to NRC, Subject: Application for License Amendment to Increase the Design Basis Inlet Temperature of the Service Water System, dated July 13, 1989.

2. Westinghouse calculation CN-SEE-03-5, Indian point Unit 2 RHR Cooldown Analysis for the 5% Power Uprate Program, Rev. 0.

TABLE 9.3-1
Auxiliary Coolant System Code Requirements

Component	Code
Component cooling heat exchangers	ASME VIII
Component cooling surge tank	ASME VIII
Component cooling loop piping and valves	USAS B31.1

Residual heat exchangers side ASME VIII, shell side	ASME III, Class C, tube
Residual heat removal piping and valves	USAS B31.1
Spent fuel pit filter	ASME III, Class C
Spent fuel heat exchanger side ASME VIII, shell side	ASME III, Class C, tube
Spent fuel pit loop piping and valves	USAS B31.1

TABLE 9.3-2 (Sheet 1 of 2)
Component Cooling Loop Component Data

Component Cooling Pumps	Parameters
Quantity	3
Type	Horizontal centrifugal
Rated capacity (each), gpm	3600
Rated head, ft H_2O	220
Motor horsepower, hp	250
Material (pump casing)	Cast iron or Carbon steel
Design pressure, psig	150
Design temperature, °F	200
Component Cooling Heat Exchangers	
Quantity	2
Type	Shell and straight tube
Design heat transfer, Btu/hr	31.4×10^6
Shell side (component cooling water)	
Operating inlet temperature, °F	100.1
Operating outlet temperature, °F	88.2
Design flow rate, lb/hr	2.66×10^6
Design temperature, °F	200
Design pressure, psig	150
Material	Aluminum-bronze
Tube side (service water)	
Operating inlet temperature, °F	75[1]
Operating outlet temperature, °F	81.9
Design flow rate, lb/hr	4.55×10^6
Design temperature, °F	200
Design pressure, psig	150
Material	Copper-nickel (90-10)

TABLE 9.3-2 (Sheet 2 of 2)

Component Cooling Loop Component Data

Component Cooling Surge Tank

Quantity	1
Volume, gal	2000
Normal water volume, gal	1000
Design pressure, psig	100
Design temperature, °F	200
Construction material	Carbon steel
Relief valve setpoint, psig	52

Auxiliary Component Cooling Water Pumps

Quantity	2
Type	Vertical centrifugal
Rated capacity, gpm	80
Rated head, ft H_2O	100
Motor horsepower, hp	5
Casing material	Cast steel
Design pressure, psig	150
Design temperature, °F	200

CCW Circulating Water Pumps
(Safety Injection Pumps)

Quantity	3
Type	Centrifugal
Rated capacity, gpm	40
Rated head, ft H_2O	110
Casing material	Stainless Steel
Design pressure, psig	225
Design temperature, °F	200

Component Cooling Loop Piping and Valves

Design pressure, psig	150
Design temperature, °F	200

Notes:
1. Operation is acceptable up to 95°F.

TABLE 9.3-3 (Sheet 1 of 2)
Residual Heat Removal Loop Component Data

Reactor coolant temperature at startup of heat removal, °F	350
Time to cool reactor coolant system from	
350°F to 200°F, hr (all equipment operational)	48 [1]
350°F to 140°F, hr (all equipment operational)	113.6 [1]
Refueling water storage temperature, °F	Ambient
Decay heat generation at 10 hrs after shutdown condition, Btu/hr	85.6×10^6 [1]
Reactor cavity fill time, hr	1
Reactor cavity drain time, hr	4

Residual Heat Removal Pumps

Quantity	2
Type	Vertical centrifugal
Rated capacity (each), gpm	3000
Rated head, ft H_2O	350
Motor, hp	400
Material	Stainless steel
Design pressure, psig	600
Design temperature, °F	400

TABLE 9.3-3 (Sheet 2 of 2)
Residual Heat Removal Loop Component Data

Residual Heat Exchangers

Quantity	2
Type	Shell and U-tube
Design heat transfer (each), Btu/hr	30.8×10^6
Shell side (component cooling water)	
Operating inlet temperature, °F	88.3
Operating outlet temperature, °F	100.8
Design flow rate, lb/hr	2.46×10^6
Design temperature, °F	200
Design pressure, psig	150
Material	Carbon steel
Tube side (reactor coolant)	
Operating inlet temperature, °F	135
Operating outlet temperature, °F	113.5
Design flow rate, lb/hr	1.44×10^6
Design temperature, °F	400
Design pressure, psig	600
Material	Stainless steel

Residual Heat Removal Loop Piping and Valves

1. Isolated loop	
Design pressure, psig	600
Design temperature, °F	400
2. Loop Isolation	
Design pressure, psig	2485
Design temperature, °F	650

Notes:

1. Aligned to RHR system at 20 hours after shutdown, 95°F Service Water

TABLE 9.3-4 (Sheet 1 of 3)
Spent Fuel Cooling Loop Component Data

Spent fuel pit heat exchanger	
Quantity	1
Type	Shell and U-tube
Design heat transfer, Btu/hrs$_1$	7.96×10^6
Shell side (component cooling water)	
Normal operating inlet temperature, °F$_1$	100
Normal operating outlet temperature, °F$_1$	105.7
Design flow rate, lb/hr	1.4×10^6
Design temperature, °F	200
Design pressure, psig	150
Material	Carbon steel
Tube side (spent fuel pit water)	
Normal operating inlet temperature, °F$_1$	120
Normal operating outlet temperature, °F$_1$	112.8
Design flow rate, lb/hr	1.1×10^6
Design temperature, °F	200
Design pressure, psig	150
Material	Stainless steel
Spent fuel pit skimmer pump	Retired in place
Refueling water purification pump	
Quantity	1
Type	Horizontal centrifugal
Rated capacity, gpm	100
Rated head, ft H_2O	150
Design pressure, psig	150
Design temperature, °F	200
Material	Stainless steel

TABLE 9.3-4 (Sheet 2 of 3)
Spent Fuel Cooling Loop Component Data

Spent fuel pit cooling loop piping and valves	
Design pressure, psig	150
Design temperature, °F	200
Spent fuel pit skimmer loop piping and valves	Retired in place
Refueling water purification loop piping and valves	
Design pressure, psig	150
Design temperature, °F	200
Spent fuel pit pump	
Quantity	2
Type	Horizontal centrifugal
Material	Stainless steel
Rated capacity, gpm	2,300
Rated head, ft H_2O	125
Motor, hp	100
Design pressure, psig	150
Design temperature, °F	200
Spent fuel storage pool	
Volume ft^3	37,300
Typical Boron concentration, ppm boron	>2,000 min
Tech Spec Boron concentration, ppm boron	>2,000 min
Spent fuel pit filter	
Quantity	1
Internal design pressure of housing, psig	200
Design temperature, °F	250
Rated flow, gpm	100
Maximum differential pressure across filter element at rated flow (clean cartridge), psi	5
Maximum differential pressure across filter element prior to removing, psi	20
Filtration requirement	98-percent retention of particles down to 5 μ

TABLE 9.3-4 (Sheet 3 of 3)

Spent Fuel Cooling Loop Component Data

Spent fuel pit strainer	
Quantity	1
Rated flow, gpm	2,300
Maximum differential pressure across the strainer element at rated flow (clean), psi	1
Perforation, in.	~0.2
Spent fuel pit demineralizer	
Quantity	1
Type	Flushable
Design pressure, psig	200
Design temperature, °F	250
Flow rate, gpm	100
Resin volume, ft^3	30
Spent fuel pit skimmers	Deleted
Spent fuel pit skimmer strainer	Retired in place
Spent fuel pit skimmer filter	Retired in place

Notes:
1. Original design.

TABLE 9.3-5
Failure Analysis of Pumps, Heat Exchangers, and Valves

Components	Malfunction	Comments and Consequences
1. Component cooling water pumps	Rupture of a pump casing	The casing and shell are designed for 150 psi and 200°F, which exceeds maximum operating conditions. Pump is inspectable and protected against credible missiles. Rupture is not considered credible. However, each unit is isolable. Two of the three pumps are needed to carry total pumping load.
2. Component cooling water pumps	Pump fails to start	One operating pump supplies sufficient cooling water for emergency core cooling during recirculation.
3. Component cooling water pumps	Manual valve on a pump suction line	This is prevented by pre-startup and operational checks. Further, during normal operation, each pump is checked on a periodic basis, which would show if a valve is closed.
4. Component cooling water valve	Normally open valve	The valve is checked open during periodic operation of the pumps during normal operation.
5. Component cooling heat exchanger	Tube or shell rupture	Rupture is considered improbable because of low operating pressures. Each unit is isolable. Both units may be required to carry total heat load for normal operation at 95°F Service Water.
6. Demineralized water makeup line check valve	Sticks open	The check valve is backed up by the manually-operated valve. Manual valve is normally closed.
7. Component cooling heat exchanger vent or drain valve	Left open	This is prevented by pre-startup and operational checks. On the operating unit such a situation is readily assessed by makeup requirements to system. On the second unit such a situation is ascertained during periodic testing.
8. Component cooling water outlet valve to residual heat exchanger	Fails to open	There is one valve on each outlet line from each heat exchanger. One heat exchanger remains in service and provides adequate heat removal during long-term recirculation. During normal operation the cooldown time is extended.

9.3 FIGURES

Figure No.	Title
Figure 9.3-1 Sh. 1	Auxiliary Coolant System - Flow Diagram, Sheet 1, Replaced with Plant Drawing 227781
Figure 9.3-1 Sh. 2	Auxiliary Coolant System - Flow Diagram, Sheet 2, Replaced with Plant Drawing 9321-2720
Figure 9.3-1 Sh. 3	Auxiliary Coolant System - Flow Diagram, Sheet 3, Replaced with Plant Drawing 251783

9.4 SAMPLING SYSTEM

9.4.1 Design Basis

9.4.1.1 Performance Requirements

This system provides for analysis of liquid and gaseous samples obtained during normal operation and postaccident conditions. The containment atmosphere postaccident sampling system is discussed in Sections 6.8.2.2 and 6.8.2.3. Sampling of the primary and secondary coolant systems is discussed below.

Primary samples include the following:

1. Reactor coolant system hot-leg loops 21 and 23.
2. Pressurizer steam space and liquid space.
3. Residual heat removal loop.
4. Safety injection system accumulators 21, 22, 23, and 24.
5. Recirculation pumps 21 and 22 discharge.
6. Chemical and volume control system letdown lines at demineralizer inlet and outlet.
7. Holdup tanks.
8. CVCS holdup tank transfer pumps discharge.
9. Chemical drain pump 21 discharge.
10. Waste evaporator feed pump 21 discharge.
11. High-radiation sampling system collection tank discharge.

These samples are obtained at the high-radiation sampling system panels and evaluated by the online analysis systems or manual analysis. Secondary samples are obtained from the secondary sampling system, which is separate from the high–radiation sampling system. Postaccident sampling of the primary system is an extension of the use of the high-radiation sampling system for routine sampling.
The NRC approved[3] the removal of the requirements and administrative controls for the postaccident sampling system from the Technical Specifications and accepted regulatory commitments to maintain:

1. contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere;

2. the capability for classifying fuel damage events at the Alert threshold within the Emergency Plan Implementing Procedures (EPIPs); and

3. the capability for monitoring radioactive iodines that have been released to offsite environs within the EPIPs.

Sampling system discharge flows are limited under normal and anticipated fault conditions (malfunctions or failure) to preclude any fission product releases beyond the limits of 10 CFR 20. Shielding has been provided to minimize operator exposure to any radiation during the sampling procedures.

The primary coolant sampling system was evaluated by the NRC against the criteria in Item II.B.3 of NUREG-0737 and found acceptable.[1,2]

9.4.1.2 Design Characteristics

The design characteristics of the high-radiation sampling system include the following:

1. Control of background radiation and operator exposure to radiation.
2. Rapid sampling and analysis.
3. Sampling and transfer of undiluted samples.

In addition, the system is capable of the following:

1. The system can be used for both routine and postaccident sampling and has the capability to obtain an undiluted reactor coolant sample under accident conditions for transport offsite for independent analyses.

2. Inline measurement of the reactor coolant specific conductivity, pH, and dissolved oxygen, hydrogen, chlorides, and boron under both routine and postaccident conditions.

3. Additional sample connections are available for more flexibility in selecting sample points; redundant sample connections allow for further expansion if needed to ensure sample acquisition under postaccident conditions.

4. Methods for cooling and depressurizing all high temperature-high pressure fluids for gas sampling and inline analyses.

5. Specially designed shielded transfer casks minimize operator radiation exposure when obtaining diluted and undiluted liquid samples. A small aliquot of reactor coolant system liquid or containment air samples is transferred as required to designated areas for analyses using a holder to maintain adequate distance and provide low operator radiation exposure.

Flow paths are also provided for boron concentration, and isotopic inline analysis.

Sampling of other process coolants, such as tanks in the waste disposal system, is accomplished locally. Equipment for sampling secondary and nonradioactive fluids is separated from the equipment provided for reactor coolant samples. Leakage and drainage resulting from the sampling operations are collected and drained to tanks located in the waste disposal system.

9.4.1.3 Primary Sampling

Two types of samples are obtained by the primary sampling system: high temperature-high pressure reactor coolant system and steam generator blowdown samples, which originate inside the reactor containment, and low temperature-low pressure samples from the chemical and volume control and auxiliary coolant systems.

9.4.1.3.1 High Pressure-High Temperature Samples

A sample connection is provided from each of the following:

1. The pressurizer steam space.
2. The pressurizer liquid space.
3. Hot legs of loops 21 and 23.
4. Blowdown from each steam generator.

9.4.1.3.2 Low Pressure-Low Temperature Samples

A sample connection is provided from each of the following:

1. The letdown demineralizers inlet and outlet header.
2. The residual heat removal loop, just downstream of the heat exchangers.
3. The volume control tank gas space.
4. The (safety injection system) accumulators 21, 22, 23, and 24.
5. Recirculation pumps 21 and 22 discharge.

9.4.1.4 Expected Operating Temperatures

The high pressure-high temperature samples and the residual heat removal loop samples leaving the sample heat exchangers are cooled to minimize the generation of radioactive aerosols.

9.4.1.5 Secondary Sampling

The secondary sampling system provides continuous sampling and analysis of the plant's secondary systems. This ensures the maintenance of proper water chemistry conditions in the secondary side piping and equipment.

A sample connection is provided from each of the following:

1. Each of the four main steam lines.
2. Each condenser hotwell section.
3. Condensate pump discharge.
4. Outlet of the 26 feedwater heaters.
5. Drains collection tank inlet from primary water.

9.4.1.6 Codes and Standards

System code requirements are given in Table 9.4-1. In addition, the high radiation sampling system was designed and installed to meet the provisions of NUREG-0737. These provisions include the following:

1. Provide postaccident sampling and analysis capability. The combined time for sampling and analysis is 3 hr or less from the time a decision is made to take a sample.

2. Provide capability to obtain and analyze a sample without radiation exposure to any individual exceeding the criteria of GDC 19 (10 CFR Part 50, Appendix A).

3. Provide means of measuring pH, conductivity, chlorides, dissolved hydrogen, dissolved oxygen, inline isotopic analysis, and boron analysis.

4. Provide means of safely obtaining pressurized samples, depressurized samples, and diluted and undiluted samples for laboratory analysis.

5. Safely store the sampled fluid until its disposal is determined.

6. Provide means of diverting to the containment the stored sample fluid.

7. Provide the capability to use the system on a continuous day-to-day basis.

8. Provide the capability to flush the sampled lines.

9. Provide the capability of drawing samples even when the reactor coolant system is depressurized (reactor coolant system, residual heat removal, and recirculation lines).

9.4.2 System Design and Operation

9.4.2.1 Primary Sampling System

The primary sampling system consists of the high-radiation sampling system, which is shown in Plant Drawing 9321-2745. The high-radiation sampling system provides the representative samples for inline monitoring and laboratory analysis under normal or postaccident conditions. Analytical results provide guidance in the operation of the reactor coolant, auxiliary coolant, steam, and chemical and volume control systems. Analyses show both chemical and radiochemical conditions. Typical information obtained includes reactor coolant boron and chloride concentrations, fission product radioactivity level, hydrogen, oxygen, and fission gas content, corrosion product concentration, and chemical additive concentration.

The information is used in regulating boron concentration, evaluating fuel element integrity and mixed-bed demineralizer performance, and regulating additions of corrosion controlling chemicals to the systems. The high-radiation sampling system can be operated intermittently or on a continuous basis. Samples can be withdrawn under conditions ranging from full power to cold shutdown to postaccident conditions.
Reactor coolant liquid, [***Note*** *- For postaccident conditions, the reactor coolant liquid sample may be taken from the reactor coolant system hot legs 21 and 23 or the recirculation pump*

discharge or the residual heat removal loop.], which is normally inaccessible or which requires frequent sampling, is sampled by means of permanently installed piping leading to either the inline isotopic analyzer, or the liquid sampling panel located in the sentry high-radiation sampling system room (formerly the waste evaporator room) at the 80-ft level of the primary auxiliary building. A seismic Class I concrete wall surrounds the high-radiation sampling system panel and a combination of lead shot and steel composes the shielding for the panel itself. These materials provide the shielding necessary to allow access to the high-radiation sampling system during and following accident conditions. Most of the primary sampling equipment is located in the sentry high-radiation sampling system room although some of it is located in other areas such as the pipe trench area of the 51-ft elevation and the 68-ft elevation of the mezzanine within the primary auxiliary building. The delay coils and remotely operated valves on the reactor coolant system hot-leg sample lines are located inside the reactor containment. Containment isolation valves are located immediately outside containment and are controlled, in an accident, from either the central control room or the sample system valve control panel. A line from the makeup water system has been installed to provide water for flushing of the sample lines.

Reactor coolant hot-leg liquid, pressurizer liquid, and pressurizer steam samples originating inside the reactor containment flow through separate sample lines to the sentry liquid sampling panel. The samples pass through the reactor containment to the auxiliary building where they are cooled (pressurizer steam samples recondensed and cooled) in the sample heat exchangers.

The reactor coolant samples are then routed through the inline isotopic analyzer where specific nuclides are identified.

All samples then go to the sentry high-radiation sampling system panel. This consists of a liquid sampling panel, which is subdivided into a reactor coolant module, which includes the capability for dissolved gas analysis, a demineralizer sampling module, and a radwaste sampling module. Associated with the liquid sampling panel is the chemical analysis panel. These modules are discussed in detail later.

The chemical analysis panel analytical results register on the chemical monitor panel in the sentry high-radiation sampling system room. There are remote readouts for the boron analysis in the radio chemistry laboratory and nuclear service building 1.

Reactor coolant and demineralizer samples from the chemical and volume control system are depressurized and degasified in the reactor coolant module and demineralizer modules, respectively. From there they are sent to the chemical analysis panel, which can analyze for hydrogen, oxygen, chlorides, pH, and conductivity.

Provisions are included in the primary sampling system to allow each sample to be purged through the sample lines and panel to ensure that representative samples are obtained. The sample volumes are routed to the high-radiation sampling system collection tank or chemical drain tank after completion of the task.

The reactor coolant sample originating from the residual heat removal loop of the auxiliary coolant system has a motor-operated isolation valve located close to the sample source outside the containment. The sample line from this source intersects the sample line coming from the hot leg at a point ahead of the sample heat exchanger. This sample then follows the same flow path as that described for the reactor coolant system hot-leg samples. See Plant Drawings 9321-2745 and 227178 [Formerly UFSAR Figure 9.4-1].

A steam-generator sample line is taken from each blowdown line outside containment. The sample lines are routed to the blowdown tank room adjacent to the primary auxiliary building where the samples are cooled and are then passed through a radiation monitor as well as routed to cell 2 of the support facilities.

These sample streams pass through additional local heat exchangers in cell 2 and subsequently through radiation, pH, conductivity, and chloride monitors. The sample waste under normal conditions is then routed to the river. Samples not suitable for release are diverted to the support facilities contaminated drain tank and waste disposal system.

In the event of primary-to-secondary coolant leakage in one or more of the steam generators, the blowdown will be diverted to the support facilities secondary boiler blowdown purification system flash tank. This system cools the blowdown and either stores it in the support facilities waste collection tanks or purifies it. The purification process consists of filtering and demineralizing the blowdown. The filters will remove undissolved material of 25 μ or greater. Mixed-bed demineralizers, which utilize cation and anion resin, remove isotopic cations and anions as well as nonradioactive chemical species. The effluents of the demineralizers are monitored and the specific activity is recorded on a two-pen recorder in the support facilities chemical system control room.

Local instrumentation is provided to permit manual control of sampling operations and to ensure that the samples are at suitable temperatures and pressures before diverting flow to the sample sink.

9.4.2.1.1 Components

A summary of principal component data is given in Table 9.4-2.

9.4.2.1.1.1 Sample Heat Exchangers

Ten sample heat exchangers reduce the temperature of samples from the pressurizer steam space, the pressurizer liquid space, each steam generator, and the reactor coolant system liquid before samples reach the sample vessels and the sample sink. The tube side of the heat exchangers is austenitic stainless steel, the shell side is carbon steel.

The inlet and outlet tube sides have socket-weld joints for connections to the high-pressure sample lines. Connections to the component cooling water lines are socket-weld joints. The samples flow through the tube side and component cooling water from the auxiliary coolant system circulates through the shell side.

9.4.2.1.1.2 Delay Coil and Restriction Orifice

The high-pressure reactor coolant sample line, which contains a delay coil consisting of coiled tubing and a restriction orifice, will provide at least 40 sec sample transit time within the containment and an additional 20 sec transit time from the reactor containment to the sampling station. This allows for decay of short-lived isotopes to a level that permits normal access to the sampling room.

9.4.2.1.2 Liquid Sampling Panel

The liquid sampling panel valves and components are arranged in three modules installed in a common panel shield:

1. Module 1 - Reactor coolant sampling module (RC).
2. Module 2 - Demineralizer sampling module (DM).
3. Module 3 - Radwaste sampling module (RW).

Sample tubing and components are mounted behind the shielded panel within a plenum. Any gas leakage is vented to a local prefilter and HEPA filters and finally to existing ventilation ducts containing charcoal filters. A vessel at the bottom of the plenum collects any minor liquid leakage, which is pumped to radwaste. This provides containment of radioactivity during sampling operations.

As a safety measure, the liquid sampling panel has a hooded splash box to contain any accidental liquid spill or gaseous release during normal sampling of pressurized reactor coolant or liquid grab sampling from all three modules.

Each system can be purged through the sample lines and panel to ensure representative samples will be obtained. The purge flow can be directed back to the containment to chemical drain tank 21 and the associated waste disposal system or to the shielded high-radiation sampling system waste collection tank.

All lines of the liquid sampling panel can be flushed with demineralized water following each sampling operation. Provisions are included for eliminating water from the gas expansion vessel and drying the gas lines of the panel.

Included as part of the liquid sampling panel are carts, shielded casks, and other specialized equipment for sampling under accident conditions. After sampling, the shielded casks can be removed to provide samples for backup in-house analyses or stored for subsequent offsite analysis. The viewing window and sampling compartment for alignment of the cart and cask are located in the lower right section of the liquid sampling panel.

The types of samples that can be obtained from the liquid sampling panel during normal operation are:

1. Undiluted, depressurized liquid grab samples from the reactor coolant, demineralizer, and radwaste modules.
2. Removable 75-ml pressurized liquid samples from the reactor coolant module, for subsequent analysis in the chemical analysis panel.
3. Inline pressurized liquid samples from the reactor coolant module.

Additional functions of the liquid sampling panel during normal operation include:

1. Purging of lines with sample to ensure representative samples will be obtained.
2. Reduction of pressure and control of flow rate of the primary coolant as it flows to the chemical analysis panel.
3. Routing of stripped gas from the pressurized liquid sample to the chemical analysis panel gas chromatograph.

The types of samples that can be obtained from the liquid sampling panel during accident conditions are:

1. Undiluted liquid samples from the reactor coolant and radwaste modules in cart/cask.
2. Diluted (1 to 1000) liquid samples from the reactor coolant and radwaste modules in cart/cask.
3. Inline pressurized liquid sample from the reactor coolant module.
4. Diluted (1 to 15,000) stripped gas sample from the reactor coolant pressurized liquid sample.

Additional functions of the liquid sampling panel during accident conditions include:

1. Purging of lines with sample to ensure representative samples will be obtained.
2. Capability for back-flushing the inline filters of the reactor coolant and radwaste modules.
3. Capability for flushing all lines and sample bottles on an individual section basis to control radiation levels as necessary.
4. Routing of stripped gas from the pressurized reactor coolant sample to the chemical analysis panel gas chromatograph.
5. Reduction of pressure and control of flow rate of the primary coolant as it flows to the chemical analysis panel.

9.4.2.1.3 Isotopic Analyzer

Isotopic analyses may be performed on the following samples obtained from the liquid sampling panel:

1. Pressurized reactor coolant sample (gas and liquid) in removable sample flask for normal sampling.
2. Undiluted grab samples from the reactor coolant, demineralizer and radwaste modules of the liquid sampling panel for normal sampling.
3. Diluted liquid samples from the reactor coolant and radwaste modules of the liquid sampling panel for accident sampling.
4. Undiluted liquid samples from the reactor coolant and radwaste modules of the liquid sampling panel for offsite analyses during accident conditions.
5. Diluted stripped gas samples from the reactor coolant module of the liquid sampling panel for accident sampling.

Isotopic analyses are performed using a Ge(Li) detector gamma spectroscopy system using previously established counting geometries.

9.4.2.1.4 Boron Analyzer

Backup boron analyses may be performed on the following samples from the liquid sampling panel for analysis in the onsite laboratory.

1. Undiluted grab samples from the reactor coolant, demineralizer, and radwaste modules of the liquid sampling panel for normal sampling.

2. Diluted liquid samples obtained from the liquid sampling panel shielded cart/cask from the reactor coolant and radwaste modules of the liquid sampling panel for accident sampling.

The primary sampling system provides that both the routine and accident sample analyses of undiluted samples are performed online using a mannitol titration boron analyzer. It periodically samples an identical line from the chemical analysis panel from which conductivity, dissolved oxygen, and pH are measured.

The range of the accident procedure is from 0.5 to 6.0 ppm boron. The estimated precision at the 95-percent confidence level is +13-percent, -3.3-percent at the 2-ppm boron level.

9.4.2.1.5 Cart and Casks

The cart and casks associated with the liquid sampling panel are used for removal of samples obtained from the reactor coolant and radwaste modules during accident conditions. The shielded casks are mounted on a cart, which moves the cask into position for sampling from the liquid sampling panel. The carts permit access to the casks to obtain a laboratory sample or for storage in a remote area upon completion of the sampling operation.

9.4.2.1.6 Chemical Analysis Panel

The chemical analysis panel receives an undiluted liquid sample stream and stripped gas from the reactor coolant module of the liquid sampling panel.

The chemical analysis panel is divided into three major sections:

1. Flow control and cell section, consisting of the appropriate tubing, valves, and sensing elements.
2. Chromatograph section, containing two ion chromatographs for liquid analysis and a gas chromatograph for gas analysis.
3. Calibration section, where the solutions required for calibrating the pH, specific conductivity, and dissolved oxygen monitors, and ion chromatograph are available for use.

Valves, tubing, cells, and transmitters are mounted on the back of the panel shield within a plenum. Any gas leakage from the liquid sampling panel, chemical analysis panel, or boron analyzer is vented to a pre-filter and HEPA filter and subsequently to the primary auxiliary building ventilation ducts containing charcoal filters. Drip pans are mounted beneath the flow control/cell section and ion chromatograph to collect any minor leakage and to protect other equipment.

The ion and gas chromatographic equipment, which contacts radioactive liquid or gas is mounted behind the shield to minimize operator exposure during the sampling/analysis process. The chemical analysis panel gas chromatograph and ion chromatograph sampling operations are controlled from the chemical monitor panel.

The chemical analysis panel provides the capability for inline determination of the pH, specific conductivity, dissolved oxygen, temperature, and chloride content of a reactor coolant sample flowing from the liquid sampling panel during normal or accident conditions. In addition, the gas chromatograph permits determination of the hydrogen concentration of the stripped gas from the reactor coolant. Remote readouts of the instrumentation measuring the chemical parameters are on the chemical monitor panel.

Flushing lines are provided to flush all internal liquid and gas panel lines, and sample lines connecting the chemical analysis panel to the liquid sampling panel. Reagent calibration tanks may be flushed with nitrogen.

9.4.2.1.7 Chemical Monitor Panel

The chemical monitor panel is an auxiliary recorder/monitor panel, which contains the indicating and recording equipment for the cells and analyzers, which are mounted in the chemical analysis panel. The panel permits the operator to work with and observe indicating and recording equipment from a remote location, to reduce exposure under accident conditions.

Prior to sampling, the operator performs instrument zero and calibration adjustments of the monitors and evaluates chromatograms during the process of calibrating the instrumentation. This is accomplished prior to the chemical analysis panel receiving reactor coolant liquid or stripped gas from the liquid sampling panel.

The monitor indicator readings include conductivity, pH, and dissolved oxygen measurements. The dissolved oxygen monitor, for low level routine analysis, includes a meter indication while the oxygen/temperature monitor provides a recording during accident conditions for higher levels of dissolved oxygen.

A three-channel recorder records the chromatograms from the ion and gas chromatograph. The ion chromatogram is evaluated to determine the chloride concentration in the reactor coolant. Dissolved hydrogen concentration in the reactor coolant is determined by evaluating the gas chromatogram. Control of the sample injection to the chromatographs is provided by controls on the front of the panel.

9.4.2.1.8 High Radiation Sampling System Collection Tank

After analysis, the liquid and gaseous samples are routed to the high radiation sampling system collection tank. A nitrogen line to the tank provides a pressurized noncombustible atmosphere. A vent line is provided for the venting of excess gases. There is also a line running back to the high radiation sampling system panel for analysis of the contents of the tank. If the level of radiation is too high following an accident the samples in the tank can be routed back to containment; otherwise the samples will be routed to the chemical drain tank.

9.4.2.1.8.1 Chemical Drain Tank

During normal operation the liquid and gaseous samples are routed to the chemical drain tank. This tank is then pumped to the Unit 2 waste holdup tank. A sample can be directed to the radwaste module, if analysis is required prior to transfer.

9.4.2.1.8.2 Piping and Fittings

All liquid and gas sample lines are austenitic stainless steel tubing and are designed for high pressure service. With the exception of the sample pressure vessel quick-disconnect couplings and compression fittings at the sample sink and at the liquid sampling panel sump and pump connections, socket-welded joints are used throughout the sampling system. Lines are so located as to protect them from accidental damage during routine operation and maintenance.

9.4.2.1.8.3 Valves

Remotely-operated stop valves are used to isolate all sample points and to route sample fluid flow inside the reactor containment. Manual or motor-operated stop valves are provided for component isolation and flow path control at all normally accessible sampling system locations. Manual throttle valves are provided to adjust the sample flow rate.

All valves in the system are constructed of austenitic stainless steel or equivalent corrosion resistant material.

Isolation valves are provided outside the reactor containment, which trip closed upon generation of the containment isolation signal.

9.4.2.2 Secondary Sampling System

The secondary sampling system is shown in Plant Drawing 9321-7020 [Formerly UFSAR Figure 9.4-2]. This system is used to determine steam and condensate/feedwater quality and chemical addition requirements.

The steam and water analysis station is located in the turbine building. It consists of a local panel where various controls, alarms, recorders and indicators are located; racks for the sample coolers and analyzers; and, a sample sink where grab samples can be obtained.

The main steam can be analyzed for various additives, contaminants or isotopes.

The condensate and/or feedwater can be analyzed for salinity, pH, conductivity, dissolved oxygen, residual hydrazine, and various additives and contaminants. High salinity is indicative of river water leakage into the condenser or makeup carryover.

Conductivity is measured to determine the degree of possible dissolved solids entrainment into the systems.

Because of its corrosive effects, dissolved oxygen is measured and recorded and used as a guide in determining the proper amount of hydrazine to be added to the condensate.

The six individual condenser hotwells are provided with specific conductivity analyzers. These instruments are used to identify the specific condenser sextant that has salt water ingress.

9.4.3 System Evaluation

9.4.3.1 Availability and Reliability

Automatic action is not required of the sampling system during an emergency or to prevent an emergency condition. In a postaccident situation, after proper safeguards are instituted between the central control room and the liquid sample control panels 1 and 2, permission could be granted for operators to activate specific valve combinations on these panels. This would permit selective use of the inline isotopic analyzer and associated high radiation sampling system liquid sampling panel.

9.4.3.2 Leakage Provisions

Leakage of radioactive reactor coolant from this system within the containment is evaporated to the containment atmosphere and removed by the cooling coils of the containment fan coolers. Leakage of radioactive material from the most likely places outside the containment is collected by running a ventilation line from the high radiation sampling system panel to an existing exhaust duct in the old sampling room. This duct has a diffuser with a damper. During normal operation, air from the room is taken in through the diffuser; during accident conditions the damper is closed and air is taken into the ventilation system only from the high radiation sampling system panel ventilation. The gases from the panel pass through a pre-filter, a HEPA filter, a 450 cfm exhaust fan, and then into the existing ventilation system, which contains a charcoal filter. This system is seismic Class I. Liquid leakage from the sentry liquid sampling panel, chemical analysis panel, and boron analyzer valves within the common vented system is drained to the liquid sampling panel sump and pumped to either the chemical drain tank 21 or the high radiation sampling system collection tank.

9.4.3.3 Incident Control

The system operates on a continuous basis for isotopic analysis, conductivity, dissolved oxygen, pH, and during steam-generator blowdown sampling. The inline dissolved hydrogen, chloride and boron concentrations can be obtained periodically from the sentry high radiation sampling system room.

9.4.3.4 Malfunction Analysis

To evaluate system safety, the failures or malfunctions are assumed concurrent with a loss-of-coolant accident, and the consequences analyzed. The results are presented in Table 9.4-3. From this evaluation it is concluded that proper consideration has been given to station safety in the design of the system.

9.4.3.5 High Radiation Sampling System Evaluation

The high radiation sampling system is an independent system to provide information to plant operators. It is separate from other safety and non-safety systems. It is located in an area served by the primary auxiliary building ventilation system.

The high radiation sampling system has the capability of handling both low and high radiation sampling without exceeding personnel exposure guidelines. Sufficient shielding is provided on the high radiation sampling system liquid sampling panel to allow personnel access for postaccident sampling.

REFERENCES FOR SECTION 9.4

1. Letter from S. A. Varga, NRC, to J. D. O'Toole, Con Edison, Subject: Postaccident Sampling at the Indian Point Unit 2, Safety Evaluation Report, dated June 28, 1984.

2. Letter from S. A. Varga, NRC, to J. D. O'Toole, Con Edison, Subject: Postaccident Sampling at the Indian Point Unit 2, Safety Evaluation Report, dated December 12, 1984.

3. Letter from P.D Milano, NRC to M.R. Kansler, Entergy, Subject: Indian Point Nuclear Generating Unit No. 2 – Amendment Re: Deletion of Technical Specifications for the Post Accident Sampling System (PASS) using the Consolidated Line Item Improvement Process (TAC No. MB2991). Dated January 30, 2002.

TABLE 9.4-1
Sampling System Code Requirements

	Code
Sample heat exchanger	ASME III,[1] Class C, tube side ASME VIII, shell side
Piping and valves	USAS B31.1[2]

Notes:

1. ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.
2. USAS B31.1 - Code for pressure piping and special nuclear cases where applicable.

TABLE 9.4-2
Primary Sampling System Components

Sample Heat Exchanger	
Number	10
Type	Coiled tube in shell
Heat exchanged (each), Btu/hr	2.14×10^5
Surface area (each), ft^2	3.73
Shell	
Design pressure, psig	150
Design temperature, °F	350
Component cooling water flow (nominal), gpm	17
Flow, lb/hr	20,000
Component cooling water	
inlet temperature, °F	105
outlet temperature, °F	130
Material	Carbon steel
Tubes	
Tube diameter in., O.D.	3/8
Design pressure, psig	2485
Design temperature, °F	680
Flow, lb/hr	209
Inlet temperature (saturated steam), °F	653
Outlet temperature, °F	127
Material	Austenitic stainless steel

TABLE 9.4-3
Malfunction Analysis of Sampling System

Sample Chains	Malfunction	Comments and Consequences
Pressurizer steam space sample, pressurizer liquid space sample, or hot-leg sample.	Remotely operated sampling valve inside reactor containment fails to close.	Diaphragm or motor-operated valve outside the reactor containment closes automatically on containment isolation signal or by operator action from the control room.
Any sample train.	Sample line break inside containment.	Same as above.

9.4 FIGURES

Figure No.	Title
Figure 9.4-1 Sh. 1	Primary Sampling System - Flow Diagram, Sheet 1, Replaced with Plant Drawing 9321-2745
Figure 9.4-1 Sh. 2	Primary Sampling System - Flow Diagram, Sheet 2, Replaced with Plant Drawing 227178
Figure 9.4-2	Secondary Sampling System - Flow Diagram, Replaced with Plant Drawing 9321-7020

9.5 FUEL HANDLING SYSTEM

The fuel handling system provides a safe, effective means of transporting and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the plant after postirradiation cooling.

The system is designed to minimize the possibility of mishandling or maloperations that could cause fuel damage and potential fission product release.

The fuel handling system consists basically of:

1. The reactor cavity, which is flooded only during plant shutdown for refueling.
2. The spent fuel pit, which is kept full of water and is always accessible to operating personnel.
3. The fuel transfer system, consisting of an underwater conveyor that carries the fuel through an opening between the areas listed in the discussion of plant containment.

9.5.1 Design Basis

9.5.1.1 Prevention of Fuel Storage Criticality

Criterion: Criticality in the new and spent fuel storage pits shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls. (GDC 66)

During reactor vessel head removal and while loading and unloading fuel from the reactor, boron concentration is maintained at not less than that required to shutdown the core to a k_{eff} = 0.95. Periodic checks of refueling water boron concentration ensure the proper shutdown margin. The new and spent fuel storage racks are designed so that it is impossible to insert assemblies in other than the prescribed locations. The new fuel racks and spent fuel storage pit have accommodations as defined in Table 9.5-1. In addition, the spent fuel pit has the required spent fuel shipping area. The spent fuel storage pit is filled with borated water at a concentration to match that used in the reactor cavity and refueling canal during refueling. The fuel is stored vertically in an array with sufficient center-to-center distance between assemblies to assure K_{eff} <1.0 even if unborated water was used to fill the pit and ≤0.95 when filled with water borated ≥ 2000 ppm boron. Limits on enrichment and burnup of fuel in the spent fuel storage pit are given in the Technical Specifications.

Detailed instructions are available for use by refueling personnel. These instructions, the minimum operating conditions, and the design of the fuel handling equipment incorporating built in interlocks and safety features, provide assurance that no incident could occur during the refueling operations that would result in a hazard to public health and safety.

In lieu of maintaining a monitoring system capable of detecting a criticality as described in 10CFR70.24, IP2 has chosen to comply with the seven criteria of 10CFR50.68(b).

9.5.1.2 Fuel and Waste Storage Decay Heat

Criterion: Reliable decay heat removal systems shall be designed to prevent damage to the fuel in storage facilities and to waste storage tanks that could result in radioactivity release, which would result in undue risk to the health and safety of the public. (GDC 67)

The refueling water provides a reliable and adequate cooling medium for spent fuel transfer and heat removal from the spent fuel pit. Overall this is provided by an auxiliary cooling system. Natural radiation and convection is adequate for cooling the holdup tanks.

9.5.1.3 Fuel and Waste Storage Radiation Shielding

Criterion: Adequate shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities. (GDC 68)

Adequate shielding for radiation protection is provided during reactor refueling by conducting all spent fuel transfer and storage operations underwater. This permits visual control of the operation at all times while maintaining radiation levels as low as reasonably achievable for the period of occupancy of the area by operating personnel. Pit water level is indicated, and water removed from the pit must be pumped out since there are no gravity drains. Shielding is provided for waste handling and storage facilities to permit operation within requirements of 10 CFR 20.

Gamma radiation is continuously monitored in the auxiliary building. A high level signal is alarmed locally and is annunciated in the control room.

9.5.1.4 Protection Against Radioactivity Release from Spent Fuel and Waste Storage

Criterion: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (GDC 69)

All fuel and waste storage facilities are contained and equipment designed so that accidental releases of radioactivity directly to the atmosphere are monitored and do not exceed the applicable limits.

The reactor cavity, refueling canal and spent fuel storage pit are reinforced concrete structures with a seam-welded stainless steel plate liner. These structures are designed to withstand the anticipated earthquake loadings as seismic Class I structures so that the liner prevents leakage even in the event the reinforced concrete develops cracks.

All vessels in the waste disposal system, which are used for waste storage are designed as seismic Class I equipment.

9.5.2 System Design and Operation

The reactor is refueled with equipment designed to handle the spent fuel underwater from the time it leaves the reactor vessel until it is placed in a cask for shipment from the site. Boric acid is added to the water to ensure subcritical conditions during refueling.

The fuel handling system may be generally divided into two areas:

The reactor cavity, which is flooded only during plant shutdown for refueling and the spent fuel pit, which is kept full of water and is always accessible to operating personnel. These two areas are connected by the fuel transfer system consisting of an underwater conveyor that carries the fuel through a fuel transfer tube, which penetrates the plant containment.

The reactor cavity is flooded with borated water from the refueling water storage tank. In the reactor cavity, fuel is removed from the reactor vessel, transferred through the water and placed in the fuel transfer system by a manipulator crane. In the spent fuel pit the fuel is removed from the transfer system and placed in storage racks with a long manual tool suspended from an overhead hoist.

New fuel assemblies are received and stored in racks in the new fuel storage area. New fuel is delivered to the reactor by lowering it into the spent fuel pit and taking it through the transfer system. The new fuel storage area is sized for storage of the fuel assemblies and inserts normally associated with the replacement of one-third of a core.

9.5.2.1 Major Structures Required for Fuel Handling

9.5.2.1.1 Reactor Cavity

The reactor cavity is a reinforced concrete structure that forms a pool above the reactor when it is filled with borated water for refueling. The cavity is filled to a depth that limits the radiation at the surface of the water during fuel assembly transfer.

The reactor vessel flange is sealed to the bottom of the reactor cavity by a Presray seal, which prevents leakage of refueling water from the cavity. This seal is installed after reactor cooldown but prior to flooding the cavity for refueling operations. Following refueling operations and prior to return to power, this seal is removed. The cavity is large enough to provide storage space for the reactor upper and lower internals, the control cluster drive shafts, and miscellaneous refueling tools.

The floor and sides of the reactor cavity are lined with stainless steel.

9.5.2.1.2 Refueling Canal

The refueling canal is a passageway extending from the reactor cavity to the inside surface of the reactor containment. The canal is formed by two concrete shielding walls, which extend upward to the same elevation as the reactor cavity. The floor of the canal is at a lower elevation than the reactor cavity to provide the greater depth required for the fuel transfer system tipping device and the control cluster changing fixture located in the canal. The transfer tube enters the reactor containment and protrudes through the end of the canal. Canal wall and floor linings are similar to those for the reactor cavity.

9.5.2.1.3 Refueling Water Storage Tank

The normal duty of the refueling water storage tank is to supply borated water to the refueling canal and reactor cavity for refueling operations. In addition, the tank provides borated water for delivery to the core following either a loss-of-coolant or a steam line rupture accident. This is described in Chapter 6.

The minimum volume of water and the minimum amount of boration of the water in the refueling water storage tank is defined in the Technical Specifications. Heating is provided to maintain the temperature above freezing. The tank design parameters are given in Chapter 6.

9.5.2.1.4 Spent Fuel Storage Pit

The spent fuel storage pit is designed for the underwater storage of spent fuel assemblies, failed fuel cans if required, and control rods after their removal from the reactor.

The pit accommodations are listed in Table 9.5-1.

Spent fuel assemblies are handled by a long-handled tool suspended from an overhead hoist and manipulated by an operator standing on the movable bridge over the pit.

The spent fuel storage pit is constructed of reinforced concrete and is seismic Class I design. This structure was analyzed to determine compliance with ACI-318(77), and SRP 3.8 of NUREG-0800. In addition to the mechanical loadings, the pool structure was also analyzed to include the temperature induced loadings. For this purpose, the thermal boundary conditions were conservatively specified as 180°F pool water temperature and 0°F outside ambient. The thermal moments computed by the finite element analyses were combined with those due to mechanical loads. The results of these analyses show that there are large margins between the factored loads and corresponding design strengths.

The pit is lined with a leak-proof stainless steel liner. All welds were vacuum-box tested during construction to assure a leaktight membrane. The effect of a thermal gradient would be to compress the liner. A review of the stress factors resulting from the finite element analyses demonstrates that an adequate design margin exists for the spent fuel pit liner walls and basemat.

Storage racks are provided to hold spent fuel assemblies and are erected on the pit floor. Fuel assemblies are held in a square array, and placed in vertical cells. Fuel inserts are stored in place inside the spent fuel assemblies.

9.5.2.1.5 Storage Rack

High density fuel storage racks have been designed to provide a maximum storage capacity of 1376 locations. The arrangement of the fuel storage racks in the spent fuel storage pool is shown in Figure 9.5-2.

The fuel storage rack arrangement contains two types of storage rack arrays.

Region 1, consisting of three racks that use the flux trap design, can store 269 new or irradiated fuel assemblies. The flux trap design used in Region 1 uses spacer plates in the axial direction to separate the cells. Boraflex absorber panels are held in place adjacent to each side of the cell by picture-frame sheathing. The spacer plates between cells form a flux trap between the boraflex absorber panels. Region 1 racks were originally designed to store new fuel with enrichments up to 5.0 w/o U^{235}. Region 1 is subdivided into two regions (Region 1-1 and Region 1-2):

Region 1-1 is assumed to have sustained a 100% loss of Boraflex (i.e., none of the boraflex in the panels is assumed to be available). Technical Specifications show the fuel assembly criteria that will meet the requirements of 10 CFR 50.68(b)(4) if stored in Region 1-1. The maximum initial enrichment that can be stored in Region 1-1 with no burnup is 1.95 w/o U^{235}.

Region 1-2 is assumed to have sustained a 50% loss of Boraflex (i.e., 50% of the boraflex in the panels is assumed to be available). Region 1-2 can accommodate unirradiated fuel up to 5.0 w/o U^{235} assuming the presence of a minimum number of IFBA rods. The maximum initial enrichment that can be stored in Region 1-2 when there are no IFBA rods is 4.50 w/o U^{235}.

Each Region I storage cell, as shown in Figure 9.5-3, is a square box with an 8.75 inch inside dimension. Boraflex poison is held in place adjacent to each side of the box by "picture-frame" sheathing. The boxes are assembled into racks with an east-west pitch of 10.765 inches (center-to-center) and a north-south pitch of 10.545 inches, as shown in Figure 9.5-4. A 1/2 inch thick base plate is provided at the bottom of the rack. Adjustable leg supports are welded to the underside of the base plate. A six-inch diameter flow hole is provided in the base plate for each storage cell, and two one-inch holes are provided for cross flow at the bottom of each cell.

Region 2, consisting of nine racks that use the egg-crate design, can store 1105 fuel assemblies and two failed fuel canisters. Region 2 racks consist of boxes welded into a “checkerboard” array with a storage location in each square. One Boraflex absorber panel is held to one side of each cell wall by picture frame sheathing. Region 2 racks were originally designed to store fuel assemblies that have undergone significant burnup (e.g., ≤5.0 w/o U^{235} with a burnup of at least 40,900 megawatt days per metric ton (MWD/MT)) or fuel assemblies with a relatively low initial enrichment and low burnup (i.e., ≤1.764 w/o U^{235} at zero burnup).

Region 2 is subdivided into two regions (Region 2-1 and Region 2-2):

Region 2-1 is assumed to have sustained a 100% loss of Boraflex (i.e., none of the boraflex in the panels is assumed to be available). The maximum initial enrichment that can be stored in Region 2-1 with no burnup is 1.06 w/o U^{235}.

Region 2-2 is assumed to have sustained only a 30% loss of Boraflex (i.e., 70% of the boraflex in the panels is assumed to be available).

"Peripheral" Cells, consisting of six select cells along the SFP west wall in Region 2-2, may be used to store fuel that meets the requirements for storage in any other location in the SFP. Cells between and adjacent to the "peripheral" cells may be filled with fuel assemblies that meet the requirements for storage in Region 2-2). The two prematurely discharged fuel assemblies meet the requirements and qualify for storage in the "peripheral" cells.

The storage racks are positioned on the floor so that adequate clearances are provided between racks and between the rack and pool structure to avoid impacting of the sliding racks during seismic events. The horizontal seismic loads transmitted from the rack structure to the pool floor are only those associated with friction between the rack structure and the pool liner. The vertical deadweight and seismic loads are transmitted directly to the pool floor by the support feet.

9.5.2.1.6 New Fuel Storage

New fuel assemblies and control rods are stored in a separate area with a location that facilitates the unloading of new fuel assemblies or control rods from trucks. This storage vault is designed to hold new fuel assemblies in specially constructed racks and is utilized primarily for the storage of the replacement fuel assemblies.

Criticality analyses have been performed assuming the fully loaded racks are flooded with water. The analyses demonstrated that K_{eff} is less than 0.95 for fuel with Integral Fuel Burnable Absorbers (IFBA) and enrichments in the range 4.5 w/o to 5.0 w/o. K_{eff} is also less than 0.95 for fuel enriched to 4.5% or less with no absorbers.

9.5.2.2 Major Equipment Required for Fuel Handling

9.5.2.2.1 Reactor Vessel Stud Tensioner

Stud tensioners are used to make up the head closure joint and during this process all studs are stretch tested to more than nominal working loads at every refueling.

The stud tensioner is a hydraulically-operated (oil as the working fluid) device provided to permit preloading and unloading of the reactor vessel closure studs at cold shutdown conditions. A stud tensioner was chosen in order to minimize the time required for the tensioning or unloading operations. Three tensioners are provided and they are normally applied simultaneously to three studs 120° apart. One hydraulic pumping unit operates the tensioners, which are hydraulically connected in parallel. The studs are tensioned to their operational load in a number of steps to prevent high stresses in the flange region and unequal loadings in the studs. A relief addition, micrometers are provided to measure the elongation of the studs after tensioning.

9.5.2.2.2 Reactor Vessel Head Lifting Device

The reactor vessel head lifting device consists of a welded and bolted structural steel frame with suitable rigging to enable the crane operator to lift the head and store it during refueling operations. The lifting device is permanently attached to the reactor vessel head.

9.5.2.2.3 Reactor Internals Lifting Device

The reactor internals lifting device is a fixture providing the means to grip the top of the reactor internals package and to transfer the lifting load to the crane. The device is lowered onto the guide tube support plate of the internals and is manually bolted to the support plate by three bolts. The bolts are controlled by long torque tubes extending up to an operating platform on the lifting device. Bushings on the fixture engage guide studs mounted on the vessel flange to provide close guidance during removal and replacement of the internals package.

9.5.2.2.4 Manipulator Crane

The manipulator crane is a rectilinear bridge and trolley crane with a vertical mast extending down into the refueling water. The bridge spans the reactor cavity and runs on rails set into the floor along the edge of the reactor cavity. The bridge and trolley motions are used to position the vertical mast over a fuel assembly in the core. A long tube with a pneumatic gripper on the end is lowered out of the mast to grip the fuel assembly. The gripper tube is long enough so the upper end is still contained in the mast when the gripper end contacts the fuel. A winch mounted on the trolley raises the gripper tube and fuel assembly up into the mast tube. The fuel is transported while inside the mast tube to its new position.

Controls for the manipulator crane are located inside the control console mounted on the trolley platform. Bridge, trolley and hoist positions are electronically displayed via encoders on the control console. The drives for the bridge, trolley and hoist are variable speed. Crane interlocks and limit switches are monitored by a Programmable Logic Controller (PLC). In an emergency the bridge trolley and hoist can be operated manually.

An electronic load cell located on the trolley platform monitors the suspended weight on the gripper tool. This load cell sends a low voltage signal to a PLC and to a display located on the control console. This load is electronically displayed on the control console. An overload condition stops the hoist drive from moving in the up direction. The gripper is interlocked through a weight-sensing device and also a mechanical spring lock so that it cannot be opened when supporting a fuel assembly.

Safety features are incorporated in the system as follows:

1. Encoders provide feedback pertaining to the bridge, trolley and hoist positions. Bridge, trolley, and hoist positions are displayed to the operator on the control console.

2. Only the bridge and trolley are allowed to simultaneously operate at the same time. Bridge and trolley motion will be prohibited if hoist is in motion. Likewise, hoist motion will be prohibited if the bridge and trolley are already in motion.

3. Encoders determine the position of the mast, which will prohibit bridge and trolley movement based on the gripper height. The hoist also has a mechanical limit switch serving as a redundant mast “full up” limit.

4. A mechanical weight actuated lock in the gripper prevents operation of the gripper under load even if air pressure is applied to the operating cylinder. As backup protection to the mechanical interlock, an electrical interlock prevents the opening of a solenoid valve in the air line to the gripper except when the gripper is unloaded as indicated by a load cell.

5. Hoist load monitoring components detect overload conditions which will prohibit hoist raise motion when loading is excessive.

6. The PLC monitors the status of the gripper selector switch. Crane motion will not be allowed if the gripper indicator shows that the gripper is in transition or both conditions are activated (between OPEN and CLOSED).

7. The systems encoders along with the Crane’s PLC will establish a boundary zone within the pool area. Crane motion is prohibited through these established boundary zones unless the bypass mode has been selected. Motion speeds will be decreased when operating in the bypass mode.

8. When the gripper is loaded with an assembly the mast must be in the full up position before bridge and trolley motion are allowed. With an empty gripper, bridge and trolley motion are prohibited until the “Gripper in Mast” elevation is present (full up is not required to traverse with an empty gripper).

9. Hoist load monitoring components detect underload conditions which will prohibit hoist lower motion. This prevents continued hoist motion if an assembly is hung up while being inserted between other fuel assemblies.

10. An encoder positioning system displays to the operator the precise position of the manipulator crane over each row of core coordinates for bridge, trolley and hoist movement over the reactor and the transfer canal.

Suitable restraints are provided between the bridge and trolley structures and their respective rails to prevent derailing and the manipulator crane is designed to prevent disengagement of a fuel assembly from the gripper in the event of a design basis earthquake.

9.5.2.2.5 FSB Fuel Handling Bridge Crane

The PaR Systems, Inc. Crane is a wheel-mounted platform, which spans the East-West (E-W) direction of the Spent Fuel Pool (SFP) and travels in the North-South (N-S) direction. The PaR Crane is secured to the crane rails on the FSB El. 95’-0”, via seismic hold-down brackets and associated bolting. An Encoder Tracking Device is mounted on the FSB West Walkway, El. 96’-6”, which positions the crane in the N-S direction. The crane mounted computer will position the Crane Trolley-Tower Structure in the E-W direction. This equipment will position the Crane Motorized Hoist over a pre-assigned Spent Fuel Assembly (SFA) within the SFP. In addition, the PaR Crane controls interface with the existing FSB Up-Ender Control Console No. 21 (PK1). This computerized control feature provides assurance that the PaR Crane will not interfere with the FSB Up-Ender Assembly, which is located in the Fuel Transfer Canal.

The Motorized Hoist-Sheave Assembly is attached to a Trolley Structure, which is located on the wheel-mounted platform. The Motorized Hoist design incorporates a single lifting cable, which has a safety factor 11.49:1. This safety factor exceeds the design criteria (10:1) for single lifting cables, as outlined in NUREG-0612. The Tower Structure is mounted on a Motorized Trolley, which travels in the E-W direction on the wheel-mounted work platform. The Motorized Hoist-Sheave Assembly, which has a 1-Ton rated capacity, will transfer SFAs within the SFP, via long-handled tolls suspended from the hoist hook. The hoist travel and tool length are designed to limit the maximum lift of a SFA and maintain a safe shield depth below the water surface of the SFP. A load weighing system will sense overload and underload conditions. This system will stop the upward movement of a SFA, when it senses a load greater than a programmed set-point. In addition, this system will stop the downward movement of a SFA, when it senses a slack cable condition.

A 480V, 3-phase, 50 AMP power feed (normal supply) is provided from Distribution Panel No. EP57 to the PaR Crane. In addition, a 480V, 3-phase, 100 AMP power feed (alternate supply) is provided from MCC27 to the PaR Crane. Transfer Switch No. EDA57 is provided, so that, the reliable power feeds can be provided by Distribution Panel No. EP57 or MCC27.

9.5.2.2.6 Fuel Transfer System

The fuel transfer system, shown in Figure 9.5-1, is a cable driven system that traverses the conveyor car carriage on tracks extending from the refueling canal through the transfer tube and into the spent fuel pit. The conveyor car receives a fuel assembly in the vertical position from the manipulator crane. The fuel assembly is then lowered to a horizontal position for passage through the tube, and then is raised to a vertical position in the spent fuel pit.

During plant operation, the conveyor car is stored in the refueling canal inside the containment. A blank flange is bolted on the transfer tube on the reactor side and a gate valve closed on the spent fuel pit side (see Figure 5.2-5) to seal the reactor containment. The blind flange is supplied with a double o-ring seal and is pressurized by the WCCPP System during normal operation to assure containment isolation.

9.5.2.2.7 Rod Cluster Control Changing Fixture

A fixture is mounted on the reactor cavity wall for removing rod cluster control (RCC) elements from spent fuel assemblies and inserting them into new fuel assemblies. The fixture consists of two main components: a guide tube mounted to the wall for containing and guiding the RCC element; and, a wheel-mounted carriage for holding the fuel assemblies and positioning fuel assemblies under the guide tube. The guide tube contains a pneumatic gripper on a winch that grips the RCC element and lifts it out of the fuel assembly. By repositioning the carriage, a new fuel assembly is brought under the guide tube and the gripper lowers the RCC element and releases it. The manipulator crane loads and removes the fuel assemblies into and out of the carriage.

9.5.2.2.8 Lower Internals Support Stand

A support stand for the lower internals package is installed in the lower internals laydown area at the east end of the refueling canal. The stand is to be used to rest the lower internals package to facilitate access to the internal surfaces of the reactor vessel.

9.5.3 System Evaluation

Underwater transfer of spent fuel provides essential ease and corresponding safety in handling operations. Water is an effective, economic, and transparent radiation shield and a reliable cooling medium for removal of decay heat.

Basic provisions to ensure the safety of refueling operations are:

1. Gamma radiation levels in the containment and fuel storage areas are continuously monitored. These monitors provide an audible alarm at the initiating detector indicating an unsafe condition. Continuous monitoring of reactor neutron flux provides immediate indication and alarm of an abnormal core flux level in the control room.

2. Violation of containment integrity is not permitted when the reactor vessel head is removed unless the shutdown margin is maintained greater than 5-percent $\Delta k/k$.

3. Whenever fuel is added to the reactor core, a reciprocal curve of source neutron multiplication is recorded to verify the sub-criticality of the core.

4. A Boraflex surveillance program was established when the high density racks utilizing Boraflex were installed. This program now includes coupon surveillance and monitoring of silica level (which is indicative of Boraflex degradation) in the spent fuel pit water.

9.5.3.1 Incident Protection

Direct communication between the control room and the refueling cavity manipulator crane operator is available whenever changes in core geometry are taking place.

This provision allows the control room operator to inform the manipulator crane operator of any impending unsafe condition detected from the main control board indicators during fuel movement.

This provision shall be satisfied with fuel in the reactor and when:
1) the reactor head is being moved, or
2) the upper internals are being moved, or
3) loading and unloading fuel from the reactor, or
4) heavy loads greater than 2300 lbs (except for installed crane systems) are being moved over the reactor with the reactor vessel head removed.

If direct communication between the control room and the refueling cavity manipulator cannot be met, suspend any and all of these operations. Suspension of these operations shall not preclude completion of movement of the above components to a safe conservative position.

9.5.3.2 Malfunction Analysis

Various potential failures, which could create paths for drainage from the refueling cavity have been considered. A plant procedure defines actions to deal with these postulated events. All credible failures result in drainage to safe storage. An analysis evaluating the environmental consequences of a fuel handling incident is presented in Section 14.2.1.1.

Inadvertently locating an unirradiated fuel assembly of 5.0-percent enrichment in a region II storage location has been analyzed. The analysis shows that the array would be subcritical even with no soluble boron poison in the water in the fuel storage pool. With a boron concentration of 350 ppm the shutdown margin would be more than 5-percent. The technical specifications require that the boron concentration be maintained at 2000 ppm or more at all times.

9.5.4 Minimum Operating Conditions

Minimum operating conditions are specified in the facility Technical Specifications. In addition, when fuel is in the reactor vessel and the reactor head bolts are less than fully tensioned the reactor Tavg shall be less than or equal to 140°F.

9.5.5 Tests and Inspections

During preoperational testing, the Presray seal (which seals the reactor vessel flange to the bottom of the reactor cavity) was deflated with a full head of water in the cavity. No leakage was observed.

9.5.6 Control of Heavy Loads

9.5.6.1 Introduction / Licensing Background

A generic letter dated December 22, 1980, required responses to the guidelines of NUREG-0612 “Control of Heavy Loads at Nuclear Power Plants.’ In response, the IP2 provisions for handling and control of heavy loads at Indian Point Unit 2 were addressed by letters June 22, 1981, September 30, 1982, January 31, 1983, and January 20, 1984. The NRC Safety Evaluation Report in letter dated February 19, 1985, concluded that the guidelines of NUREG-0612, Sections 5.1.1 and 5.3 have been satisfied and the Phase I of this issue for Indian Point Unit 2 is acceptable.

The NRC Safety Evaluation Report in letter dated November 21, 2005 authorized the use of a single-failure-proof gantry crane for spent fuel cask handling operations up to 110 tons in weight.

Additional information was provided in letter dated July 12, 1996 in response to NRC Bulletin 96-02.

NEI-08-05 R0, “Industry Initiative on Control of Heavy Loads” documented the industry initiative to address NRC staff concerns regarding the interpretation and implementation of regulatory guidance associated with heavy load lifts, was endorsed in Regulatory Issues Summary 2008-28 and has been addressed at Indian Point 2. This supersedes prior head drop analyses.

9.5.6.2 Safety Basis

NUREG 0612 has two basic approaches available to demonstrate compliance: demonstrate adequate load handling reliability, or demonstrate that load drop consequences are within the limits of Criteria I-IV listed in Section 5.1 of the NUREG. Both approaches have been utilized in performing the evaluations described in the following sections. The postulated drop of the Reactor Head onto the Reactor Vessel must satisfy the requirements set forth in NEI 08-05.

In situations where a demonstration of handling system reliability was employed, the guidelines of NUREG 0612, Section 5.1.6, "Single-Failure Proof Handling Systems," were utilized. The Ederer crane for cask handling was designed as a single failure proof crane.

In situations where a demonstration of limited load drop consequences was employed, a combination of system analyses and structural analyses was utilized. The specific approach chosen was based on the completeness of the available information, and a preliminary assessment of the likelihood of success of the possible approaches.

Auxiliary Feedwater Pump (AFP) Monorail / Plant Auxiliary Building (PAB) Monorail

The AFP Monorail and the PAB monorail were determined to meet the intent of the NRC guidance by demonstrating that adequate load handling reliability will be achieved.

Containment Polar Crane

The Containment Polar Crane was evaluated using a combination of the approaches. The principal approach was systems evaluations to demonstrate that sufficient redundancy and separation are available to maintain core cooling even in the unlikely event of a heavy load drop inside containment.

The containment was subdivided into 10 regions of interest. For all regions, with the exception of the Reactor Vessel and the annulus outside the Crane Wall, the postulated load drops were evaluated using systems evaluations. The evaluations established if the load drop could cause loss of the primary cooling mode or, if the primary cooling mode is lost, if backup cooling modes could be lost from the same drop.

In the annulus region between the crane wall and the containment, it was necessary to demonstrate that sufficient load handling reliability of the auxiliary hoist will be available. This precludes the need for evaluating the consequences of load drops in this region. In one area, the annulus region between the crane wall and the containment, load handling reliability can not be demonstrated for the Equipment Hatch. This is the area over which the containment equipment hatch door/airlock is carried. The hatch door weighs approximately 25tons. Accordingly, a systems evaluation of the potential consequences of a drop of the equipment hatch door into region demonstrates successful core cooling.

In the Reactor Vessel area, a Reactor Head drop analysis was performed to show that the structural integrity of the critical components is maintained such that the core cooling will not be compromised and the core will remain covered.

9.5.6.3 Scope of Heavy Load Handling Systems

The following cranes and hoists were determined to be capable of handling heavy loads based on the criteria of NUREG-0612:

- Containment Polar Crane (175/35-ton)
- 7-ton Plant Auxiliary Building (PAB) monorail
- 5-ton Auxiliary Fuel Pump (AFP) building monorail
- 2-ton diesel generator building overhead crane

- Fuel Handling crane (40/5-ton)
- 110t Ederer crane (110-ton)

9.5.6.4 Control of Heavy Loads Program

The following discuss the results of our evaluations and submittals and are controlled using commitments A-873, A-887, A-1010, A-1015, A-1207, A-2467, A-2491, A-2492, A-2493, A-3174, A-3175, A-3176, A-3179, A-3180 and A-3465.

9.5.6.4.1 Response to NUREG 0612, Phase I Elements

A defense-in-depth approach was used to ensure that all load handling systems are designed and operated so that their probability of failure is appropriately small. The basis for the approach was the Staff guidelines tabulated in Section 5 of NUREG-0612 and the program initiated to ensure that these guidelines are implemented. These guidelines consist of the following criteria from Section 5.1.1 of NUREG-0612:

Guideline 1 - Safe Load Paths
Guideline 2 - Load Handling Procedures
Guideline 3 - Crane Operator Training
Guideline 4 - Special Lifting Devices
Guideline 5 - Lifting Devices (Not Specially Designed)
Guideline 6 - Cranes (Inspection, Testing, and Maintenance)
Guideline 7 - Crane Design

Satisfaction of these guidelines for the Polar Crane and the Fuel Handling Crane is shown in Table 9.5-2.

Guideline 1 - Safe Load Paths

To ensure that crane operators remain knowledgeable of load handling precautions, annual refresher training is conducted to identify exclusion areas and to review load handling procedures.

In addition to the above procedures, additional structural and systems analyses were performed to determine the consequences of a load drop indicate that suitable system redundancy and structural integrity exist so that the consequences of a load drop would not exceed the criteria of NUREG-0612, Section 5.1. The specific requirements for the polar crane and fuel handling crane are below:

Polar Crane

The containment building polar crane is utilized to remove and replace heavy loads during refueling operations. These include:

1. Control rod drive missile shield
2. Reactor vessel head
3. Reactor internals

For the Indian Point Unit 2 polar crane, operating procedures define three areas over which loads are not allowed to be carried with the exception of certain pre-identified load movements. These areas are as follows:

1. WHEN RV head is removed and fuel is in the Reactor Vessel, THEN NO heavy loads shall be moved over the RV area, with the exception of the RV head, the Upper Internals, the RV weld ISI inspection tool and their associated lifting devices.
2. WHEN RV head is removed and fuel is in the RV, THEN NO heavy loads shall be moved over the Reactor Cavity Area, with the exception of the RV head, the Upper Internals, the RV weld ISI inspection tool, the Polar Crane Load Block, the Regenerative Heat Exchanger Concrete Floor Plug and their associated lifting devices.
3. WHEN fuel is in the RV, THEN NO loads including the Polar Crane Load Block shall be moved over the #22 RHR HX area.

No unidentified loads are moved over either exclusion area at any time. For certain loads (identified by procedures) which must be moved in and out of the reactor vessel area, the loads are moved by the most direct route to pre-designated lay down areas. A load handling supervisor or person in charge is present to ensure that procedures are followed and that exclusion area boundaries are not violated.

Since the geometry of the Indian point reactor is the same as that analyzed in NUREG-0612 therefore the maximum expected increase in Keff would be about 0.02 and a criticality condition will not occur as a result of fuel crushing. Thus, criterion II of NUREG-0612, Section 5.1 is satisfied.

Auxiliary Hoist of the Polar Crane

The Polar Crane Auxiliary Hoist has a capacity of 35 tons and has a hook travel that can service the Annulus Region between the containment wall and the crane wall. For the purpose of addressing the NUREG 0612 guidelines for this region of the containment, the load handling reliability of the Auxiliary Hoist has been evaluated against the criteria of Section 5.1.6. , Based on the discussion below, adequate load handling reliability of the Auxiliary Hoist in the Annulus Region is demonstrated and, therefore, with one exception, load drops into this region have not been postulated.

The auxiliary hoist is mounted on the trolley frame and fully satisfies the criteria in CMAA-70-1975 and ANSI B30.2-1976. For most load handling operations, the auxiliary hoist satisfies the intent of Section 5.1.6 of NUREG 0612 (i.e., dual load path or increased safety factors of 10:1 in lieu of normal 5: 1).

One load carried over the open reactor vessel that could potentially damage fuel in the vessel, is the Reactor Vessel Weld ISI tool (5 tons). For this particular lift, by the Auxiliary Hoist, adequate load handling reliability is assured because the hoist was designed to and fully satisfies current industry standards and was built with a safety factor of 5:1. Therefore, the safety factor for the load of concern is far greater than 10:1. Adequate load handling reliability will be assured on the same basis as for loads lifted by the Auxiliary Hoist in the Annulus Region.

The auxiliary hoist components are designed with a 5:1 design safety factor on ultimate strength. For loads of less than 17.5 tons, the design safety factor for the hoist will be better than 10:1. With the exception of the containment equipment hatch door/airlock, all loads typically carried in the Annulus Region are less than 17.5 tons. The equipment hatch door weighs approximately 25 tons. For this reason an evaluation of the consequences of a postulated drop of this door into the Annulus Region has been performed. This is the area over which the containment equipment hatch door/airlock is carried.

The very conservative assumption that all equipment within the region is lost was made for evaluating the consequences of a load drop for the equipment hatch door. Systems analyses demonstrate that the consequences of this load drop will not preclude the ability to maintain core cooling.

Fuel Storage Building Ederer Crane

The Ederer 110-ton design rated gantry crane is used to move spent fuel casks up to 110 tons into and out of the spent fuel pit by lifting a fully loaded Holtec HI-TRAC® 100 spent fuel transfer cask and its associated components. The HI-STORM® cask system utilizes the HI-TRAC® 100 transfer cask for transporting a multi-purpose canister (MPC) from the spent fuel pit, and for inter-cask MPC transfers required for on-site storage. However, this crane is restricted from handling casks over spent fuel in the spent fuel pit and will only be utilized for other loading activities in the FSB.

Safe load paths have been determined, analyzed and documented in procedures for control of heavy loads handled by the Ederer gantry crane. Deviations from the safe load paths will require written alternative procedures reviewed and approved in accordance with IP2 procedures.

The Ederer gantry crane (by design) is unable to move spent fuel casks over any area of the spent fuel pit where the spent fuel is stored.

Fuel Handling Crane

The Fuel handling Crane is utilized over the Spent Fuel Pit to move fresh fuel to the New Fuel Elevator. Also, it may be used to transport equipment, such as inspection rigs or electronics, to the Spent Fuel Pit area. For equipment handling, the crane is utilized to transport loads of no greater than 2000 lbs over the pool area. For fuel handling, the crane may carry a load no heavier than the weight of a fuel assembly containing a control rod assembly, plus the tool and small load block.

No object weighing more than 2,000 pounds may be moved over any region of the spent fuel pit when the pit contains spent fuel, unless a technical analysis has been performed consistent with the requirements of NUREG-0612 establishing the necessary controls to assure that a load drop accident could damage no more than a single fuel assembly. Administrative and procedural controls to protect fuel and fuel racks may include path selection to prevent loads from passing over or near fuel. For cases in which very heavy loads (>30,000 pounds) are transported over the spent fuel pit, the loads cannot under any circumstances pass over fresh or irradiated fuel. In all cases where loads >2,000 pounds are carried over the pit, the ventilation system must be operable.

All standard modes of failure have been considered in the design of the Fuel Handling Crane. These modes of failure were provided for by utilization of a minimum safety factor of 5 based on the ultimate strength of the material used in the design of cables, shafts and keys, gear teeth and brakes.

All crane equipment was sized to handle the single heaviest load realized during plant operation. All lifts are made by qualified personnel. The equipment is properly maintained and periodically inspected by qualified personnel. An analysis of impact loading of the spent fuel cask into the spent fuel storage pool is provided in Section 9.5.3

Mechanical stops incorporated on the bridge rails of the Fuel Handling Crane make it impossible for the bridge of the crane to travel further north than a point directly over the spot in the spent fuel pit that is reserved for the spent fuel cask. Therefore, it will be impossible to carry any object over the spent fuel storage areas north of the spot in the pit that is reserved for the cask with either the 40 or 5-ton hook of the Fuel Handling Crane. However, to further minimize the potential for a heavy load impacting irradiated fuel in the spent fuel pit, load paths will be defined in procedures and shown on equipment layout drawings.

The mechanical stops may be removed under administrative controls and the crane moved over spent fuel storage areas, provided that the fuel storage building ventilation system is operable, the spent fuel pit boron concentration is at least 1000 ppm and there is no heavy load carried. This allows operations over the spent fuel pit with the 5-ton hoist. The 40-ton hoist may not carry any load over the SFP since the load block is a one-ton load and has not been fully evaluated for heavy loads.

The existing 40-ton non-single-failure-proof Fuel Handling Crane does not have the capacity to handle the HI-TRAC® 100 transfer cask and its associated components. Performance of the crane satisfies the objectives of NUREG-0612 and the intent of NUREG-0554 with regard to maintaining the potential for a load drop extremely small.

Guideline 2 - Load Handling Procedures

A series of operating procedures have been developed for operation of load handling equipment at Indian Point Unit 2.

Load handling procedures provide for the movement of all heavy loads in the vicinity of irradiated fuel or systems and equipment required for safe shutdown and decay heat removal, and that load designation was based on the generic load identified in Table 3-1 of NUREG-0612. Further, these procedures contain the precautionary information required by NUREG-0612, Guideline 2. These procedures comply with the commitments made for safe load handling.

The 110T Ederer gantry crane operating procedures utilized for cask and cask component lifts include: identification of required equipment; inspection and acceptance criteria required before load movement; the steps and proper sequence to be followed in handling the load; defining the safe load path; and other precautions. A specific cask loading and handling procedure will provide additional details for controlled movement during cask handling operations.

Guideline 3 – Crane Operator Training

A qualification program for the qualification and training of crane operators at Indian Point Unit 2 have been developed to meet the provisions of ANSI 830.2-1976, with no exceptions taken. Crane operator training and qualification is addressed in the qualification program and include precautions and instructions to assure proper operator conduct.

This qualification program meets the requirements of Chapter 2-3 of ANSI B 30.2-1967, “Operation – Overhead and Gantry Cranes”, as developed by the American National Safety Code for Cranes, Derricks, Hoists, Jacks and Slings.

Guideline 4 - Special Lifting Devices

The following special lifting devices are subject to compliance with the requirements of NUREG 0612, Guideline 4:

- reactor vessel head lifting rig (also described in Section 9.5.2.2)
- internals lift rig (also described in Section 9.5.2.2)
- reactor vessel ISI tool.

All three devices were designed and manufactured prior to the existence of ANSI N14.6-1978. Based on review of ANSI criteria, detailed evaluation of these devices has been limited to Sections 3.2 (Design Criteria) and 5 (Acceptance Testing, Maintenance, and Assurance of continuing Compliance). Detailed comparison of each of the devices indicates that the devices comply with ANSI criteria with limited exceptions.

The designer verified that each device was originally designed with a factor of safety of 5:1 on ultimate strength and that suitable margins to yield exist for all components. The Licensee stated that further consideration of dynamic effects is not necessary since the maximum dynamic load has been calculated to be less than 5.5% of the static load and does not significantly affect the load handling reliability of these devices.

Although only one of the devices was originally load tested to 150% of rated load or greater, the Licensee stated that adequate documentation exists to document proof of workmanship of these devices. The internals lift rig has been load tested to over 200% of the heavy load of concern (the upper internals). The ISI tool has been load tested to 137% of rated load. The reactor vessel head lift rig was only lifted 100% of rated load on various occasions with no signs of deformation or overstress.

To ensure continued load handling reliability, these devices are inspected by qualified personnel at regular intervals (12 months or prior to use). Inspection and NDE on the devices is performed at extended intervals (5 years) since annual inspection is impractical; these extended intervals are justified on the basis of the limited frequency of use and the controlled storage and handling of these devices.

The HI-TRAC® lifting yoke used with the Ederer crane is the only special lifting device that is required to meet the guidelines of ANSI N14.6-1993 and the additional guidelines of NUREG-0612, Section 5.1.6(1)(a).

Guideline 5 - Lifting Devices (Not Specially Designed)

Plant procedures require that sling selection and use for all loads requiring sling lifting devices be in accordance with ANSI B30.9.

As noted for special lifting devices, calculations indicate that the maximum dynamic load experienced is only 2.1% of the maximum static load for the main hoist and 5.5% for the auxiliary hoist. Addition of these dynamic loads does not significantly affect load handling reliability and therefore dynamic loads have not been considered in selection of slings.

Other lift components utilized with the Ederer Crane and HI-STORM® 100 cask system meet ANSI B30.9-1971 requirements, including the additional guidelines of NUREG-0612, Section 5.1.6(1)(b).

Guideline 6 - Cranes (Inspection, Testing, and Maintenance)

A program for inspection, testing, and maintenance of the polar crane has been developed that satisfies the criteria in ANSI B30.2-1976 Chapter 2-2, with no exceptions noted. The criteria of ANSI B30.2-1976 are not easily applied to such handling systems as monorails and hand-driven hoists. Accordingly, a procedure has been developed based on the criteria of ANSI B30.11-1973, "Monorail Systems and Underhung Cranes", with no exceptions noted from the criteria of the standard.

The 110T Ederer gantry crane is inspected, tested and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976 and the additional guidance contained in NUREG-0612, Section5.1.1(6) regarding frequency of inspections and test.

Guideline 7 - Crane Design

A design analysis of each handling system using the design criteria of the applicable standards has been performed. The polar crane has been evaluated in accordance, with
ANSI B30.2-1976, while the AFP building monorail has been evaluated in accordance with ANSI B30.11, 'Monorail Systems and Underhung Cranes,' and ANSI B30.16, 'Overhead Hoists'.

The polar crane and the 40ton Fuel Handling Crane were built prior to the issuance of ANSI B30.2-1976 and CMAA-70. However, a detailed point-by-point comparison has been performed, comparing information from the manufacturer with the criteria of these standards. Analysis was performed for only those components that are load bearing or are necessary to prevent conditions which could lead to a load drop. This review indicates that both cranes comply with all requirements with the exception of Specification 3.2 of CMAA-70 and Section 2.1.4.1 of ANSI B30.2-1976. These specifications require that welding be performed in accordance with AWS D1.1, 'Structural Welding Code', and AWS D14.1, 'Specifications for Welding Industrial and Mill Cranes'. The welding procedures used are equivalent to current welding criteria based on the following:

a) welding was performed in accordance with the then-current code AWS Dl,l, 'Structural Welding Code'

b) practices and procedures used for welding are equivalent to those in AWS D14.l, which was not issued at the time

c) welders were qualified to existing AWS criteria

d) all welds were visually inspected

e) structural integrity was demonstrated when the polar crane was used to perform a 450-ton (250% of rated capacity) construction lift.

Section 9.5.7 Fuel Storage Building (FSB) Dry Cask Storage (DCS) Operations, provides more detail on the FSB 110-Ton Ederer Single Failure Proof Gantry Crane and section 9.5.2.2.5 provides more detail on the FSB Fuel Handling Bridge crane.

In the AFP building, no hoist is permanently attached to the monorail system. Hoist selection criteria for the AFP and PAB monorails comply with the requirements of ANSI B30.16-1973 and have been included in procedures. Review of monorail design indicates that the AFP and PAB monorails comply with the criteria of ANSI B30.11-1973.

Additional specific information concerning design compliance with the more restrictive requirements of CMAA-70 is contained in the safety evaluation report.

The 110t Ederer gantry crane is installed on a crane rail system. The crane rail system for the Ederer crane consists of crane rail, rail pad, rail clip, sole plate assembly, and sole plate anchor embedments. The sole plate assembly consists of 2" thick steel plate which is held to the concrete slab with 1" diameter rod anchor embedments. The crane rail is attached to the sole plate assembly by rail clips with a rail pad between the crane rail and the sole plate assembly. The crane rail and the concrete slab of the reconstructed truck bay are designed and built to withstand seismic loads, as well as the static loads.

The Ederer gantry crane was designed with a telescopic tower and automated folding cantilever arms to avoid interference with either the existing overhead crane or the refueling bridge crane. During dry cask loading operations the gantry crane will be in its raised position and the existing overhead crane will remain in the south position and de-energized to prevent accidental movement. Once the cask loading operation is completed, the gantry crane will be stored in its far west position, with the tower lowered and the arms folded. This will allow unobstructed use of both the existing overhead and refueling bridge cranes.

The cantilevered girder for the main hoist trolley will extend over the spent fuel pit cask laydown area. The girders are equipped with a retraction mechanism, accomplished via lead screw actuators that allow them to be folded back in order to permit unobstructed use of the existing overhead and refueling bridge cranes. Because of the cantilevered design, the gantry crane requires provisions to ensure stability against overturning. This is accomplished via a floor anchorage system with fixed-in-place hold down features that oppose crane uplift forces. To provide a foundation system capable of resisting these uplift forces, the design includes a steel ballast box filled with steel plates that will act as a counterbalance. The ballast box foundation consists of a 2-foot thick reinforced concrete slab founded on bedrock, and its primary function is to transmit all bearing loads from the weight of the ballast box directly to the underlying bedrock.

The Ederer gantry crane movements are governed by a series of limit and proximity switches that are controlled by a programmable logic controller (PLC) which ensures that: (1) movement of the trolley towards the spent fuel pit is only permitted if turnbuckles are attached to the crane tie down points, cantilever arms are extended and locked in place, and the main transfer hoist is operating at an elevation that allows the HI-TRAC® to clear the south wall of the spent fuel pit; (2) limit switches on the trolley rails limit excessive movement of the trolley to the north and prohibit lowering of the load until a minimum northward travel is reached; and (3) main transfer hoist operation is prohibited until the Ederer gantry crane tower is in its raised position and pinned in place.

9.5.6.4.2 Reactor Pressure Vessel Head (RPVH) Lifting Procedures

In response to NEI 08-05, an evaluation of a head drop was performed. For this drop scenario, it was postulated that during removal or installation of the closure head assembly, in which the closure head is lifted or lowered directly above the reactor vessel (RV), the polar crane fails and the closure head assembly falls and impacts flat and concentrically with the RV flange.

The stresses and strains caused by the postulated impact were evaluated to demonstrate that structural integrity of the critical components is maintained such that core cooling will not be compromised and the core will remain covered.

The analysis used a conservative weight for the Reactor Head of 350,000 pounds, which matches the Polar Crane Main Hook capacity and exceeds the weight of the Reactor Head and Lifting Rig, and considered a drop through air from a height of 32 feet above the Reactor Vessel flange, the maximum height as controlled by plant procedures. The finite element model was prepared using ANSYS, the Reactor Head drop and impact was simulated using LS-DYNA, and the response of the Reactor Vessel, Reactor Vessel support components, and main loop piping were obtained with the postprocessor LS-PREPOST.

The maximum primary stress intensity in the Reactor Vessel shell at the Inlet nozzle is 60,255 psi, versus a 72,000 psi allowable. The maximum primary stress intensity in the Reactor Vessel shell at the Outlet nozzle is 60,766 psi, versus a 72,000 psi allowable.

The maximum primary stress intensity at the inlet and outlet nozzles was found to be 68,388 psi and 63,936 psi, respectively, against a 72,000 psi allowable.

The analysis concludes that the structural integrity of the critical components is maintained such that core cooling is not compromised and the core remains covered.

The Polar Crane and Reactor Pressure Vessel Head lifts procedures are used to control the lift and replacement of the reactor pressure vessel head. These procedures incorporate the 32 feet limit on the lift height of the Reactor Vessel Head assembly which weighs less than 350,000 pounds.

One other load is carried over the open reactor vessel that could potentially damage spent fuel in the vessel. This is the Reactor Vessel Weld ISI tool. Its weight is approximately 5 tons. For this particular lift, which is performed by the Auxiliary Hoist, adequate load handling reliability will be assured on the same basis as for loads lifted by the Auxiliary Hoist in the Annulus Region. This basis is described in Section 9.5.6.2, Safety Basis.

9.5.6.4.3 Single Failure Proof Cranes for Spent Fuel Casks

Sections 9.5.6.4.1, Response to NUREG 0612, Phase I Elements and 9.5.7, Fuel Storage Building (FSB) Dry Cask Storage (DCS) Operations, provide more detail on the FSB 110-Ton Ederer Single Failure Proof Gantry Crane.

9.5.6.5 Safety Evaluation

The controls implemented to address NUREG- 0612 Phase 1 elements make the risk of a load drop very unlikely. The use of increased safety factors for load path elements makes the risk of a load drop extremely unlikely and acceptably low. In the event of a postulated load drop, the consequences are acceptable, as demonstrated by system analyses or the load drop analysis. Restrictions on load height, load weight, and medium under the load are reflected in plant procedures. The risk associated with the movement of heavy loads is evaluated and controlled by station procedures.

The design and use of the Ederer single-failure-proof gantry crane is in accordance with NUREG-0554 and satisfies the guidelines of NUREG-0612. The crane enables the use of the HI- TRAC® transfer cask and associated components with very low risk to irradiated fuel stored in the spent fuel pit or to redundant trains of safe shutdown equipment during spent fuel transfer activities. The use of the Ederer single-failure-proof gantry crane for cask handling operations for loads up to 110 tons is approved.

9.5.7 Fuel Storage Building (FSB) Dry Cask Storage (DCS) Operations

The 100-Ton Dry Cask Storage System (HI-TRAC, Multi-Purpose Canister (MPC) and HI-STORM Overpack), FSB 110-Ton Single Failure Proof Gantry Crane, FSB Low Profile Transporter (LPT) System, and Vertical Cask Transporter (VCT) facilitate removal of Spent Fuel Assemblies (SFAs) from the Spent Fuel Pool (SFP). During FSB Dry Cask Storage Operations, SFAs are transferred from the SFP with the HI-TRAC / MPC, inserted into the HI-STORM Overpack. The LPT System transfers the HI-STORM Overpack from the FSB to the east side of the PAB / MOB Crossover Walkway. The Vertical Cask Transporter transports the HI-STORM Overpack to the IPEC Independent Spent Fuel Storage Installation (ISFSI) Facility.

9.5.7.1 FSB 110-Ton Ederer Single Failure Proof Gantry Crane

The 110-Ton Ederer Crane was designed to withstand normal operating loads, rated loads, seismic loads and extraordinary loads. The design of the 110-Ton Ederer Crane satisfies the design requirements and safety factors of CMAA-70, NUREG-0554 and Regulatory Guide 1.29. The 110-Ton Ederer Crane conforms to the single failure proof requirements addressed in NRC NUREG-0554 and will retain and control a suspended critical load during and following a Safe Shutdown Earthquake (SSE).

The 110-Ton Ederer Crane is normally located on the west side of the FSB Truck Bay Floor, EL 77'-6" in its lowered position and rests on rails that are installed within the FSB Truck Bay Floor. In order to lift and transfer a fully-loaded HI-TRAC / MPC with 32 SFAs from the SFP, the 110-Ton Ederer Crane is raised to its upper position. Once in the upper position, the East and West Crane Girder Assemblies, and the North Tie-End Crane Girder Assembly are fully-extended (cantilevered position) out over the SFP. The 110-Ton Ederer Crane is in position to lift and transfer a fully-loaded HI-TRAC / MPC from the SFP Cask Pit Area. A Laser Positioning System enables crane operators to position the HI-TRAC / MPC along the SFP Cask Pit Area North-South and East-West centerlines and accurately place the Hi-TRAC / MPC within the SFP Cask Pit Area.

The 110-Ton Ederer Crane is connected, via tie-down turnbuckles, to the 30-Ton Ballast Box, which is embedded within the FSB Truck Bay Floor. The Ballast Box is filled with ~200-Tons of counter weight steel plates. The Ballast Box and tie-down turnbuckles provide stability and restraints for the 110-Ton Ederer Crane during a seismic event. The 110-Ton Ederer Crane is provided with counter weight to reduce the uplift (tension) loads in the tie-down turnbuckles, when the Crane Trolley travels onto the East and West Crane Girder Assemblies towards the SFP Cask Pit Area.

The 110-Ton Ederer Crane is provided with numerous limit switches, which control movement of the 110-Ton Ederer Crane. The limit switches are mounted on the Trolley, Girder Assemblies, Jacking Screw System, and Gantry Crane Structure. The limit switches control the speed of the equipment, limit travel distances and provide interlock signals to defeat some crane functions, when the 110-Ton Ederer Crane is not in the correct configuration. In addition, a Seismic Accelerometer automatically de-energizes the power feed to the 110-Ton Ederer Crane during a seismic event.

9.5.7.2 FSB Low Profile Transporter (LPT) System

The FSB LPT System was designed to withstand normal operating loads, maximum vertical – lateral track loads, maximum static stack-up loads, maximum transit loads, and Safe Shutdown Earthquake (SSE) loads. The design of the FSB LPT System satisfies the design requirements and safety factors of AISC, IPEC and Hilman-Rollers.

The FSB Gantry Crane transports the fully-loaded HI-TRAC / MPC towards the east for stake-up onto the Hi-STORM Overpack. The LPT Assembly, Chain Drive Assembly and Chain Drive Control Panel control internal FSB movements in the East-West direction.

The FSB LPT System transports the fully-loaded HI-STORM Overpack towards the east and south, so that, the HI-STORM Overpack can exit the FSB. The LPT Transporter Assembly, Transfer Table, Hydraulic Cylinders, and Transfer Table Hydraulic Cart control internal FSB movements in the North-South direction.

The FSB LPT System transports the fully-loaded HI-STORM Overpack through the FSB Truck Bay Roll-Up Door Opening, into the FSB Alleyway Trench and to the east side of the IP2 PAB / MOB Crossover Walkway. The HI-STORM Overpack is in position to be lifted and transported by the Vertical Cask Transporter to the IPEC ISFSI Facility. The LPT Assembly, Track Assemblies, Guide Bars and Aircraft Tugger control external FSB movements in the East-West direction. Empty HI-STORM Overpacks will be transported into the FSB in the reverse order from above.

TABLE 9.5-1
Fuel Handling System Data

NEW FUEL STORAGE PIT	
Core storage capacity	1/3
Equivalent fuel assemblies	72
Center-to-center spacing of assemblies, in.	20.5
Maximum K_{eff} with unborated water	0.95
SPENT FUEL STORAGE PIT	
Equivalent fuel assemblies[1]	1376
Number of space accommodations for failed fuel cans	2
Number of space accommodations for spent fuel shipping cask	1
Center-to-center spacing of Regions 1-1,1-2 assembly storage cells, in	10.545(N-S) 10.765(E-W)
Center-to-center spacing of Regions 2-1, 2-2 assembly storage cells, in	9.04
Maximum K_{eff} with borated water (Regions 1-1, 1-2 and Regions 2-1, 2-2)	≤0.95
Maximum K_{eff} with unborated water (Regions 1-1, 1-2 and Regions 2-1, 2-2)	<1.0
MISCELLANEOUS DETAILS	
Width of refueling canal, ft	3
Wall thickness for spent fuel storage pit, ft	3 to 6
Weight of fuel assembly with rod cluster control (dry), lb	1,580
Quantity of water required for refueling, gal	300,000

Notes:
1. After reracking.

TABLE 9.5-2
NUREG-0612 Compliance Matrix

Heavy Loads	Weight or Capacity (tons)	Guideline 1 Safe Load Paths	Guideline 2 Procedures	Guideline 3 Crane Operator Training	Guideline 4 Special Lifting Devices	Guideline 5 Slings	Guideline 6 Crane – Test and Inspection	Guideline 7 Crane Design	Interim Measure 1 Technical Specifications	Interim Measure 6 Special Attention
1. Containment Polar Crane	175	++	++	C	++	++	C	R	++	++
Reactor Vessel Head	169	R	C	++	R	++	++	++	++	++
Upper Internals (Plenum)	67	R	C	++	R	++	++	++	++	++
Inservice Inspection Tool	5	R	C	++	R	++	++	++	++	++
Reactor Coolant Pumps	32	R	C	++	R	C	++	++	++	++
Missile Shields	7.5	R	C	++	++	C	++	++	++	++
Crane Load Block	4.5	R	C	++	++	C	++	++	++	++
Concrete Hatch Cover	7.3	R	C	++	++	C	++	++	++	++
2. Fuel Handling Crane	40	R	R	C	++	C	C	R	R	++
3. 110t Ederer Crane	110	C	C	C	C	C	C	C	++	++

C - Action complies with NUREG-0612 Guideline.
R - Revisions/modifications designed to comply with NUREG-0612 Guideline.
++ - Not applicable.

9.5 FIGURES

9.6 FACILITY SERVICE SYSTEMS

9.6.1 Service Water System

9.6.1.1 Design Basis

The service water system is designed to supply cooling water from the Hudson River to various heat loads in both the primary and secondary portions of the plant. Provision is made to ensure a continuous flow of cooling water to those systems and components necessary for plant safety either during normal operation or under abnormal and accident conditions. Sufficient redundancy of active and passive components is provided to ensure that cooling is maintained to vital loads for short and long periods. The design of the essential header is to provide cooling water in the event of a single failure of any active component used during the injection phase of a loss-of-coolant accident. The system also provides water required for cleaning the traveling screens.

9.6.1.2 System Design and Operation

The service water system flow diagram is shown in Plant Drawings 9321-2722 and 209762 [Formerly UFSAR Figure 9.6-1, sheets 1 and 2]. Six identical vertical, centrifugal sump-type pumps, each having a capacity of at least 5000 gpm at 220-ft total design head, supply service water to two independent discharge headers; each header may be supplied by three of the pumps. Two pumps are required for design flow in each header. A rotary-type strainer is in the discharge of each pump, and is designed to remove solids down to 1/16-in. diameter. Each header is connected to an independent supply line. Either of the two supply lines can be used to supply the essential loads, with the other line feeding the nonessential loads. The essential loads are those, which must have an assured supply of cooling water in the event of a loss of offsite power and/or a loss-of-coolant accident. The cooling water for these loads is supplied by the designated essential service water header. The nonessential loads are those, which are supplied with cooling water from the designated nonessential service water header by manually starting a service water pump when required following a loss-of-coolant accident. The essential and nonessential service water requirements are listed in Table 9.6-1.

The nonessential loads are the component cooling heat exchangers, the turbine lube oil coolers, the main boiler feed pump lube oil coolers, and the remaining steam generation plant services. By manual valve operation, the essential loads can be transferred to the supply line carrying the nonessential loads and vice versa. Connections have been provided so the turbine generator lube oil coolers and other non-safety related loads can be supplied from the Unit 1 river water system.

Water is drawn from the river and passes under a debris wall, through two racks in parallel and finally two traveling screens. Each pump in the circulating water system is installed in an individual chamber while the service water pumps are in a common chamber with two intakes. Each intake is provided with a traveling screen. Openings are also provided between the main circulating water pump chambers and the service water pump chamber. These two openings can be closed by gates. One gate is normally open.

The service water pumps can therefore obtain water through four separate intakes each equipped with means to prevent debris from entering the pumps, and each capable of supplying all the water required for the service water pumps. Electric heaters are provided in the traveling screens 27 and 28 to prevent icing of the screens. Even if the main circulating pump intake were 90-percent blocked, that intake alone would be capable of supplying all water required for the service water pumps at design conditions.

Service water is chlorinated by the addition of sodium hypochlorite solution as required to control micro-organism fouling of the system.

The intake structure is designed as seismic Class I, and is therefore not subject to collapse under earthquake loading.

During normal operation, the essential loads are supplied by at least one of the three pumps provided and the nonessential loads are normally supplied by two of the three pumps provided.

Following a simultaneous incident and loss of offsite power, the cooling water requirements for all five fan cooling units and the other essential loads can be supplied by any two of the three service water pumps on the header designated to supply the nuclear and essential secondary load supply lines. Any two of these three pumps can be powered by the emergency diesels as described in Chapter 8. These emergency powered pumps are those necessary and sufficient to meet blackout and emergency conditions. Either one of the two sets of three pumps can be placed on the diesel starting logic.

The containment ventilation cooling units are supplied by individual lines from the containment service water header. Each inlet line is provided with redundant motor-operated shutoff valves and drain valves. Similarly, each discharge line from the cooler is provided with redundant motor-operated shutoff valves and a manual balancing valve. This allows each cooler to be isolated individually for leak testing of the system or to be drained and maintained open to atmosphere during the integrated leak tests of containment. The ventilation cooler and motor cooler discharge lines will be monitored for radioactivity by routing a small bypass flow from each through redundant radiation monitors. Upon indication of radioactivity in the effluent, each cooler discharge line would be monitored individually to locate the defective cooling coil. This feature has been incorporated into the design since the service water system pressure at locations inside the containment with the system in the incident mode alignment could be below the containment post-accident design pressure of 47 psig. Thus, there could be outleakage of radioactivity to the environment if a break occurred in the service water system. However, since the cooling coils and service water lines are completely closed inside the containment, no contaminated leakage is expected into these units. The service water system pressure at locations inside the containment with the system in the incident mode alignment is below the containment design pressure of 47 psig.

During normal plant operation, flow through the cooling units will normally be throttled for containment temperature control purposes by a valve on the common discharge header from the cooling units. Two independent, full-flow isolation valves open automatically in the event of a safety injection signal to bypass the control valve. Both valves fail in the open position upon loss of air pressure and either valve is capable of passing the full flow required for all five fan cooling units for accident mitigation. Should there be a failure in the piping or valves at the header supplying water to the containment cooling coils, one of the two series header isolation valves in the center of the header can be manually closed and service will continue on the side of the header opposite the failure. The supply line attached to this side of the header now supplies the essential loads, whether or not it did so before the failure.

Likewise, operation of at least one component cooling heat exchanger is ensured despite the failure of any single active or passive component in the system from the service water pumps to the heat exchangers themselves.

Following a simultaneous incident and blackout, the component cooling heat exchangers are not needed during the injection phase: thus they are normally fed from the nonessential supply header. At the beginning of the recirculation phase at least one of the service water pumps on the nonessential header is manually started to supply at least 2500 gpm of service water to each of the component cooling heat exchangers.

The emergency diesel-driven generator units are supplied with cooling water from the essential supply line on a continuous basis. One of the two parallel modulating control valves in the common discharge line from the diesel coolers is flow-controlled during normal operation, and on a safety injection signal, both valves open fully to ensure a sufficient supply of cooling water to the diesels. The inlet valving is arranged so that each of the three diesels can be served by either of the supply headers and, furthermore, the failure of a single passive or active component will not result in the loss of all diesel power.

9.6.1.3 Design Evaluation

The nonessential portion of the service water system is not required for the maintenance of plant safety immediately following an accident. The essential portion of the service water system is designed to provide cooling water in the event of a single failure of any active component used during the injection phase of the safety injection system (Section 6.2).

Sufficient pump capacity is included to provide design service water flow under all conditions and the headers are arranged in such a way that even loss of a complete header does not jeopardize plant safety.

In response the NRC Generic Letter 96-06, the containment fan cooler units and their associated service water piping were evaluated for susceptibility to waterhammer or two-phase flow. In the event of a loss of offsite power, the flow of essential service water will be interrupted until the emergency diesel generators start and restore power to the essential service water pumps. The pressure in the cooling coils and service water piping will drop to subatmospheric and a vapor pocket will form in the region of the fan coolers. When the essential service water pumps restart, the pocket will close and a water hammer will occur. The magnitude of waterhammer is approximately 394 psig. Dynamic analysis of the piping and supports shows that stresses meet the criteria for upset and faulted conditions, respectively.

In the case of loss of offsite power and a loss of coolant accident, water trapped in the tubes and piping will be heated and vaporized. When the service water pumps are restarted, rapid condensation of trapped steam and collapsing of the void causes a waterhammer pressure pulse, with a magnitude less than that discussed in the preceding paragraph.

The potential for two-phase flow conditions has also been evaluated. If it is assumed that there is no fouling of the fan cooler tubes, there will be flashing and two-phase flow in the discharge piping. However, analyses show that, although the flow will be reduced, the clean fan cooler units will exchange enough heat to meet required removal rates.

9.6.1.4 Tests and Inspections

Each service water pump underwent a hydrostatic test in the shop in which all wetted parts were subjected to a hydrostatic pressure of one-and-one-half times the shutoff head of the pump. In addition, the normal capacity versus head tests were made on each pump.

Valves in the portions of the service water system essential to safety underwent a shop hydrostatic test of 250 psi on the body and 175 psi on the seat. The service water system design pressure is 150 psig.

All service water piping was hydrostatically tested in the field at 225 psig or one-and-one-half times design. The welds in shop-fabricated service water piping were liquid penetrant or magnetic particle inspected in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII.

Electrical components of the service water system are tested periodically.

9.6.2 Fire Protection System

Criterion: Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and the control room. Fire detection and protection systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Fire fighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components. (GDC 3, Appendix A to 10 CFR 50)

This criterion (GDC 3, 10 CFR 50 Appendix A) represents a revised design basis for the Indian Point Unit 2 fire protection system as was established for the original plant design and initial license application. In 1976 at the request of the NRC, Con Edison initiated a review and evaluation of the station fire protection system to this new criterion; modifications were subsequently proposed by Con Edison to the overall fire protection program. On January 31, 1979, the NRC approved the Indian Point Unit 2 overall fire protection program as providing additional assurance that safe shutdown can be accomplished and that the plant can be maintained in a safe condition during and following potential fire situations. This NRC approval was made as Amendment No. 46 to the facility operating license.

Additional fire protection regulations were issued in 10 CFR 50.48 and Appendix R to Part 50 on November 19, 1980, with an effective date of February 17, 1981. These regulations established requirements for utilities to implement a fire protection program, and backfitted certain requirements in Appendix R to all utilities. For Con Edison, these included the various separation and protection requirements contained within Section III.G, emergency lighting requirements as stipulated by III.J, and oil collection system requirements for reactor coolant pumps as contained in Section III.O. Additionally, Section III.L established performance requirements for alternative shutdown systems. Subsequent to the regulations established in 10 CFR 50.48, various NRC generic letters and guidance documents have been issued to provide clarification of the Appendix R requirements.

NRC approval of the Indian Point Unit 2 Fire Protection Program including safe shutdown capability is provided in the Fire Protection Safety Evaluations Reports (SERs) dated:

- November 30, 1977
- February 3, 1978
- January 31, 1979
- October 31, 1980
- August 22, 1983
- March 30, 1984
- October 16, 1984
- September 16, 1985
- November 13, 1985
- March 4, 1987
- January 12, 1989
- March 26, 1996

Incorporation of the NRC approved Fire Protection Program into the UFSAR represents one of the elements of Generic Letter 88-12 required to remove the fire protection requirements from the Technical Specifications (TS). The Fire Protection Program requirements were removed from the TS under Amendment No. 186. This information needs to remain in the UFSAR. Entergy may make changes to the NRC approved Fire Protection Program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

The Indian Point 2 Fire Protection Program description is provided separately in the following documents:

- IPEC Fire Protection Program Plan
- IP2 Fire Hazards Analysis Report
- IP2 Safe Shutdown Analysis Report

These documents provide a complete description of the Indian Point 2 Fire Protection Program including a description of fire areas, fire suppression and detection as well as other fire protection features credited to limit the effects of fires and the credited safe shutdown capability include the Alternate Safe Shutdown System (ASSS).

9.6.3 City Water System

The functions of the city water system are:

1. To provide the water supply for the fire protection system.
2. To provide an emergency supply of water to the suction of the auxiliary boiler feed pumps.
3. To provide makeup water to various systems.
4. To provide cooling water to various components.

5. To provide water to areas where hose connections are located for general usage.

City water for the Indian Point Unit 2 comes from the city water main on Broadway via the Unit 1 mains and storage tanks and is under cathodic protection where the piping crosses the Algonquin Gas pipes. Unit 2 is tied to this system primarily through piping connections at two locations on the low pressure header (see Plant Drawings 192505, 192506, and 193183 [Formerly UFSAR Figure 9.6-5]). One connection is in the vicinity of the Unit 1 superheater building on the south side of the header. This connection provides water for:

1. Emergency makeup to the house service boilers.
2. Cooling the house service boiler water samples.
3. General usage at the house service boilers.
4. Makeup to the expansion tank of the conventional plant closed cooling system.
5. Cooling and general usage at the steam and water analysis station.

The second connection is at the north side of the header. This connection provides water for:

1. Makeup to the expansion tanks of the diesel-generator jacket water cooling system.
2. Emergency feed to the auxiliary boiler feed pumps.
3. Makeup to the expansion tank of the instrument air compressor closed cooling system.
4. General usage via hose connections inside the primary auxiliary building and waste holdup tank pit.
5. Emergency makeup to the isolation valve seal-water supply tank.
6. Spray water to the steam-generator blowdown tank.

A backup water supply is also provided for the circulating water pump seals and bearings.

There are also emergency city water connections in the primary auxiliary building that can be used for the charging pumps, residual heat removal pumps, and safety injection pumps.

9.6.4 Compressed Air Systems

9.6.4.1 Instrument Air System

The instrument air system is designed such that the instrument air shall be available under all operating conditions; all essential systems requiring air during or after an accident shall be self supporting; all controls shall fail to a safe position on loss of power; and, after an accident, the air system shall be re-established. The system is shown in Plant Drawing 9321-2036 [Formerly UFSAR Figure 9.6-6].

To meet the design criteria the following design features have been incorporated. Duplicate compressors are installed with duplicate dryers and filters throughout. In addition, alternate supplies are provided from the Unit 2 station air system, and Unit 1 station air system. A connection has been provided in the station air system to allow a backup supply of air from portable compressed air equipment. Those items essential for safe operation and safe cooldown are provided with air reserves or gas bottles. These supplies enable the equipment to function in a safe manner until the air supply is reestablished. The controls are specified to fail to a safe position on loss of air or electrical power. The compressors, filters and air dryers are located on the ground floor of the control building, a seismic Class I structure, and they, along with other essential sections of the air supply system, have been designed to operate after a seismic event. In the event of a break in the non-essential portion of the system, a flow restrictor in the supply line to the non-essential portion will limit flow to the capacity of one instrument air compressor.

The system is served by two 225-scfm Worthington teflon-ring compressors, which discharge into a common air receiver. The instrument air from the receiver passes through one of two full-capacity heatless dryers. These heatless dryers are rated at 750 scfm, dewpoint compatible with the lowest expected outdoor temperature, and are dual-tower type dryers, with one of the dryers in service and one on standby. However, in the event that the transfer mechanism should fail during cycling of the dryer, the other dryer can be brought in to service. Each dryer is basically a stand-alone system, with dual prefilter, dryer and afterfilter units, and with local alarms and category alarms to the control room. An alternate air supply line from the station air system is provided, and has its own pair of full-capacity heatless regenerative dryers.

The instrument air compressors may be operated in two modes. One mode provides for the compressors to be in standby and to come on automatically in the event of low pressure in the common air receiver. During this mode, air is supplied by the station air system. The other mode of operation provides for simultaneous running of both compressors in order to provide continuity of service to Class I areas in the event of outage of the conventional plant instrument air header. A restriction orifice is provided so as to limit the flow to the capacity of one instrument air compressor into a possible line break in the secondary plant air header.

Upon notification of this break, a valve is provided to isolate the secondary plant and prevent pressure decay in the primary plant header. Valving has been installed to provide flexible operations as related to the alternate station air supply and to maintain proper isolation capabilities.

All air and oil filters are dual type to provide maintenance during operation.

9.6.4.2 Station Air System

The station air system shown in Plant Drawing 9321-2035 [Formerly UFSAR Figure 9.6-7] is supplied by a Worthington Corporation two-stage 650-scfm compressor located in the turbine building. The air is discharged through an aftercooler and moisture separator at 100 psig and 110°F. The maximum discharge pressure will be 125 psig. The cooling water for the aftercooler and compressor jacket is supplied from a closed cooling water system, which contains treated city water.

The compressor is controlled by the solenoid unloader valves, which are energized through a pressure switch arrangement in automatic or hand (manual) modes. In the automatic mode, the compressor will run in single- or two-stage operation and unload at a predetermined pressure setting with motor and compressor stopped. In manual mode, the compressor runs continuously and is loaded and unloaded at predetermined pressure settings. High-water and high-air temperature switches are connected to the control annunciator.

This system is alternatively supplied by the Unit 1 service air system through a manually operated valve interconnection to the Unit 2 air receiver. The size of the connection is equal to the Unit 2 supply pipe.

The station air system can also serve as an alternate supply to the Unit 2 instrument air system. In addition, an automatic emergency supply is supplied to the containment building weld channel and penetration pressurization system. Valve position lights in the control room advise the operator as to the status of emergency makeup control valve PCV-1140. A manual local reset solenoid valve is provided at the emergency valve.

9.6.5 Heating System

The heating system for Unit 2 represents an extension of the heating system for the Indian Point Unit 1.

Package boilers have been installed to supply steam for Unit 2 and are interconnected with the distribution header of the boilers for Unit 1. The main steam header from these boilers links the existing steam header to Unit 2 and also to Unit 3, so that output from any of the package boilers may be made available for the heating requirements of Unit 1, Unit 2, or Unit 3.

With respect to Unit 2, there are separate piping circuits for the unit heater steam supply to the east side and the west side of the turbine hall, including the heater bay. An extension from the circuit to the east side of the turbine hall serves the turbine oil storage tanks for both clean and dirty oil storage. Other heating services extend to the fan room, the fuel storage building, the containment building, the primary auxiliary building, the primary water storage tank, and the refueling water storage tank.

Provision is made for the following heating services:

1. Containment building.
   a. Steam unit heaters.
   b. Valves with hose bibs for maintenance purposes.

2. Primary auxiliary building.
   a. Electric strip heaters.
   b. Steam unit heaters.
   c. Air makeup steam tempering units.

3. Purge system containment building.
   a. Air makeup steam tempering units.

4. Fuel storage building.
   a. Steam unit heaters for standby heating.
   b. Air makeup steam tempering units. (Steam supply isolated)

5. Fan room.
   a. One steam unit heater.

9.6.6 Plant Communications Systems

For discussion of the facility communications systems, see Section 7.7.4.

REFERENCES FOR SECTION 9.6

1. Letter from Donald S. Brinkman, NRC, to Stephen B. Bram, Con Edison, Subject: Emergency Amendment to Increase the Service Water Temperature Limit to 90^{o}F (TAC 73764), dated August 7, 1989.

TABLE 9.6-1

Minimum Essential Service Water Requirement
Under Accident Conditions

Service	Flow each (gpm)	Number	Total Flow (gpm)
Containment Recirculation Fan Coolers	1600	5	8000
Containment Recirculation Fan Coolers Motors	17	5	85
Emergency Diesel Generators	400	3	1200
Instrument Air Compressor Heat Exchangers	65	2	65
Radiation Monitor Sample Coolers	2.5	2	5
Service Water Pump Strainer Blowdown	100	3	300 (750)$_1$

Minimum Non Essential Service Water Requirements
Post LOCA Recirculation

Service	Flow each (gpm)	Number	Total Flow (gpm)
Component Cooling Water Heat Exchangers	2500	2	5000
Service Water Pump Strainer Blowdown	100	3	300 (750)$_1$

Note:
1. Each strainer is mechanically set for 225 ± 25 gpm backflush flow, 750 gpm total (max).

9.6 FIGURES

Figure 9.6-7	Station Air - Flow Diagram, Replaced with Plant Drawing 9321-2035

9.7 EQUIPMENT AND SYSTEM DECONTAMINATION

9.7.1 Design Basis

Activity outside the core can result from fission products from defective fuel elements, fission products from tramp uranium left on the cladding in small quantities during fabrication, products of n-γ or n-p reactions on the water or impurities in the water, and activated corrosion products. Fission products in the reactor coolant associated with normal plant operation and tramp uranium are generally removed with the coolant or in subsequent flushing of the system being decontaminated. The products of water activation are not long lived and may be removed by natural decay during reactor cool-down and subsequent flushing procedures. Activated corrosion products are the primary source of the remaining activity.

The corrosion products contain radioisotopes from the reactor coolant, which have been absorbed on or have diffused into the oxide film. The oxide film, essentially magnetite (Fe_30_4) with oxides of other metals including Cr and Ni, can be removed by chemical means presently used in industry.

Water from the primary coolant system and the spent fuel pit is the primary potential source of contamination outside of the corrosion film of the primary coolant system components. The contamination can be spread by various means when access is required. Contact while working on primary system components can result in contamination of the equipment, tools and clothing of the personnel involved in the maintenance. Also, leakage from the system during operation or spillage during maintenance can contaminate the immediate areas and contribute to the contamination of the equipment, tools, and clothing.

9.7.2 Methods of Decontamination

Surface contaminates, which are found on equipment in the primary system and the spent fuel pit that are in contact with the water are removed by conventional techniques of flushing and scrubbing as required. Tools are decontaminated by flushing and scrubbing since the contaminates are generally on the surface only of nonporous materials. Personnel and their clothing are decontaminated according to the standard health physics requirements.

Those areas of the plant, which are susceptible to spillage of radioactive fluids are painted with a sealant to facilitate decontamination that may be required. Generally washing and flushing of the surface are sufficient to remove any radioactivity present.

The corrosion films generally are tightly adhering surface contaminates, and must be removed by chemical processes. The removal of these films is generally done with the aid of commercial vendors who provide both services and formulations. Since decontamination experience with reactors is continually being gained, specific procedures may change for each decontamination case.

Portable components and tools can be cleaned by the use of a liquid abrasive bead decontamination unit, an ultrasonic unit, a sandblast unit or a Freon degreaser unit installed in Unit 1.

9.7.3 Decontamination Facilities

Decontamination facilities onsite consist of an equipment pit and a cask pit located adjacent to the spent fuel storage pit. In the stainless steel-lined equipment pit, fuel handling tools and other tools can be cleaned and decontaminated.

In the cask decontamination pit, the outside surfaces of the shipping casks are decontaminated, if required, by using steam, water detergent solutions, and manual scrubbing to the extent required. When the outside of the casks are decontaminated, the casks are removed by the auxiliary building crane and hauled away.

For the personnel, a decontamination shower and washroom is located adjacent to the radiation control area locker room. Personnel decontamination kits with instructions for their use are in the radiation control area locker room.

9.8 PRIMARY AUXILIARY BUILDING VENTILATION SYSTEM

9.8.1 Design Basis

The primary auxiliary building ventilation system is designed to accomplish the following:

1. Provide sufficient circulation of filtered air through the various rooms and compartments of the building to remove equipment heat and maintain safe ambient operating temperatures.
2. Control flow direction of airborne radioactivity from low activity areas toward higher activity areas and through monitored exhaust paths.
3. Provide purging of the building to the plant vent for dispersion to the environment.

The air exhausted by the system is filtered, monitored, and diluted so that offsite dose during normal operation will not exceed Offsite Dose Calculation Manual (ODCM).

9.8.2 System Design and Operation

The primary auxiliary building ventilation system (See Plant Drawing 9321-4022 [Formerly UFSAR Figure 5.3-1]) is composed of the following systems:

1. Makeup air handling system complete with fan, filters, heating coils, and supply ductwork.
2. Exhaust system complete with fans, ductwork, roughing filters, HEPA filters, and charcoal filters.
3. Outside air intake for the waste storage tank pit area.

Design parameters for the system components are given in Table 9.8-1.

Branch supply ducts direct makeup air to the various floors at the east end of the building, from where it flows to the rooms and compartments. Air is exhausted from each of the building compartments through ductwork designed to make the supply air sweep across the room as it travels to the room exhaust register. The air then flows to the exhaust fan inlet plenum, and is drawn by the operating exhaust fan through roughing filters, HEPA filters, and charcoal filters before discharge to the plant vent. The exhaust system has been designed to ensure that air flows from the "clean" end of the building through the "hot" areas.

Ventilating air exhausted from the waste storage tank pit is arranged to bypass the primary auxiliary building system and flow directly into the exhaust fan inlet plenum.

There are four fans in the containment building purge system and primary auxiliary building ventilation system. The two exhaust fans (containment building purge and/or primary auxiliary building exhaust fans 21 and 22) are common to both the containment building purge system and primary auxiliary building ventilation system. The supply fan in each of the ventilation systems operates only in its individual ventilation system.

The primary auxiliary building supply fan normally runs, along with either or both of the exhaust fans. The containment building purge supply fan runs with either of the exhaust fans, with the other exhaust fan as a backup. All four fans may also run simultaneously. The interlocking for the fans is such that in no event will the number of supply fans operating be greater than the number of exhaust fans operating. However, operation of an exhaust fan without a supply fan running is acceptable.

Fans are manually selected. All four fans can be started and stopped by four discrete control switches located on the fan room control panels. Each fan has indicating lights on the fan room control panel and in the main control room. An auto trip alarm is also provided. In addition, each of the fans have a "jog" pushbutton located on the fan room control panel for testing.

TABLE 9.8-1
Primary Auxiliary Building Ventilation System Component Data

System	Units Installed	Units Capacity	Units Required for Normal Operation
Exhaust[1]			
Fans, standard conditions	2	55,500 cfm	1
Fan pressure	-	10.3 in. H_2O	-
Fan motors	2	125 hp	1
Plenums	2	55,500 cfm	1
Roughing filters	2	55,500 cfm	1
HEPA filters	2	55,500 cfm	1
Carbon Filters	1	55,500 cfm	1
Supply Tempering Unit (Primary Auxiliary Building)			
Fans, standard conditions	1	50,400 cfm	1
Fan pressure	1	2.5-in. H_2O	-
Fan motor	1	50 hp	1
Filters	1	50,400 cfm	1
Coils	1	50,400 cfm	1
Outside Air Intake (Waste Storage Tank Pit Area)	1	5100 cfm	1[2]

Notes:
1. These two exhaust fans are used interchangeably and/or as backup for:
(1) ventilation of primary auxiliary building, (2) containment building purge system.
2. Outside Air Intake may be covered during cold weather conditions.

9.9 CONTROL ROOM VENTILATION SYSTEM

9.9.1 Design Basis

The control room heating, ventilation, and air conditioning system is designed to accomplish the following:

1. Maintain 75°F dry bulb and approximately 50-percent relative humidity in the control room at outside design conditions at 93°F dry bulb and 75°F wet bulb.
2. Permit cleanup of airborne particulate radioactivity entering the control room with normal makeup air flow and by infiltration.

9.9.2 System Design and Operation

The Unit 2 control room ventilation system is composed of the following equipment:

1. A direct expansion air conditioning unit complete with fan, steam heating coil and roughing filter. The design capacity of the unit is 9200 cfm. A backup fan of the same design capacity has been installed in parallel with the air conditioning unit.
2. A filter unit consisting of case, HEPA filters, charcoal filters, post-filters and booster fans with a capacity of approximately 2000 cfm.
3. Duct system complete with dampers and controls to allow three system operating modes.

The Unit 1 control room ventilation equipment for the central control room has been modified for recirculation mode only.

The control room ventilation systems are shown on Plant Drawings 252665 and 138248 [Formerly UFSAR Figure 9.9-1]. The Unit 2 control room ventilation system can be operated as follows:

1. Normal Conditions

   a. With outside air makeup will supply cooling or heating for the control room atmosphere as required, using fresh outside air makeup and with the charcoal filter unit bypassed. (Mode 1)

2. Incident Conditions

   a. On safety injection and/or high radiation signal, with outside air makeup filtered the booster fan will start and dampers will be positioned to permit outside air to flow through the charcoal filter unit. (Mode 2)

   b. On toxic gas and/or smoke signal, the outside makeup air will be isolated and the carbon filter booster fan will not operate, the system will be in 100% recirculation mode. (Mode 3)

All these operations can be performed manually from the control room. However, in the event of a safety injection signal and/or high radiation signal, the control room dampers will automatically reposition and start the booster fan to place the charcoal filter unit in service, for system operating mode 2. A redundant toxic chemical and radiation monitor for central control room air intakes has been installed.

The control room does not see toxic limits of hazardous chemicals since regulatory guidance allows; “a control room operator will take protective measures within two (2) minutes (adequate time to don a respirator and protective clothing) after …detection.” There are eight (8) sets of self-contained breathing apparatus in Central Control Room with ten (10) extra bottles, of ½ hour each, to replace expended bottles of the sets. Forty two (42) bottles containing 250 cu. ft. at 2000 psig each are used for filling self-contained apparatus.

For additional discussion of this system, see Section 7.2.

9.9 FIGURES

Figure No.	Title
Figure 9.9-1	Central Control Room HVAC (Heating, Ventilation, and Air Conditioning), Replaced with Plant Drawings 252665 & 138248

9.10 FUEL STORAGE BUILDING VENTILATION SYSTEM

9.10.1 Design Basis

The fuel storage building ventilation system is designed to perform the following functions:

1. Maintain the fuel storage building at negative pressure so as to prevent unmonitored releases.

2. Provide sweep ventilation of the building, across the spent fuel pool, from areas of low potential contamination to areas of higher potential contamination.

3. Filter particulates and iodine through HEPA and charcoal filters to reduce the postulated offsite dose, which may result from a dropped fuel rod. NRC SER dated July 27, 2000 approved a fuel handling accident analysis that took no credit for filtration to reduce offsite dose so this design feature is no longer required for accident mitigation.

4. Remove normal building heat.

9.10.2 System Design And Operation

The fuel storage building ventilation system, shown in Figure 5.3-1, consists of two air supply units (whose fans have been retired in place) and one exhaust system. In addition, an axial spot cooling fan circulates 3000 cfm of air to the spent fuel pit heat exchanger room.

The power and control circuits for the fuel storage building (FSB) air supply fans and dampers, and dampers for the FSB exhaust fan, have been retired-in-place. Each supply unit has manually-operated outlet dampers that allow the exhaust fan to draw air through the building. Each also has a tempering (heating) coil which have been retired in place. Steam supply to the heating coils have been isolated and retired in place and the condensate line isolated.

The exhaust system consists of registers, ductwork, a filter bank, and a fan. Three exhaust registers are located near the pool surface level, at the north end, and a fourth is near the ceiling at the north end of the building. The registers near the pool surface are intended to provide a sweep flow over the pool.

Air from the registers is ducted to a plenum chamber, which contains the filter banks. It flows sequentially through filter banks, consisting of roughing filters, HEPA filters, and charcoal filters, and then to the exhaust fan. Air from the exhaust fan is discharged to the plant vent.

The exhaust fan is the centrifugal type, belt-driven by 100 hp 480-V motor.

The system provides an air flow rate of nominally 20,000 cfm. The system is balanced to divide the exhaust air flow equally between the exhaust registers and to maintain the building at a slight negative pressure. The exhaust fan is operated and controlled from a single local control room.

As a result of IP2 Operating License Amendment No. 229 (dated June 5, 2002), the limiting conditions for operation and the surveillance requirements for the fuel storage building air filtration system were relocated from the Technical Specifications to the UFSAR. These relocated requirements have been modified to reflect the assumptions used for the fuel handling accidents approved by the Technical Specification Amendment 211 (July 27, 2000). These are contained in UFSAR Sections 9.10.3 and 9.10.4 below.

9.10.3 Limiting Conditions for Operation (Fuel Storage Building Air Filtration System)

The fuel storage building ventilation system is assumed to be operating whenever spent fuel movement is taking place within the spent fuel storage areas, allowed after the fuel has had a continuous 100 hour decay period.

9.10.4 Surveillance Requirements (Fuel Storage Building Air Filtration System)

Amendment 211 recognized the fuel storage building ventilation system would be operating for an accident even though the assumptions were to release the source term over a 2 hour period at ground level (FSAR Section 14.2). The fuel storage building ventilation system does not have to be demonstrated operable in the assumed configuration each refueling, prior to refueling operations, and prior to handling fuel. The fuel storage building air filtration system shall be periodically tested (a 25% allowance is allowed consistent with the philosophy of Technical Specification SR 3.0.2) to assure continued compliance with 10 CFR 50, Appendix I and design criteria in accordance with ASME N510-1989, as follows:

1. verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches water gauge while operating the system at ambient conditions and at a flow rate of 20,000 cfm ±10% at least once each 24 months during aerosol or leak rate system tests.

2. verifying that the system maintains the spent fuel storage pool area at a pressure less than that of the outside atmosphere during system operation at least once each 24 months.

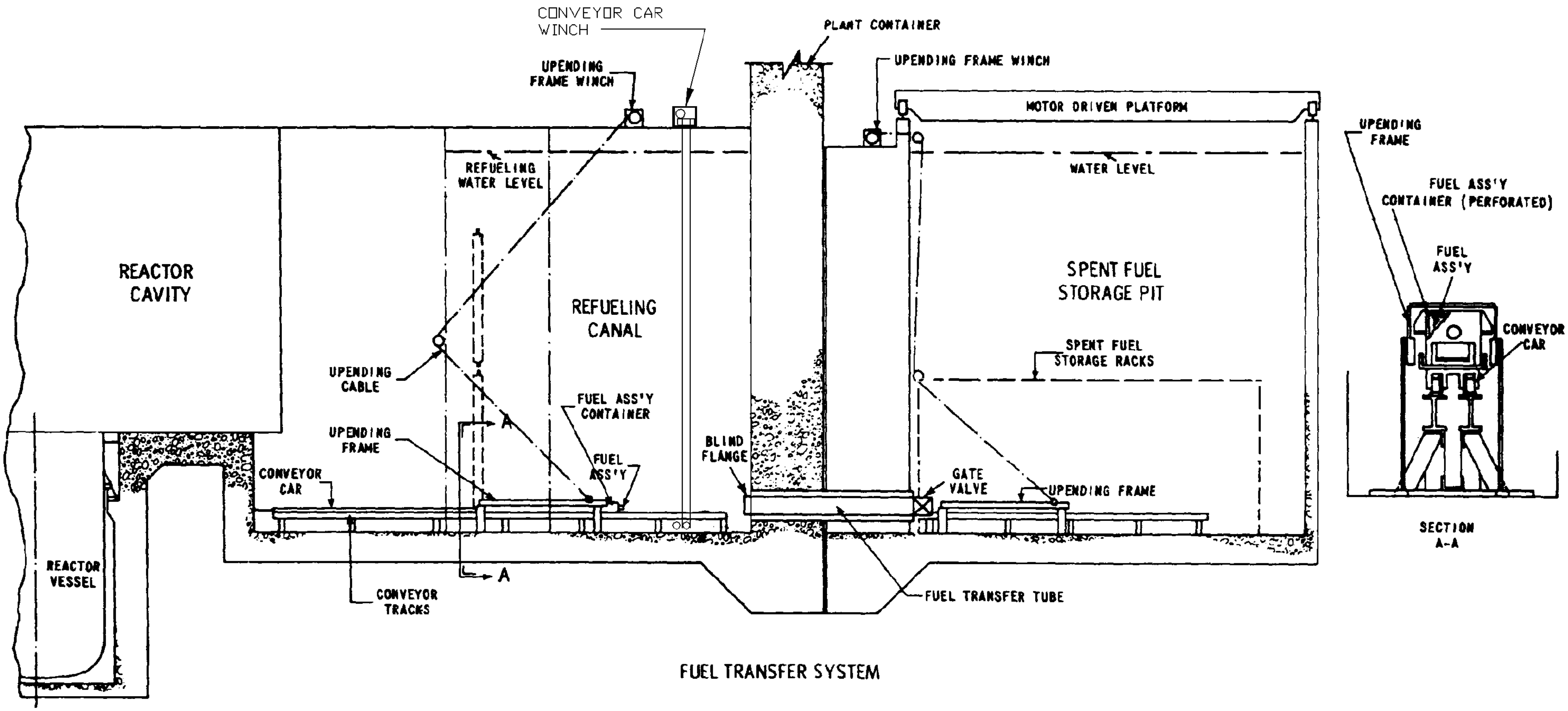
3. A visual inspection of the normal atmosphere cleanup system and all associated components should be performed in accordance with Section 5 of ASME N510-1989.

4. In-place aerosol leak tests, in accordance with Section 10 of ASME N510-1989, for HEPA filters upstream from the carbon adsorbers in normal atmosphere cleanup systems should be performed: at least once each 24 months; after each partial or complete replacement of a HEPA filter bank; following detection of, or evidence of, penetration or intrusion of water or other material into any portion of a normal atmosphere cleanup system that may have an adverse effect on the functional capability of the filters; and, following painting, fire, or chemical release in any ventilation zone communicating with the system that may have an adverse effect on the functional capability of the system. The leak test should confirm a combined penetration and leakage (or bypass) of the normal atmosphere cleanup system of less than 0.05% of the challenge aerosol at rated flow ±10%. A filtration system

satisfying this condition can be considered to warrant a 99% removal efficiency for particulates.

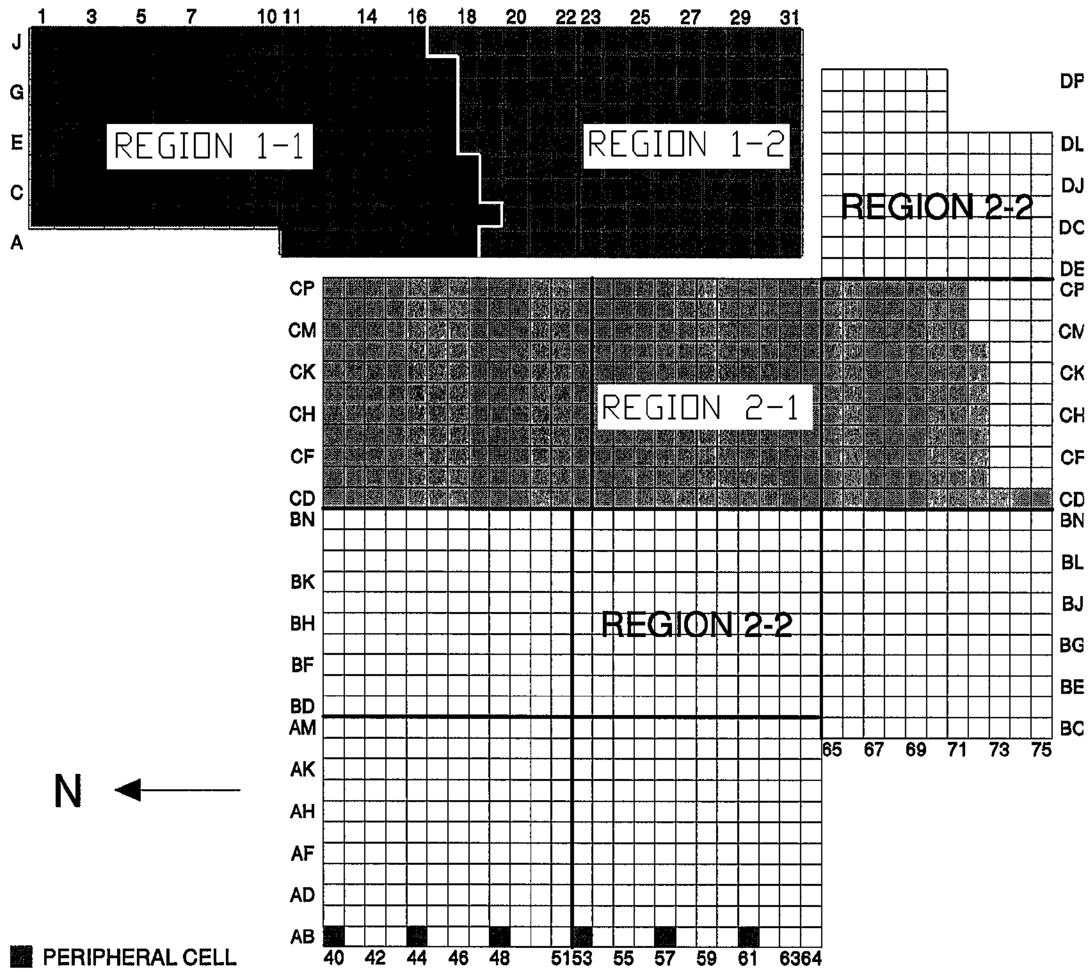
5. In-place leak testing, in accordance with Section 11 of ASME N510-1989, for adsorbers should be performed: at least once each 24 months; following removal of an adsorber sample for laboratory testing if the integrity of the adsorber section is affected; after each partial or complete replacement of carbon adsorber in an adsorber section; following detection of, or evidence of, penetration or intrusion of water or other material into any portion of a normal atmosphere cleanup system that may have an adverse effect on the functional capability of the adsorbers; and, following painting, fire, or chemical release in any ventilation zone communicating with the system that may have an adverse effect on the functional capability of the system. The leak test should confirm a combined penetration and leakage (or bypass) of the adsorber section of 0.05% or less of the challenge gas at rated flow ±10%.

6. The efficiency of the activated carbon adsorber section should be determined by laboratory testing of representative samples of the activated carbon exposed simultaneously to the same service conditions as the adsorber section in accordance with ASTM D3803-1989 at a face velocity of 50 ft/min, a temperature of 89F, and a 95% relative humidity. Sampling and analysis should be performed: at intervals of approximately 24 months; following painting, fire, or chemical release in any ventilation zone communicating with the system that may have an adverse effect on the functional capability of the carbon media; and, following detection of, or evidence of, penetration of water or other material into any portion of the filter system that may have an adverse effect on the functional capability of the carbon media. The acceptance criteria is a methyl iodide penetration of less than 7.5%.



FUEL TRANSFER SYSTEM

INDIAN POINT UNIT No. 2	
UFSAR FIGURE 9.5-1 FUEL TRANSFER SYSTEM	
MIC. No. 1999MC3886	REV. No. 17B

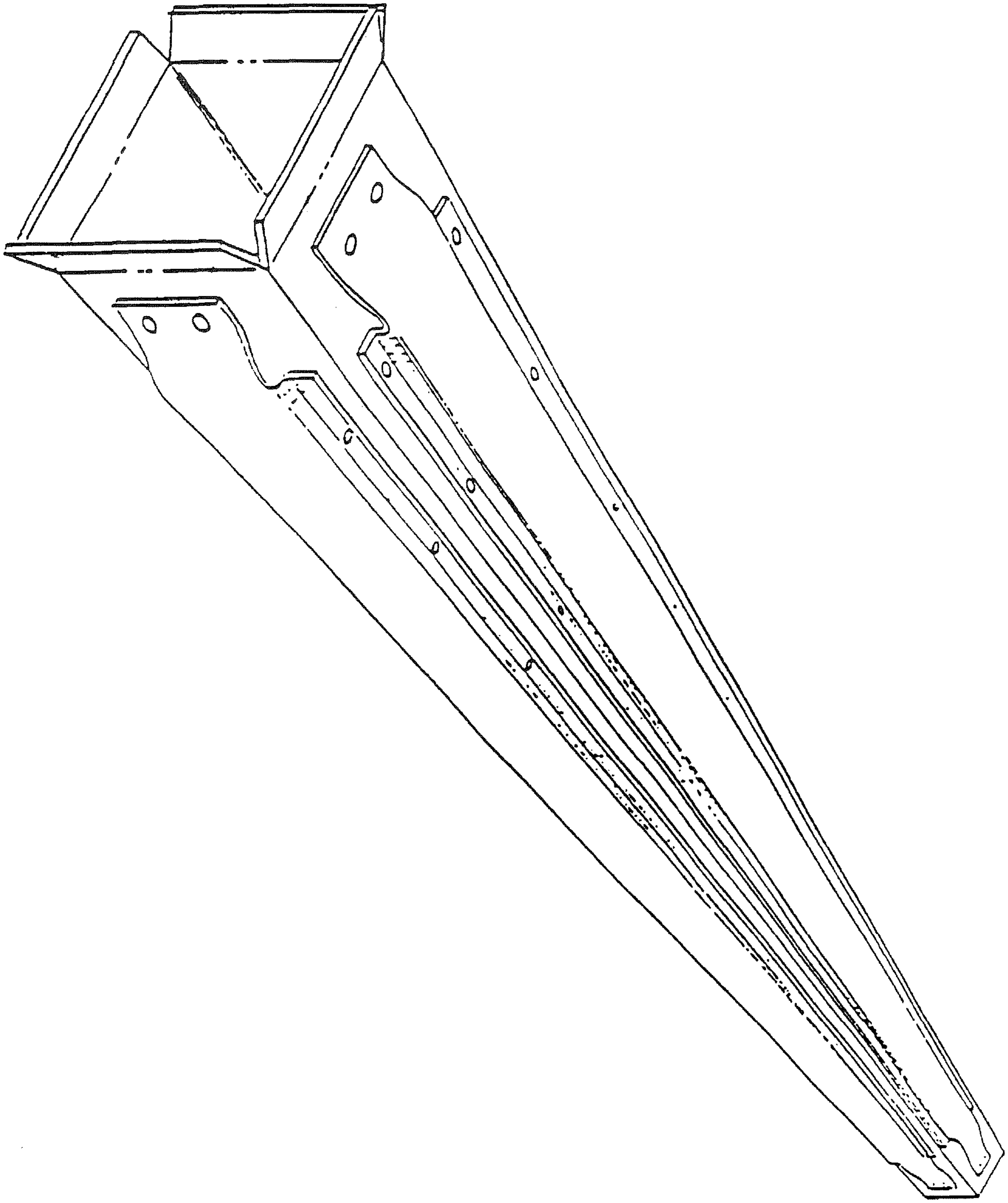


INDIAN POINT UNIT No. 2

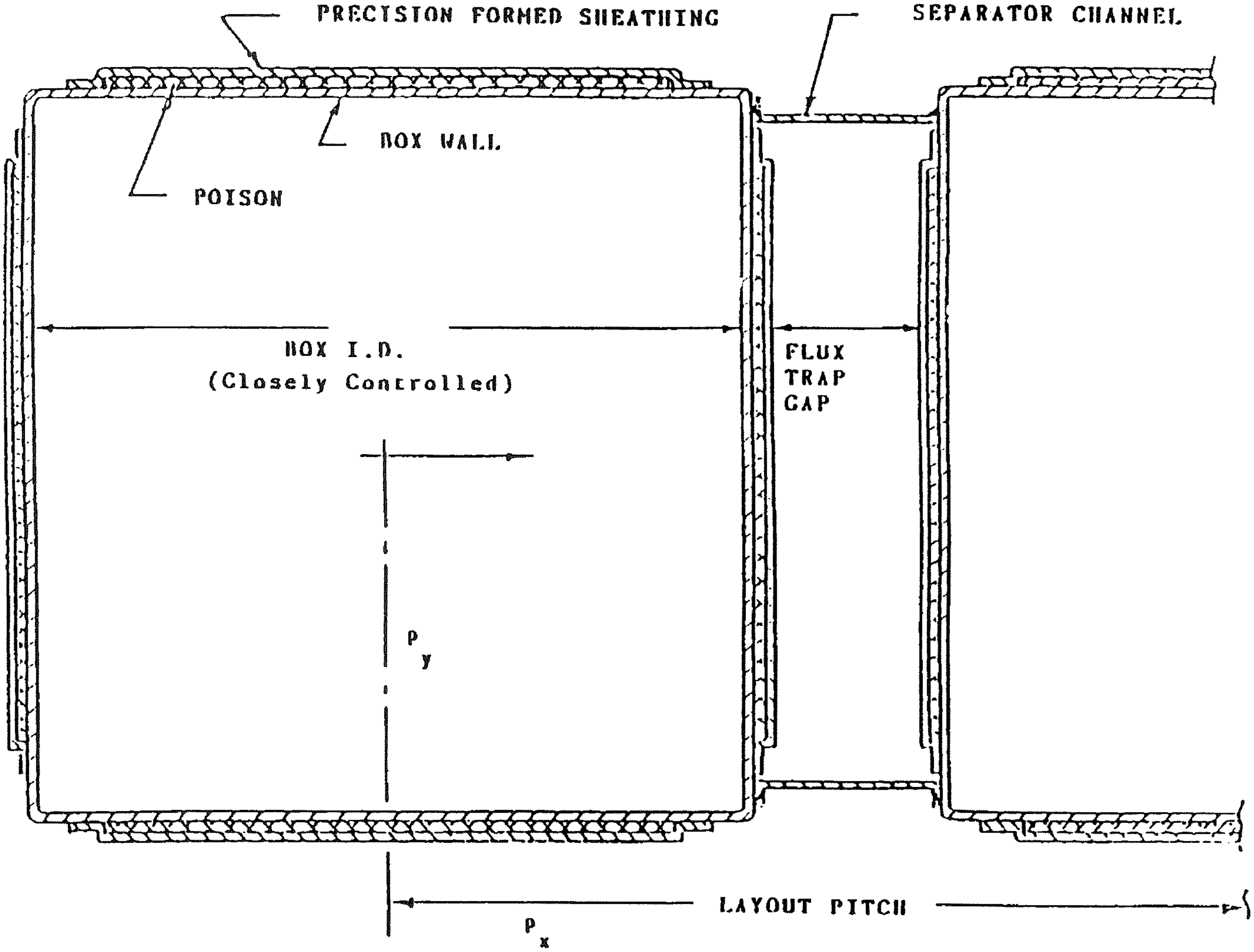
UFSAR FIGURE 9.5-2

SPENT FUEL STORAGE RACK LAYOUT

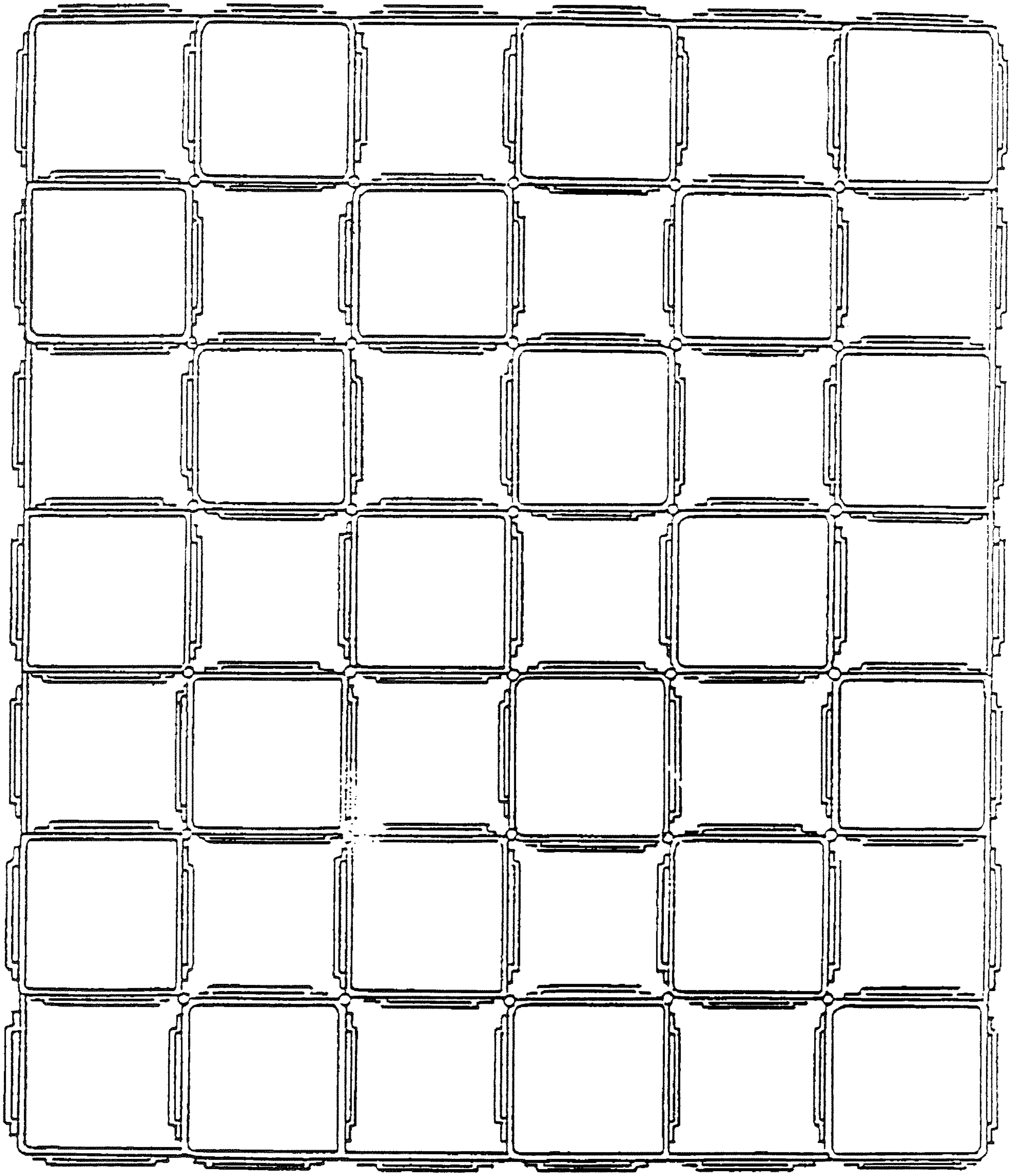
MIC. No. 1999MC3887	REV. No. 17B



INDIAN POINT UNIT No. 2	
UFSAR FIGURE 9.5–3 SPENT FUEL STORAGE CELL REGION I	
MIC. No. 1999MC3888	REV. No. 17A



INDIAN POINT UNIT No. 2	
UFSAR FIGURE 9.5–4 REGION I CELL CROSS SECTION	
MIC. No. 1999MC3889	REV. No. 17A

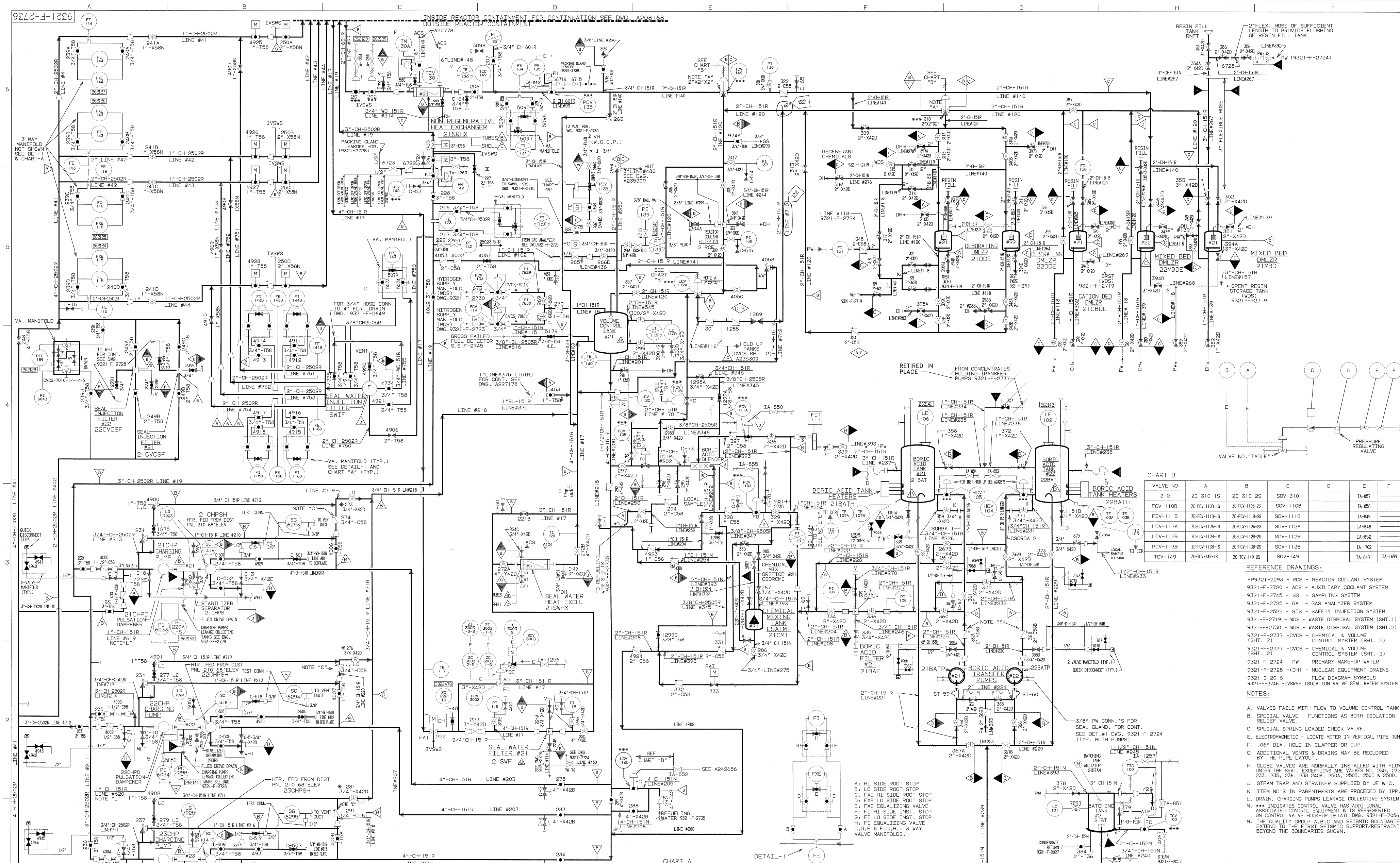


INDIAN POINT UNIT No. 2

UFSAR FIGURE 9.5–5

REGION II
CROSS SECTION

MIC. No. 1999MC3890	REV. No. 17A



NOTE:
FOR INSTRUMENT AIR & N_2 BACK-UP TO CHARGING PUMP CONTROLS SEE DWG. A242656

CHART A

FI/FE/FXE	A	B	C	D	E	F	G	H
116	239C	240C	5026	5027	5028	5029	5030	5031
115	239D	240D	5032	5033	5034	5035	5036	5037
143	239B	240B	5038	5039	5040	5041	5042	5043
144	239A	240A	5044	5045	5046	5047	5048	5049
116B	4916	4915	——	——	——	5071	5070	5069
115B	4918	4917	——	——	——	5067	5068	5066
143B	4914	4913	——	——	——	5077	5075	5076
144B	4912	4911	——	——	——	5080	5079	5078

CHART B

VALVE NO	A	B	C	D	E	F
310	ZC-310-1S	ZC-310-2S	SOV-310		IA-857	——
FCV-110B	ZC-FCV-110B-1S	ZC-FCV-110B-2S	SOV-110B		IA-856	——
FCV-111B	ZC-FCV-111B-1S	ZC-FCV-111B-2S	SOV-111B		IA-849	——
LCV-112A	ZC-LCV-112A-1S	ZC-LCV-112A-2S	SOV-112A		IA-848	——
LCV-112B	ZC-LCV-112B-1S	ZC-LCV-112B-2S	SOV-112B		IA-852	——
PCV-113B	ZC-PCV-113B-1S	ZC-PCV-113B-2S	SOV-113B		IA-1702	——
TCV-149	ZC-TCV-149-1S	ZC-TCV-149-2S	SOV-149		IA-847	IA-1699

REFERENCE DRAWINGS:

FP9321-2293 - RCS - REACTOR COOLANT SYSTEM
9321-F-2720 - ACS - AUXILIARY COOLANT SYSTEM
9321-F-2745 - SS - SAMPLING SYSTEM
9321-F-2725 - GA - GAS ANALYZER SYSTEM
9321-F-2522 - SIS - SAFETY INJECTION SYSTEM
9321-F-2719 - WDS - WASTE DISPOSAL SYSTEM (SHT.1)
9321-F-2730 - WDS - WASTE DISPOSAL SYSTEM (SHT.2)
9321-F-2737 -CVCS - CHEMICAL & VOLUME CONTROL SYSTEM (SHT. 2)
(SHT. 2)
9321-F-2737 -CVCS - CHEMICAL & VOLUME CONTROL SYSTEM (SHT. 3)
(SHT. 2)
9321-F-2724 - PW - PRIMARY MAKE-UP WATER
9321-F-2728 -(DH) - NUCLEAR EQUIPMENT DRAINS
9321-C-2016 ------- FLOW DIAGRAM SYMBOLS
9321-F-2746 -IVSWS- ISOLATION VALVE SEAL WATER SYSTEM

NOTES:

A. VALVES FAILS WITH FLOW TO VOLUME CONTROL TANK.
B. SPECIAL VALVE - FUNCTIONS AS BOTH ISOLATION RELIEF VALVE.
C. SPECIAL SPRING LOADED CHECK VALVE.
E. ELECTROMAGNETIC - LOCATE METER IN VERTICAL PIPE RUN.
F. .06" DIA. HOLE IN CLAPPER OR CUP.
G. ADDITIONAL VENTS & DRAINS MAY BE REQUIRED BY THE PIPE LAYOUT.
H. GLOBE VALVES ARE NORMALLY INSTALLED WITH FLOW UNDER THE SEAT. EXCEPTIONS ARE VALVES NO. 230, 232, 233, 235, 236, 238 240A, 250A, 250B, 250C & 250D.
J. STEAM TRAP AND STRAINER SUPPLIED BY UE & C.
K. ITEM NO'S IN PARENTHESIS ARE PROCEDED BY IPP.
L. DRAIN, CHARGING PUMPS LEAKAGE COLLECTIVE SYSTEM.
M. *** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT & IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL DWG. 9321-F-7056.
N. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

EVERYTHING ON THIS DRAWING (EXCLUDING THOSE PORTIONS SHOWN WITH DASHED LINES) IS PART OF THE CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS) LISTED IN EXHIBIT "A" QAPD

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN ENTERGY AS:
"CLASS A " ITEMS PER THE Q.A.P.D.

THIS DWG. TO BE REVISED ONLY IN AUTOCAD

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
122	INCORPORATED DRN-05-03254, ER MAF-75-2-07	5-25-05	RM	JF	N/A

REVISIONS

DATE	CKR.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.
1/27/88	A.G.	F.A.	W.J.KING 1/27/88		

REVIEW — APPROVALS

TITLE: FLOW DIAGRAM
CHEMICAL & VOLUME CONTROL
SYSTEM -
UFSAR FIGURE No. 9.2-1 (SHT. 1)

DRWN. BY GIBBS&HILL | SCALE NONE | REC'D

Entergy
Nuclear Northeast

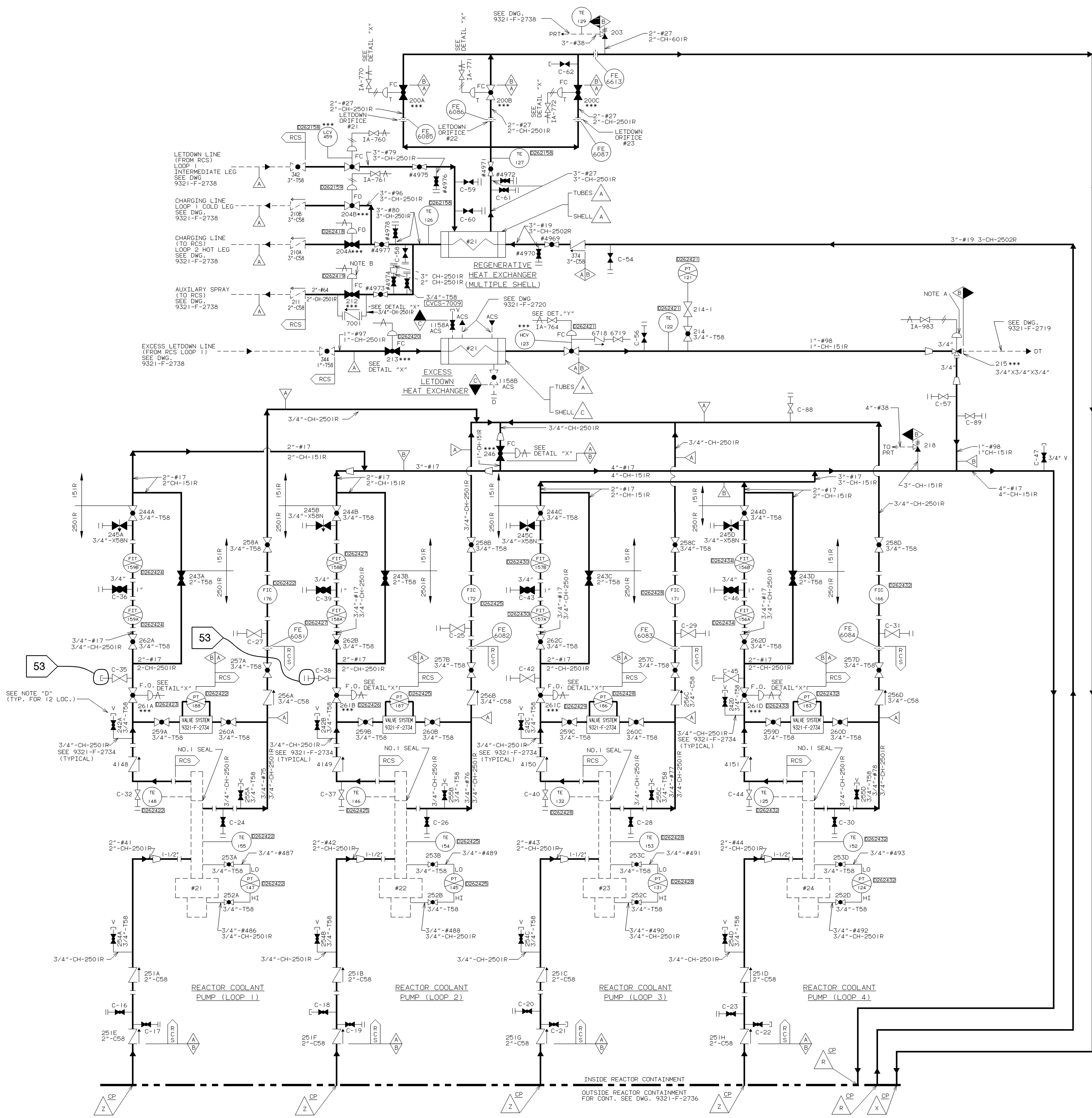
STATION
INDIAN POINT

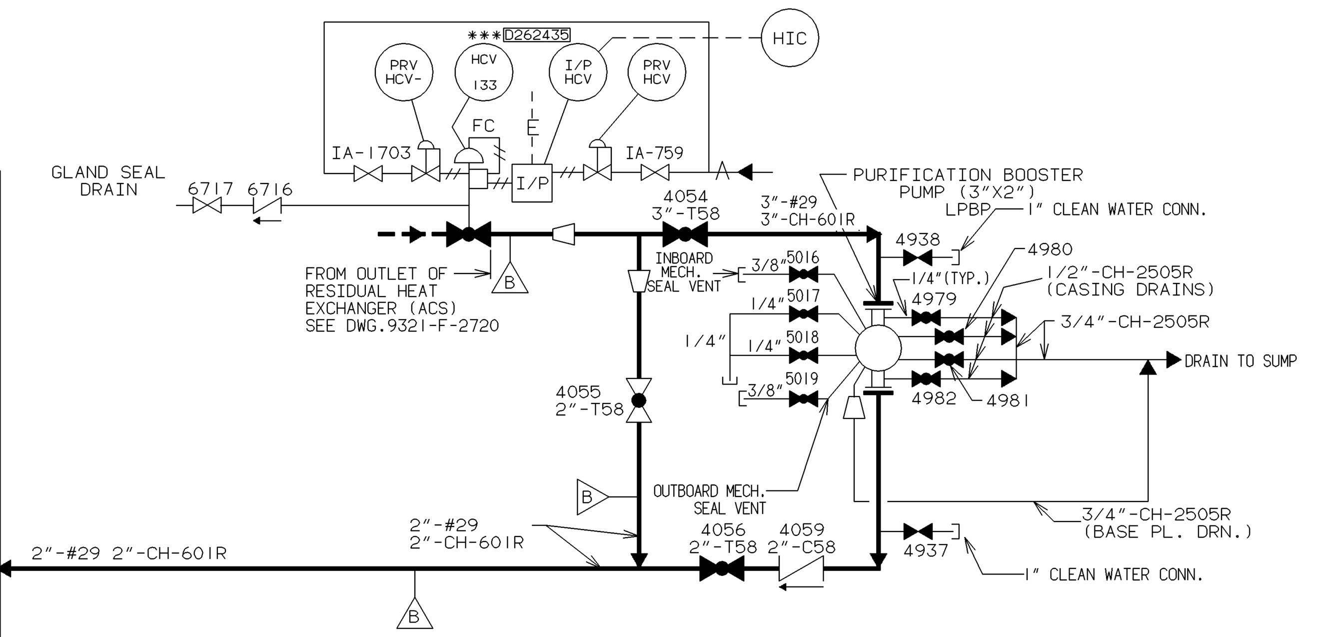
DWG. NO. 9321-F-2736-122 MY

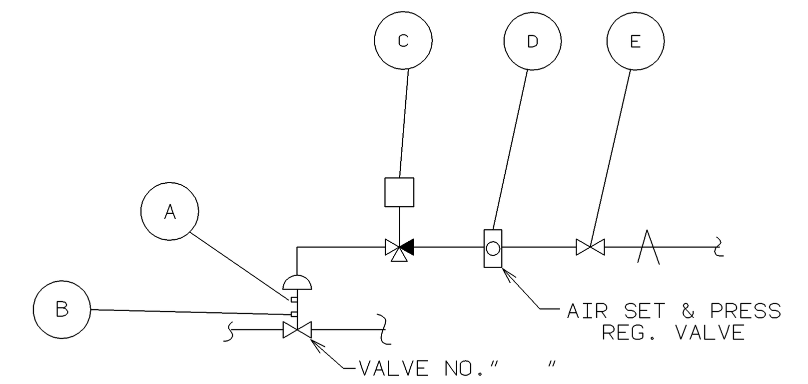
REVISION
USE .1 SIZE TEXT ONLY

G. BHALLA
12/10/02 53

THIS REVISION IS CLASS "A" PER THE QAPD. UPDATED DWG. PER CR #IP-2-2001-10397 AND FIELD VERIFICATION. CHANGED PLUG ON VA. C-38 TO FLG AND FLG ON VA. C-35 TO PLUG. RELEASED AS CONSTRUCTED P.N. 69901-AF D.B./G.B.

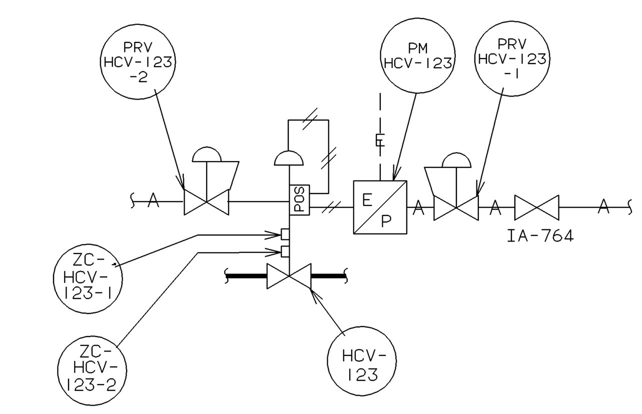






VALVE NO	A	B	C	D	E
246	ZC-246-1	ZC-246-2	SOV-246	PRV-246	IA-773
261A	ZC-261A-1S	ZC-261A-2S	SOV-261A	PRV-261A	IA-766
261B	ZC-261B-1S	ZC-261B-2S	SOV-261B	PRV-261B	IA-767
261C	ZC-261C-1S	ZC-261C-2S	SOV-261C	PRV-261C	IA-768
261D	ZC-261D-1S	ZC-261D-2S	SOV-261D	PRV-261D	IA-769
212	ZC-212-1S	ZC-212-2S	SOV-212	PRV-212	IA-1312
213	ZC-213-1S	ZC-213-2S	SOV-213	PRV-213	IA-765
200A	ZC-200A-1	ZC-200A-2	SOV-200A	PRV-200A	IA-770
200B	ZC-200B-1	ZC-200B-2	SOV-200B	PRV-200B	IA-771
200C	ZC-200C-1	ZC-200C-2	SOV-200C	PRV-200C	IA-772
215	ZC-215-1	ZC-215-2	SOV-215	PRV-215	IA-983
204A	ZC-204A-1	ZC-204A-2	SOV-204A	PRV-204A	IA-762
204B	ZC-204B-1	ZC-204B-2	SOV-204B	PRV-204B	IA-761
LCV-459	ZC-LCV-459-1	ZC-LCV-459-2	SOV-459	PRV-LCV-459	IA-760

DETAIL "X"



DETAIL "Y"

WORK THIS DRAWING WITH DWG. 9321-F-2734 AND DWG. 9321-F-2736

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN ENTERGY AS:
"CLASS A" ITEMS
PER THE QAPD

NOTES

A. VALVE FAILS WITH FLOW TO VOLUME CONTROL TANK
B. SPECIAL VALVE-FUNCTIONS AS BOTH ISOLATION & RELIEF VALVE.
C. *** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT & IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL DRAWING 9321-F-7056.
D. FOR CONTINUATION SEE DWG. 9321-F-2734 (TYP. FOR 12 LOC.)
E. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

REF. DWG.

9321-C-2016	FLOW DIAGRAM SYMBOLS
9321-F-2538	CONTAINMENT BLDG PRIMARY COOLANT PRESSURIZER PIPING PLAN (SOUTH HALF)
9321-F-2734	PIPING AT REACTOR COOLANT PUMPS

EVERYTHING ON THIS DRAWING (EXCLUDING THOSE PORTIONS WITH DASHED LINES) IS PART OF THE CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS) LISTED IN EXHIBIT A, CI-240-1 EXCEPT AS SPECIFICALLY INDICATED HEREIN

RCS REACTOR COOLANT SYSTEM

REVISION SIGNATURES

REV	DES	ENG
53		G. BHALLA 12/10/02

DWG. NO. A208168-53
DWG. SIZE A | DWG. TYPE COMPANY
CON EDISON | STATION INDIAN POINT
BORO: WESTCHESTER
TITLE: FLOW DIAGRAM
CHEMICAL & VOLUME CONTROL SYSTEM
UFSAR FIGURE No. 9.2-1 (SHT. 2)

APPROVALS
ENGINEERING
ENGINEER MANAGER:
DISCIPLINE ENGINEER:
DESIGN
DESIGN MANAGER: W.J. KING 11-6-87
DESIGN SUPERVISOR: F.A. 8-17-90
DRAWN BY: MARZULLO 8-17-90
DESIGN CHECKER: L.H. 8-17-90
SCALE: NONE | DISCIPLINE CODE: MY

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REFERENCE DWGS:
U.E.& C.DWG.NO.

9321-F-2738----------------RCS REACTOR COOLANT SYSTEM
9321-F-2724----------------PRIMARY MAKE-UP WATER
9321-F-2720----------------ACS-AUXILIARY COOLANT SYSTEM
9321-F-2727----------------NUCLEAR EQUIP.VENT SYS.SS SAMPLING SYS.
9321-F-2016----------------FLOW DIAGRAM SYMBOLS
9321-H-2739----------------TEMP.STRAINER TABULATION
9321-F-2735----------------SIS SAFETY INJECTION SYSTEM
9321-F-2027----------------AUXILIARY STEAM SYSTEM
9321-F-2719----------------WDS WASTE DISPOSAL SYS.(SH.1)
9321-F-2720----------------WDS WASTE DISPOSAL SYS.(SH.2)
9321-F-2723----------------NITROGEN
9321-F-2736----------------CVCS-CHEMICAL & VOLUME CONT.SYS.(SH1)
9321-F-2725------(GA)--------GAS ANALYZER SYSTEM
9321-F-2728------(DH)--------NUCLEAR EQUIPMENT DRAINS

NOTES:

A. DIAPHRAGM SEAL.
B. LOOP SEAL SHOULD EXTEND ONE FOOT BELOW AND ONE FOOT ABOVE OUTLET NOZZLE.
C. SOLENOID VALVE ACTUATED BY GAS ANALYZER CHANNEL (LATER)
D. ADDITIONAL VENTS & DRAINS MAY BE REQUIRED BY THE PIPE RUN
E. GLOBE VALVES ARE NORMALLY INSTALLED WITH FLOW UNDER THE SEAT. EXCEPTIONS ARE NC.(LATER)
F. STEAM TRAP ASSY.BY U.E.&C. TRAP BY VENDOR F.P.933FD
G. TANK IS SUPPLIED WITH DIAPHRAM SEAL.
H. VOL CONTROL TK. RELIEF LINE SHOULD TAP IN CLOSE TO TANK #21.
I. SEE BELOW:
J. ••• INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT & IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL DWG. 9321-F-7056.
K. ALL HEAT TRACE CIRCUITS ON THIS DRAWING ARE DISCONNECTED.
L. STRAINER INTERNALS HAVE BEEN REMOVED.

REFERENCES:

1. PROCESS FLOW DIAGRAM CVCS (SH.2) Ⓦ E.C.DWG.540F892
2. PROCESS FLOW DIAGRAM CVCS (SH.3) Ⓦ E.C.DWG.540F893
3. DEFINITIONS OF SYMBOLS Ⓦ E SPEC G675176 REV.2 AND Ⓦ E SPEC G675164 REV.0
4. INSTALLATION OF INSTR. Ⓦ PROC.SPEC CAP 294367 REV.1
5. MATR.SPEC PIPE & FITTINGS Ⓦ E.SPEC G569866 REV.2 AND Ⓦ E.SPEC G676398 REV.0

EXCEPT WHERE NOTED.
EVERYTHING ON THIS DRAWING (EXCLUDING THOSE PORTIONS SHOWN WITH DASHED LINES) IS PART OF THE CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS) LISTED IN EXHIBIT "A"..CI-240-1
NOTE 1 THE ITEMS SHOWN DASHED WITH IN THIS COMPONENT BOUNDARY ARE PART OF (CVCS)

LEGEND:
SRST - SPENT RESIN STORAGE TANK
VS - VENTILATION SYSTEM

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS:
"CLASS A" ITEMS
PER CI-240-1

WORK THIS DRAWING WITH DWG. A235309

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DWG. TO SHOW RETIRED BORON RECOVERY EQUIPMENT PER CRS #199806527. RELEASE AS CONSTRUCTED. P/N 69901-AF
D.B./Y.J. 2/09/01
G. BHALLA 02/09/01
2/8/88 A.G. W.J.KING 2/9/88

TITLE: FLOW DIAGRAM
CHEMICAL & VOLUME CONTROL SYSTEM - SH.NO.2 -
UFSAR FIGURE No. 9.2-1 (SHT. 3)
DRAWN BY GIBBS&HILL SCALE NONE
Con Edison STATION INDIAN POINT
DWG. NO. 9321-F-2737-53 MY

MECHANICAL

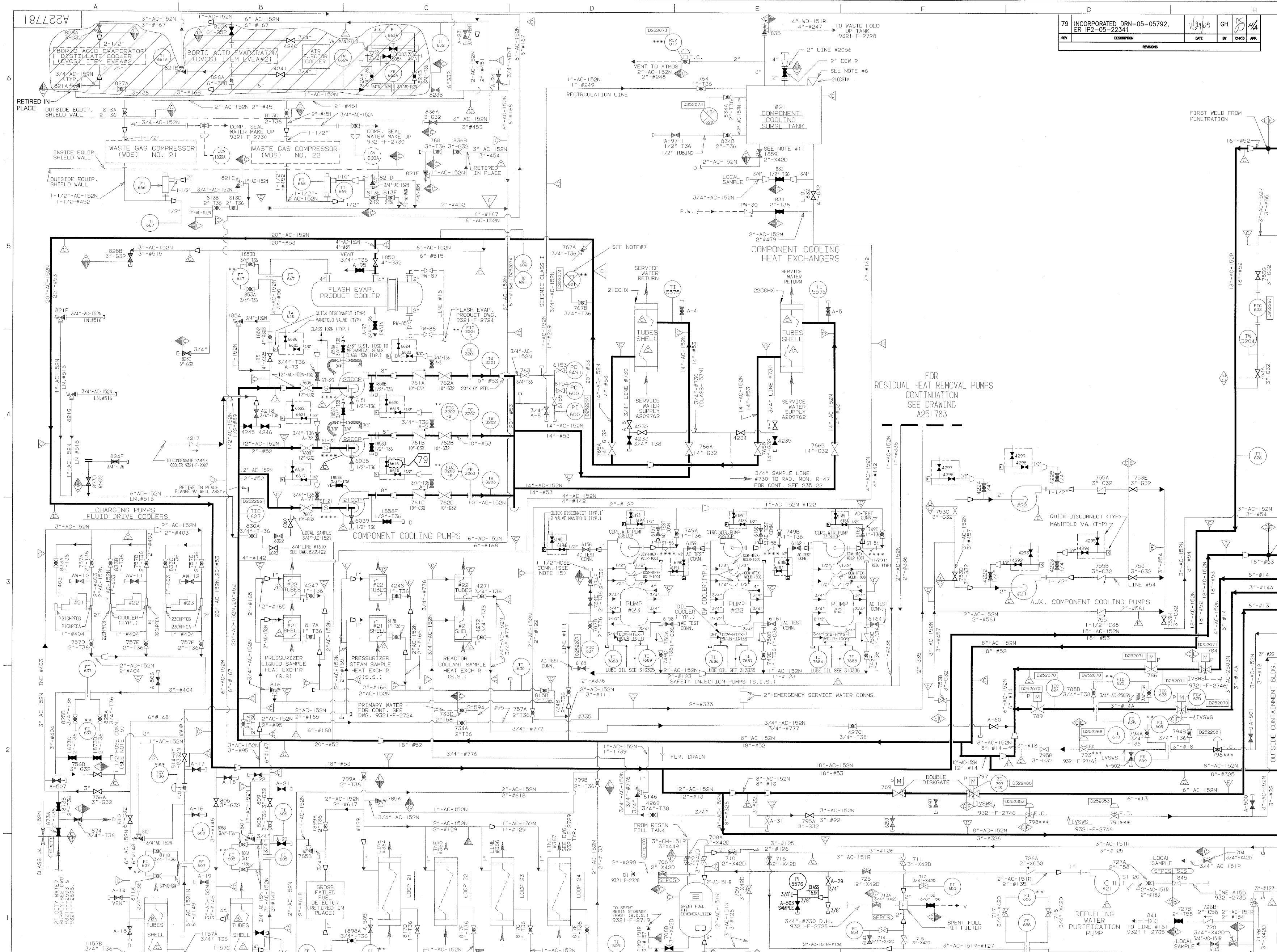

A235309
RETIRED IN PLACE
PREVIOUSLY RETIRED IN PLACE
EVAPORATOR CONDENSATE DEMINERALIZERS
CONDENSATE FILTER ITEM NO.22
CONDENSATE FILTER ITEM NO.21
MONITOR TANK #21 RETIRED IN PLACE
MONITOR TANK #22 RETIRED IN PLACE
MONITOR TANK #23 RETIRED IN PLACE
MONITOR TANK PUMPS RETIRED IN PLACE
PRIMARY WATER STORAGE TANK DWG 9321-F-2724
REACTOR COOLANT LETDOWN CVCS (VOLUME CONTROL TANK) DWG 9321-F-2736
REACTOR COOLANT DRAIN PUMP
BORIC ACID BLENDER OR SPENT FUEL PIT TEMP. DRAIN
HOLD-UP TANK #21
HOLD-UP TANK #22
HOLD-UP TANK #23
RECIRCULATION PUMP
CVCS HOLDUP TANK TRANSFER PUMPS
UNIT #2 WASTE TRANSFER PUMP DISCH.SEE DWG.A188852
LINE # 794 TO PRIMARY SAMPLING SYSTEM DWG. 9321-F-2745
TO WASTE HOLD-UP TANK VIA #261
WORK THIS DRAWING WITH 9321-F-2737
EXCEPT WHERE NOTED.
EVERYTHING ON THIS DRAWING (EXCLUDING THOSE PORTIONS SHOWN WITH DASHED LINES) IS PART OF THE CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS) LISTED IN EXHIBIT "A"..CI-240-1
NOTE I THE ITEMS SHOWN DASHED WITHIN THIS COMPONENT BOUNDARY ARE PART OF (CVCS)
NOTE:
SEE DWG. 9321-F-2737 FOR ALL NOTES, REFERENCES AND LEGEND
THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.
* FOR CONTINUATION SEE DWG. 9321-2730
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS: "CLASS A" ITEMS PER CI-240-1
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
THIS REVISION IS NON-CLASS PER CI-240-1. UPDATED DWG. TO SHOW RETIRED BORON RECOVERY EQUIPMENT PER CRS #199806527 RELEASED AS CONSTRUCTED. P/N 69901-AF D.B./G.B. 03/12/01
G. BHALLA 03/12/01
W.J.KING 2/23/88
TITLE: FLOW DIAGRAM CHEMICAL & VOLUME CONTROL SYSTEM - UFSAR FIGURE No. 9.2-1 (SHT. 4)
DRAWN BY GIBBS&HILL SCALE NONE
Con Edison
STATION INDIAN POINT
DWG. NO. A235309-33 MY


9321-F-2724
COMPONENT COOLING SURGE TANK NO. 21
FLASH EVAPORATOR PRODUCT COOLER
A.C.S. RETURN DWGA227781
4"LINE #90 A.C.S. SUPPLY DWG A227781
FROM FLASH EVAPORATOR DISTILLATE PUMPS - SEE DWG NO 9321-F-2021
W.D.S. DRUMMING STATION DEPENS'G MANIFOLD LN'S 596,597,598,& 599
DRUM STORAGE AREA
RETIRED IN PLACE
TO SOV-10001 FOR CONT. SEE 303235
LN #163-3"-PW-151N
RECIRCULATION (30GPM)
ORIFICE PLATE 0.40 INCH I.D.
OUTSIDE PAB
INSIDE PAB
PRIMARY WATER STORAGE TANK 165,000 GAL. 30'Ø X 35'-3"
24" MUSHROOM VENT & MH.
COND. DRAIN 4 REQD.EQ. SPACED
3"CHEMICAL ADDITION PORT
FROM MONITOR TANK PUMPS
TO REFUELING WATER STORAGE TANK(SIS)SEE DWG.9321-F-2735
1-1/2" STEAM FROM AUXILIARY STEAM SYS. SEE DWG. 9321-F-2027
3/4" B.D. UH
TO COND. RETURN SEE DWG. 9321-F-2027
NOTE A
PRIMARY WATER MAKE-UP PUMP
CHESTERTON SYSTEM-ONE
1 1/2 X3 X8
INSIDE P.A.B.
OUTSIDE P.A.B.
FUEL STORAGE BUILDING
SPENT FUEL PIT
HOSE VALVES
BORIC ACID BLENDER & CHEMICAL MIX TANKS
BORIC ACID TRANSFER PUMPS
SEAL WATER STORAGE TANK (IVSWS)
BATCH TANK
CONCENTRATE HOLD TANKS TRANS PUMPS
TO RESIN FILL TANK
TO GAS STRIPPER #21 FLUSH INLET
TO CONCENTRATOR FLUSH INLET
TO CONCENT'R PUMP
TO LEVEL CONTL'R
BORIC ACID EVAPORATOR PACKAGE #21
RETIRED IN PLACE
BARRIER FLUID TK.#21 21BFT
BARRIER FLUID TK.#22 22BFT
SINK
DRAIN
SEAL GLAND
BORIC ACID TRANSFER PUMPS (SEE DWG. 9321-F-2736)
DETAIL "I"
NOTE:S.C. INDICATES "SEALED CLOSED"
CONTAINMENT BUILDING
PRESSURE RELIEF TANK
RCP #24
RCP #23
RCP #22
RCP #21
R.C. PUMP #22 SEAL LEAK OFF
FAN ROOM
EVAPORATOR FEED ION EXCHANGERS
TO SPENT FUEL PIT DEMINERALIZER
TO RESIN DISCHARGE HDR. NO.157 SEE DWG A227781
FLANGED HOSE CONN.
TO SPENT RESIN STORAGE TANK
TO MIX BED DEMINERALIZER
TO CATION BED DEMINERALIZER
TO DEBORATING DEMINERALIZERS
TO FILTER DRAIN HEADER LN#114
FOR RESIDUAL HEAT REMOVAL PUMP FLUSHING
1-1/2"MALE HOSE CONN.
CONDENSATE DEMINERALIZERS NO. 21 & 22
PRIMARY AUXILIARY BUILDING
REFERENCE DRAWINGS
DWG. NO. SYSTEM
9321-F-2738 ---- REACTOR COOLANT
9321-F-2719 ---- WASTE DISPOSAL SH.1
9321-F-2736 ---- CHEMICAL VOLUME CONTROL SH.1
9321-F-2737 ---- CHEMICAL VOLUME CONTROL SH.2
A235309 ------ CHEMICAL VOLUME CONTROL SH.3
9321-F-2720 ---- AUXILIARY COOLANT
9321-F-2673 ---- ISOLATION VALVE SEAL WATER
9321-F-2728 ---- NUCLEAR EQUIP. DRAINS
FP9321-20224 --- GAS STRIPPER CONTROL SCHEMATIC
9321-C-2016 ---- FLOW DIAGRAM-SYMBOLS
EVERYTHING ON THIS DRAWING (EXCLUDING THOSE PORTIONS SHOWN WITH DASHED LINES) IS PART OF THE PRIMARY MAKEUP WATER SYSTEM (PW) LISTED IN EXHIBIT A, CI-240-1. EXCEPT AS SPECIFICALLY INDICATED HEREIN.
NOTE A
AUXILIARY STEAM SYSTEM - NOT LISTED IN CI-240-1.
NOTES:
1. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS:
"CLASS A" ITEMS
PER QAPD
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
REVISION
DES
G. BHALLA 08/24/01
ENG
THIS REVISION IS CLASS "A" PER THE QAPD. UPDATED DRAWING PER MOD PROCEDURE #FMX-99-12267-M TRANSFERRED DMD9321-2724-AN REV.0 AND DMD9321-2724-AO REV.0.
RELEASE AS CONSTRUCTED.
P.N. 12267-99 JF/DB
3/28/87
A.G.
F.A.
W.J.KING 3-30-87
DATE
CKR.
SUPV.
REVIEW
DESIGN ENG
DISC. ENG.
ENG. MGR.
APPROVALS
TITLE: FLOW DIAGRAM
PRIMARY MAKE-UP WATER SYSTEM
NUCLEAR STEAM SUPPLY PLANT. -
UFSAR FIGURE No. 9.2-2
DRWN. BY GIBBS&HILL
SCALE NONE
REC'D
Con Edison
STATION
INDIAN POINT
DWG. NO. 9321-F-2724-55
MY

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
79	INCORPORATED DRN-05-05792, ER IP2-05-22341	11/29/05	GH	JS	N/A

REVISIONS

MECHANICAL



NOTES

1. VALVES ARE NORMALLY INSTALLED WITH FLOW UNDER SEAT, EXCEPT FOR VALVE NO. 831.
2. LOCATE SUCTION CONNECTION IN BOTTOM HALF OF REACTOR COOLANT PIPING ON 45° ANGLE TO VERTICAL.
3. SPRING LOADED CHECK VALVE.
4. LOCATE IN ANNULAR RING BETWEEN SECONDARY SHIELD AND CONTAINMENT WALL.
5. LOCATE VALVE CLOSE TO SPENT FUEL PIT WALL
6. VACUUM BREAKER: SUPPLIED WITH TANK.
7. PRESSURE TAP LOCATED PER Ⓦ I&C STANDARDS.
8. PENETRATE WALL 6 FT. ABOVE FUEL ASSEMBLIES.
9. TERMINATE PIPE 6 FT. ABOVE FUEL ASSEMBLIES.
10. VENT AND DRAIN REQUIREMENT DEPEND UPON PIPING LAYOUT TO BE SPECIFIED BY A.E..
11. ELEVATION OF SURGE TANK NORMAL WATER LEVEL TO BE HIGHEST POINT IN COMPONENT COOLING SYSTEM.
12. REACTOR COOLANT PRESSURE INTERLOCK PREVENTS ISOLATION VALVE OPENING ABOVE SET PRESSURE.
13. SCHEDULE 140 PIPE.
14. FOR MISC. VENTS AND DRAINS REFER TO PHYSICAL PIPING DRAWINGS.
15. HOSE PROVIDED TO ENABLE COOLING WATER TO BE PIPED OUTSIDE THE BUILDING.
16. FOR LENGTH TABLE SEE 9321-F-2720.
17. *** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT AND IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL DWG. 9321-F-7056.
18. ** -INDICATES INSTRUMENT HAS ADDITIONAL VALVES. DETAILS & VALVE IDENTIFICATION SHOWN ON DWGS. B242828.
19. **** ST-21, ST-22, ST-23, ST-54, ST-55 AND ST-56 ARE TEMPORARY START-UP STRAINERS WITH INTERNAL SCREENS REMOVED.
20. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.
21. 14" DIA. LINE NO 10 HAS 6" THICK INSULATION BETWEEN VALVES #730 AND #731.

REF. DWG.

B207540-INSTRU. PIPING ARR'GT FOR FE-3201,FE-3202 & FE-3203.

9321-F-2016-FLOW DIAGRAM SYMBOLS

EVERYTHING ON THIS DRAWING (EXCEPT FOR DASHED LINES) IS PART OF THE COMPONENT COOLING SYSTEM (CCS) AS DESCRIBED IN EXHIBIT "A" TO CI-240-1. UNLESS OTHERWISE INDICATED HEREIN.

CWS CITY WATER SYSTEM (PORTION NOT LISTED IN CI-240-1)
SFPCS SPENT FUEL POOL COOLING SYSTEM
RHR RESIDUAL HEAT REMOVAL

LEGEND

T-VALVE TO TRIP OR CLOSE ON HIGH CONTAINMENT PRESSURE
P-VALVE TO TRIP OR CLOSE ON HIGH-HIGH CONTAINMENT PRESSURE

WORK THIS DRAWING WITH DRAWING 9321-F-2720

COMPUTER GENERATED DRAWING, NOT TO BE HAND REVISED.

6/30/89	D.M.	F.A.	W.J.KING 1/29/88			
DATE	CKR.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.	
	REVIEW		APPROVALS			

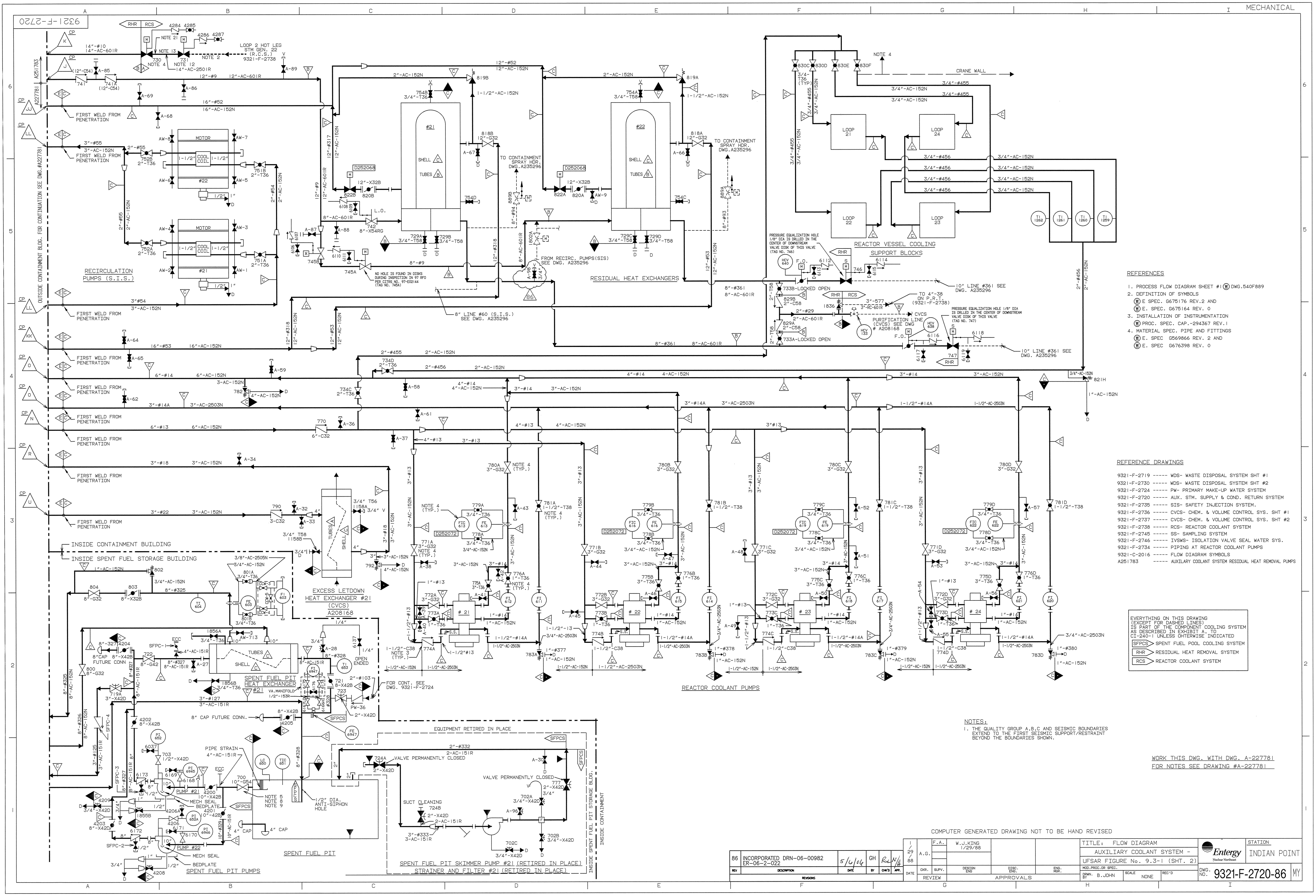
TITLE: FLOW DIAGRAM
AUXILIARY COOLANT SYSTEM -

UFSAR FIGURE No. 9.3-1 (SHT. 1)

DRWN. BY D. BALADO | SCALE NONE | REC'D

STATION INDIAN POINT

DWG. NO. A227781-79 MY



MECHANICAL
9321-F-2720
OUTSIDE CONTAINMENT BLDG. FOR CONTINUATION SEE DWG.#A227781
LOOP 2 HOT LEG STM GEN. 22 (R.C.S.) 9321-F-2738
RECIRCULATION PUMPS (S.I.S.)
FIRST WELD FROM PENETRATION
RESIDUAL HEAT EXCHANGERS
REACTOR VESSEL COOLING SUPPORT BLOCKS
CRANE WALL
TO CONTAINMENT SPRAY HDR. DWG.A235296
FROM RECIRC. PUMPS(SIS) SEE DWG. A235296
8" LINE #60 (S.I.S.) SEE DWG. A235296
10" LINE #361 SEE DWG. A235296
PURIFICATION LINE (CVCS) SEE DWG # A208168
INSIDE CONTAINMENT BUILDING
INSIDE SPENT FUEL STORAGE BUILDING
EXCESS LETDOWN HEAT EXCHANGER #21 (CVCS) A208168
SPENT FUEL PIT HEAT EXCHANGER #21
FOR CONT. SEE DWG. 9321-F-2724
EQUIPMENT RETIRED IN PLACE
VALVE PERMANENTLY CLOSED
SUCT CLEANING
SPENT FUEL PIT
SPENT FUEL PIT PUMPS
SPENT FUEL PIT SKIMMER PUMP #21 (RETIRED IN PLACE)
STRAINER AND FILTER #21 (RETIRED IN PLACE)
INSIDE SPENT FUEL PIT STORAGE BLDG.
INSIDE CONTAINMENT
REACTOR COOLANT PUMPS
REFERENCES
1. PROCESS FLOW DIAGRAM SHEET #1 (W) DWG.540F889
2. DEFINITION OF SYMBOLS
(W) E SPEC. G675176 REV.2 AND
(W) E. SPEC. G675164 REV. 0
3. INSTALLATION OF INSTRUMENTATION
(W) PROC. SPEC. CAP.-294367 REV.1
4. MATERIAL SPEC. PIPE AND FITTINGS
(W) E. SPEC G569866 REV. 2 AND
(W) E. SPEC G676398 REV. 0
REFERENCE DRAWINGS
9321-F-2719 ----- WDS- WASTE DISPOSAL SYSTEM SHT #1
9321-F-2730 ----- WDS- WASTE DISPOSAL SYSTEM SHT #2
9321-F-2724 ----- PW- PRIMARY MAKE-UP WATER SYSTEM
9321-F-2720 ----- AUX. STM. SUPPLY & COND. RETURN SYSTEM
9321-F-2735 ----- SIS- SAFETY INJECTION SYSTEM.
9321-F-2736 ----- CVCS- CHEM. & VOLUME CONTROL SYS. SHT #1
9321-F-2737 ----- CVCS- CHEM. & VOLUME CONTROL SYS. SHT #2
9321-F-2738 ----- RCS- REACTOR COOLANT SYSTEM
9321-F-2745 ----- SS- SAMPLING SYSTEM
9321-F-2746 ----- IVSWS- ISOLATION VALVE SEAL WATER SYS.
9321-F-2734 ----- PIPING AT REACTOR COOLANT PUMPS
9321-C-2016 ----- FLOW DIAGRAM SYMBOLS
A251783 ----- AUXILARY COOLANT SYSTEM RESIDUAL HEAT REMOVAL PUMPS
EVERYTHING ON THIS DRAWING (EXCEPT FOR DASHED LINES) IS PART OF THE COMPONENT COOLING SYSTEM AS DESCRIBED IN EXHIBIT A. TO CI-240-1 UNLESS OHTERWISE INDICATED
SFPCS SPENT FUEL POOL COOLING SYSTEM
RHR RESIDUAL HEAT REMOVAL SYSTEM
RCS REACTOR COOLANT SYSTEM
NOTES:
1. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.
WORK THIS DWG. WITH DWG. A-227781
FOR NOTES SEE DRAWING #A-227781
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
86 INCORPORATED DRN-06-00982 ER-06-2-022
TITLE: FLOW DIAGRAM
AUXILIARY COOLANT SYSTEM -
UFSAR FIGURE No. 9.3-1 (SHT. 2)
Entergy
STATION
INDIAN POINT
DWG. NO. 9321-F-2720-86
W.J.KING 1/29/88
DRWN. BY B.JOHN
SCALE NONE
REVIEW
APPROVALS

2/21/2004 7:04:02 AM 251783-0-28.DWG

MECHANICAL

NOTES:

1. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

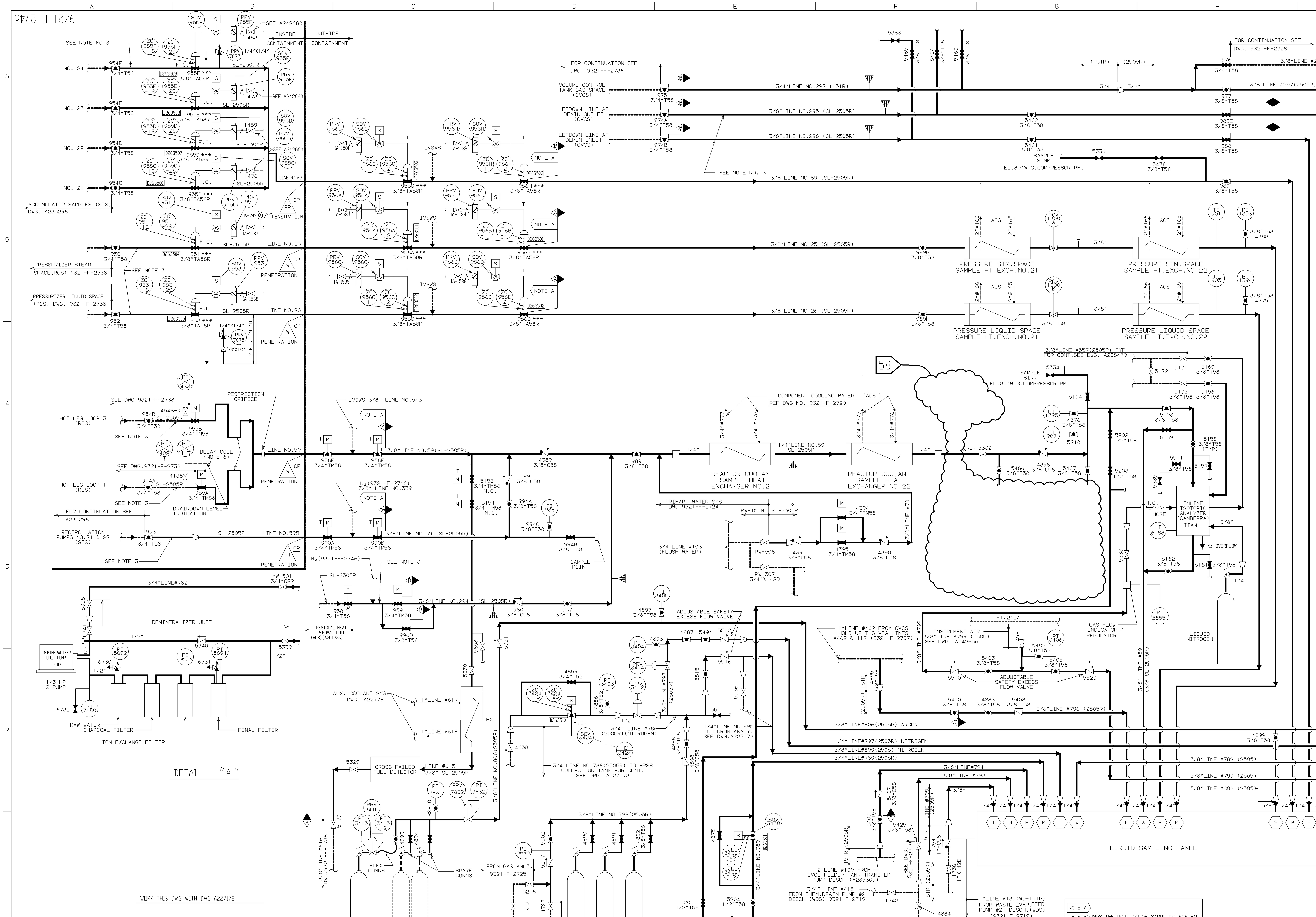
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN ENTERGY AS:
"CLASS A " ITEMS
PER THE QAPD

FOR NOTES AND REF. DWGS. SEE DWG. A227781

THIS DWG. TO BE REVISED ONLY IN AUTOCAD.

REVISION	DES		DATE	CHK.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.
	M.RADVANSKY 04/10/03 ENG	THIS REVISION IS CLASS A PER THE QAPD. UPDATED DWG TO SHOW THE WORK DONE ON MOD. PROC. # FFX-91-07049-M, GMT-07049 SH. 61, & DMD251783-AN REV. 00 RELEASED AS CONSTRUCTED. P.N. 07049-91 GH/MR	6/25/92	G.B.	F.A. W.J. KING 6-26-92			
				REVIEW		APPROVALS		

TITLE: FLOW DIAGRAM
AUXILIARY COOLANT SYSTEM
RESIDUAL HEAT REMOVAL PUMPS -
UFSAR FIGURE No. 9.3-1 (SHT. 3)
DRWN. BY J.SESE | SCALE NONE | REC'D
ConEdison
STATION INDIAN POINT
DWG. NO. A251783-28
MY



NOTES:

1. ALL TUBING IS 3/8" O.D. EXCEPT AS DETAILED.
2. ALL VALVES INSTALLED WITH FLOW UNDER SEAT EXCEPT VALVE NUMBERS 962A, 962B, 962C, 968, 970A, 978, 980.
3. 3/4" NOMINAL PIPE O.D. X 3/8" O.D. TUBING INSERT.
4. ADDITIONAL VENTS AND DRAINS MAY BE REQUIRED BASED ON PIPE LAYOUT.
5. ALL CHECK VALVES SHOULD BE "Y" TYPE LIFT CHECK.
6. DELAY COIL --- 125 FT. X 3/8" O.D. TUBING X 0.245 I.D. OR EQUIVALENT.
7. *** INDICATESS CONTROL VALVE HAS ADDITIONAL ASSOCIATED EQUIPMENT AND IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL DRAWING 9321-F-7056.
8. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

REFERENCE DRAWING:

CVCS - CHEMICAL VOLUME CONTROL SYSTEM
U.E.& C. DWG. ------ 9321-F-2736
U.E.& C. DWG. ------ 9321-F-2737
RCS - REACTOR COOLANT SYSTEM
U.E.& C. DWG. ------ 9321-F-2738
STEAM GEN. BLOWNDOWN SYS.
U.E.& C. DWG. ------ 9321-F-2729
ACS - AUXILIARY COOLANT SYSTEM
U.E.& C. DWG. ------ 9321-F-2720
WDS - WASTE DISPOSAL SYSTEM
U.E.& C. DWG. ------ 9321-F-2719
U.E.& C. DWG. ------ 9321-F-2730
SIS - SAFETY INJECTION SYSTEM
U.E.& C. DWG. ------ 9321-F-2735
IVSWS - ISOLATION VALVE SEAL WATER SYS.
U.E.& C. DWG. ------ 9321-F-2746

REFERENCES:

PROCESS FLOW DIAGRAM W-DWG.540F902

DEFINITION OF SYMBOLS:U.E.&C. SPEC. PART B. 9321-01-248-18

INSTALLATION OF INSTRUMENTATION W-PROC.SPEC. CAP - 294367 REV.1

MATERIAL SPEC. PIPE AND FITTINGS: U.E.&C. SPEC. 9321-01-248-18

9321-F-2016 FLOW DIAGRAM SYMBOLS

NUCLEAR EQUIPMENT DRAINS 9321-F-2738

SS-SAMPLING SYSTEM DWG.A227178

POST ACCIDENT CONTAINMENT AIR SAMPLING SYSTEM DWG.A208479

LEGEND

⬡ -INDICATES INTERFACE WITH PANEL MFR.

VS -VENTILATION SYSTEM

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS:
"CLASS A" ITEMS
PER CI-240-1

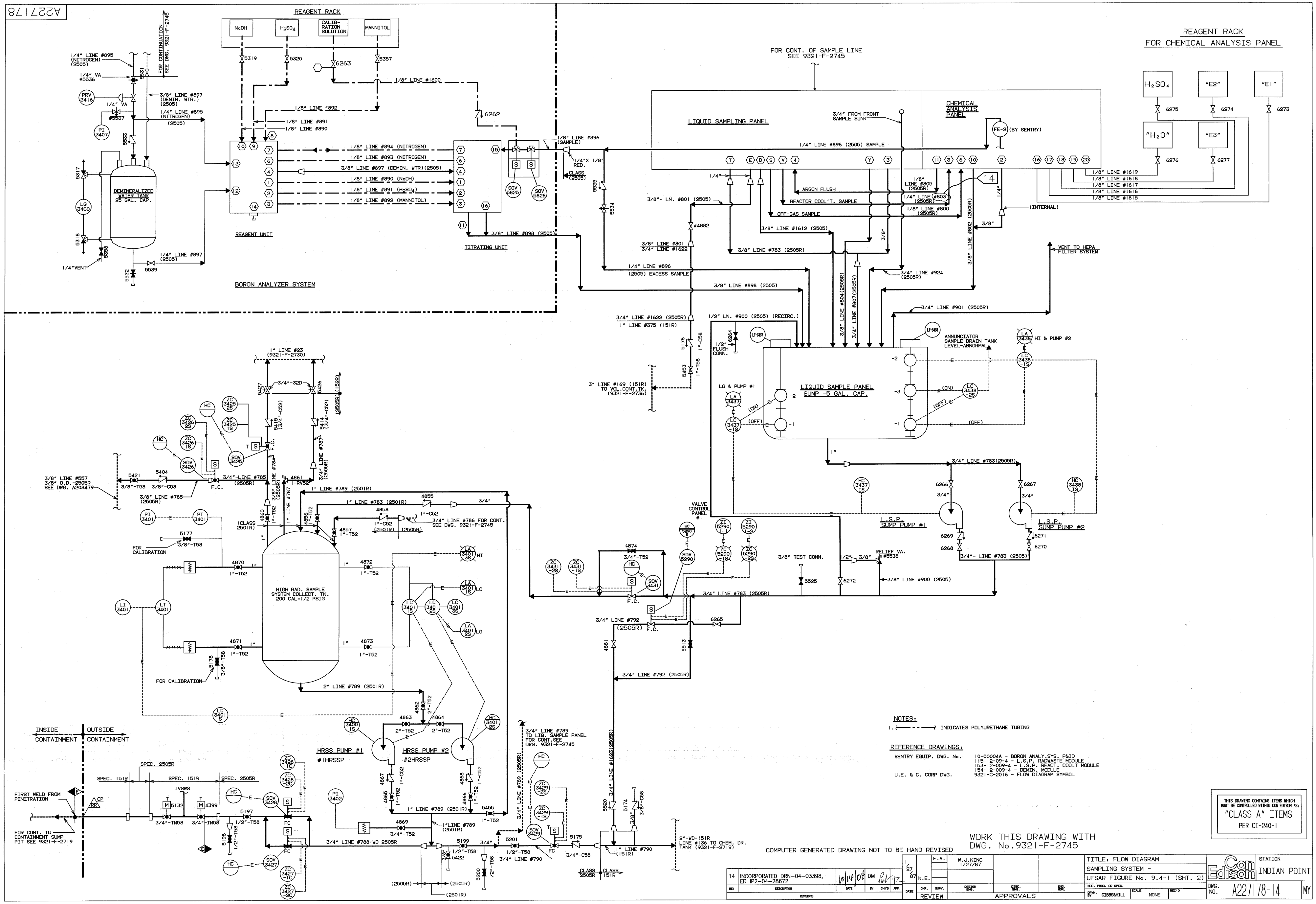
NOTE A
THIS BOUNDS THE PORTION OF SAMPLING SYSTEM AS DESCRIBED IN EXHIBIT A, CI-240-1

THIS DWG. TO BE REVISED ONLY IN CUSTOMIZED AUTOPLANT.

REVISION	DES / ENG		DATE						
	DES G. BHALLA 5/29/01 ENG	THIS REVISION IS NON-CLASS PER QAPD. UPDATED DRAWING PER MOD PROCEDURE #FPX-96-83574-F,DMD9321-2745-AI REV.0 AND DMD9321-2745-AJ REV.0. RELEASE AS CONSTRUCTED. P.N. 83574-96 D.B./J.F. 5/29/01	2/8/88	L.H.	F.A.	W.J.KING 2/9/88			
			DATE	CKR.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.	
				REVIEW		APPROVALS			

TITLE: FLOW DIAGRAM
SAMPLING SYSTEM -
UFSAR FIGURE No. 9.4-1 SHT. 1
DRWN. BY GIBBS&HILL — SCALE NONE — REC'D
Con Edison — STATION INDIAN POINT
DWG. NO. 9321-F-2745-58 MY

KARL-3898



A227178
REAGENT RACK
BORON ANALYZER SYSTEM
REAGENT UNIT
TITRATING UNIT
DEMINERALIZED WATER TANK 25 GAL. CAP.
FOR CONT. OF SAMPLE LINE SEE 9321-F-2745
LIQUID SAMPLING PANEL
CHEMICAL ANALYSIS PANEL
REAGENT RACK FOR CHEMICAL ANALYSIS PANEL
LIQUID SAMPLE PANEL SUMP =5 GAL. CAP.
L.S.P. SUMP PUMP #1
L.S.P. SUMP PUMP #2
HIGH RAD. SAMPLE SYSTEM COLLECT. TK. 200 GAL=1/2 PSIG
HRSS PUMP #1
HRSS PUMP #2
INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
NOTES:
1. INDICATES POLYURETHANE TUBING
REFERENCE DRAWINGS:
SENTRY EQUIP. DWG. No. 10-00004A - BORON ANALY.SYS. P&ID
115-12-09-4 - L.S.P. RADWASTE MODULE
153-12-009-4 - L.S.P. REACT. COOLT MODULE
154-12-009-4 - DEMIN. MODULE
U.E. & C. CORP DWG. 9321-C-2016 - FLOW DIAGRAM SYMBOL
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS:
"CLASS A" ITEMS
PER CI-240-1
WORK THIS DRAWING WITH DWG. No.9321-F-2745
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
14 INCORPORATED DRN-04-03398, ER IP2-04-28672
W.J.KING 1/27/87
TITLE: FLOW DIAGRAM
SAMPLING SYSTEM -
UFSAR FIGURE No. 9.4-1 (SHT. 2)
Con Edison
STATION
INDIAN POINT
DWG. NO. A227178-14
REVIEW
APPROVALS

REFERENCE DWG'S.

9321-F-7021	STEAM & WATER SAMPLE PIPING
9321-F-7044	STEAM & WATER ANALYSIS PANEL
9321-F-2021	FLASH EVAPORATOR FLOW DIAGRAM
9321-F-2729	STEAM GENERATOR BLOWDOWN DIAGRAM
9321-F-2597	STEAM GENERATOR BLOWDOWN SAMPLE PIPING
9321-F-2120	SERVICE BOILERS FLOW DIAGRAM
9321-F-7040	P.A. BLDG. INSTRUMENT ARRANGEMENT
9321-F-2724	PRIMARY MAKE-UP WATER FLOW DIAGRAM
A215116	COND. #21,22, & 23 SEXTANT SAMPL'G, PIP'G ARRG'T
B226920	COND.WTR CHLORIDE ANALY QUICK RESP. INST. FLOW DIAG.
2000MC6024	HW SEXTANT PANEL P& ID (JOHNSON MARCH SYS. INC DWG. D-250561-M01)
2000MC5873	HPFW SAMPLE PANEL P&ID (SENTRY EQUIP. CORP.)

NOTE:
1. COOLING WATER IS SUPPLIED FROM CLOSED COOLING WATER SYSTEM (9321-F-2033) EXCEPT WHERE NOTED OTHERWISE.
2. ALL SAMPLE TUBING SHALL BE STN. STL. TYP. TP304 INN ACCORDANCE WITH SPECIFICATION 9321-01-248-18 CLASS M-1
3. PROVIDE GATE & CHECK VALVES AT ALL TAKE-OFFS FROM CITY WATER LINES

SYMBOLS
- SAMPLE COOLER (S.C.)
CE - CONDUCTIVITY ELEMENT
1 BULKHEAD, SEE DWG.9321-F-7044

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION: THIS REVISION IS NON-CLASS PER THE QAPD. UPDATED DWG. PER CR-IP2-2003-01626 RELEASED FOR RECORD P.N 69901-AF GH/RAM
DES R.MEIKLE 05/12/03 ENG
DATE 2/8/88 — REVIEW: CKR. L.H. SUPV. F.A. — APPROVALS: DESIGN ENG W.J.KING 2/9/88; DISC. ENG.; ENG. MGR.

TITLE: STEAM & WATER ANALYSIS SYSTEM SAMPLING DIAGRAM INSTRUMENTATION -
UFSAR FIGURE No. 9.4-2
DRWN. BY | SCALE NONE | REC'D
Con Edison — STATION INDIAN POINT
DWG. NO. 9321-F-7020-39 MY

THIS DWG. TO BE REVISED ONLY IN AUTOCAD

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
117	INCORPORATED DRN-05-04013, ER-05-2-059 AND DRN-06-05485, ER IP2-06-28787	12/19/06	DM		

REVISIONS

DATE	CKR.	SUPV.	DESIGN ENG	DISC. ENG.	ENG. MGR.
12/16/87	W.S.	F.A.	W.J.KING 12-16-87		

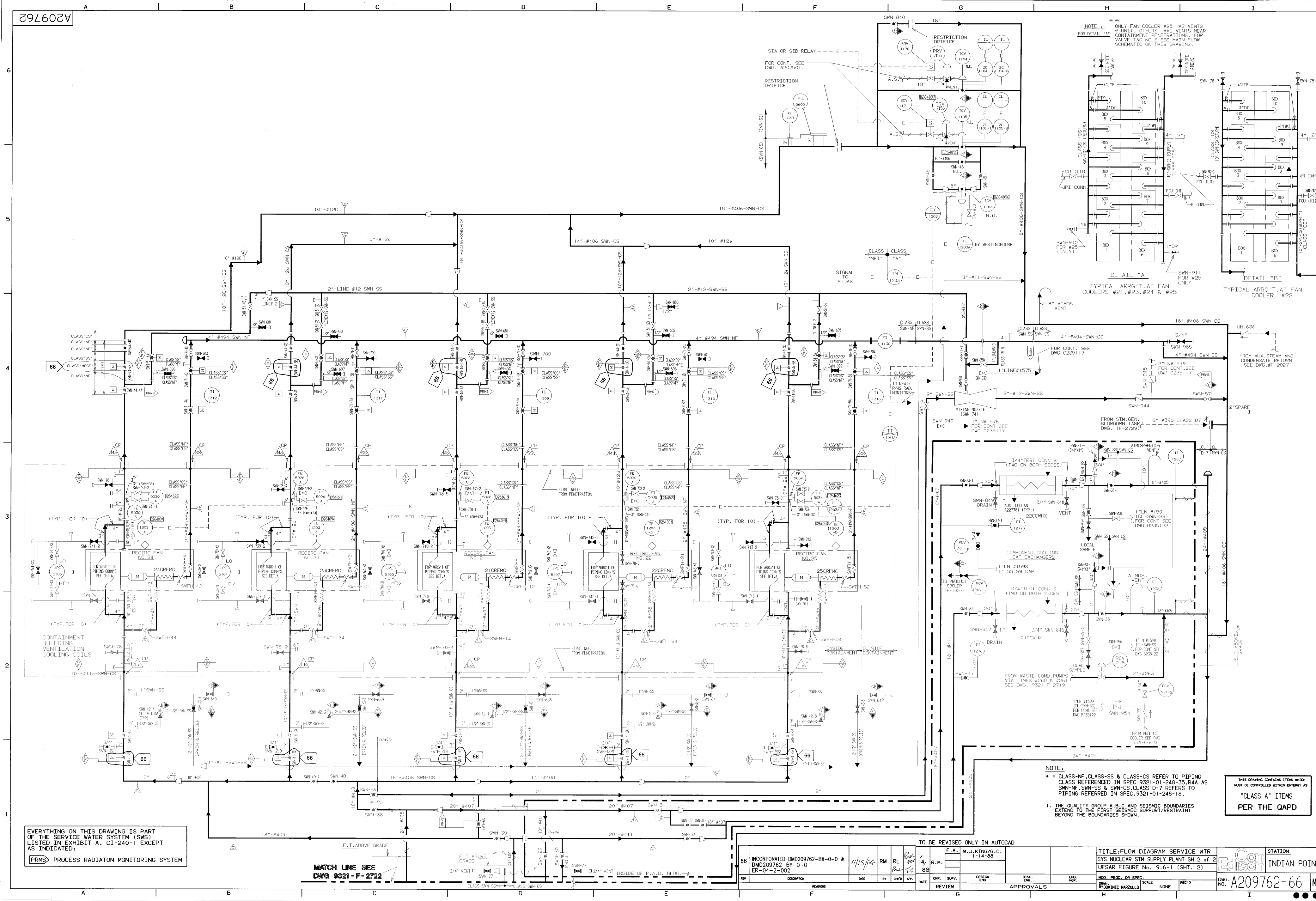
REVIEW — APPROVALS

TITLE: FLOW DIAGRAM SERVICE WATER SYSTEM NUCLEAR STEAM SUPPLY PLANT SHEET 1 OF 2 - UFSAR FIGURE No. 9.6-1 (SHT. 1)

DRWN. BY GIBBS&HILL — SCALE NONE — REC'D

Entergy Nuclear Northeast — STATION: INDIAN POINT

DWG. NO. 9321-F-2722-117 MY



A209762
NOTE: ** ONLY FAN COOLER #25 HAS VENTS @ UNIT. OTHERS HAVE VENTS NEAR CONTAINMENT PENETRATIONS. FOR VALVE TAG NO.S SEE MAIN FLOW SCHEMATIC ON THIS DRAWING.
FOR DETAIL "A"
DETAIL "A"
TYPICAL ARRG'T.AT FAN COOLERS #21,#23,#24 & #25
DETAIL "B"
TYPICAL ARRG'T.AT FAN COOLER #22
RECIRC.FAN NO.24
RECIRC.FAN NO.23
RECIRC.FAN NO.21
RECIRC.FAN NO.22
RECIRC.FAN NO.25
CONTAINMENT BUILDING VENTILATION COOLING COILS
COMPONENT COOLING HEAT EXCHANGERS
INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
FROM AUX.STEAM AND CONDENSATE RETURN SEE DWG.#F-2027
NOTE:
* = CLASS-NF,CLASS-SS & CLASS-CS REFER TO PIPING CLASS REFERENCED IN SPEC 9321-01-248-35,R4A AS SWN-NF,SWN-SS & SWN-CS.CLASS D-7 REFERS TO PIPING REFERRED IN SPEC.9321-01-248-18.
1. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN INTENT AS
"CLASS A" ITEMS
PER THE QAPD
EVERYTHING ON THIS DRAWING IS PART OF THE SERVICE WATER SYSTEM (SWS) LISTED IN EXHIBIT A, CI-240-1 EXCEPT AS INDICATED:
PRMS PROCESS RADIATON MONITORING SYSTEM
MATCH LINE SEE DWG 9321-F-2722
TO BE REVISED ONLY IN AUTOCAD
66 INCORPORATED DMD209762-BX-0-0 & DMD209762-BY-0-0 ER-04-2-002 11/15/04 RM RL
W.J.KING/G.C. 1-14-88
TITLE:FLOW DIAGRAM SERVICE WTR
SYS NUCLEAR STM SUPPLY PLANT SH 2 of 2
UFSAR FIGURE No. 9.6-1 (SHT. 2)
DRWN. BY DOMINIC MARZULLO
SCALE NONE
Con Edison
STATION: INDIAN POINT
DWG. NO. A209762-66
REVIEW
APPROVALS

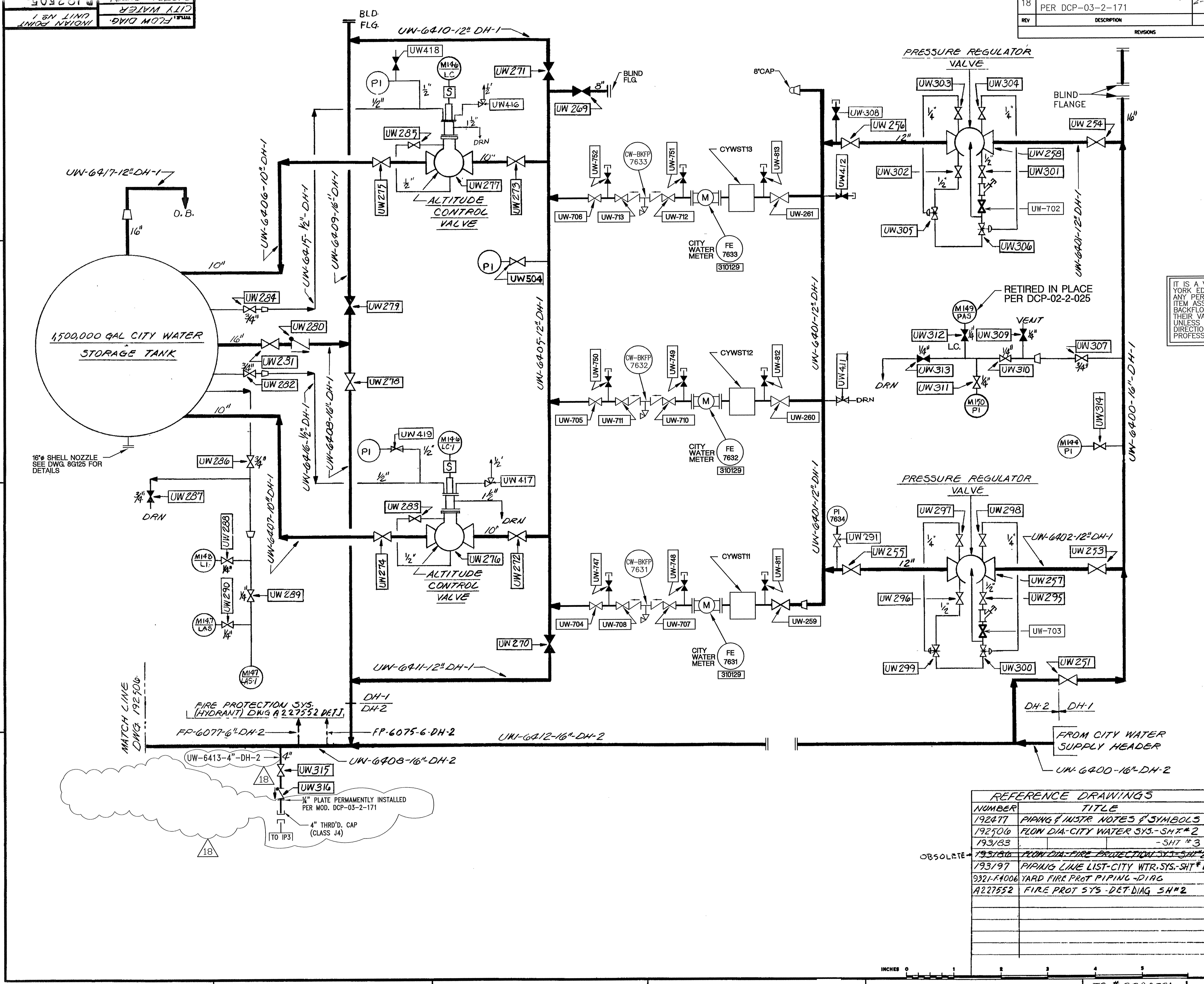
REV	DESCRIPTION	DATE	BY	CHK'D	APP.
18	INCORPORATED DMD192505-AL, PER DCP-03-2-171	2-8-2006	DM	GH	M/K

REVISIONS

REVISIONS

M.RADVANSKY 05/02/03	17

THIS REV.IS NON CLASS PER THE QAPD. UPDATED DWG. TO SHOW THE WORK DONE ON MOD. PROC. NO. FMX-94-10478-M, DMD192505-AE,REV.03 DMD192505-AF,REV.04 DMD192505-AG,REV.00 DMD192505-AH,REV.00 DMD192505-AI,REV.00 DMD192505-AJ,REV.00 RELEASE AS CONSTRUCTED P.N.10478-94 GH/MR



IT IS A VIOLATION OF NEW YORK EDUCATION LAW FOR ANY PERSON TO ALTER ANY ITEM ASSOCIATED WITH THE BACKFLOW PREVENTERS AND THEIR VALVES IN ANY WAY UNLESS UNDER THE DIRECTION OF A LICENSED PROFESSIONAL ENGINEER

REFERENCE DRAWINGS

NUMBER	TITLE
192477	PIPING & INSTR. NOTES & SYMBOLS
192506	FLOW DIA.-CITY WATER SYS.-SHT #2
193183	-SHT #3
~~193186~~	~~FLOW DIA.-FIRE PROTECTION SYS.-SHT #2~~ (OBSOLETE)
193197	PIPING LINE LIST-CITY WTR. SYS.-SHT #1
9321-F4006	YARD FIRE PROT PIPING-DIAG
A227552	FIRE PROT SYS-DET. DIAG SH#2

INCHES 0 1 2 3 4 5

B 192505-18

Entergy Nuclear Northeast

PREPARED BY: TREADWELL CORP N.Y.
STATION LOCATION: INDIAN POINT
UNIT № 1
PIPING FLOW DIAGRAM
CITY WATER SYSTEM SHEET No. 1
- UFSAR FIGURE No. 9.6-5 (SHT. 1)

SCALE: NONE | DRAWN BY: N. NATER | RECORDED: 1-6-73
J.O. 3948 | CHECKED BY: H.M. | ENG.

APPROVALS: GENERAL ENGINEERING – CHIEF DESIGN ENGINEER; MECHANICAL ENGINEERING – MECH PLANT ENGINEER; CIVIL ENGINEERING – PLANT STRUCT. ENGINEER, T&D STRUCT. ENGINEER; ELECTRICAL ENGINEERING – STATION ELECT. ENGINEER, T.&D. ENGINEER; GAS & STEAM OPERATIONS – STRUCT. ENGINEER; PRODUCTION – CONVENTIONAL POWER, NUCLEAR POWER

MB

A B C D E

TC-#2300594

1 2 3 4

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
40	INCORPORATED DMD192506-AO & -AP PER FEX-95-11491-M	7/6/06	DM		N/A

REVISIONS

NOTES:

1. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

NUMBER	TITLE
9321-F-4006	YARD FIRE PROT PIPING - DIAG
A227551	FIRE PROT SYS - DET - DIAG SH. #1

REFERENCE DRAWINGS

NUMBER	TITLE
192477	PIPING & INSTR. NOTES & SYMBOLS
192505	FLOW DIA. CITY WATER SYS. SHT #1
193183	SHT. #3
~~193185~~	~~FLOW DIAG FIRE PROTECTION SYS. SHT #1~~
~~193186~~	~~SHT #2~~
141088	COMPRESSED AIR & CITY WATER DIAG.
192483	MAIN CONDENSATE SYS DIAG SHT. #1
192494	WATER TREAT. SYSTEM DIAG SHT. #2
~~193185~~	~~FIRE PROTECTION SYS. DIAG. SHT. #1~~
193201	AUXILIARY BOILER FEED SYSTEM DIAG.
193677	FRESH WTR. RECIRC COOLING SYS-SHT #1
141069	FRESH WTR COOLING SYS PUMP AREA DIAG.
193198	PIPING LINE LIST-CITY WTR. SYS.-SHT. #2

B192506-40

Entergy Nuclear Northeast

PREPARED BY: TREADWELL CORP. N.Y.

STATION LOCATION: INDIAN POINT

UNIT NO. 1

PIPING FLOW DIAGRAM CITY WATER

SYSTEM SHEET No. 2 -

UFSAR FIGURE No. 9.6-5 SHT. 2

SCALE NONE	DRAWN BY W. NATER	RECORDED 1-6-55	
J.O. 3948	CHECKED BY H.M.	ENG.	
DIAG.	ELECT.	MECH.	STRUCT.	DIST.

APPROVALS: GENERAL ENGINEERING — CHIEF DESIGN ENGINEER; MECHANICAL ENGINEERING — MECH. PLANT ENGINEER; CIVIL ENGINEERING — PLANT STRUCT. ENGINEER, T.&D. STRUCT. ENGINEER; ELECTRICAL ENGINEERING — STATION ELECT. ENGINEER, T.&D. ENGINEER; GAS & STEAM OPERATIONS — STRUCT. ENGINEER; PRODUCTION — CONVENTIONAL POWER, NUCLEAR POWER

MY

TITLE: FLOW DIAG. CITY WATER UNIT NO. 1 INDIAN POINT — SYSTEM-SHT#2 — B192506-

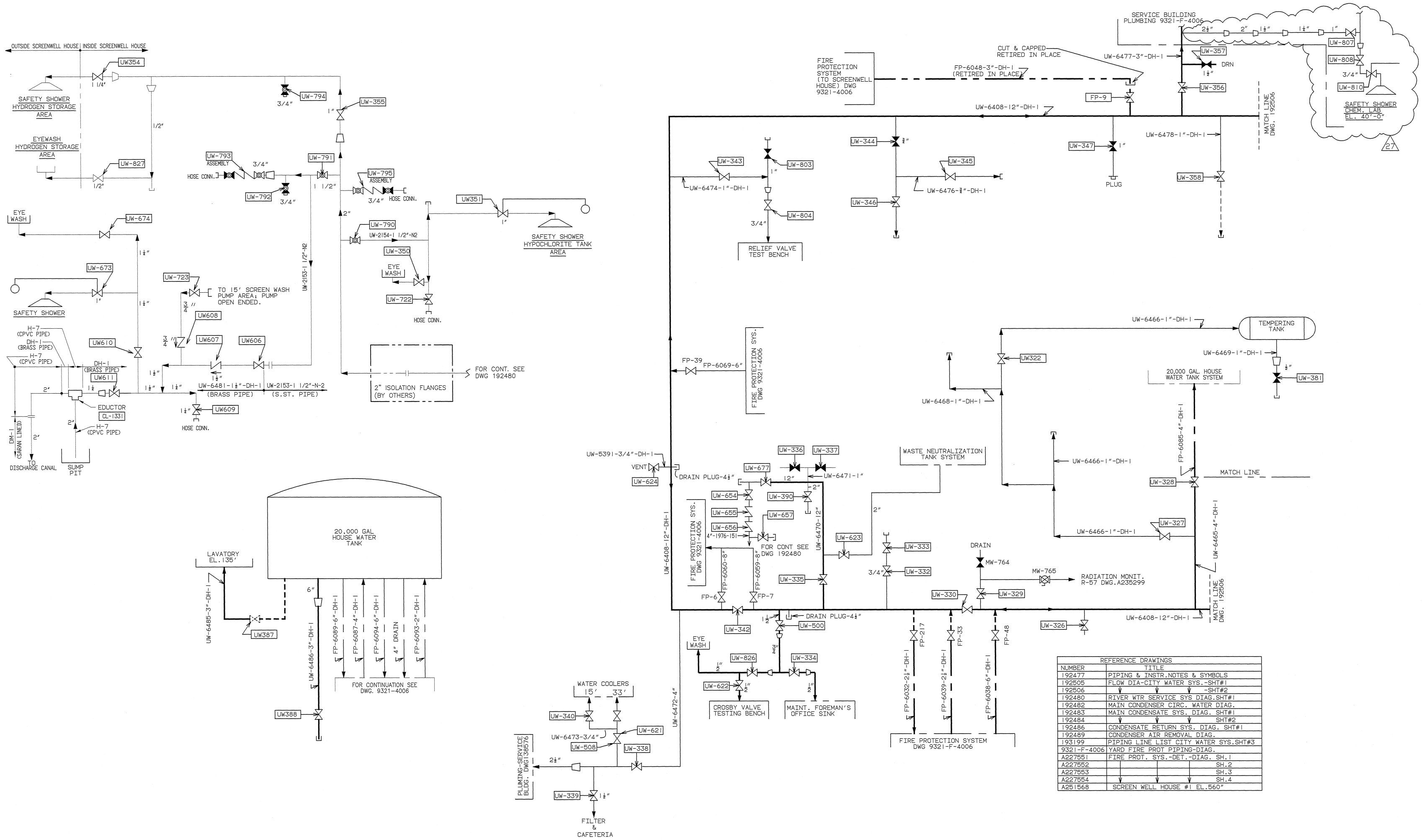
INCHES 0 1 2 3 4 5 6

TC #2300595

A B C D E

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
27	INCORPORATED DMD193183-AP, PER FPX-91-06585-F	7/12/06	DM	Ru	N/A

REVISIONS



REFERENCE DRAWINGS	
NUMBER	TITLE
192477	PIPING & INSTR.NOTES & SYMBOLS
192505	FLOW DIA-CITY WATER SYS.-SHT#1
192506	↓ ↓ ↓ -SHT#2
192480	RIVER WTR SERVICE SYS DIAG.SHT#1
192482	MAIN CONDENSER CIRC. WATER DIAG.
192483	MAIN CONDENSATE SYS. DIAG. SHT#1
192484	↓ ↓ ↓ SHT#2
192486	CONDENSATE RETURN SYS. DIAG. SHT#1
192489	CONDENSER AIR REMOVAL DIAG.
193199	PIPING LINE LIST CITY WATER SYS.SHT#3
9321-F-4006	YARD FIRE PROT PIPING-DIAG.
A227551	FIRE PROT. SYS.-DET.-DIAG. SH.1
A227552	SH.2
A227553	SH.3
A227554	↓ ↓ ↓ SH.4
A251568	SCREEN WELL HOUSE #1 EL.560"

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

DWG. NO. 193183-27

Entergy Nuclear Northeast

DWG. TYPE: MECHANICAL

DWG. SIZE: A

LOCATION: INDIAN POINT

TITLE: UNIT No. 1 PIPING FLOW DIAG.
CITY WATER SYSTEM SHEET No. 3
UFSAR FI. No. 9.6-5 (SHT. 3)

– APPROVALS –

ENGINEERING MANAGER:

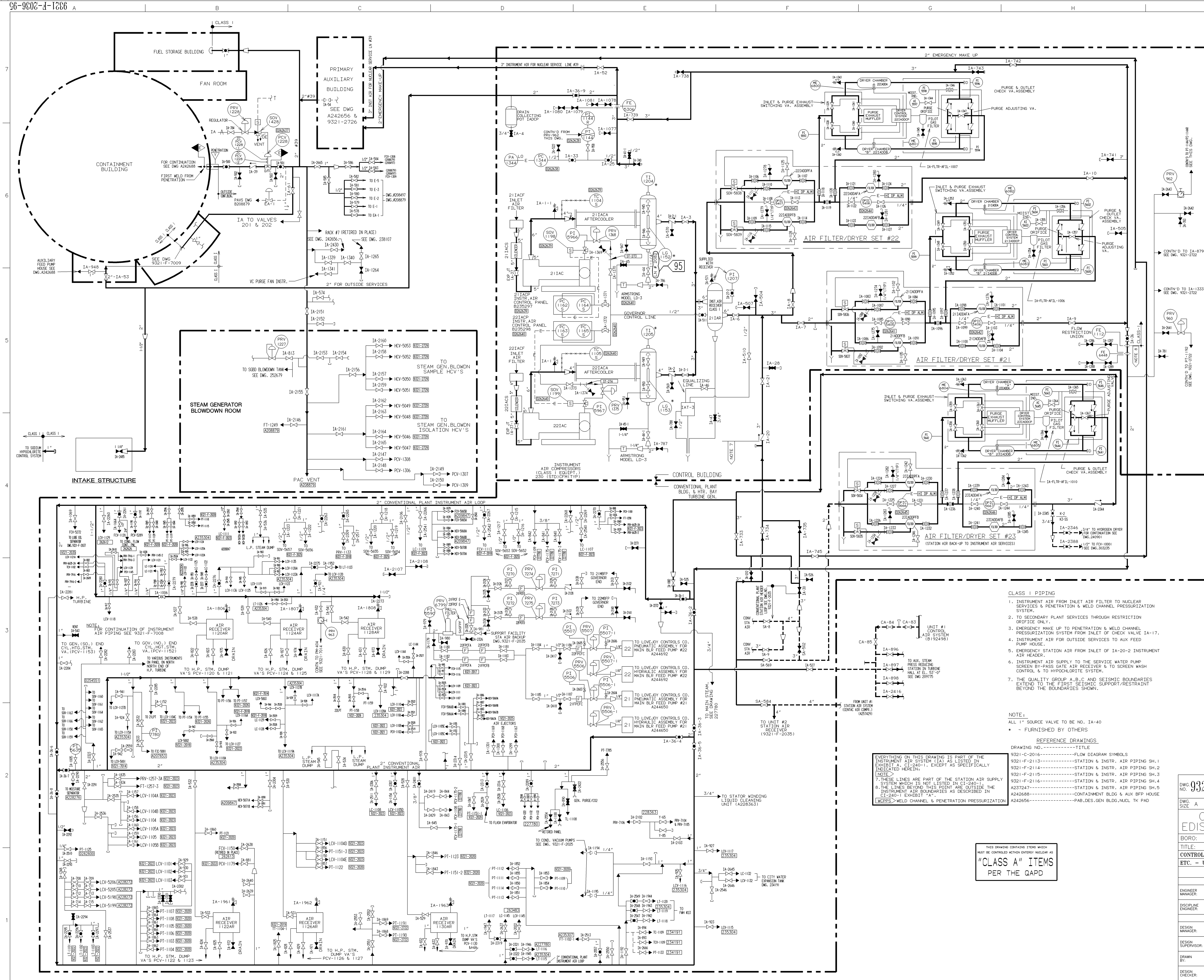
PROJECT ENGINEER:

DESIGNER:

DRAWN BY: M. HEREDIA

SCALE:

DISCIPLINE CODE: MB



CLASS I PIPING

1. INSTRUMENT AIR FROM INLET AIR FILTER TO NUCLEAR SERVICES & PENETRATION & WELD CHANNEL PRESSURIZATION SYSTEM.
2. TO SECONDARY PLANT SERVICES THROUGH RESTRICTION ORIFICE ONLY.
3. EMERGENCY MAKE UP TO PENETRATION & WELD CHANNEL PRESSURIZATION SYSTEM FROM INLET OF CHECK VALVE IA-17.
4. INSTRUMENT AIR FOR OUTSIDE SERVICES TO AUX FEED PUMP HOUSE.
5. EMERGENCY STATION AIR FROM INLET OF IA-20-2 INSTRUMENT AIR HEADER.
6. INSTRUMENT AIR SUPPLY TO THE SERVICE WATER PUMP SCREEN BY-PASS GATE AIR RECEIVER & TO SCREEN WASH CONTROL & TO HYPOCHLORITE SYSTEM.
7. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

NOTE:

ALL 1" SOURCE VALVE TO BE NO. IA-40

* ~ FURNISHED BY OTHERS

REFERENCE DRAWINGS

DRAWING NO.	TITLE
9321-C-2016	FLOW DIAGRAM SYMBOLS
9321-F-2113	STATION & INSTR. AIR PIPING SH.1
9321-F-2114	STATION & INSTR. AIR PIPING SH.2
9321-F-2115	STATION & INSTR. AIR PIPING SH.3
9321-F-2116	STATION & INSTR. AIR PIPING SH.4
A237247	STATION & INSTR. AIR PIPING SH.5
A242688	CONTAINMENT BLDG & AUX BFP HOUSE
A242656	PAB,DES.GEN BLDG,NUCL TK PAD

EVERYTHING ON THIS DRAWING IS PART OF THE INSTRUMENT AIR SYSTEM (IA) AS LISTED IN EXHIBIT A, CI-240-1. EXCEPT AS SPECIFICALLY INDICATED HEREIN:

NOTE

7. THESE LINES ARE PART OF THE STATION AIR SUPPLY SYSTEM WHICH IS NOT LISTED IN CI-240-1.
8. THE LINES BEYOND THIS POINT ARE OUTSIDE THE INSTRUMENT AIR BOUNDARIES AS DESCRIBED IN CI-240-1 EXHIBIT "A".

WCPPS WELD CHANNEL & PENETRATION PRESSURIZATION

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLED WITHIN ENTERGY NUCLEAR AS

"CLASS A" ITEMS PER THE QAPD

REVISION

USE .1 SIZE TEXT ONLY

V. MYERS 8/04/03	94
THIS REVISION IS CLASS "A" PER THE QAPD. UPDATED DRAWING PER MOD. PROC. # FFX-91-07049-M, DMD9321-2036-BC-00. RELEASE AS CONSTRUCTED. P/N 07049-91 SW/VM	
V. MYERS 08/29/03	95
THIS REVISION IS CLASS "A" PER THE QAPD. DRAWING REVISED TO SHOW WORK COMPLETED IN FIELD PER MOD. PROC. No. MFI-88-01408-M GMT SHT. 86. INCORPORATED DMD9321-2036-BG. RELEASE "AS-CONSTRUCTED". P/N: 01408-88 S. O'BRIEN 08/29/03	

REVISION SIGNATURES

REV	DES	ENG
95	S. O'BRIEN 08-29-03	V. MYERS 08-29-03

DWG. NO. 9321-F-2036-95

DWG. SIZE A | DWG. TYPE COMPANY

CON EDISON | STATION INDIAN POINT

BORO: WESTCHESTER

TITLE: FLOW DIAG. INSTR. AIR CONTROL BLDG. CONVENTIONAL PLANT, ETC. - UFSAR FIGURE No. 9.6-6

APPROVALS

ENGINEERING

ENGINEER MANAGER:

DISCIPLINE ENGINEER:

DESIGN

DESIGN MANAGER: W.J. KING 7-30-87

DESIGN SUPERVISOR: F.A. 7-30-87

DRAWN BY: GIBBS & HILL

DESIGN CHECKER: L.H. 7-30-87

SCALE: NONE | DISCIPLINE CODE: MY

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

CLASS I PIPING

DOUBLE ISOLATION VALVE THROUGH CONTAINMENT INCLUDING ISOLATION VALVE SEAL WATER SUPPLY.

THE QUALITY GROUP A, B, C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

REFERENCE DRAWINGS

U.E.&C. DWG. NO.	DESCRIPTION
9321-F-2113	TURB. BLDG. & HTR. BAY-STA. & INSTR. AIR PIP'G SHT. #1
9321-F-2114	TURB. BLDG. & HTR. BAY-STA. & INSTR. AIR PIP'G SHT. #2
9321-F-2115	TURB. BLDG. & HTR. BAY-STA. & INSTR. AIR PIP'G SHT. #3
9321-C-2016	FLOW DIAGRAM SYMBOLS
9321-F-2687	CONTAINMENT BLDG SERVICE AIR CITY WATER PIPING

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS: "CLASS A" ITEMS PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

L.A. 12/20/99 — THIS REVISION IS NON CLASS PER CI-240-1 UPDATED DWG. PER CRS #199904407, OIR FILE NO. 0-2602 RELEASED AS BUILT P/N 69982-CD GB/SW 12/20/99

7/30/87 E.C. — F.A. W.J.KING 7-30-87

TITLE: FLOW DIAGRAM STATION AIR -

UFSAR FIGURE No. 9.6-7

DRAWN BY GIBBS & HILL — SCALE NONE

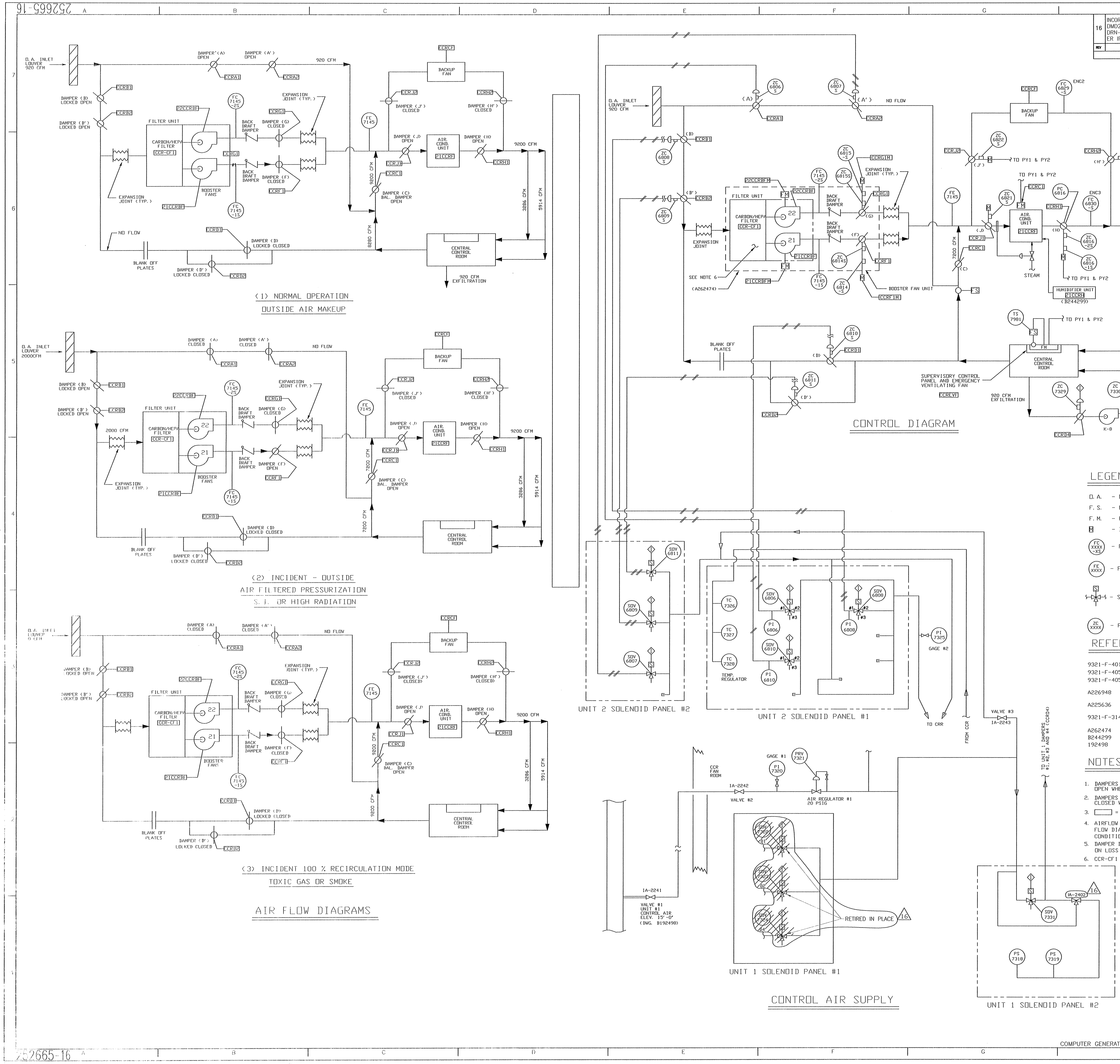
Con Edison — STATION INDIAN POINT

DWG. NO. 9321-2035-43 MY

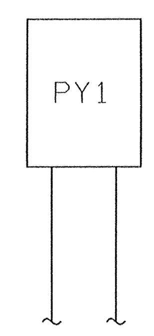
REV	DESCRIPTION	DATE	BY	CHK'D	APP.
16	INCORPORATED DMD252665 AH-0-0, DMD252665 AI-0-0 & DRN-06-02367, ER IP2-06-17277	6/20/06	RM		

REVISIONS

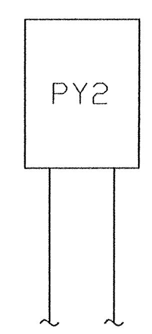
REVISION
USE .1 SIZE TEXT ONLY
16



CONTROL PANEL
EL. 15'-0"



CONTROL PANEL
EL. 53'-0"



LEGEND

- O.A. - OUTSIDE AIR
- F.S. - FIRE STAT
- F.M. - FAN MOTOR
- M - DAMPER MOTOR
- FC XXXX -XS - FLOW SWITCH
- FE XXXX - FLOW MEASUREMENT DEVICE
- S - SOLENOID VALVE
- ZC XXXX - POSITION CONTROLLER

REFERENCE DRAWINGS

- 9321-F-4017 - CONTROL BUILDING -HVAC- PLANS.
- 9321-F-4050 - CONTROL BUILDING -HVAC- SECTIONS.
- 9321-F-4055 - CONTROL BUILDING - COOLING WATER TO AIR COND. UNIT.
- A226948 - CENTRAL CONTROL RM. HVAC SYSTEM DAMPERS AND REDUNDANCY.
- A225636 - SUPP'Y DWG MODIFICATION OF CCR VENTILATION SYSTEM.
- 9321-F-3147 - CONDUIT LAYOUT - CONTROL ROOM AIR CONDITIONING.
- A262474 - CARBON FILTER UNIT (SHEET 1 OF 2)
- B244299 - CCR HUMIDIFIER FLOW DIAGRAM
- 192498 - PIPING FLOW DIAGRAM-CONTROL AIR SYSTEM

NOTES

1. DAMPERS J' & H' ARE NORMALLY CLOSED. OPEN WHEN A.C. FAN IS OFF. (BACKUP FAN ON)
2. DAMPERS J & H ARE NORMALLY OPEN. CLOSED WHEN A.C. FAN OFF. (BACKUP FAN ON)
3. $\boxed{}$ = "Q" DESIGNATED EQUIPMENT NO.
4. AIRFLOW RATES (CFMs) SHOWN ON THIS FLOW DIAGRAM DRAWING ARE FOR DESIGN CONDITIONS ONLY.
5. DAMPER D & D' WILL REMAIN CLOSED ON LOSS OF POWER OR AIR.
6. CCR-CF1 FILTER TAG NUMBERS .
   - HEPA FILTER (CCRHF)
   - CARBON FILTER STACK A (CCRCFA)
   - CARBON FILTER STACK B (CCRCFB)
   - POST FILTER (CCRPF)

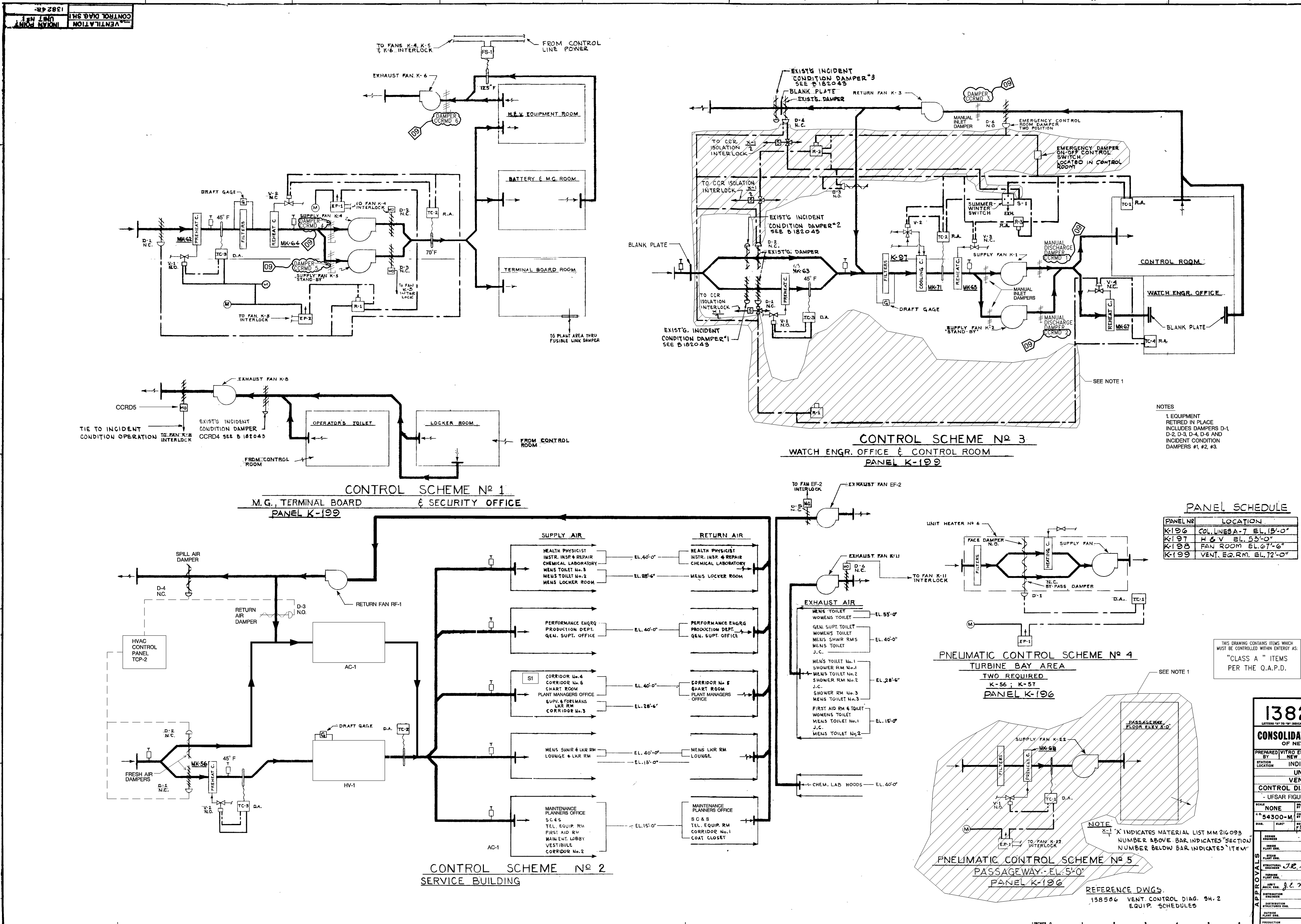
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REVISION SIGNATURES		
REV	DES	ENG
00		

DWG. NO. 252665 -16	
DWG. SIZE A	DWG. TYPE COMPANY
Entergy Nuclear Northeast	STATION INDIAN POINT
BORO: WESTCHESTER	
TITLE: CONTROL BUILDING (CCR) CONTROL AND AIR FLOW DIAGRAMS -UFSAR FIGURE NO. 9.9-1	
APPROVALS	
ENGINEERING	
ENGINEER MANAGER:	
DISCIPLINE ENGINEER:	
DESIGN	
DESIGN MANAGER: M. J. CAPUTO 12/30/93	
DESIGN SUPERVISOR: A. D.	
DRAWN BY:	
DESIGN CHECKER: E. D.	
SCALE: NONE	DISCIPLINE CODE: MY

252665-16

2/17/2004 5:54:42 PM 138248-0-9.DWG



PANEL SCHEDULE

PANEL №	LOCATION
K-196	COL. LINE 9A-7 EL. 15'-0"
K-197	H & V EL. 53'-0"
K-198	FAN ROOM EL. 67'-6"
K-199	VENT. EQ. RM. EL. 72'-0"

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN ENTERGY AS: "CLASS A" ITEMS PER THE Q.A.P.D.

NOTE
"X" INDICATES MATERIAL LIST MM 216093
NUMBER ABOVE BAR INDICATES "SECTION"
NUMBER BELOW BAR INDICATES "ITEM"

REFERENCE DWGS.
138586 VENT. CONTROL DIAG. SH. 2
EQUIP. SCHEDULES

REVISIONS

3 — THIS REVISION CONTAINS CLASS "A" ITEMS PER CI-240-1 MOD PROC CPG-82-07961-00 F4, F5 ADDED SOLENOID VALVES B4 CHANGED DAMPER OPERATION H1 ADDED NOTE RELEASE FOR CONSTRUCTION P.N. 07961 WG/JM 4/15/82

4 — THIS REVISION CONTAINS CLASS "A" ITEMS PER CI-240-1 UPDATED DWG. TO SHOW WORK OF REV. 3 & FIELD ENG. SKETCHES FE1820625, FE1830082, FE1830083, FE1830093, FE1830097 & FIELD MARKED PRINTS 138643-9 & 138248-3 MOD PRO CPG-82-07961 RELEASE AS CONSTRUCTED P.N. 07961 LH/WG 7-27-84

5 — S.M. 2/8/96 L.V. 2/8/96 — THIS REVISION IS CLASS "A" AS PER PER CI. - 240 - 1 UPDATED DWG. AS PER CAMP 95 - 12 - 11 -A- 008 REVISED K - 8 FAN DISCHARGE DAMPER TAG No. TO CCRD5 RELEASED AS CONSTRUCTED P.N. 69982 - QA A.M.M. 2/8/96

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7 — L. LIBERATORI 01/19/01 — THIS REVISION IS CLASS "A" AS PER PER CI. - 240 - 1 UPDATED DWG. TO INCLUDE UFSAR FIG. NO. IN TITLE RELEASED FOR RECORD P.N. 69911 - NP DLA/STRATUS 01/19/01

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138248-9

CONSOLIDATED EDISON CO. OF NEW YORK, INC.

PREPARED BY: VITRO ENGINEERING CO. NEW YORK, N.Y. — 1194-K-1
STATION LOCATION: INDIAN POINT
UNIT No. 1
VENTILATION
CONTROL DIAGRAMS SHEET 1
- UFSAR FIGURE NO. 9.9-1

SCALE: NONE — DRAWN BY: P. JAMES — RECORDED: 6-27-58
J.O. 54300-M

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INDIAN POINT UNIT No 1 — VENTILATION CONTROL DIAG SH 1 — 138248

CHAPTER 10
STEAM AND POWER CONVERSION SYSTEM

10.1 DESIGN BASIS

10.1.1 Performance Objectives

The turbine-generator systems consist of components of conventional design acceptable for use in large power stations. The equipment is arranged to provide high thermal efficiency without sacrificing safety. The component design parameters are given in Table 10.1-1.

The steam and feedwater system is designed to remove heat from the reactor coolant in the four steam generators and produce steam for use in the turbine-generator. It can receive and dispose of, in its cooling systems and through atmospheric relief valves, the total heat existent or produced in the reactor coolant system following an emergency shutdown of the turbine-generator from a full-load condition.

The heat balance diagram at 1,078,200 kWe, maximum calculated; is shown on Figure 10.1-1. The stretch rating heat balance diagram, Figure 10.1-2A for 1,007,838 kWe incorporates the new electrical generator, uprated HP element and ruggedized LP element.

The system design monitors and restricts radioactivity discharge to normal heat sinks or the environment so that the limits of 10 CFR 20 are not exceeded under normal operating conditions or in the event of anticipated system malfunctions.

One steam turbine- and two electric motor-driven auxiliary feedwater pumps are provided to ensure that adequate feedwater is supplied to the steam generators for removing reactor decay heat under all circumstances, including loss of power and normal heat sink (e.g., condenser isolation, loss of circulating water flow). Feedwater flow can be maintained until either power is restored or reactor decay heat removal can be accomplished by other systems. Auxiliary feedwater pumps and piping are designed as seismic Class I components.

10.1.2 Load Change Capability

Load changes up to step increases of 10-percent and ramp increases of 5-percent per min within the load range of 15 to 100-percent and with manual rod control can be accommodated without reactor trip subject to possible xenon limitations late in core life. Similar step and ramp load reductions are possible within the range of 100 to 15-percent of full load. The reactor coolant system will accept a complete loss of load from full power with reactor trip. In addition, the turbine bypass and steam dump systems make it possible to accept a turbine load decrease of up to 25- to 50-percent of full power at a maximum turbine unloading rate of 200%/minute without reactor trip (see Section 7.3.3.1). The plant is normally in base-loaded operation.

10.1.3 Functional Limits

The system design incorporates backup means (power relief and code safety valves) of heat removal under any loss of normal heat sink (e.g., condenser isolation, loss of circulating water flow) to accommodate reactor shutdown heat rejection requirements. System atmospheric discharges under normal operation are made only if the releases are within the acceptable limits of 10 CFR 20. All discharges to the atmosphere that may contain non-negligible contributions to the offsite radiation environment are monitored to ensure acceptable radiation levels.

10.1.4 Secondary Functions

The steam and power conversion system provides steam for the turbine-driven auxiliary feedwater pump and for the operation of the air ejectors. The turbine bypass system is designed to dissipate the heat in the reactor coolant following a full-load trip. This heat is removed by the steam bypass of the turbine generator to the condenser circulating water and by the steam dump through the atmospheric power relief valves and safety valves in the event of loss of vacuum in the condenser.

TABLE 10.1-1

Steam and Power Conversion System
Component Design Parameters

Turbine Generator	
Turbine type	Four-element, tandem-compound, six-flow exhaust
Turbine capacity (MWe)	
Initial license application	906.6
At current licensed Reactor Power	1078.2
Generator rating (kVA)	1,439,200 (0.91pf; 75 psig H_2)
Turbine speed (rpm)	1,800
Condensers	
Type	RADIAL FLOW, SINGLE-PASS, DIVIDED WATER BOX, DEAERATING
Number	3
Condensing capacity (pounds of steam per hour, total)	7,243,971 (plus BFPT)
Condensate pumps	
Type	Eight-stage, vertical, pit-type, centrifugal
Number	3
Design capacity, each (gpm)	7,860
Motor type	Vertical, induction
Motor rating (hp)	3,000
Feedwater pumps	
Type	High-speed, barrel casing, single-stage, centrifugal
Number	2
Design capacity, each (gpm)	15,300
Pump drive	Horizontal steam turbine
Drive rating, each (hp)	8,350
Auxiliary feedwater pumps	
Number	3 (one steam-turbine- driven, two electric- motor-driven)
Design capacity (gpm)	800 (turbine-driven) 400 (each, motor-driven pump)
Auxiliary feedwater source	360,000-gal ensured reserve in 600,000-gal condensate tank Alternate supply from 1,500,000-gal city water tank

10.1 FIGURES

Figure No.	Title
Figure 10.1-1	Deleted
Figure 10.1-1a	Uprate PEPSE Model with New HP Turbine High Pressure Turbine Expansion
Figure 10.1-1b	Uprate PEPSE Model with New HP Turbine Moisture Separator Reheater Train A
Figure 10.1-1c	Uprate PEPSE Model with New HP Turbine Moisture Separator Reheater Train B
Figure 10.1-1d	Uprate PEPSE Model with New HP Turbine Low Pressure Turbine Expansion
Figure 10.1-1e	Uprate PEPSE Model with New HP Turbine Main Condensers
Figure 10.1-1f	Uprate PEPSE Model with New HP Turbine Notes and Significant Results
Figure 10.1-2	Deleted
Figure 10.1-2a	Deleted
Figure 10.1-3	Deleted
Figure 10.1-4	Deleted
Figure 10.1-5	Deleted
Figure 10.1-6	Deleted
Figure 10.1-7	Load Heat Balance Diagram at 1,034,072 kWe

10.2 SYSTEM DESIGN AND OPERATION

10.2.1 Main Steam System

The main steam system, which is designed for a pressure of 1085 psig at 600^{o}F, conducts steam from the four steam generators, which are located inside the containment structure, to the turbine generator unit, located in the Turbine Generator Building. The system, shown in Plant Drawings 227780, 9321-2017, and 235308 [Formerly UFSAR Figure 10.2-1, sheets 1, 2 and 3], has four 28-inch main steam pipes, one from each steam generator to the turbine stop and control valves. The four lines are interconnected local to the turbine. Each steam pipe has a swing disk type main steam isolation value (MSIV) and a swing disk type nonreturn valve located outside the containment. The MSIVs were redesigned to better withstand the dynamic forces associated with rapid closure in the event of a steam line rupture and thus reduce the likelihood of damage. The material for the valve discs was upgraded to stainless steel and the design of the disc arms was improved to reduce valve strains. In their Safety Evaluation Report (SER) dated September 15, 1976, the NRC determined that these modifications would satisfy General Design Criteria 4 of 10 CFR 50, Appendix A. A flow venturi upstream of the isolation valve measures steam flow, providing flow signals used by the automatic feedwater control system (see Section 7.3.3.3). The venturi also limits the steam flow rate in the event of a steam line break downstream of the venturi. Steam pressure is also measured upstream of the isolation valve.

The MSIVs each contain a free-swinging disk that is normally held out of the main steam flow path (valve open) by a solenoid controlled air piston. On receipt of a signal from the steam line break protection system described in Section 7.2.3.2.3.7, the solenoid valves are energized, releasing air from the piston and thereby allowing the MSIV to close. The MSIVs are designed to close in 5 seconds or less.

The nonreturn valves are activated on reverse flow of steam in case of accidental pressure reduction in any steam generator or its piping.

The system is classified as Class I for seismic design up to and including the isolation valves.

The steam line break incident is analyzed in Section 14.2.5.

10.2.1.1 Turbine Steam Bypass System

Excess steam generated by the reactor coolant system is bypassed, during conditions described below, from the four 28-in. main steam lines ahead of the turbine stop valves directly to the condensers by two 20-in. main steam bypass lines that run on either side of the turbine. From each 20-in. line, six 8-in. lines are taken, each with an 8-in. bypass control valve installed. Each bypass valve discharges into a 10-in. pipe that is connected by a manifold with one other 8-in. bypass valve and discharges into a 12-in. manifold. Each 12-in. manifold is taken to a separate section of the condenser where it discharges into the condenser through a perforated diffuser. Each bypass valve has a maximum capacity of 505,000 lb/hr and is rated at 442,000 lb/hr with 650 psia inlet pressure. The total capacity of all 12 bypass valves when operated with 765 psia in the steam generators (stretch rated load of 1078.2 MWe) is approximately 5,561,500 lb/hr (40-percent of the steam generator steam flow). The large number of small-size valves installed limit the uncontrolled steam flow to less than that of a steam generator/main steam safety valve should one valve stick open. Thus, a stuck open bypass valve will not result in a plant cooldown in excess of the steam line rupture/malfunction cases analyzed in UFSAR section 14.2.5. Additionally, local manually operated isolation valves are provided at each control valve.

On a turbine trip with reactor trip, the pressure in the steam generators rises. To prevent overpressure without main steam safety valve operation, the 12 turbine steam bypass valves open and discharge to the condenser for several minutes. The operation of the valves is initiated by a signal from the reactor coolant average temperature instrumentation. In the event of a turbine trip, all valves open fully in 3 sec. After the initial opening, the valves are modulated by the T_{avg} signal to reduce the average temperature and to maintain it at the no-load value. This is described further in Section 7.3.3.

After a normal orderly shutdown of the turbine generator leading to plant cooldown, the operator may select pressure control for more accurate maintenance of no-load conditions using the bypass valves to release steam generated by the residual heat. Plant cooldown, programmed to minimize thermal transients and based on residual heat release, is effected by a gradual manual adjustment of this pressure setpoint until the cooldown process is transferred to the residual heat removal system.

During startup, hot standby service, or physics testing, the bypass valves may be controlled manually from the pressure controllers located on the main control board.

The 12 bypass valves open on temperature control on turbine trip or large load rejection. All 12 valves are prevented from opening on loss of condenser vacuum. They are also blocked on trip of the associated condenser circulating water pump.

10.2.1.2 Steam Dump to Atmosphere

If the condenser heat sink is not available during a turbine trip, excess steam, generated as a result of reactor coolant system sensible heat and core decay heat, is discharged to the atmosphere.

There are four 6-in. by 10-in. and one 6-in. by 8-in. code safety valves located on each of the four 28-in. main steam lines outside the reactor containment and upstream of the isolation and nonreturn valves. Discharge from each of the 20 safety valves is carried to the atmosphere through individual vent stacks. The five safety valves in each main steam line are set to relieve at 1065, 1080, 1095, 1110, and 1120 psig. The total relieving capacity of all 20 valves is 15,108,000 lb/hr.

In addition, four 6-in. power-operated relief valves are provided, which are capable of releasing steam to the atmosphere to dissipate the sensible and core decay heat. These valves are automatically controlled by pressure or may be manually operated from the main control board and are capable of releasing 10-percent of the equivalent rated steam flow (1,390,375 lb/hr of steam at 1020 psig pressure). One power-operated relief valve is located on each main steam line upstream of the swing disk isolation valve. Discharge from each of the four power relief valves is carried to the atmosphere through individual muffled (silencer-fitted) vent stacks. In addition, the power-operated relief valves may be used to release the steam generated during reactor physics testing and plant hot standby operation if the main condenser is not available.

10.2.1.3 Low-Pressure Steam Dump System

A low pressure steam dump system is provided to bypass steam from the exhaust lines from the high-pressure turbine directly to the condenser. The system is provided to minimize turbine speedup immediately following a turbine trip or generator breaker opening.

The low-pressure steam dump system consists of six dump valves, which connect the high-pressure turbine exhausts to the condensers through individual breakdown orifices. An isolation valve is provided for each dump valve. At any generator breaker opening, turbine trip, or overspeed trip with the isolation valves open and dump valves closed, the dump valves would be activated. This would divert approximately 25-percent of the steam available to overspeed the turbine to the condensers, thus reducing the potential maximum turbine speed.

10.2.1.4 Steam for Auxiliaries

The steam for the turbine-driven auxiliary feedwater pump is obtained from two of the 28-in. steam-generator outlet mains upstream of the swing disk isolation valves. A pressure-reducing control valve reduces the steam to 550 psig for the auxiliary turbine.

Auxiliary steam for the turbine gland steam supply control valve, the three steam-jet air ejectors, the reheater section of the six moisture separator-reheaters, the three priming ejectors, and supplementary steam for the main feed pump turbines is obtained from branches on the steam lines ahead of the turbine stop valves. Pressure-reducing stations are used for the priming and main air ejectors. Reheater temperature control valves are located in the steam line to the reheaters. The design pressure and temperature for this system are 1085 psig and 600°F. Steam from six extraction openings in the turbine casings is piped to the shells of the three parallel strings of feedwater heaters. The first extraction point originates at the high-pressure turbine casing and supplies steam to the shells of the No. 26 A/B/C (high-pressure) feedwater heaters. The second extraction point originates in the moisture preseparators located in the high-pressure turbine exhaust piping ahead of the moisture separators and supplies steam to the No. 25 A/B/C (low-pressure) feedwater heaters. The third, fourth, fifth, and sixth extraction points all originate at the low-pressure turbine casings and supply steam to the Nos. 24 A/B/C, 23 A/B/C, 22 A/B/C, and 21 A/B/C (all low-pressure) feedwater heaters, respectively.

Nonreturn valves are provided in all but the two lowest pressure extraction steam lines to prevent turbine overspeed from the backflow of flashed condensate from the heaters after a turbine trip. All of these valves are air-cylinder operated and close automatically on turbine trip. Two of these valves are installed in each of the steam lines to heater Nos. 25 and 26 and also in the extraction line from each moisture preseparator. One of these valves is installed in the steam lines to heater Nos. 23 and 24. The low-pressure fifth and sixth point extraction lines are located entirely in the condenser shells and do not contain nonreturn valves.

10.2.1.5 Steam Generator Blowdown

Each steam generator is provided with two 2½ in. bottom blowdown connections to control the shell solids concentration. The two connections are at the same level but are on opposite sides of the shell. Piping from 2½ to 2 in. reducing inserts at each of the two connections join to form a 2-in. blowdown header for each steam generator. The bottom of each steam generator is also provided with a drain connection, except in the case of the steam-generator No. 21 drain, which has been blanked off.

Each blowdown line has two diaphragm-operated trip valves acting as isolation valves and a hand shutoff valve. The isolation valves are solenoid controlled and open when their individual solenoid is energized. The isolation valves will fail shut on loss of air or power. Each valve is provided with position indicating lights in the control room. In addition to the isolation valves, each line includes a manually operated needle-type flow control valve for blowdown flow or sample flow adjustment and an air-operated valve acting as a fluid trap valve. The steam-generator sample line is taken off from the blowdown line outside containment downstream of the isolation valves. A small flow from each sample line is combined and is monitored for radiation. In the event of a high-radiation signal, both isolation diaphragm valves in the blowdown lines close automatically. They also shut on a phase A containment isolation signal and on an automatic start signal for the motor-driven auxiliary feedwater pumps. The two isolation valves and the fluid trap valve are electrically interlocked to preclude water hammer during closure of the valves on an isolation signal. On an open signal, the isolation valves open prior to the fluid trap valve.

Blowdown from all four steam generators passes to the blowdown flash tank. The flashed vapor is discharged to the atmosphere while the condensate drains by gravity through a service water discharge line into the circulating water discharge canal.

If drains from the blowdown flash tank become contaminated, or in the event of primary to secondary coolant leakage in one or more of the steam generators, the blowdown may be manually diverted to the support facilities (Unit 1 site) secondary boiler blowdown purification system flash tank. This system cools the blowdown and either stores it in the support facilities waste collection tanks or purifies it.

The normal full-load blowdown rate from four steam generators is approximately 57,455 lb/hr or 0.41-percent of feedwater flow. The design basis blowdown flow for four steam generators is 265,200 lb/hr. The maximum limit for blowdown flow is 198,900 lb/hr per steam generator for short periods of operation, not to exceed one year cumulative over the life of the steam generator. This provides for occasionally higher blowdown rates should they be required to reduce solids concentration, and/or sodium carry over via the feedwater system in case of small condenser leaks.

10.2.2 Turbine Generator

The original turbine generator had a guaranteed capability of 1,021,793 kWe at 1.5-in. Hg absolute exhaust pressure with zero percent makeup and six stages of feedwater heating. The unit currently operates at 1800 rpm with steam supplied ahead of the main stop valves at 737 psia, 509°F, and enthalpy of 1200 BTU/lb. Steam is admitted to the turbine through four stop valves and four control valves. The expected throttle flow at 1078 MWe is 12,971,500 lb of steam per hour.

The turbine (TC6F-45) is a four-casing, tandem-compound, six-flow exhaust unit with 45-in. last row blades and consists of one double-flow high-pressure element in tandem with three double-flow low-pressure elements. The low pressure rotors are of the fully-integral design, which eliminates the separate discs (with their bores and keyways) of the earlier design. Steam, after passing through the stop and control valves, passes through the high-pressure turbine, then through the moisture preseparators, through the moisture separator reheaters, and then to the low-pressure turbines as shown in Plant Drawings 227780, 9321-2017, and 235308 [Formerly UFSAR Figure 10.2-1, sheets 1, 2 and 3].

There are four moisture preseparators and six horizontal-axis, cylindrical shell, combined moisture separator/steam reheater assemblies. Steam from the exhaust of the high-pressure turbine element passes through the preseparators and enters each reheater assembly at one end. Internal manifolds in the lower section distribute the wet steam. The steam then rises through a chevron moisture separator where the moisture is removed and drained to a drain tank. The steam leaving the chevron separator flows over a tube bundle where it is reheated. This reheated steam leaves through nozzles in the top of the assemblies and flows to the low-pressure turbines. The tube bundle is supplied with main steam from ahead of the turbine throttle valves, which condenses in the tubes and leaves as condensate. Condensate from the reheater assemblies flows to the high-pressure heaters. The turbine-generator building general arrangement, operating floor, and cross section are shown in Plant Drawings 9321-2004 and 9321-2008 [Formerly UFSAR Figures 10.2-2 and 10.2-3].

The turbine oil system consists of a high-pressure hydraulic control system and a low-pressure lubrication system. Oil is also used to seal the generator shaft seals to prevent hydrogen leakage from the generator into the turbine building. The oil pump mounted on the main turbine shaft normally supplies all oil requirements. A motor-driven auxiliary oil pump supplies the oil required during turbine startup and whenever there is low pressure in the bearing oil header. The auxiliary unit is a centrifugal pump driven by a 150-hp motor. Oil is supplied to the hydraulic control mechanisms at 300 psig. A motor-driven bearing oil pump is also provided to supply oil whenever there is a low pressure in the bearing oil header. This is a centrifugal-type pump with a 75-hp motor. During startup, these auxiliary oil pumps supply all the oil while the main pump acts against a closed check valve. An alternating current motor-driven oil pump is provided for turning gear and emergency operation. A direct current motor-driven oil pump, operated from a station battery, provides additional backup to ensure a supply of lubricating oil to the machine. An alternating current motor-driven generator seal oil pump is furnished for normal operation with a direct current motor-driven backup pump to ensure confinement of the hydrogen within the generator.

A continuous bypass turbine oil purification system removes contaminants from the oil.

To maintain shaft alignment while the unit is down, a motor-driven turning gear is provided.

In 1987, the original generator was replaced with a generator of larger capacity. The new generator has a hydrogen cooled rotor and a water cooled stator, and is rated at 1,439,000 kVA at 75 psig hydrogen pressure. It has sufficient capability to accept the gross kilowatt output of the steam turbine with its control valves wide open, at a reactor power of 3216 MWt.

10.2.3 Turbine Controls

High-pressure steam enters the turbine through four stop valves and four governing control valves. The four main stop valves are designed for the specific operating conditions. Each stop valve is a single-seated, oil-operated, spring-closing valve controlled primarily by the turbine overspeed trip device. The turbine overspeed trip pilot is actuated by one of the following to close the stop valves:

1. Turbine thrust bearing trip.
2. Low bearing oil pressure trip.
3. Low condenser vacuum.
4. Solenoid trip.
5. Overspeed trip.
6. Manual trip.

Each stop valve has limit switches that operate position lights on the main control board.

Test switches on the main control board permit test closure of each valve. The valve position can be observed at the turbine. Periodic tests exercise the stop valves and ensure their ability to close during an emergency. The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525 “Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency,” and in accordance with established NRC acceptance criteria for the probability of a missile ejection incident at IP-2. In no case shall the test interval for these valves exceed one year.

Before a stop valve can be opened, the pressure across the valve must be equalized. This is done by opening a small bypass valve around each of the stop valves.

Electrical interlocks (e.g. circuit breaker position contacts, instrument contacts, relay contacts, valve limit switch contacts) are utilized in control circuits that actuate the turbine trip auxiliary relays. This will initiate a reactor trip.

Four hydraulically operated control valves of the single-seated plug type open and close in sequence to control steam admission to the turbine. They are actuated by the turbine speed governor, which is responsive to turbine speed.
It includes:

1. A speed changer or synchronizing device.
2. A load limit device that must be reset after operation of the overspeed trip before the control valves can be opened.

3. A second load limit device without reset, furnished to give redundancy of load cutback following a rod drop.
4. The governing emergency trip valve, actuated by loss of low pressure auto stop oil pressure.
5. An auxiliary governor, responsive to the rate of turbine speed increase to close the control valves.

Each control valve has a motor-controlled hydraulic pilot valve to test the operation of the valve. Test switches with indicating lights are provided on the main control board turbine section. Removable strainers are located in each control valve body to protect the valves and turbine from foreign material in the steam.

The normal governing devices that operate through hydraulic relays to operate the control valves are as follows:

1. The governor handwheel at the unit.
2. The governor synchronizing motor, which is controlled by a switch on the electrical section of the main control board and is used for raising or lowering turbine speed or load.
3. The load limit handwheel at the unit.
4. The load limit motor, which is controlled by a switch on the turbine section of the main control board and by a reactor control rod drop runback signal (this is described further in Chapter 7).

The preemergency device functions similarly to the normal governing devices by operating the control valves in case of abnormal operating conditions in the auxiliary governor. This preemergency device closes the control valves on rapid increase in turbine speed. The control valves will be actuated by either the speed governor or load limit. The device delivering the lowest oil pressure will be in control. Pressure gauges on the main control board indicate the oil pressure from these devices.

The emergency devices that will trip the stop valves, the control valves, and the air relay dump valves are as follows:

1. Solenoid trip.
2. Low condenser vacuum trip.
3. Low bearing oil trip.
4. Thrust bearing trip.
5. Manual trip at the unit.
6. Overspeed trip.

The solenoid trip is produced directly by the following:

1. Reactor trip breakers opening.
2. Turbine generator primary lockout relay.
3. Turbine generator backup lockout relay.
4. Manual trip push button at control board.
5. Vibration.
6. Main steam isolation valve closure.
7. Steam generator high-high level.
8. [Deleted]

9. Safety injection.
10. [Deleted]
11. AMSAC trip
12. [Deleted by EC-20569]
13. Loss of stator cooling

The solenoid trip signals and logic are shown in Plant Drawing 225096 [Formerly UFSAR Figure 7.2-3].

The mechanical overspeed trip mechanism consists of an eccentric weight mounted in the end of the turbine shaft that is balanced in position by a spring until the speed reaches the point at which the trip is set to operate.

The centrifugal force overcomes the restraining spring and the eccentric weight flies out striking a trigger that trips the overspeed trip valve and releases the autostop fluid to drain. The resulting decrease in autostop pressure causes the governing emergency trip valve to release the control oil pressure.

This closes the main stop and control valves. An air pilot valve used to control the extraction lines nonreturn valves is also actuated by the autostop pressure.

The independent electrical overspeed protection system (IEOPS),has been disabled and is out of service. IEOPS is not required by the Technical Specifications, and is redundant to the Turbine Mechanical Overspeed Protection and it was not credited for Turbine Overspeed Protection.

The autostop valve is also tripped when any one of the protective devices is actuated. The protective devices include low bearing oil pressure, solenoid, thrust bearing, and low vacuum trips. These devices are all included in a separate assembly, but they are connected hydraulically to the overspeed trip valve. An additional protective feature includes a turbine trip following a reactor trip.

When the unit load is at or above P-8, trip of the turbine generator requires a reactor trip.

A loss of one main feedwater pump initiates automatic turbine load cutback. This is described further in Chapter 7.

10.2.4 Circulating Water System

Hudson River water is used for the condenser circulating water. River water flows under the floating debris skimmer wall, through traveling screens, and into six separate screenwells. The traveling screens, which operate continuously, are designed to reduce the potential for fish and debris from entering the circulating water pumps. Each screenwell is provided with stop logs to allow dewatering of any individual screenwell for maintenance purposes.

The water from each individual screenwell flows to a motor-driven, vertical, mixed flow condenser circulating water pump. Each of the six condenser circulating water pumps provides 140,000 gpm and 21-ft total dynamic head when operating at 254 rpm and 84,000 gpm and 15-ft total dynamic head when operating at 187 rpm. Each pump is located in an individual pump well, thus tying a section of the condenser to an individual pump. The circulating water is piped to the condensers and is discharged back into the river far enough away from the intake to minimize recirculation. To protect the traveling screens against ice during freezing water conditions, bar grates with ice shields are installed upstream of the traveling screens at the inlet of the intake bays. Heating elements located in the traveling screen head section prevents ice from forming on the screens.

Sodium hypochlorite, is available for injection into the circulating water to prevent the buildup of bacterial slime on the traveling water screens, condenser tubes, and piping. Sodium hypochlorite may be stored in two 4000-gal tanks in the hypochlorite room of the Unit 1 screenwell house. [Deleted] These tanks supply the 500 gallon day tank for the Unit 2 sodium hypochlorite feed pump skids and the Unit 3 sodium hypochlorite storage tank via the Unit 3 transfer pump.

10.2.5 Condenser and Auxiliaries

Three surface-type, single-pass, radial flow condensers with bolted divided water boxes at both ends are provided. Fabricated steel water boxes and shell construction is used. Hotwell design is for at least 4-min storage while operating at maximum turbine throttle flow with free volume for condensate surge protection. The hotwells are longitudinally divided to facilitate the detection of condenser tube leakage. Each half is provided with separate conductivity measurement devices. In the event of high conductivity (high salinity) in a hotwell, it will be manually isolated. The condensate will be dumped overboard instead of being used to provide suction for the condensate pumps. The deaerating hotwells reduce the residual oxygen in the condensate to less than 0.01 cm^3/l. Condensers 21, 22 and 23 use titanium tubes and tube sheets. Water box manholes are provided for access. Provision is made steam turbine bypass condensing arrangements to condense turbine bypass steam for controlled startup and to condense residual and decay heat steam following a shutdown.

Three motor-driven, eight-stage, one-third capacity, vertical, pit-type, centrifugal condensate pumps are provided, each taking suction from the condenser hotwells. The condensate pumps discharge into three separate parallel streams of feedwater heaters and provide the suction supply to the feedwater pumps.

Each condenser has one four-element, two-stage air ejector with separate intercondensers and common aftercondensers as shown in Figure 10.2-4. The ejectors function by using steam from the main steam system supplied through a pressure-reducing valve. Motor driven vacuum pumps are also provided. Air removed from the condenser is monitored for radioactivity. In the event of a steam-generator leak and the subsequent presence of radioactive contaminated steam in the secondary system, the radioactive noncondensable gases that concentrate in the air ejector effluent will be detected by this radiation monitor. A high activity level signal automatically diverts the exhaust gases from the vent stack to the containment.

For initial condenser shell side air removal, three noncondensing priming ejectors are provided. Each has a capacity of 900 cfm. This apparatus may be used during periods of plant shutdown where decay heat is involved. The main ejectors will also be operated at the same time to ensure that the effluent is monitored for radioactivity.

Examinations of condensers are conducted regularly during scheduled outages in accordance with engineering recommendations. Examinations typically include visual inspections and eddy current tests.

For startup operation two full size motor driven vacuum pumps with all ancillary equipment are installed to reduce oxygen levels in the feedwater and condensate prior to and during start-up. The pumps are also capable of being used for the normal holding operation in lieu of the air ejector system or as a backup to the air ejector system. For the start-up operation steam from the house boiler is used for turbine gland sealing.

10.2.6 Condensate and Feedwater System

The condensate and feedwater system is designed to supply a total of 13,957,950 lb of feedwater per hour to the four steam generators at a turbine load of 1078 MW(e). This system is composed of:

1. A condensate system that collects and transfers condensed steam and the drains from five feedwater heaters through five stages of feedwater heating to the suction of the main feedwater pumps.

2. A condensate makeup and surge system that maintains a normal water level in the condenser hot wells.

3. A heater drain system that collects and transfers the drains from Nos. 25 and 26 feedwater heaters, the moisture preseparators and the six moisture separator/reheaters to the suction of the main feedwater pumps.

4. A feedwater system that delivers the condensate and heater drains through the final stage of feedwater heating to the steam generators.

5. An auxiliary feedwater system that provides a flow of water from the condensate storage tank to the steam generators when the main feedwater pumps are unavailable. The flow is equivalent to that required for makeup because of reactor core decay heat removal requirements.

10.2.6.1 Condensate System

The condensate system transfers condensate and low-pressure heater drains from the condenser hotwell through five stages of feedwater heating to the suctions of the main feedwater pumps. The system flow diagram is shown in Plant Drawings 9321-2018 and 235307 [Formerly UFSAR Figure 10.2-5].

Three one-third size condensate pumps, arranged in parallel, take suction from the bottoms of the condenser hotwells. The pumps discharge into a common header that carries a portion of the condensate through three steam jet air ejector condensers, arranged in parallel, and through one gland steam condenser. The remaining portion flows in parallel with the first flow path, bypassing the steam jet air ejectors and the gland steam condenser. The second flow path rejoins the first in the header downstream of the gland steam condenser.

The condensate pumps are eight-stage, vertical, pit-type pumps. Each pump is rated at 7860 gpm and 1150-ft total dynamic head when operating at 1185 rpm. A standard packed stuffing box is used for shaft sealing. The pump bearings are lubricated by the pumped liquid. Each pump is driven through a solid coupling by a 3000-hp, vertical, solid shaft, induction motor that has an open drip-proof enclosure. The condensate pumps are operated by manual control on the main control board. To maintain the condenser vacuum and turbine steam seals during startup, shutdown, and at very low loads, an 8-in. condensate recirculation line, containing a diaphragm-operated valve, is provided to maintain minimum flow through the air ejector condensers and gland steam condenser. The recirculation line originates at the condensate header downstream of the gland steam condenser and terminates at the condenser hotwell. The diaphragm-operated recirculation valve is automatically controlled by the minimum flow required by the air ejector condensers.

The 24-in. header divides into three 14-in. lines downstream of the gland steam condenser. From these lines, the condensate passes through the tube sides of three parallel strings of two low-pressure feedwater heaters. The flow from these heaters is combined in another 24" pipe, and then divided to go to the remaining three strings of three low-pressure heaters. After the No.25 feedwater heater, the three condensate lines join into a common header. The heater drain pump discharge enters this header and then continues on to the suction of the main feedwater pumps.

Each parallel string of feedwater heaters may be taken out of service by closing a manual gate valve at the inlet to the string of heaters and at the outlet of the string of heaters.

The condensate makeup and surge systems maintain normal water level in the condenser hotwell.

The makeup system connects the 600,000-gal capacity condensate storage tank to a diffusing pipe in the condenser shell. This line contains a diaphragm-operated valve that can automatically open on low level in the condenser hotwell to pass makeup water from the tank to the condenser. This valve may be operated manually or automatically. An isolating valve will close the condenser makeup before the condensate storage tank level reaches its Technical Specification minimum capacity. This will ensure a reserve of condensate for the auxiliary feedwater pumps that will hold the plant at hot shutdown for 24 hr following a trip at full power.

The condensate surge system connects the condensate pump discharge header to the condensate storage tank. This line contains a diaphragm-operated valve that automatically opens on high level in the condenser hotwell to pass excess condensate from the condensate pump discharge header to the condensate storage tank.

Hotwell levels are indicated on the main control board. Should the automatic makeup valve or the surge valve become inoperative, it may be isolated from its respective system and the hotwell level controlled from the control room by remote manual positioning. The condenser hot-wells contain 114,000 gal, which is equal to approximately 5.63-min condensate flow at 1078 MWe load.

The drains from the No. 26 A/B/C feedwater heaters flow to the heater drain tank. Normal condensate level is maintained in the No. 26 heaters by diaphragm-operated level control valves.

The drains from the No. 25 A/B/C feedwater heaters flow by gravity directly to the heater drain tank. There are no level control valves in the drains from these heaters.

Two half-size heater drain pumps pump the drains from the drain tank into the condensate header upstream of the main feedwater pumps. Both pumps discharge through diaphragm-operated level control valves.

The heater drain pumps are 14-stage, vertical, enclosed suction-type pumps. Each pump is rated at 4150 gpm and 720-ft total dynamic head when operating at 1170 rpm. Each pump is driven through a solid coupling by a 1000-hp, vertical, solid shaft, induction motor that has an open drip-proof enclosure.

The heater drain pumps are operated by manual controls on the main control board. A heater drain pump is automatically stopped on low drain tank level or if the flow falls below a set minimum. After the pump has stopped, the water level in the heater drain tank will increase. An alarm sounds in the control room on both tank low level and pump low flow.

When a high level occurs in the heater drain tank, diaphragm-operated valves open to discharge the excess condensate from the heater drain tank directly to the shell of a condenser. An alarm sounds in the control room. The heater drain tank has a 5660-gal storage capacity at normal water level or approximately 0.64-min storage of drains at the normal full load of 1078 MWe.

Drains from the Nos. 24, 23, and 22 feedwater heater strings normally flow through diaphragm-operated level control valves to the shells of the next lowest pressure feedwater heater. On high level in any heater, a separate high-level drain from the heater discharges directly to the condenser.

Drains from the No. 21 feedwater heaters normally flow through diaphragm-operated level control valves to the condenser. When a high level occurs in the heaters, a separate high-level drain for each heater discharges to the condenser.

10.2.6.2 Main Feedwater System

Two half-size steam-driven main feedwater pumps increase the pressure of the condensate for delivery through the final stage of feedwater heating and then the feedwater regulating valves to the steam generators. The system flow diagram is given in Plant Drawing 9321-2019 Figure 10.2-7.

The main feedwater pumps are single-stage, horizontal, centrifugal pumps with barrel casings. Each pump is rated at 15,300 gpm and 1700-ft total dynamic head when operating at 4740 rpm. Seal-water injection is used for shaft sealing. Bearing lubrication for both the pump and its turbine drive is accomplished by an integral lubricating oil system. Normal circulation of the lubricating oil is by a motor-driven pump. The lubricating oil system includes a reservoir, a cooler, and two motor-driven oil pumps. Each main feedwater pump is driven through a flexible coupling by an 8350-hp horizontal steam turbine that uses steam from the discharge of the three reheater moisture separators on one side of the turbine hall. The main feedwater pumps are operated automatically by the feed control system. Manual controls are also provided on the main control board for remote operation and testing during normal operation. During normal startup of the plant, these pumps are started locally. A minimum flow control system is provided to ensure that each pump is handling at least a 3000-gpm flow at all times.

Above a preset turbine power, the operator may arm the condensate pump auto-start circuit (MBFP trip or MBFP low suction pressure or running condensate pump trip).

Low suction pressure starts any idle condensate pumps (if armed) and reduces the feed pump turbine speed to maintain suction pressure. Normal speed is regained when the suction pressure and flow is reestablished. High discharge pressure reduces turbine speed to prevent excessive pressure in the feed piping.

In the original design, a bypass was provided around the low pressure heaters, which was to be used to provide sufficient suction pressure at the feed pumps during a transient when flashing might occur in the heater drain tank and affect the performance of the heater drain pumps. The bypass valve was retired in place when operating experience proved that it was not required to perform this function.

High main feedwater pump bearing temperatures are alarmed in the main control room. However, they do not automatically stop the pump.

The two parallel main feedwater pumps operate in series with the condensate pumps and discharge through check valves and motor-operated gate valves into a common header. The feedwater then flows through the three parallel, high-pressure feedwater heaters into a common header. Four parallel 18-in. lines containing the feedwater metering and regulating stations feed the four steam generators.

Shutoff valves at the inlets and outlets of the feedwater heaters permit a heater to be taken out of service. Bypass lines are provided around the heaters to allow operation when a heater is out of service for maintenance.

A long loop recirculation line, from the high pressure feedwater header, leading back through an installed particulate removal filter and portable demineralizers to the condenser, is available for secondary coolant cleanup during plant outages.

The steam-generator feedwater metering and regulating stations measure, indicate, record, and control the water level in each of the four steam generators. A conventional three-element system receives flow and load signals from the reactor protection system through isolation amplifiers and compares the difference between steam and feedwater flows to adjust the level setpoint. The deviation of level measurement from this setpoint positions the feedwater control valve accordingly. Totalized steam flow controls the speed of the main feedwater pump turbines.

Low-flow feedwater regulating valves bypass the main control valves for the control of low-load feedwater flow.

On trip of one main feedwater pump above a preselected turbine power, the following actions are automatically initiated to prevent a trip of the reactor and turbine-generator.

a. The turbine load limit is run back to reduce the steam demand.
b. Any idle condensate pumps are started. (if armed)
c. Non tripped pump to pick up additional load.

A reactor trip is actuated on a coincidence of steam flow-feedwater flow mismatch, coupled with a low level in the corresponding steam generator. A reactor trip is also initiated on a coincidence of two-out-of-three low-low water-level signals from any one steam generator. Whenever this reactor trip occurs, the main feedwater valves move to the fully open position in response to an increased level demand signal from the feedwater control system. This provides an additional heat sink for the reduction of reactor coolant temperature to the no-load average temperature value. The feedwater regulating valves close on one of the following conditions:

1. High-high steam generator water level.
2. Reactor trip coincident with low T_{avg} signal.
3. Safety injection signal.

In the case of reactor trip coincident with low T_{avg} signal, the low flow feedwater bypass valve closure may be delayed by means of an installed timer to allow main feedwater to moderate the cooler auxiliary feedwater before it enters the steam generators. The feedwater control system is an electronic analog instrumentation system.

Readout and control equipment is as follows:

1. Wide and narrow range level shown on recorder calibrated for cold conditions in the steam generator, permits observation of the level essentially over the full height of each steam-generator shell.

2. Visual indication is provided in the main control room of feedwater flows in pounds per hour for each steam generator.

3. A leading edge flow meter in each steam-generator feedline provides feedwater flow data for thermal power calculations.

4. Each flow channel and each narrow-range level channel is indicated on the main control board.

5. Each feedwater controller has one manual control station. The unit consists of an auto/manual transfer switch and an analog output control, which serves as the valve position signal when in "Manual." The "Automatic" setpoint is preset, but adjustable in the instrument rack.

6. Other manual control stations are used to position auxiliary feedwater regulating valves.

10.2.6.3 Auxiliary Feedwater System

This system is used for normal startup. The auxiliary feedwater system supplies high-pressure feedwater to the steam generators to maintain a water inventory. This is needed to remove decay heat energy from the reactor coolant system by secondary-side steam release in the event that the main feedwater system is inoperable. The head generated by the pumps is sufficient to deliver feedwater into the steam generators at safety valve pressure. Diverse auxiliary feedwater supplies are provided by using two pumping systems using different sources of motive power for the pumps. The system flow diagram is given in Figure 10.2-7.

The capacity of each system is set so that all four steam generators can be supplied with auxiliary feedwater. Under limiting conditions, at least two steam generators will not boil dry nor will the primary side relieve water through the pressurizer relief/safety valves following a loss of main feed-water flow. Further details are given in Section 14.1.9.

One system uses a steam-turbine-driven pump with the steam capable of being supplied from two of the steam generators. This system is designed to supply up to 800 gpm of feedwater (200 gpm to each steam generator). The estimated (expected) design performance characteristic of the pump is given in Figure 10.2-8. The technical specification requirement is that this pump be capable of supplying at least 380 gpm.

Steam to drive the turbine is supplied from two of the main steam lines upstream of the isolation valves at steam-generator outlet pressure and is reduced to within the 550-psig turbine design pressure by a pressure-reducing control valve (PCV-1139). The turbine is started by opening the pressure-reducing valve between the turbine supply steam header and the main steam lines. The turbine sleeve journal bearings are ring oil-lubricated, water cooled. The pump uses oil slinger lubricated ball bearings. The drive is a single-stage turbine, capable of quick starts from cold standby, and is directly connected to the pump.

The speed of the turbine can be adjusted manually via a remote pneumatic speed controller (HC-1118). It is normally set at zero percent (i.e., minimum setting of approximately 3200 rpm). Upon generation of an automatic start signal for the turbine-driven pump, PCV-1139 will open, and the turbine will start and run. The pump itself will only operate on recirculation flow since the auxiliary feedwater regulating valves in its discharge are normally closed. In order to deliver flow to the steam generators using this pump, the operator must open one or more of the associated auxiliary feedwater regulating valves, and manually adjust the speed controller for the turbine. Both of these actions can be performed from the central control room control board or locally at the valves. The auxiliary feedwater regulating valves are pneumatically operated. PCV-1139 opens fully on loss of control air. All pneumatic instruments and valves associated with the auxiliary feedwater system requiring instrument air for their safety function have automatic nitrogen back-up.

Since the single failure criterion for loss of normal feedwater events can be satisfied by one motor-driven auxiliary feedwater pump providing flow for a sufficiently long period of time before an operator action is taken to align the turbine-driven auxiliary feedwater pump, manual alignment of the turbine-driven pump is acceptable. Further details are given in Section 14.1.9.

The other system uses two motor-driven pumps with lubricated ring oiled ball bearings. Each pump has a design capacity of 400 gpm, and the discharge piping is arranged so that each pump supplies two of the four steam generators. The estimated design performance characteristic for these pumps is given in Figure 10.2-9. The technical specification requirement is that each pump be capable of supplying at least 380 gpm.

The motors are of open drip-proof design with ball bearings. In the event of complete loss of power, electrical power is automatically obtained from the diesel generators. Each motor-driven pump is provided with a discharge pressure sustaining control system to prevent the pump from "running out" on its curve. The Regulating valves are pneumatically operated and have an automatic nitrogen bottle backup system to maintain operability in the event that control air is lost. A recirculation line and control system are provided for each pump to maintain a minimum flow when it is running.

Upon generation of an automatic start signal for the motor-driven auxiliary feedwater pumps, both pumps will start and each will deliver at least 380 gpm. The regulating valves for each motor-driven pump are controlled such that each steam generator receives approximately 190 gpm. An additional restriction on auxiliary feedwater flow when a steam generator feed ring has been uncovered for an extended period of time provides added assurance against a potentially damaging water hammer upon initiation of cold auxiliary feedwater to the steam generators. This restriction limits auxiliary feedwater flow to the affected steam generator(s) until an increase in steam generator level can be seen. The accident analyses in Sections 14.1.9 (Loss of Normal Feedwater) and 14.1.12 (Loss of All AC Power to the Station Auxiliaries) assume that only one motor-driven pump starts one minute after accident initiation and delivers 380 gpm (nominal 190 gpm to each of two steam generators). Further, operator action is credited at 10 minutes after reactor trip to start the second motor-driven pump or to align the steam-driven-turbine pump.

The auxiliary feedwater pumps are located in an enclosed room in the auxiliary feedwater building, which houses the area of the main steam and feedwater penetrations immediately outside the reactor containment.

Safety-grade flow measurement devices are installed in the feedwater supply to each steam generator with indicators on the main control board. In addition, wide-range and safety-grade narrow-range steam-generator level indications are provided in the main control room. These provide the operator with the information necessary to route auxiliary feedwater discharge flow through the remote manual discharge regulating valves.

The distribution piping is seismic Class I throughout. It is designed to ensure that a single fault will not restrict the system function.

The overall seismic qualification of the auxiliary feedwater system was reviewed and found acceptable by NRC Safety Evaluation Reports issued September 7, 1982 and September 29, 1987.

The water supply source for this system is redundant. The main source is by gravity feed from the condensate storage tank. This tank is sized to meet the normal operating and maintenance needs of the turbine cycle systems. However, a minimum water level will be maintained, equivalent to the steam generation from 24 hr of residual heat generation at hot shutdown conditions. The condensate storage tank is considered the safety grade source for the auxiliary feedwater system.

The auxiliary feedwater pumps can draw from an alternative supply of water to provide for long-term cooling. This alternative supply is from the 1.5 million gal city water storage tank. This supply is manually aligned to the auxiliary feedwater pumps in the event of unavailability of the condensate storage tank.

The auxiliary feedwater pumps are automatically started on receipt of any of the following signals:

1. Steam-driven auxiliary feedwater pump:
   a. Low-low water level in any two of the four steam generators.
   b. Loss of offsite power concurrent with a unit trip and with no safety injection signal present.

2. Motor-driven auxiliary feedwater pumps:
   a. Low-low water level in any steam generator.
   b. Automatic trip of main feedwater pumps [*Note - One main feedwater pump trip automatically sends a demand start signal to both motor-driven auxiliary feedwater pumps*.] as indicated by loss of main feed pump control oil pressure after manual control switch was last operated to the "start" position.
   c. Safety injection signal.
   d. Loss of outside power concurrent with a unit trip.

The auxiliary feedwater system automatic initiation signals and circuits meet safety-grade requirements. Interfacing AMSAC signals and circuits which are not safety-grade are provided with Class 1E isolation devices.

In the event of a complete loss of offsite power, the electrical power is supplied by the diesel generators as described in Chapter 8.

In addition, the steam-driven and the motor-driven auxiliary feedwater pumps can be started manually from the control room and locally at the pumps.

In the event of a loss of the condensate storage tank supply (e.g., one or both condensate storage tank discharge valves are closed), immediately place the auxiliary feedwater pump controls in the manual mode. Within 1 hour either the valve(s) shall be reopened or the valves from the alternate city water supply shall be opened and the auxiliary feedwater pump controls restored to the automatic mode.

10.2.6.4 System Chemistry

Steam-generator water chemistry is maintained within the required water quality limits. A nitrogen blanket in the condensate storage tank minimizes oxygen ingress. During outages, as part of the wet lay-up process, nitrogen is introduced as a sparging gas to displace air from the steam generators. Hydrazine is added to the condensate for oxygen control and ammonium hydroxide and/or volatile amines are added to maintain the pH at the optimum value for the materials of construction for the system.

No radiation shielding is required for the components of the steam and power conversion system. During normal operation, continuous access to the components of this system outside of containment is possible.

Under normal operating conditions, no radioactive contaminants are present in the steam and power conversion system. It is possible for this system to become contaminated through steam-generator tube leaks. In this event, any contamination is detected by monitoring the steam-generator shell-side blowdown sample points and the condenser air ejector discharge. Operation with a steam-generator tube leak is discussed in Chapter 14. Radiation monitors are installed in the main steam lines outside of the containment wall to provide continuous readout on recorders in the control room.

Steam generator feedwater is monitored at the main condensers. The condensate is analyzed for the major chemical constituent of river water (sodium) and is monitored for total dissolved solids.

10.2.7 Codes and Classifications

The pressure-retaining components or compartments of components comply, as a minimum, with the codes detailed in Table 10.2-1.

TABLE 10.2-1
Codes and Classifications

System pressure vessels and$_3$ pump casing	ASME Boiler and Pressure Vessel Code,

	Section VIII
Steam-generator vessel (shell side)	ASME Boiler and Pressure Vessel Code, Section III, Class C_1 (required)
System valves, fittings, and piping$_2$	USAS Section B31.1 Power Piping Code (1955) ASA, USAS, ANSI
Pressure Testing of Repairs and Modifications	USAS Section B31.1 Power Piping Code (1992)

Notes:

1. The shell side of the steam generator conforms to the requirements for Class A vessels (Actual) and is so stamped as permitted under the rules of Section III.
2. Except piping supplied by Westinghouse as part of the Turbine generator package, which was designed and fabricated to Westinghouse proprietary standards. This includes crossover, crossunder and lube oil piping.
3. Nos. 26A and 26B feedwater heater extraction steam inlet nozzles were modified in 1995 under the provisions of ASME Section VIII and were inspected and accepted under the provisions of the licensee's 10 CFR 50 Appendix B Quality Assurance Program.

10.2 FIGURES

10.3 SYSTEM EVALUATION

10.3.1 Safety Features

Trips, automatic control actions, and alarms will be initiated by deviations of system variables within the steam and power conversion system. Appropriate corrective action is taken as required to protect the reactor coolant system. The more significant malfunctions or faults that cause trips, automatic actions, or alarms in the steam and power conversion system are:

1. Turbine trip (see Section 10.2.3 for further discussion of trip actions):
   a. Generator/electrical faults.
   b. Low condenser vacuum.
   c. Thrust bearing failure.
   d. Low lubricating oil pressure.
   e. Turbine overspeed.
   f. Reactor trip.
   g. Manual trip.
   h. Main steam isolation valve closure.

2. Automatic control actions (see Chapter 7 for a further discussion of trip actions):
   a. High level in steam generator stops feedwater flow.
   b. Normal and low level in steam generator modifies feedwater flow by continuous proportional control.

3. Principal alarms:
   a. Low vacuum in condenser.
   b. Thrust bearing failure.
   c. Low lubricating oil pressure.
   d. Turbine overspeed.
   e. Low level in steam generator.
   f. High level in steam generator.
   g. Condenser hotwell high and low levels.

A reactor trip from power requires the removal of core decay heat. Immediate decay heat removal requirements are satisfied by the steam bypass to the condensers. Thereafter, core decay heat can be continuously dissipated by the steam bypass to the condenser as feedwater in the steam generator is converted to steam by heat absorption.

Normally, the capability to return feedwater flow to the steam generators is provided by the operation of the turbine-cycle feedwater system. In the unlikely event of a complete loss of offsite electrical power to the station and concurrent reactor trip, decay heat removal would be ensured by the single turbine-driven and two motor-driven (by emergency diesel-generator power) auxiliary feedwater pumps, and steam dump to atmosphere by the main steam safety and/or power relief valves. Further details are given in Section 14.1.12. In this case, feedwater from the condensate storage tank is available by gravity feed to the auxiliary feedwater pumps. The minimum 360,000 gal of water in the condensate storage tank is adequate for decay heat removal at hot shutdown conditions for at least 24 hr. A backup source of feedwater is available from the city water storage tank.

The analysis of the effects of loss of full load on the reactor coolant system is discussed in Section 14.1.8.

10.3.2 Secondary-Primary Interactions

Following a turbine trip, the control system reduces reactor power output immediately by a reactor trip. Steam is bypassed to the condenser, and there is no lifting of the main safety valves. In the event of failure of a main feedwater pump, a motor-driven auxiliary feedwater pump is automatically started and the second main feedwater pump remaining in service will carry approximately 65-percent of full-load feedwater flow. If both main feedwater pumps fail, the reactor will be tripped as a result of steam-generator low-low level or steam-feedwater flow mismatch and the auxiliary feedwater pumps will start. Not withstanding the anticipatory reactor trip on turbine trip, if reactor coolant system conditions reach trip limits, the reactor will trip.

Pressure relief is required at the main steam system design pressure of 1085 psig. The first safety valve is set to relieve at 1065 psig. Additional safety valves are set at pressures up to 1120 psig (see Section 10.2.1.2), as allowed by the ASME Code. The pressure relief capacity is greater than the steam generation rate at maximum calculated conditions.

The evaluation of the capability to isolate a steam generator to limit the release of radioactivity in the event of a steam-generator tube leak is presented in Section 14.2.4. The steam break accident analysis is presented in Section 14.2.5.

10.3.3 Single Failure Analysis

Table 10.3-1 presents the results of a single failure analysis of selected components in the system.

TABLE 10.3-1
Single-Failure Analysis

Component or System	Malfunction	Comments and Consequences
Auxiliary feedwater system	Auxiliary feedwater pump fails to start (following loss of main feedwater)	The auxiliary feedwater system comprises one turbine-driven and two motor-driven pumps. The turbine pump has twice the capacity of a motor-driven pump. A single motor-driven pump has sufficient capacity to allow time for an operator action to align the turbine-driven train and prevent relief of water through the primary side safety/relief valves. Thus adequate redundancy of auxiliary feedwater pumps is provided, as described in UFSAR 14.1.9.

Steam line isolation system	Failure of steam line isolation valve to close (following a main steam line rupture)	Each steam line contains an isolation valve and a non-return check valve in series. Hence, a failure of an isolation (or nonreturn) valve will not permit the blowdown of more than one steam generator irrespective of the steam-line rupture location, as described in UFSAR section 14.2.5.
Turbine bypass system	Bypass valve sticks open (following operation of the bypass system resulting from a turbine trip)	The turbine bypass system comprises 12 bypass valves, each with a steam flow capacity less than a steam generator/main steam safety valve. Thus, the uncontrolled steam flow from a stuck open bypass valve will not result in a plant cooldown in excess of the bounding steam line rupture / malfunction cases analyzed in UFSAR section 14.2.5.

10.4 TESTS AND INSPECTIONS

The main steam isolation valves are tested at least at refueling intervals and a maximum closure time of 5 sec is verified.

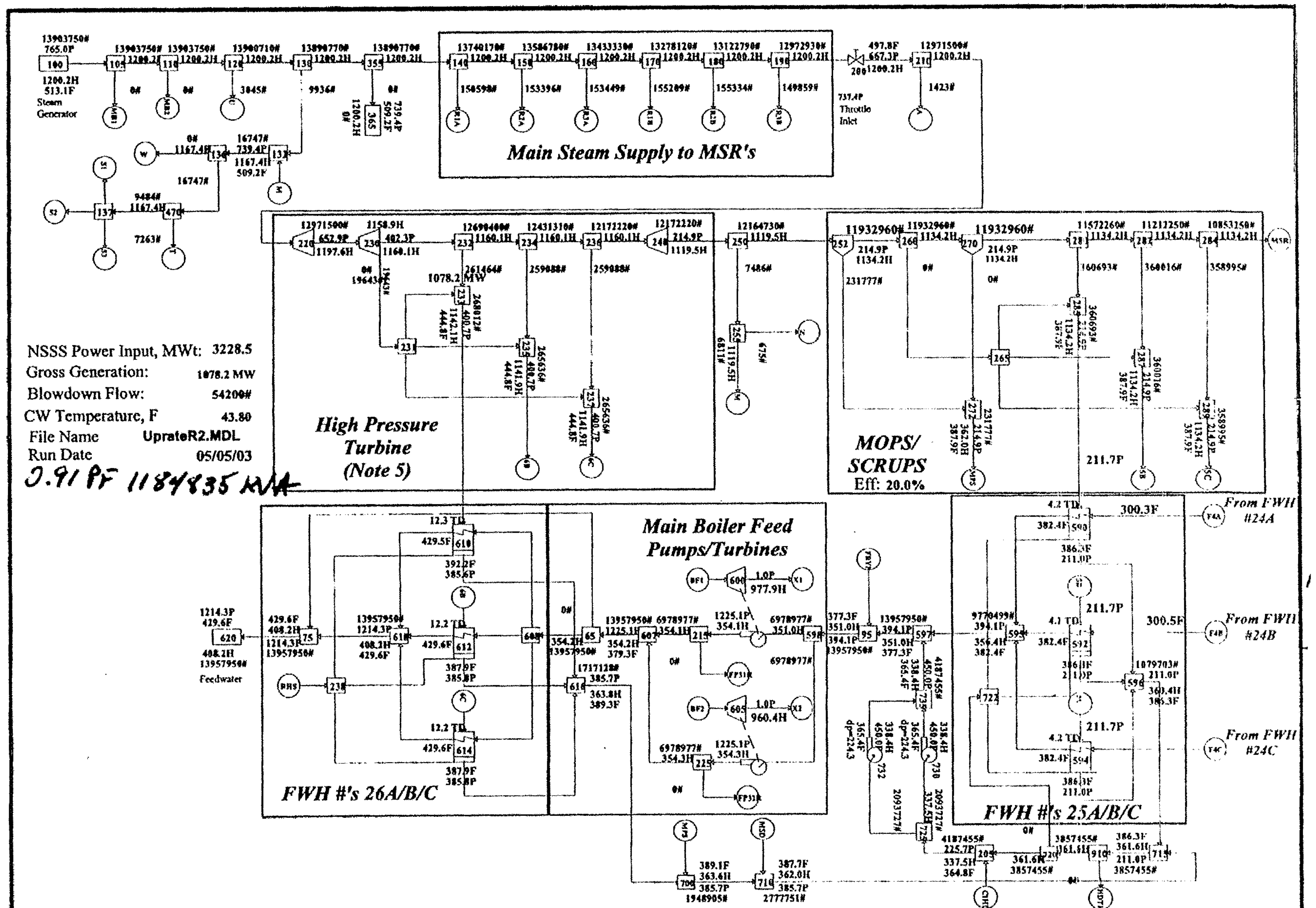
The main steam isolation valves serve to limit an excessive reactor coolant system cooldown rate and resultant reactivity insertion following a main steam break incident. Their ability to close upon signal is verified at periodic intervals. A closure time of 5 sec from receipt of closing signal was selected as being consistent with expected response time for instrumentation as detailed in the steam line break analysis. Further details are given in Section 14.2.5.

The auxiliary feedwater pumps are tested at regular intervals. Verification of correct operation is made both from instrumentation within the main control room and by direct visual observation of the pump. In addition, during reactor startup and shutdown, the auxiliary feedwater pumps (normally the motor-driven pumps) are used to deliver water from the condensate storage tank through its feedwater control valves to the feedwater line to the steam generators.

In response to NRC IE Bulletin 87-01, an inspection program has been established for piping and fittings in the extraction steam, turbine crossunder, heater drain pump discharge, condensate, feedwater and auxiliary feedwater systems. UT inspections are utilized to evaluate wall thickness at locations considered to be most susceptible to erosion/corrosion. Additional information is given in reference 1.

REFERENCES FOR SECTION 10.4

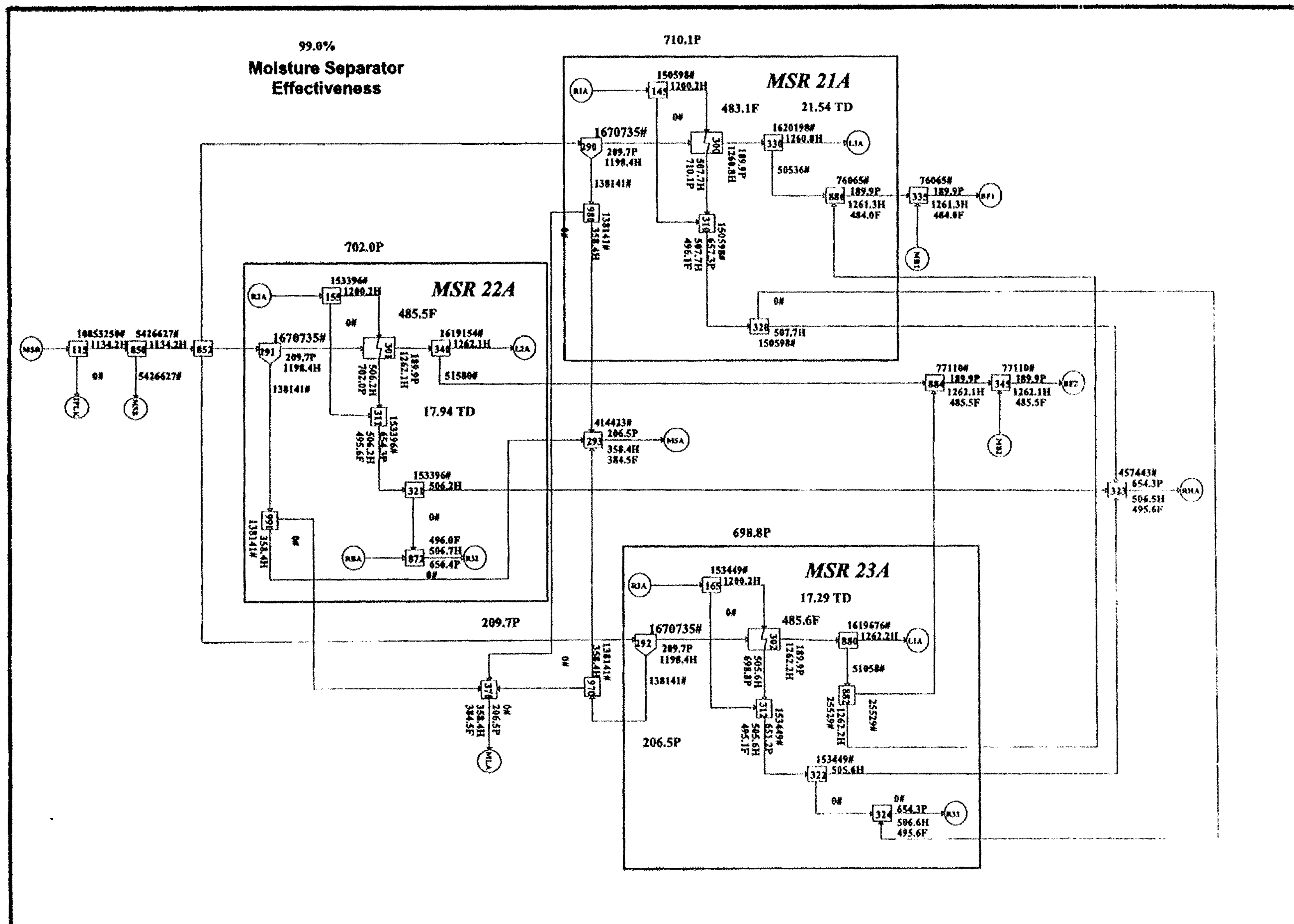
1. Letter from Murray Selman (Con Edison), to William Russell, NRC, dated 9/11/87.



Uprate PEPSE Model with New HP Turbine
High Pressure Turbine Expansion **Sheet 1 of 6**

Entergy Indian Point 2 Nuclear Power Plant

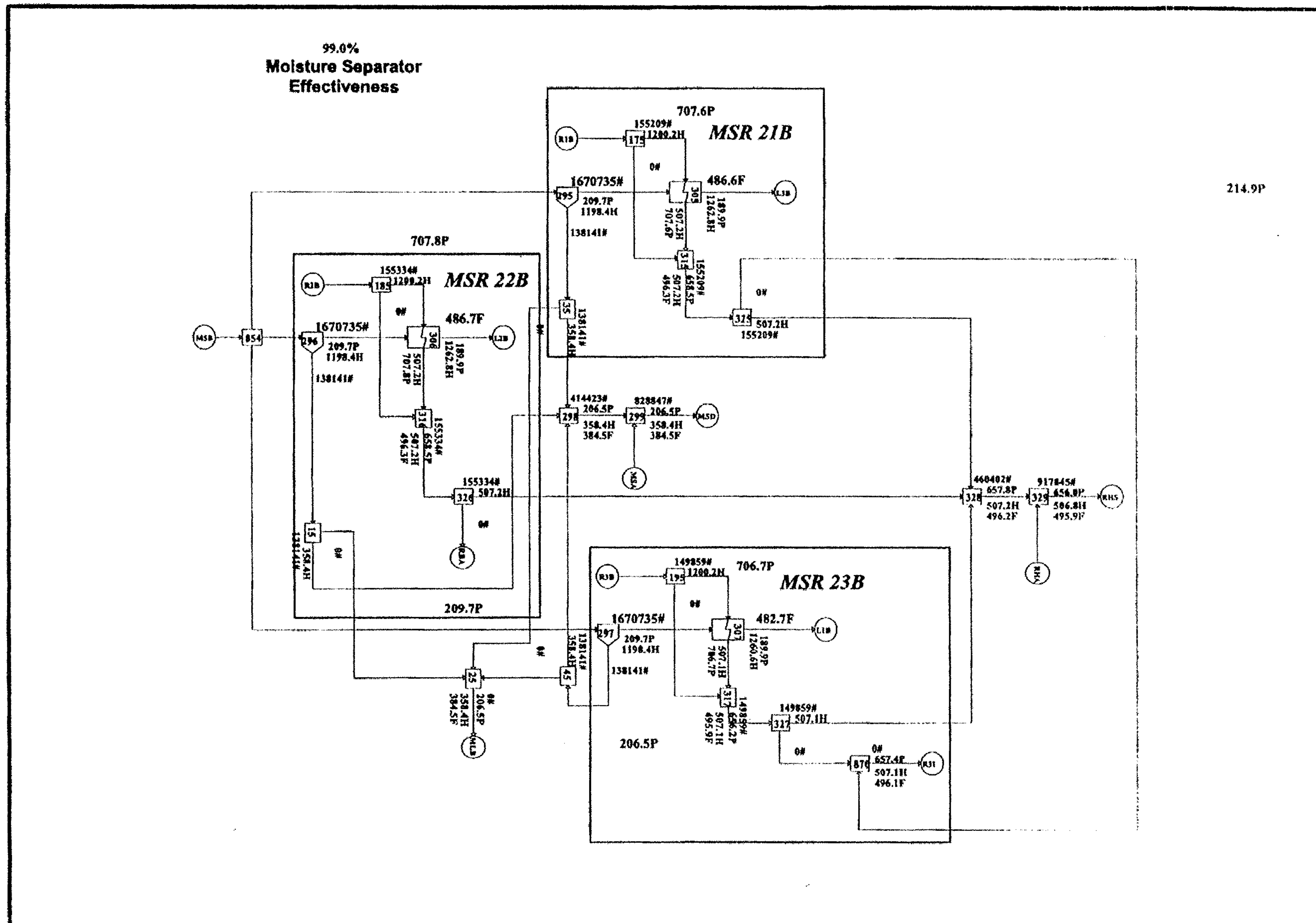
INDIAN POINT UNIT No. 2	
UPRATE PEPSE MODEL WITH NEW HP TURBINE HIGH PRESSURE TURBINE EXPANSION	
UFSAR FIGURE 10.1-1a	REV. No. 21



Uprate PEPSE Model with New HP Turbine
Moisture Seperator Reheater Train A   Sheet 2 of 6

Entergy   Indian Point 2
Nuclear Power Plant

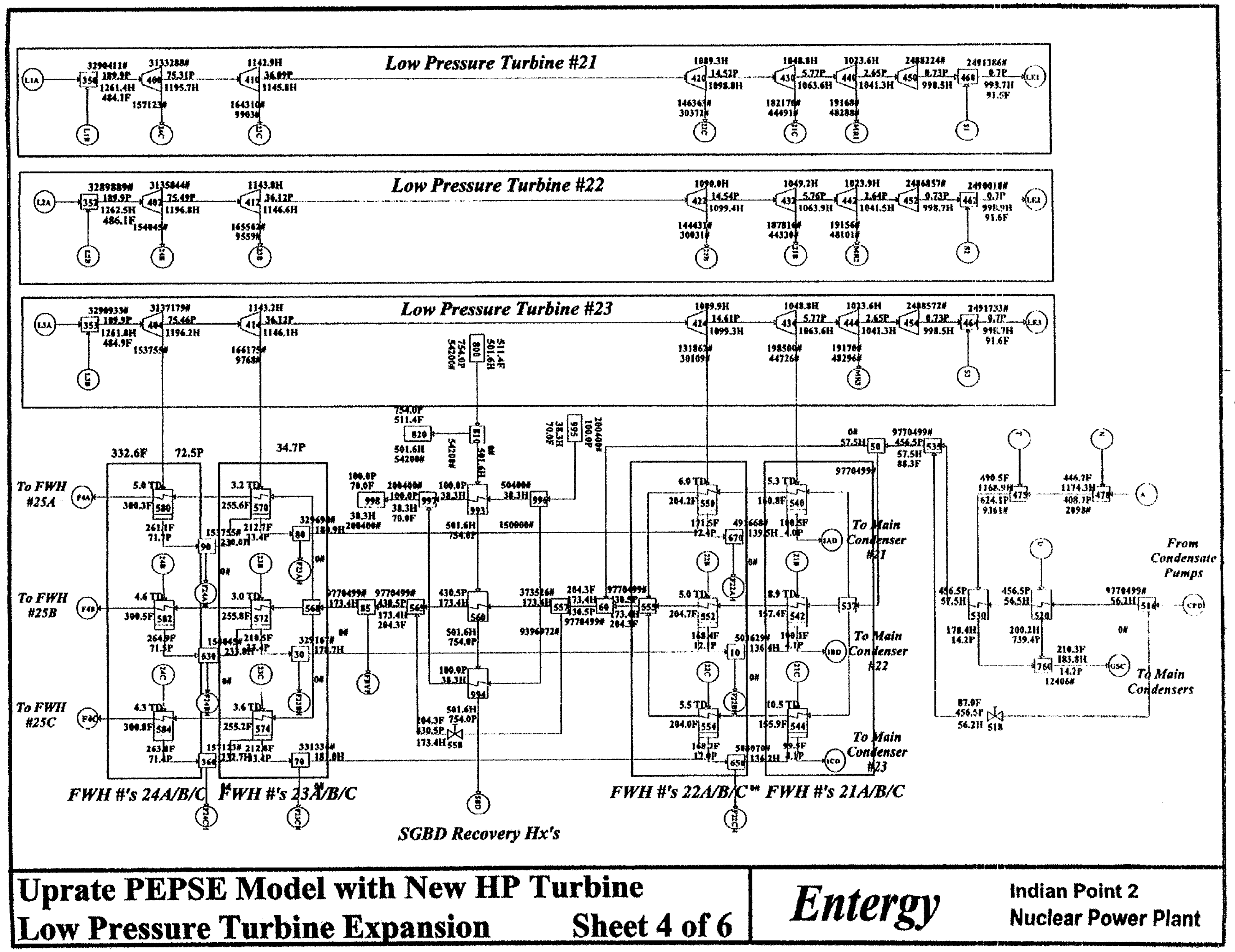
INDIAN POINT UNIT No. 2	
UPRATE PEPSE MODEL WITH NEW HP TURBINE MOISTURE SEPERATOR REHEATER TRAIN A	
UFSAR FIGURE 10.1-1b	REV. No. 21



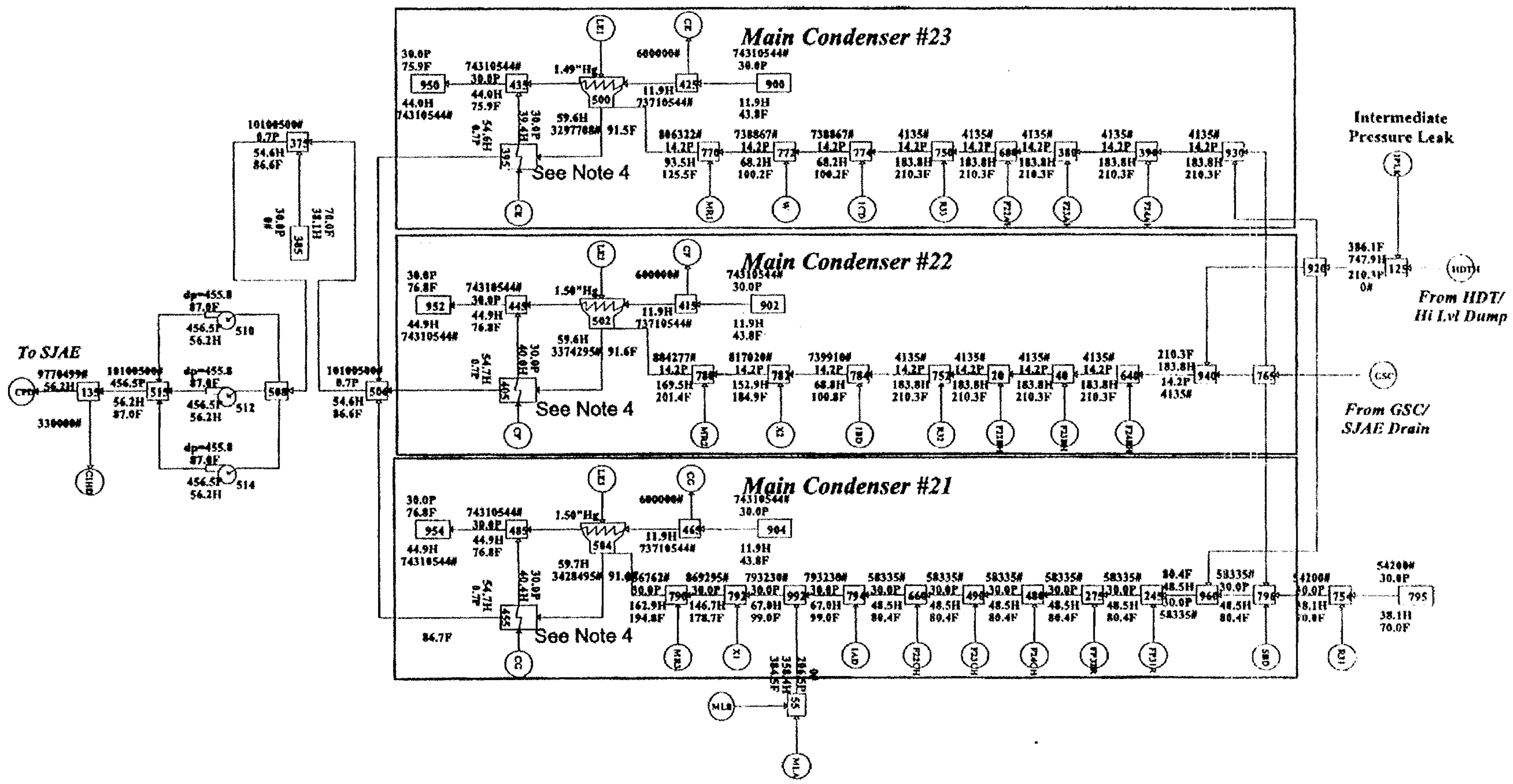
Uprate PEPSE Model with New HP Turbine
Moisture Seperator Reheater Train B   Sheet 3 of 6

Entergy   Indian Point 2
Nuclear Power Plant

INDIAN POINT UNIT No. 2	
UPRATE PEPSE MODEL WITH NEW HP TURBINE MOISTURE SEPERATOR REHEATER TRAIN B	
UFSAR FIGURE 10.1–1c	REV. No. 21



INDIAN POINT UNIT No. 2	
UPRATE PEPSE MODEL WITH NEW HP TURBINE LOW PRESSURE TURBINE EXPANSION	
UFSAR FIGURE 10.1-1d	REV. No. 21



Uprate PEPSE Model with New HP Turbine Main Condensers **Sheet 5 of 6**

Entergy Indian Point 2 Nuclear Power Plant

INDIAN POINT UNIT No. 2

UPRATE PEPSE MODEL WITH NEW HP TURBINE MAIN CONDENSERS

UFSAR FIGURE 10.1–1e | REV. No. 21

CIRCULATING WATER TEMPERATURES
INLET, F: **43.80** OUTLET #21:

NOTES:

1. This model runs Data Sets 1, 6, 5 and 16 in that order. S&W changes are in Data Set 16, or else in the last set where the data are entered.

2. OPVB 12 is the input for Circ Water Inlet Temp. Operations 103-105 set this value for the CW sources.

3. This heat balance should not be used to predict pressures in the condensate and feedwater system. The hydraulic performance has not been tuned to reflect actual plant conditions.

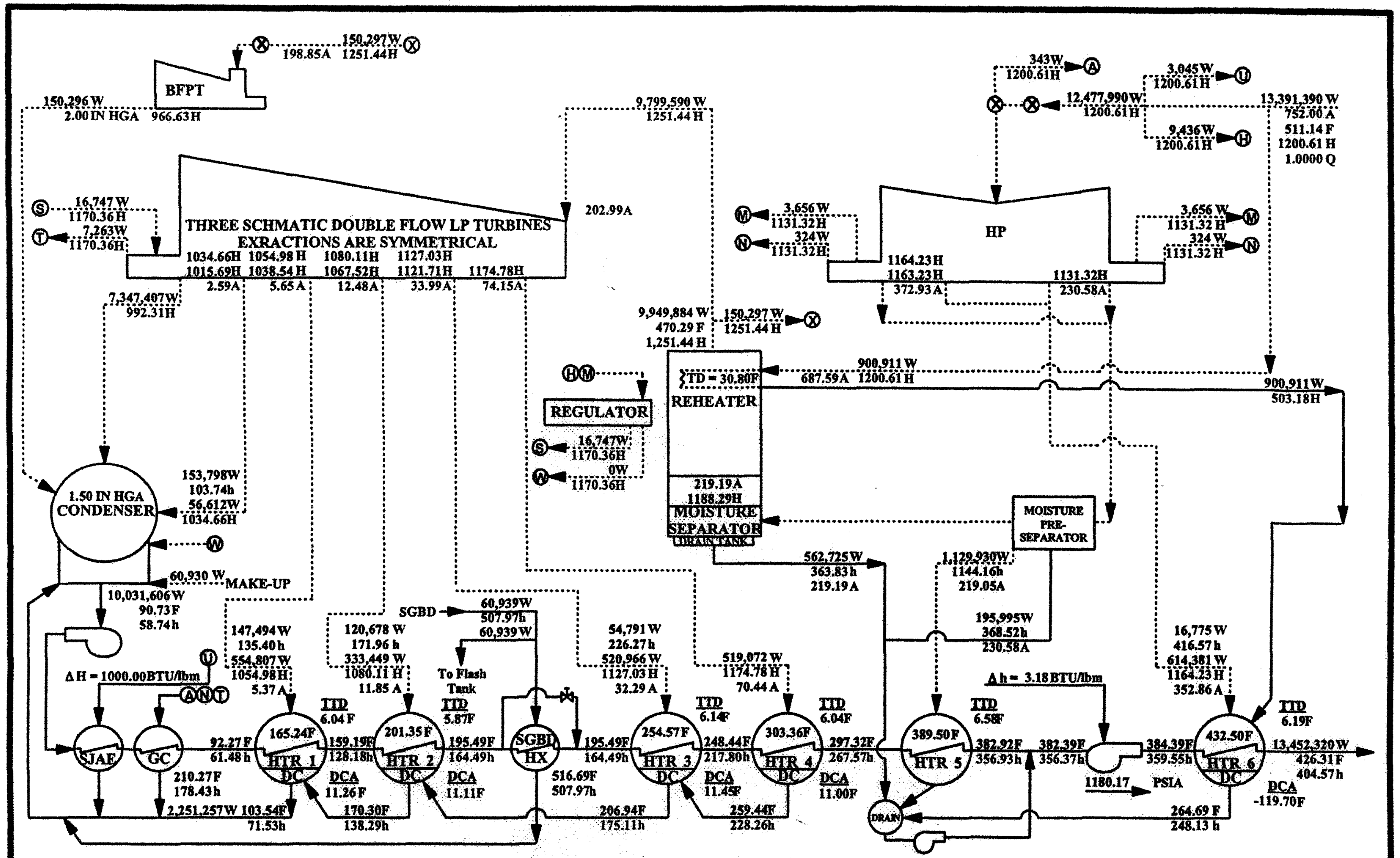
4. Hotwell subcooling is modeled by means of fictitious heat exchangers (Component Numbers 395, 405, 455) in the condensate line at the condenser exit. For the uprate case 5 Deg F subcooling has been assumed

5. New HP turbine is tuned to match turbine parameters per Siemens-Westinghouse heat balance WB-9341

6. The reheaters are modeled using the simplified design mode components of PEPSE 66. In this representation the heat transfer coefficients are fixed at the values established for the Benchmark Tuning Model, representative of pre-uprate performance. The heat transfer coefficients are expected to be somewhat higher after uprate.

Uprate PEPSE Model with New HP Turbine **Notes and Significant Results** **Sheet 6 of 6**	***Entergy***	**Indian Point 2** **Nuclear Power Plant**

INDIAN POINT UNIT No. 2
UPRATE PEPSE MODEL WITH NEW HP TURBINE NOTES AND SIGNIFICANT RESULTS
UFSAR FIGURE 10.1-1f | REV. No. 21



NET HEAT RATE = $\frac{13{,}452{,}320(1200.61 - 404.57) - 60{,}939(1200.61 - 507.97)}{1{,}034{,}072}$ = 10,314.92BTU / KW HR

1) Calculations are based on no radiation losses to heaters or extraction piping located in the condenser neck.
2) Primary valve and above heat rates are calculated on locus of valve points.

TEP =	992.08	BTU/lbm
ELEP =	974.56	BTU/lbm
MECH LOSS =	3.656	KW
ELECT LOSS =	8.565	KW
0.91 PF	75# H2	
FWP POWER =	12,545	KW
FWP EFF =	85.00	%

1028612 KW TURB - GEN UNIT TC6F - 45 IN.
668 PSIA - 497.9 F 1.5 IN.HGA
1439200 KVA 0.91 PF 22000 VOLTS 75# H2

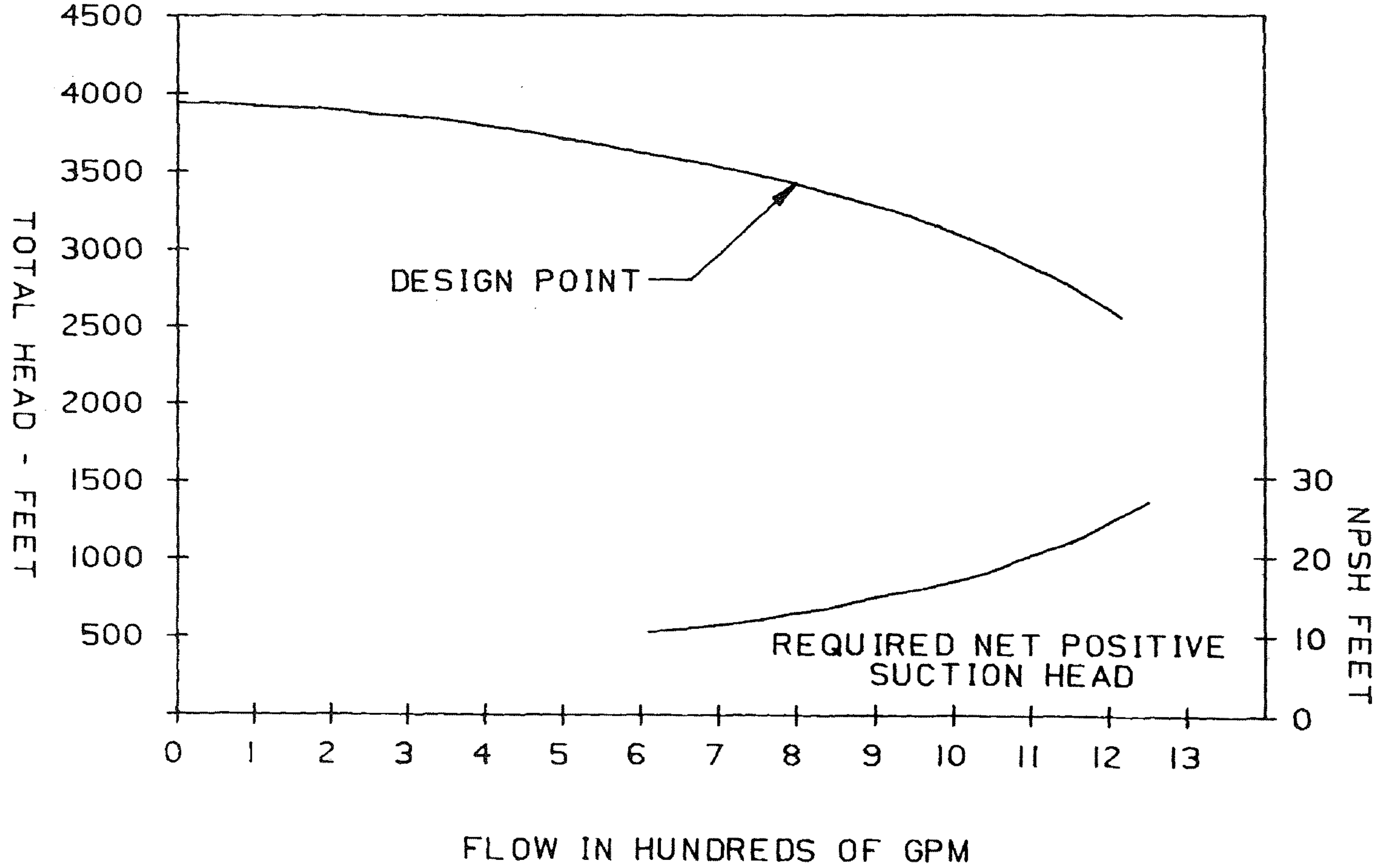
1,034,072 KW NET LOAD HEAT BALANCE
101.40% Rx Power

INDIAN POINT UNIT No. 2

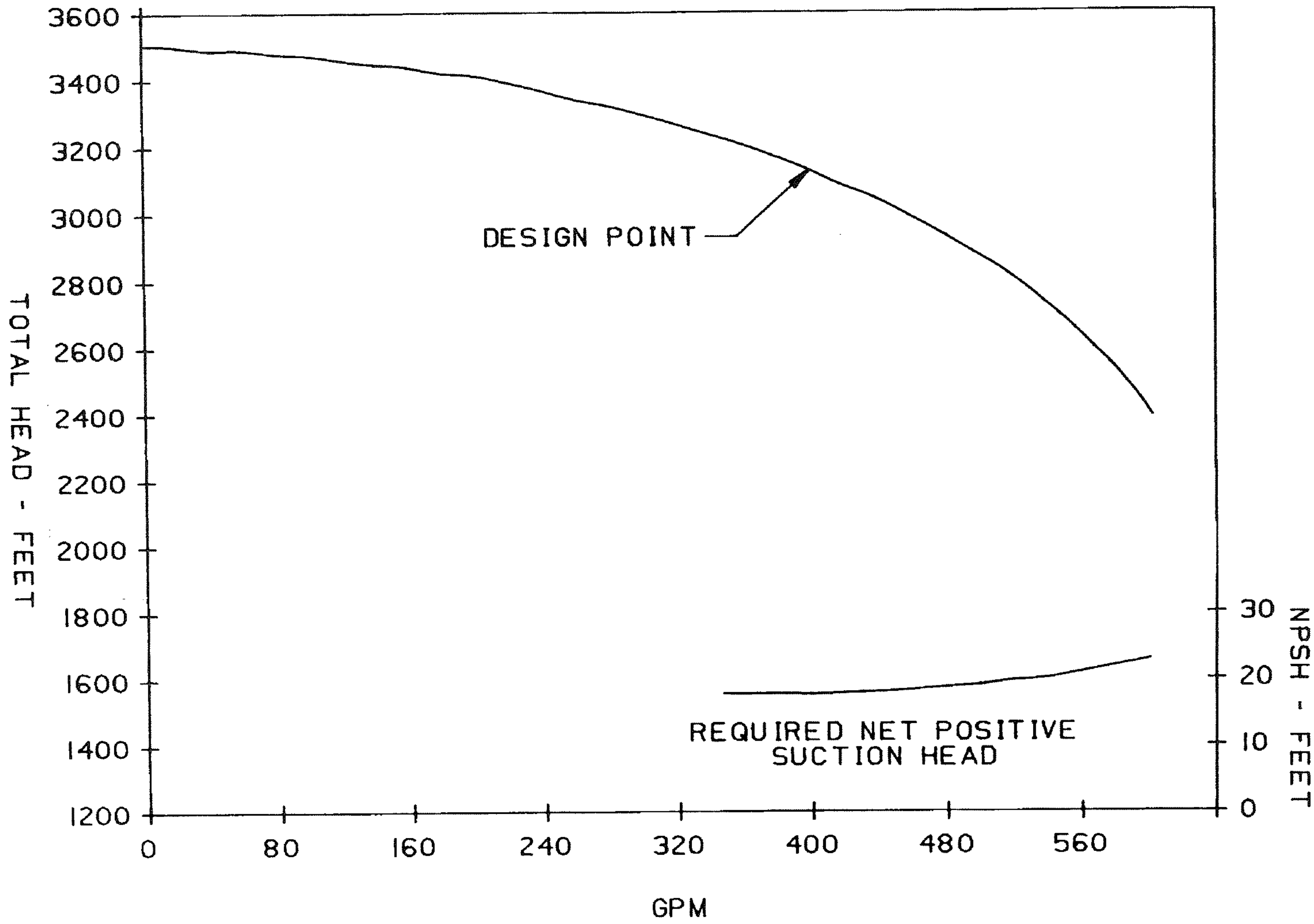
UFSAR FIGURE 10.1-7

LOAD HEAT BALANCE DIAGRAM AT 1,034,072 KWE

UFSAR FIGURE 10.1-7 | REV. No. 19



INDIAN POINT UNIT No. 2	
UFSAR FIGURE 10.2-8	
STEAM TURBINE-DRIVEN AUXILIARY FEEDWATER PUMP ESTIMATED PERFORMANCE CHARACTERISTICS	
MIC. No. 1999MC3918	REV. No. 17A



INDIAN POINT UNIT No. 2

UFSAR FIGURE 10.2–9

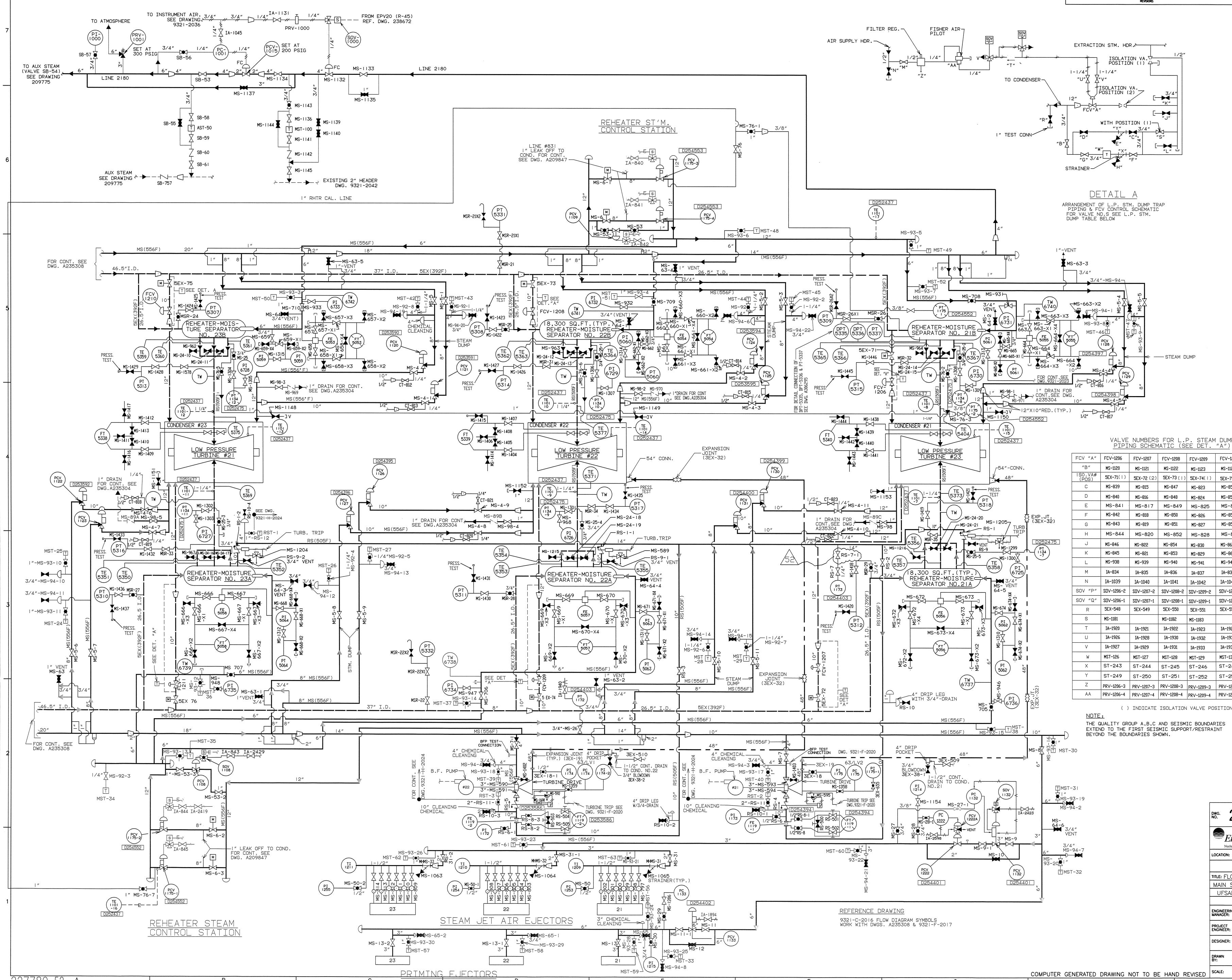
MOTOR–DRIVEN AUXILIARY FEEDWATER PUMP ESTIMATED PERFORMANCE CHARACTERISTICS

MIC. No. 1999MC3919	REV. No. 17A

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
52	INCORPORATED DRN-06-00927 ER IP2-05-26044	5/16/06	RM	JF	RH N/A

REVISIONS

REVISION
USE .1 SIZE TEXT ONLY



VALVE NUMBERS FOR L.P. STEAM DUMP PIPING SCHEMATIC (SEE DET. "A")

FCV "A"	FCV-1206	FCV-1207	FCV-1208	FCV-1209	FCV-1210	FCV-1211
"B"	MS-1120	MS-1121	MS-1122	MS-1123	MS-1124	MS-1125
ISO.VA# (POS)	5EX-71(1)	5EX-72 (2)	5EX-73 (1)	5EX-74(1)	5EX-75 (2)	5EX-76 (1)
C	MS-839	MS-815	MS-847	MS-823	MS-855	MS-831
D	MS-840	MS-816	MS-848	MS-824	MS-856	MS-832
E	MS-841	MS-817	MS-849	MS-825	MS-857	MS-833
F	MS-842	MS-818	MS-850	MS-826	MS-858	MS-834
G	MS-843	MS-819	MS-851	MS-827	MS-859	MS-835
H	MS-844	MS-820	MS-852	MS-828	MS-860	MS-836
J	MS-846	MS-822	MS-854	MS-830	MS-862	MS-838
K	MS-845	MS-821	MS-853	MS-829	MS-861	MS-837
L	MS-938	MS-939	MS-940	MS-941	MS-942	MS-943
M	IA-834	IA-835	IA-836	IA-837	IA-838	IA-839
N	IA-1039	IA-1040	IA-1041	IA-1042	IA-1043	IA-1044
SOV "P"	SOV-1206-2	SOV-1207-2	SOV-1208-2	SOV-1209-2	SOV-1210-2	SOV-1211-2
SOV "Q"	SOV-1206-1	SOV-1207-1	SOV-1208-1	SOV-1209-1	SOV-1210-1	SOV-1211-1
R	5EX-548	5EX-549	5EX-550	5EX-551	5EX-552	5EX-553
S	MS-1181		MS-1182	MS-1183		MS-1184
T	IA-1920	IA-1921	IA-1922	IA-1923	IA-1924	IA-1925
U	IA-1926	IA-1928	IA-1930	IA-1932	IA-1934	IA-1936
V	IA-1927	IA-1929	IA-1931	IA-1933	IA-1935	IA-1937
W	MST-126	MST-127	MST-128	MST-129	MST-130	MST-131
X	ST-243	ST-244	ST-245	ST-246	ST-247	ST-248
Y	ST-249	ST-250	ST-251	ST-252	ST-253	ST-254
Z	PRV-1206-3	PRV-1207-3	PRV-1208-3	PRV-1209-3	PRV-1210-3	PRV-1211-3
AA	PRV-1206-4	PRV-1207-4	PRV-1208-4	PRV-1209-4	PRV-1210-4	PRV-1211-4

( ) INDICATE ISOLATION VALVE POSITION

NOTE:

THE QUALITY GROUP A.B.C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

REVISION SIGNATURES

REV	PROJECT ENGINEER
52	

DWG. NO. 227780-52

Entergy Nuclear Northeast

DWG. TYPE FLOW DIAG.

DWG. SIZE A.

LOCATION: INDIAN POINT 2

TITLE: FLOW DIAGRAM
MAIN STEAM
UFSAR FIG. NO. 10.2-1 (SHT. 1)

- APPROVALS -

ENGINEERING MANAGER:

PROJECT ENGINEER: F.A.

DESIGNER: W.J.KING 2/12/88

DRAWN BY: GIBBS&HILL

SCALE:

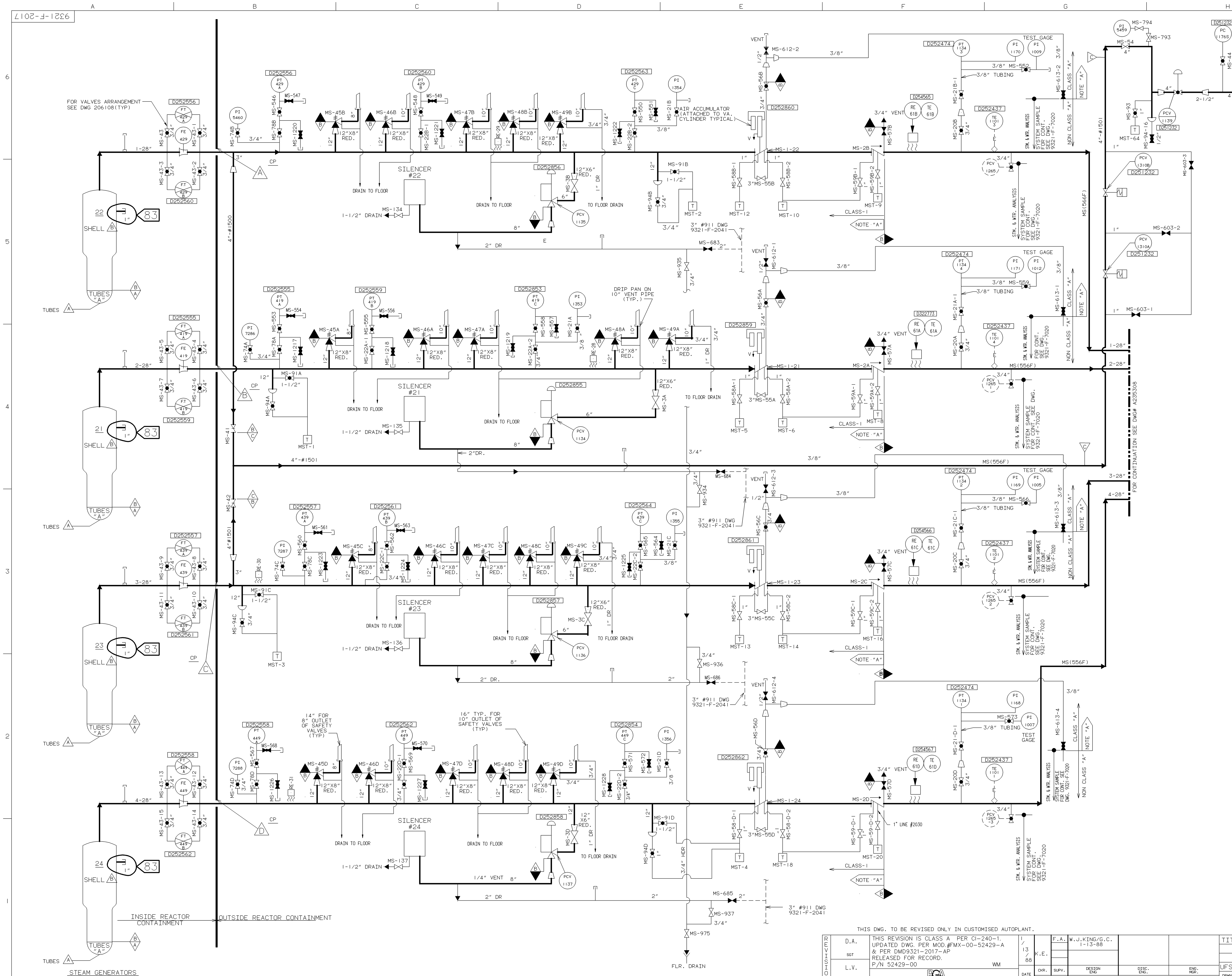
DISCIPLINE CODE: MY

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

227780-52

2/21/2004 7:18:53 AM 9321-2017-0-83.dwg

MECHANICAL



NOTE:

CLASS I FROM PUMP TO 28'HDR.

CLASS I PIPING

1. MAIN STEAM HEADERS FROM EACH STEAM GENERATOR THROUGH MAIN STEAM NON RETURN VALVES INCLUDING ALL CONNECTED VENTS DRAINS TRAP PIPING TO & INCLUDING TRAP & TRAP BY-PASS VALVES INSTRUMENTATION
2. STEAM GENERATOR SAFETY RELIEF VALVES MS-45 THROUGH MS-49 & ATMOSPHERIC DUMP VALVES PCV-1134 THROUGH PCV-1137 INCLUDING DISCHARGE PIPING THEREFROM
3. STEAM SUPPLY TO TURBINE DRIVEN AUXILIARY FEEDWATER PUMP INCLUDING ALL CONNECTED VENTS DRAINS TRAP PIPING TO & INCLUDING TRAP & TRAP BY-PASS VALVE, INSTRUMENTATION. RELIEF VALVE WITH DISCHARGE PIPING AND TURBINE EXHAUST PIPING
4. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

REFERENCE DWGS

9321-C-2016 - FLOW DIAGRAM SYMBOLS
9321-F-2049 - YARD AREA WEST OF CONTM BLD'G MAIN STEAM PIPING SHT.#1
9321-F-2041 - FLOW DIAGRAM MAIN STEAM TRAPS,SHT.#1
B235623 - ATMOSPHERIC STEAM DUMP VALVE PANEL

NOTE A
THIS BOUNDS THE PORTION OF THE MAIN STEAM SYSTEM SHOWN ON THE DRAWING WHICH IS INCLUDED IN THE SECONDARY COOLANT SYSTEM DESCRIPTION IN EXHIBIT "A" CI-240-1.

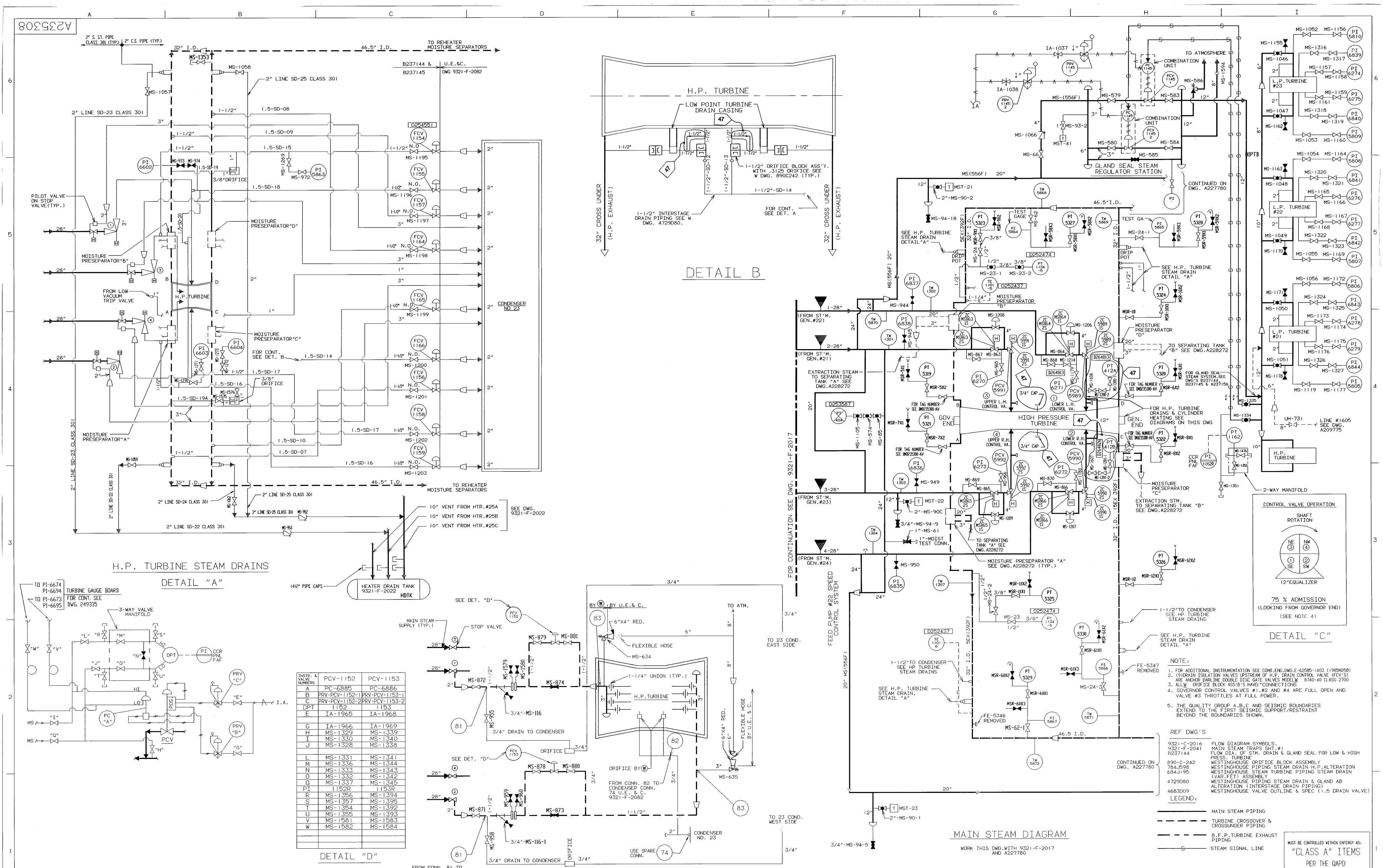
NOTE:
FOR TRAP "T" DIAGRAM SEE DWG. 9321-F-2041

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS "CLASS A" ITEMS PER CI-240-1

THIS DWG. TO BE REVISED ONLY IN CUSTOMISED AUTOPLANT.

REVISION						
D.A. SGT	THIS REVISION IS CLASS A PER CI-240-1. UPDATED DWG. PER MOD.#FMX-00-52429-A & PER DMD9321-2017-AP RELEASED FOR RECORD. P/N 52429-00 WM	1/13/88	K.E.	F.A. W.J.KING/G.C. 1-13-88		
L.V. SGR		DATE	CKR.	SUPV.	DESIGN ENG	DISC. ENG. / ENG. MGR.
			REVIEW		APPROVALS	

TITLE: FLOW DIAGRAM MAIN STEAM -
UFSAR FIGURE No. 10.2-1 (SHT. 2)
DRWN. BY GIBBS&HILL | SCALE | REC'D
Con Edison
STATION: INDIAN POINT
DWG. NO. 9321-F-2017-83 MY



INSTR. & VALVE NUMBERS	PCV-1152	PCV-1153
A	PC-6885	PC-6886
B	PRV-PCV-1152-1	PRV-PCV-1153-1
C	PRV-PCV-1152-2	PRV-PCV-1153-2
DPT	1152	1153
E	IA-1965	IA-1968
G	IA-1966	IA-1969
H	MS-1329	MS-1339
I	MS-1330	MS-1340
J	MS-1328	MS-1338
L	MS-1331	MS-1341
M	MS-1336	MS-1344
N	MS-1333	MS-1343
O	MS-1332	MS-1342
Q	MS-1337	MS-1345
PI	1152R	1153R
R	MS-1356	MS-1394
S	MS-1357	MS-1395
T	MS-1354	MS-1392
U	MS-1355	MS-1393
V	MS-1581	MS-1583
W	MS-1582	MS-1584

DETAIL "D"

NOTE:

1. FOR ADDITIONAL INSTRUMENTATION SEE COMB.ENG.DWG.E-62585-1403 (1985M250)
2. (9)DRAIN ISOLATION VALVES UPSTREAM OF H.P. DRAIN CONTROL VALVE (FCV'S) ARE ANCHOR DARLINE DOUBLE DISC GATE VALVES MODEL W 8740-40 CLASS 2700
3. ALL W ORIFICE BLOCK ASS'B'S HAVE 1" CONNECTIONS
4. GOVERNOR CONTROL VALVES #1,#2 AND #4 ARE FULL OPEN AND VALVE #3 THROTTLES AT FULL POWER.
5. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

REF DWG'S

9321-C-2016	FLOW DIAGRAM SYMBOLS.
9321-F-2041	MAIN STEAM TRAPS SHT.#1
B237144	FLOW DIA. OF STM. DRAIN & GLAND SEAL FOR LOW & HIGH PRESS. TURBINE
890-C-242	WESTINGHOUSE ORIFICE BLOCK ASSEMBLY
784J598	WESTINGHOUSE PIPING STEAM DRAIN H.P.ALTERATION
684J195	WESTINGHOUSE STEAM TURBINE PIPING STEAM DRAIN (VAR.FET) ASSEMBLY
4729D80	WESTINGHOUSE PIPING STEAM DRAIN & GLAND AB ALTERATION (INTERSTAGE DRAIN PIPING)
4683D09	WESTINGHOUSE VALVE OUTLINE & SPEC (1.5 DRAIN VALVE)

LEGEND:

- MAIN STEAM PIPING
- TURBINE CROSSOVER & CROSSUNDER PIPING
- B.F.P.TURBINE EXHAUST PIPING
- STEAM SIGNAL LINE

MAIN STEAM DIAGRAM

WORK THIS DWG.WITH 9321-F-2017 AND A227780

THIS DWG. TO BE REVISED ONLY IN CUSTOMIZED AUTOPLANT.

MUST BE CONTROLLED WITHIN ENTERGY AS: "CLASS A" ITEMS PER THE QAPD

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
47	INCORPORATED DMD235308-BA-0-0, ER-03-2-223 INCORPORATED DMD235308-BB-0-0, ER-03-2-222	11/22/04	RM	RL	

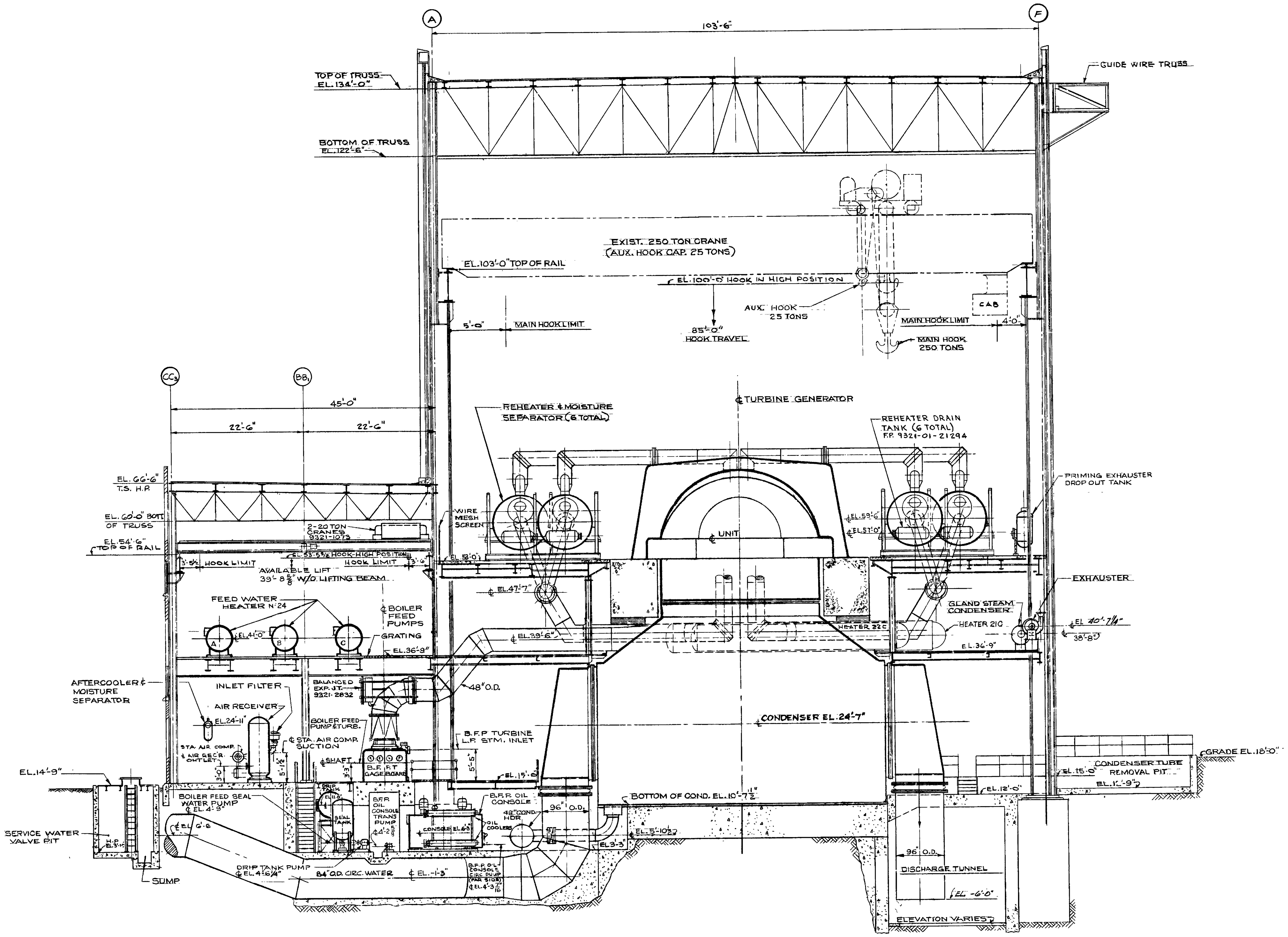
REVISIONS

DATE 2/8/88 D.P. | CKR. | SUPV. | REVIEW | F.A. W.J.KING 2/9/88 | DESIGN ENG | DISC. ENG. | ENG. MGR. | APPROVALS

TITLE: FLOW DIAGRAM
INDIAN POINT MAIN STEAM -
UFSAR FIGURE No. 10.2-1 (SHT. 3)
DRWN. BY K.EYMOLD | SCALE NONE | REC'D
Con Edison | STATION INDIAN POINT
DWG. NO. A235308-47 | MY

9321-F-2004
PLANT NORTH
9 INCORPORATED DRN-04-02056, IP2-ER-04-15884 8/18/04 RH
REV DESCRIPTION DATE BY CHK'D APP.
REVISIONS
PIPE BRIDGE
BRACING
EXISTING STAIRWELL
PRIMING EXHAUSTER DROP OUT TANK 9321-20674
PRIMING EXHAUSTER NO.21 (F.P. 9321-2364)
PRIMING EXHAUSTER NO.22 (F.P. 9321-2364)
℄ REHEATER DRAIN TANK NO.21B
NOTE: ℄ OF 6" INLET & OUTLET NOZZLES REHEATER DRAIN TANKS ON ℄ OF REHEATER & MOISTURE SEPARATOR TANKS (TYP.)
MINIMUM DISTANCE REQ'D TO WITHDRAW GENERATOR ROTOR STRAIGHT OUT.
LIMIT OF HOOK TRAVEL NORTH
NO.23B
NO.22B
NO.21B
NO.23A
NO.22A
NO.21A
TURBINE OIL PUMP HATCHES
TURBINE GENERATOR UNIT 2
TURBINE CONTROL CONSOLE
H.P. TURBINE
L.P. TURBINE
GENERATOR
EXCITER
CONDENSATE PUMP HATCHES
EXTREME TRAVEL OF CRANE AUX. HOOK (25 TONS)
EXTREME TRAVEL OF CRANE MAIN HOOK (250 T.)
38'-3" REQUIRED TO REMOVE TUBE BUNDLE (TYPICAL)
EXISTING LIFTING HATCH
REHEATER DRAIN TANK NO.21A F.P. 9321-21294 (TYP.)
REHEATER & MOISTURE SEPARATOR (6 TOTAL) 9321-2272
MOISTURE SEPARATOR DRAIN TANK (6 TOTAL) 9321-2834
VAPOR EXHAUST VENT
TUNNEL VENT
SPARE
HEATER BAY ROOF
S.V. VENT STACKS FOR HTR. DRAIN TK & NO.6 HTRS.
S.V. VENTS FOR NO.5 HTR.
6 BAYS @ 25'-0" = 150'-0"
255'-0"
275'-0"
UNIT NO.2
EXISTING UNIT NO.1
(9321-F-2007)
(9321-F-2008)
(9321-F-2009)
REHEATER & MOISTURE SEPARATOR
MOISTURE SEPARATOR DRAIN TANK F.P.9321-2834
℄ EL.53'-1"
FL. EL.53'-0"
EL.59'-6"
REHEATER DRAIN TANK NO.21A
EL.57'-0"
EL.49'-10"
EL.48'-10"
SECTION "D-D"
SCALE: 1/4"=1'-0"
PLAN
SCALE: 1/8"=1'-0"
FOR GENERAL NOTES & REFER. DWGS. SEE DWG. NO.9321-F-2006
(CON.ED.CO.DWG.NO. A200352)
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
THIS REVISION IS NON-CLASS PER CI-240-1
UPDATED DWG. TO INCLUDE UFSAR FIGURE NO. IN TITLE
RELEASED FOR RECORD P/N 69911-NP DLA/4/26/99
V.I. 04/26/99
STRATUS ENGINEERING
F.BERNARD SMITH 9-11-73
REVIEW APPROVALS
TITLE: TURBINE BLDG. & HTR. BAY GEN. ARR'GMT. OPERATING FLR.-PLAN AT EL. 53'-0"
UNIT NO.2 - UFSAR FIGURE No. 10.2-2
DRAWN BY R. HARRIS
SCALE 1/8"=1'-0"
Con Edison
STATION INDIAN PT
DWG. NO. 9321-F-2004-9
MA

3/8/2004 6:37:34 PM 9321-2008-0-7.dwg



SECTION "B-B"
9321-F-2004
SCALE: 1/8"=1'-0"

V.I. 4/26/99	07

THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DRAWING TO INCLUDE UFSAR FIGURE No. IN TITLE P/N 69911-NP RELEASED FOR RECORD DLA/4/26/99

STRATUS ENGINEERING

MA

07

WESTINGHOUSE ELECTRIC CORPORATION

TURBINE BUILDING & HEATER BAY GENERAL ARRANGEMENT CROSS SECTION

UFSAR FIGURE No. 10.2-3

FOR

CONSOLIDATED EDISON COMPANY

INDIAN POINT GENERATING STATION

UNIT NO. 2

W.E.&C. DWG. NO. 9321-F-2008 -7

CON. ED. CO. DWG. NO. 200356

INDIAN POINT UNIT NO 2 200356

REFERENCE DWG'S.

UE&C.DWG.NO.	DESCRIPTION
9321-C-2016	FLOW DIAGRAMS SYMBOLS
9321-F-2091	CONDENSER AIR REMOVAL PIPING PLAN-SHT.NO.1
9321-F-2092	CONDENSER AIR REMOVAL PIPING SECTIONS-SHT.NO.2
9321-F-2140	MISCELLANEOUS PIPING-SHT.NO.3
9321-F-2087	WATERBOX PRIMING-PIPING PLAN-SHT.NO.1
9321-F-2088	WATERBOX PRIMING-PIPING SECT.&ELEV.-SHT.NO.2

CLASS 1 PIPING

DOUBLE ISOLATION VALVES PCV-1229 & PCV-1230 THROUGH CONTAINMENT BUILDING INCLUDING PRESSURIZATION AIR SYSTEM

NOTE:
1). N.C. - NORMALLY CLOSED
2). CVP - CONDENSER VACUUM PUMP
3) THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

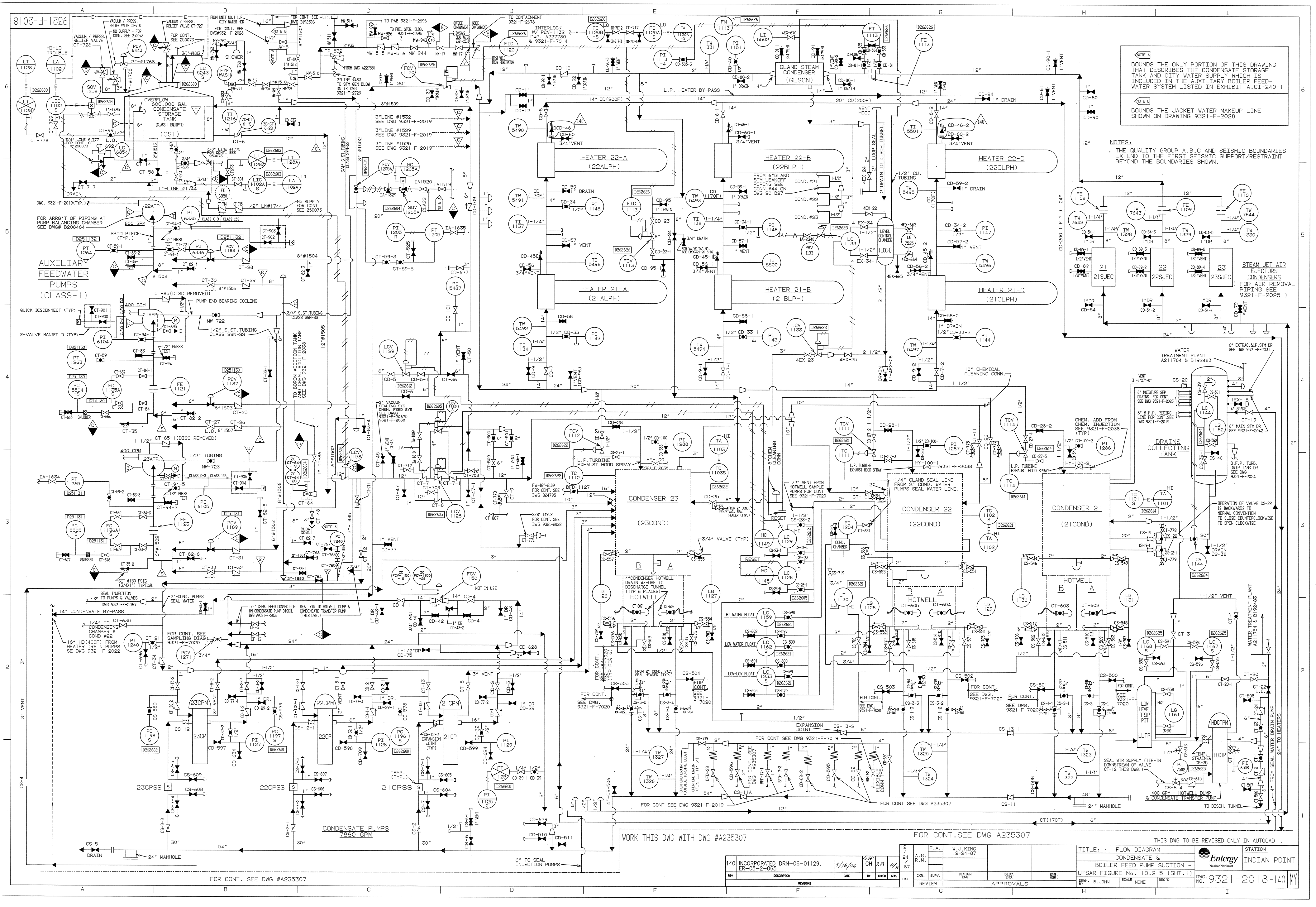
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN ENTERGY AS:
"CLASS A" ITEMS
PER THE QAPD

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

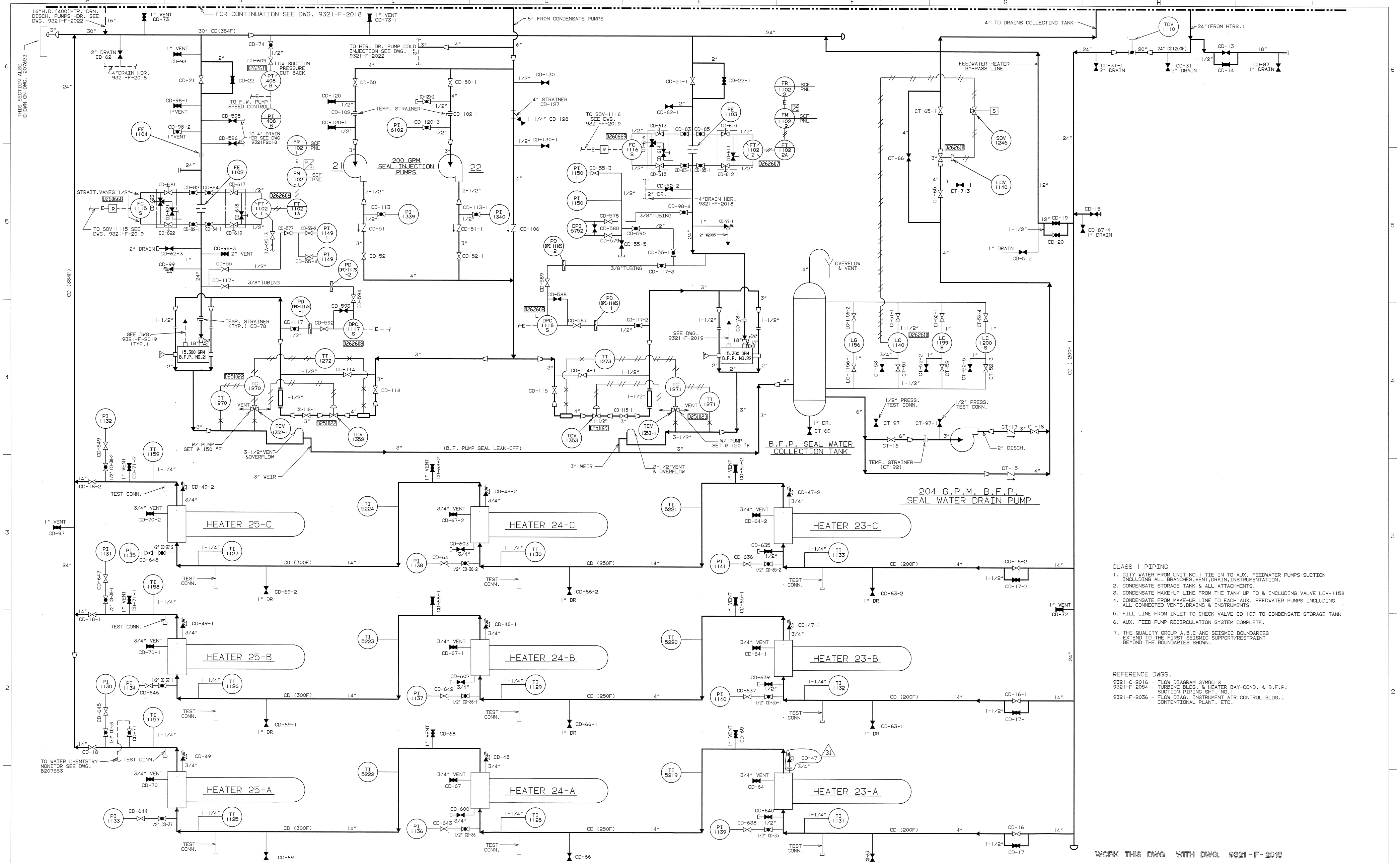
REVISION: 55 — W.RADVANSKY 04/08/03 — THIS REV. IS NON-CLASS PER QAPD. UPDATED DRAWING TO SHOW THE WORK DONE ON MOD. PROC. # DCP-200110550-P, & DMD9321-2025-BA REV.00 RELEASE AS CONSTRUCTED P.N. 10550-01 GH/MR — ENG

F.A.: W.J.KING 6/3/87 — W.S. 6/3/87
APPROVALS: DESIGN ENG — DISC. ENG. — ENG. MGR.

TITLE: FLOW DIAGRAM
CONDENSER AIR REMOVAL AND WATERBOX PRIMING (UFSAR FIG NO. 10.2-4)
DRWN. BY K. EYMOLD — SCALE NONE
Con Edison — STATION: INDIAN POINT
DWG. NO. 9321-F-2025-55 MY



9321-F-2018
NOTE A
BOUNDS THE ONLY PORTION OF THIS DRAWING THAT DESCRIBES THE CONDENSATE STORAGE TANK AND CITY WATER SUPPLY WHICH IS INCLUDED IN THE AUXILIARY BOILER FEED-WATER SYSTEM LISTED IN EXHIBIT A.CI-240-1
NOTE B
BOUNDS THE JACKET WATER MAKEUP LINE SHOWN ON DRAWING 9321-F-2028
NOTES:
1. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.
OVERFLOW 600,000 GAL CONDENSATE STORAGE TANK (CST)
AUXILIARY FEEDWATER PUMPS (CLASS-1)
HEATER 22-A (22ALPH)
HEATER 22-B (22BLPH)
HEATER 22-C (22CLPH)
HEATER 21-A (21ALPH)
HEATER 21-B (21BLPH)
HEATER 21-C (21CLPH)
GLAND STEAM CONDENSER (GLSCN)
STEAM JET AIR EJECTORS CONDENSERS (FOR AIR REMOVAL PIPING SEE 9321-F-2025)
21 21SJEC
22 22SJEC
23 23SJEC
CONDENSER 23 (23COND)
CONDENSER 22 (22COND)
CONDENSER 21 (21COND)
HOTWELL
DRAINS COLLECTING TANK
WATER TREATMENT PLANT A211784 & B192483
CONDENSATE PUMPS 7860 GPM
23CPM 22CPM 21CPM
23CPSS 22CPSS 21CPSS
HDCTPM
400 GPM - HOTWELL DUMP & CONDENSATE TRANSFER PUMP
WORK THIS DWG WITH DWG #A235307
FOR CONT. SEE DWG A235307
FOR CONT. SEE DWG #A235307
THIS DWG TO BE REVISED ONLY IN AUTOCAD
140 INCORPORATED DRN-06-01129, ER-05-2-065 5/16/06
W.J.KING 12-24-87
TITLE: FLOW DIAGRAM CONDENSATE & BOILER FEED PUMP SUCTION - UFSAR FIGURE No. 10.2-5 (SHT.1)
DRWN. BY B.JOHN
SCALE NONE
Entergy
STATION INDIAN POINT
DWG. NO. 9321-2018-140



CLASS I PIPING

1. CITY WATER FROM UNIT NO.1 TIE IN TO AUX. FEEDWATER PUMPS SUCTION INCLUDING ALL BRANCHES,VENT,DRAIN,INSTRUMENTATION.
2. CONDENSATE STORAGE TANK & ALL ATTACHMENTS.
3. CONDENSATE MAKE-UP LINE FROM THE TANK UP TO & INCLUDING VALVE LCV-1158
4. CONDENSATE FROM MAKE-UP LINE TO EACH AUX. FEEDWATER PUMPS INCLUDING ALL CONNECTED VENTS,DRAINS & INSTRUMENTS
5. FILL LINE FROM INLET TO CHECK VALVE CD-109 TO CONDENSATE STORAGE TANK
6. AUX. FEED PUMP RECIRCULATION SYSTEM COMPLETE.
7. THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

REFERENCE DWGS.

9321-C-2016 - FLOW DIAGRAM SYMBOLS
9321-F-2054 - TURBINE BLDG. & HEATER BAY-COND. & B.F.P. SUCTION PIPING SHT. NO.1
9321-F-2036 - FLOW DIAG. INSTRUMENT AIR CONTROL BLDG., CONTENTIONAL PLANT, ETC.

WORK THIS DWG. WITH DWG. 9321-F-2018

THIS DWG. TO BE REVISED ONLY IN AUTOCAD

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
31	INCORPORATED DRN-06-01130, ER-05-2-065	5/16/06	GH	R.M.	N/A

REVISIONS

W.J.KING 9/28/87		
DESIGN ENG	DISC. ENG.	ENG. MGR.

APPROVALS

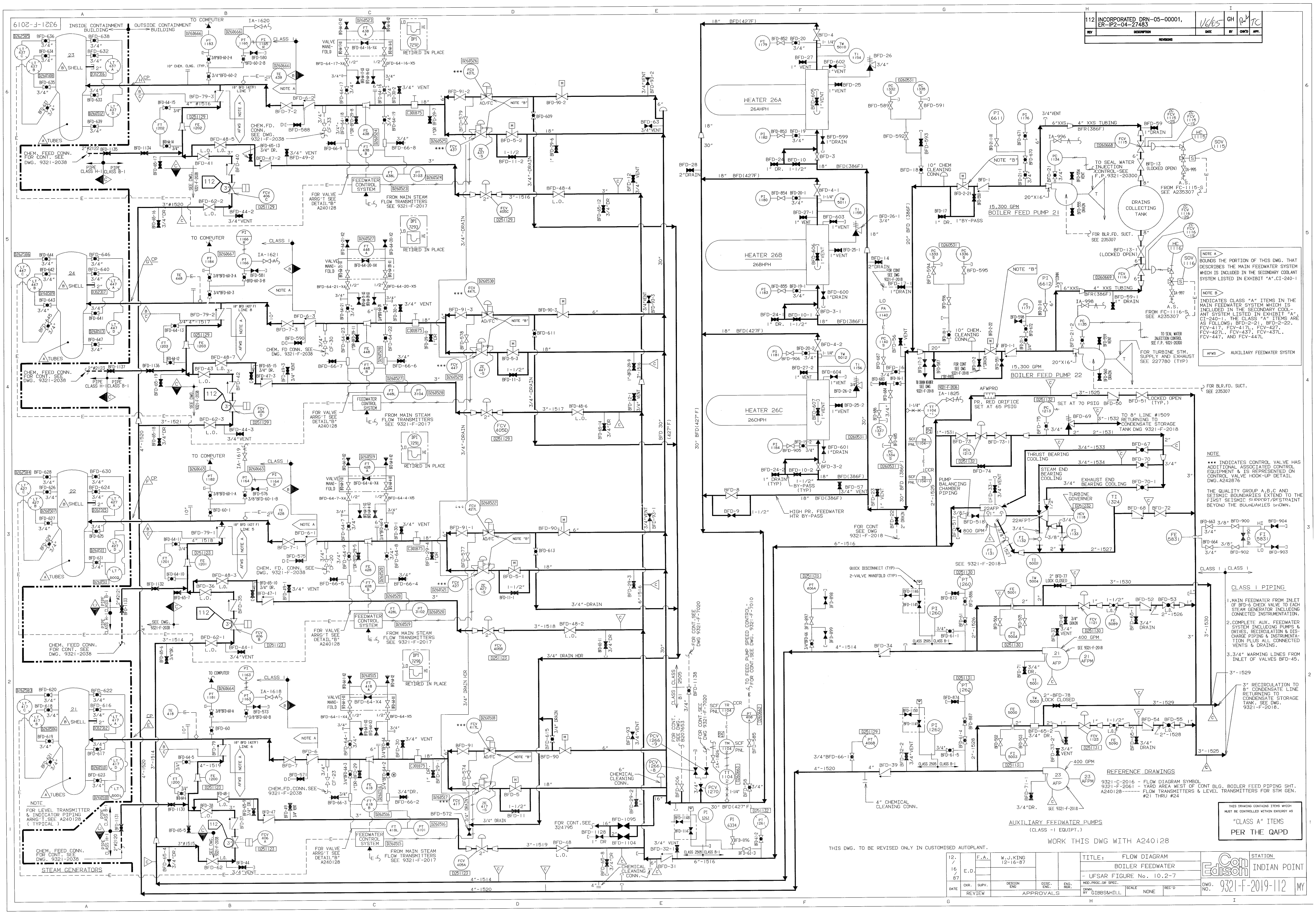
TITLE: FLOW DIAGRAM
CONDENSATE & BOILER FEED
PUMP SUCTION -
UFSAR FIGURE No. 10.2-5 (SHT. 2)

DRWN. BY B. JOHN | SCALE NONE | REC'D

Entergy Nuclear Northeast

STATION INDIAN POINT

DWG. NO. A235307-31 MY


112 INCORPORATED DRN-05-00001, ER-IP2-04-27483
STEAM GENERATORS
HEATER 26A
HEATER 26B
HEATER 26C
BOILER FEED PUMP 21
BOILER FEED PUMP 22
DRAINS COLLECTING TANK
NOTE A
BOUNDS THE PORTION OF THIS DWG. THAT DESCRIBES THE MAIN FEEDWATER SYSTEM WHICH IS INCLUDED IN THE SECONDARY COOLANT SYSTEM LISTED IN EXHIBIT "A".CI-240-1
NOTE B
INDICATES CLASS "A" ITEMS IN THE MAIN FEEDWATER SYSTEM WHICH IS INCLUDED IN THE SECONDARY COOLANT SYSTEM LISTED IN EXHIBIT "A", CI-240-1. THE CLASS "A" ITEMS ARE AS FOLLOWS; BFD-2-21, BFD-2-22, FCV-417, FCV-417L, FCV-427, FCV-427L, FCV-437, FCV-437L, FCV-447, AND FCV-447L
AFWS AUXILIARY FEEDWATER SYSTEM
NOTE
*** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT & IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL DWG.A242876
THE QUALITY GROUP A,B,C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.
CLASS I PIPING
1.MAIN FEEDWATER FROM INLET OF BFD-6 CHECK VALVE TO EACH STEAM GENERATOR INCLUDING CONNECTED INSTRUMENTATION.
2.COMPLETE AUX. FEEDWATER SYSTEM INCLUDING PUMPS & DRIVES, RECIRCULATION & DISCHARGE PIPING & INSTRUMENTATION PLUS ALL CONNECTED VENTS & DRAINS.
3.3/4" WARMING LINES FROM INLET OF VALVES BFD-45.
REFERENCE DRAWINGS
9321-C-2016 - FLOW DIAGRAM SYMBOL
9321-F-2061 - YARD AREA WEST OF CONT BLG. BOILER FEED PIPING SHT.
A240128 - FLOW TRANSMITTERS & LEVEL TRANSMITTERS FOR STM GEN. #21 THRU #24
AUXILIARY FEEDWATER PUMPS (CLASS I EQUIPT.)
WORK THIS DWG WITH A240128
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN EXTENT AS "CLASS A" ITEMS PER THE QAPD
THIS DWG. TO BE REVISED ONLY IN CUSTOMISED AUTOPLANT.
TITLE: FLOW DIAGRAM BOILER FEEDWATER
- UFSAR FIGURE No. 10.2-7
Con Edison
STATION INDIAN POINT
W.J.KING 12-16-87
DWG. NO. 9321-F-2019-112

CHAPTER 11
WASTE DISPOSAL AND RADIATION PROTECTION SYSTEM

11.1 WASTE DISPOSAL SYSTEM

11.1.1 Design Bases

Control of Releases of Radioactivity to the Environment

Criterion: The facility design shall include those means necessary to maintain control over the plant radioactive effluents whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control must be justified (a) on the basis of 10 CFR 20 requirements, for normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dose level guidelines for potential reactor accidents of exceedingly low probability of occurrence (GDC 70).

Liquid, gaseous, and solid waste processing and handling facilities are designed so that the discharge of effluents and offsite disposal shipments are in accordance with applicable government regulations.

Radioactive fluids entering the waste disposal system are collected in sumps and tanks until determination of subsequent treatment can be made. They are sampled and analyzed to determine the concentration of radioactivity, with an isotopic breakdown if necessary. Before any attempt is made to discharge radioactive waste, it is processed as required. The processed water from waste disposal, from which most of the radioactive material has been removed, is discharged through a monitored line into the circulating water discharge. The system design and operation are characteristically directed toward minimizing releases to unrestricted areas. Discharge streams are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20.

Radioactive gases are pumped by compressors through a manifold to one of the gas decay tanks where they are held a suitable period of time for decay. Cover gases in the nitrogen blanketing system are reused to minimize gaseous wastes. During normal operation, gases are discharged intermittently at a controlled rate from these tanks through the monitored plant vent. The system is provided with discharge controls so that the release of radioactive effluents to the atmosphere is controlled within the limits set in the Technical Specifications.

The spent resins from the demineralizers, the filter cartridges, and the concentrates from the evaporators are packaged and stored onsite until shipment offsite for disposal. Suitable containers are used to package these solids at the highest practical concentrations to minimize the number of containers shipped for burial.

All solid waste is placed in suitable containers and stored onsite until shipped offsite for disposal.

The application of the NUREG-1465 alternative source term methodology for Indian Point Unit 2 includes verification that the dose limits specified in 10 CFR 50.67 are met for low probability accidents.

11.1.2 System Design and Operation

The waste disposal system process flow diagrams are shown in Figure 11.1-1, Sheets 1 and 2, and performance data are given in the Annual Effluent and Waste Disposal Report.

The waste disposal system collects and processes all potentially radioactive primary plant wastes for removal from the plant site within limitations established by applicable government regulations. Fluid wastes are sampled and analyzed to determine the quantity of radioactivity, with an isotopic breakdown if necessary, before any attempt is made to discharge them. They are then released under controlled conditions. A radiation monitor is provided to maintain surveillance over the release operation, but the permanent record of activity release is provided by radiochemical analysis of known quantities of waste. The original system design was based on processing all wastes generated during continuous operation of the primary system assuming that fission products, corresponding to defects in 1-percent of the fuel cladding, escape into the reactor coolant.

As secondary functions, system components supply hydrogen and nitrogen to primary system components as required during normal operation, and provide facilities to transfer fluids from inside the containment to other systems outside the containment.

The Offsite Dose Calculation Manual (ODCM) provides the methodology to calculate radiation does rates and dose to individual persons in unrestricted areas in the vicinity of Indian Point due to the routine release of liquid effluents to the discharge canal. The ODCM also provides setpoint methodology that is applied to effluent monitors and optionally to other process monitors.

Activity release due to tritium is given in the Annual Effluent and Waste Disposal Report.

11.1.2.1 System Description

11.1.2.1.1 Liquid Processing

During normal plant operation the waste disposal system processes liquids from the following sources:

1. Equipment drains and leaks.
2. Chemical laboratory drains.
3. Decontamination drains.
4. Demineralizer regeneration.
5. Floor drains.
6. Steam generator blowdown.

The reactor coolant drain tank collects and transfers liquid drained from the following sources:

1. Reactor coolant loops.
2. Pressurizer relief tank.
3. Reactor coolant pump secondary seals.

4. Excess letdown during startup.
5. Accumulator drains
6. Valve and reactor vessel flange leakoffs.
7. Refueling Canal Drain
8. Containment Spray Header Recirculation Lines

The valve and reactor flange leakoff liquids flow to the reactor coolant drain tank and are discharged directly to the chemical and volume control system holdup tanks by the reactor coolant drain pumps, which are designed to operate automatically by a level controller in the tank.

Since the fluid pumped by the reactor coolant drain pumps is of high quality and can be reused, the discharge of these pumps will normally be routed to the holdup tanks of the chemical and volume control system. If the fluid is considered unsuitable for reuse, it will be sent to the waste holdup tank. The discharge of the reactor coolant drain pumps can also be routed to the refueling water storage tank. This path will be used when pumping down the containment refueling canal during return from refueling operations. In the event the reactor coolant drain pumps are unavailable, the contents of the reactor coolant drain tank or the pressurizer relief tank can be dumped to the containment sump.

The waste holdup tank serves as the collection point for liquid wastes. It collects fluid directly from the following sources:

1. Reactor coolant drain tank pumps
2. Containment sump pumps.
3. Holdup tank pit sump pump.
4. Sump tank pump (from primary auxiliary building).
5. Spent regenerant chemicals from demineralizers.
6. Equipment drains.
7. Chemical drain tank pump.
8. Relief valve discharge from the component cooling surge tank and the chemical and volume control system holdup tanks.
9. Waste condensate pumps.
10. Maintenance and Operation Building floor drains.
11. Primary Auxiliary Building sump pumps.

Where plant layout permits, waste liquids drain to the waste holdup tank by gravity flow. Other waste liquids, including floor drains, drain to the sump tank or to the primary auxiliary building sump. The liquid wastes are pumped to the waste holdup tank. The liquid waste holdup tank is processed by sending its contents to the Unit 1 waste collection system.

Capability exists to transfer the waste holdup tank contents to the waste condensate tank. If used, sampling indicates that the liquid is suitable for discharge and the waste liquid can be pumped from the waste holdup tank to the waste condensate tanks. There it’s activity can be determined for recording by isolation sampling and analyzing before it would be discharged through the radiation monitor to the condenser circulating water.

The Indian Point Unit 1 waste collection system has four tanks with a capacity of 75,000 gal each. From there the liquid can also be processed by use of sluiceable demineralizer vessels.

A portable demineralization system is being used in the Unit 1 Chemical System Building. The system employs a number of in-line ion exchanger resin beds and filters to remove radionuclides and chemicals as required from the waste stream. The demineralization/filtration system processes liquid waste from the unit 1 waste collection tanks and discharges the clean water to the distillate storage tanks.

Spent resins from the portable system are sluiced from the vessels into a high integrity container, which is dewatered and then transported to the burial site without solidification. Spent filters can also be placed in the high integrity container.

The distillate produced by the demineralizer water processing is collected in two distillate storage tanks. Each storage tank is vented to the unit 1 ventilation system. Normally one tank is filling while the other is sampled and discharged. When a distillate storage tank is ready for discharge, it is isolated and sampled to determine the allowable release rate. If the contents of the tank are not suitable for release, they are returned to waste collection tanks for reprocessing. If analysis confirms that the activity level is suitable for release, the distillate is discharged to the river. A radiation detector and high radiation trip valve are provided in the release line to prevent an inadvertent release of activity at concentrations in excess of the setpoint derived from the technical specifications. In the event of primary-to-secondary coolant leakage, the affected steam generator blowdown can be manually diverted to the support facilities secondary boiler blowdown purification system flash tank. This system cools the blowdown and either stores it in the support facilities waste collection tanks or purifies it. The purification process consists of filtering and demineralizing the blowdown. The filters will remove undissolved material of 25 microns or greater. Mixed-bed demineralizers, which utilize cation and anion resin, remove isotopic cations and anions, as well as nonradioactive chemical species. The effluents of the demineralizers are monitored and the specific activity is recorded. Section 10.2.1 provides further discussion of the steam generator blowdown.

Also, in the event of primary-to-secondary leakage, potentially contaminated water that collects in secondary-side drains may be collected and routed to a collection point in the auxiliary boiler feedwater building for eventual processing. The path is an alternative to the normally used path to the drains collection tank.

11.1.2.1.2 Gas Processing

During plant operations, gaseous waste will originate from:

1. Degassing the reactor coolant and purging the volume control tank.
2. Displacement of cover gases as liquid accumulates in various tanks.
3. Equipment purging.
4. Sampling operations and automatic gas analysis for hydrogen and oxygen in cover gases.

During normal operation, the waste disposal system supplies nitrogen and hydrogen to primary plant components. Two headers are provided, one for operation and one for backup. The pressure regulator in the operating header is set for 110 psig discharge and that in the backup header for 90 psig. When the operating header is exhausted, its discharge pressure will fall below 100 psig and an alarm will alert the operator. The second tank will come into service automatically at 90 psig to ensure a continuous supply of gas. After the exhausted header has been replaced, the operator manually sets the operating pressure back to 110 psig and the backup pressure at 90 psig This operation is identical for both the nitrogen supply and the hydrogen supply.

Most of the gas received by the waste disposal system during normal operation is cover gas displaced from the chemical and volume control system holdup tanks as they fill with liquid. Since this gas must be replaced when the tanks are emptied during processing, facilities are provided to return gas from the decay tanks to the holdup tanks. A backup supply from the nitrogen header is provided for makeup if return flow from the gas decay tanks is not available. Since the hydrogen concentration may exceed the combustible limit during this type of operation, components discharging to the vent header system are restricted to those containing no air or aerated liquids and the vent header itself is designed to operate at a slight positive pressure (O.5 psig minimum to 2.0 psig maximum) to prevent inleakage. On the other hand, outleakage from the system is minimized by using Saunders patent diaphragm valves, bellows seals, self-contained pressure regulators, and soft-seated packless valves throughout the radioactive portions of the system.

Gases vented to the vent header flow to the waste gas compressor suction header. One of the two compressors is in continuous operation with the second unit instrumented to act as backup for peak load conditions. From the compressors, gas flows to one of the four large gas decay tanks. The control arrangement on the gas decay tank inlet header allows the operator to place one large tank in service and to select a second large tank for backup. When the tank in service becomes pressurized to a predetermined pressure, a pressure transmitter automatically opens the inlet valve to the backup tank, closes the inlet valve to the filled tank, and sounds an alarm to alert the operator of this event so that he may select a new backup tank. Pressure indicators are supplied to aid the operator in selecting the backup tank. Gas held in the decay tanks can either be returned to the chemical and volume control system holdup tanks, or discharged to the atmosphere if the activity concentration is suitable for release. Generally, the last tank to receive gas will be the first tank emptied back to the holdup tanks in order to permit the maximum decay time for the other tanks before releasing gas to the environment. However, the header arrangement at the tank inlet gives the operator freedom to fill, reuse, or discharge gas to the environment simultaneously without restriction by operation of the other tanks.

Six additional small gas decay tanks are supplied for use during degassing of the reactor coolant prior to a cold shutdown. The reactor coolant fission gas activity inventory is distributed equally among the six tanks through a common inlet header.

A radiation monitor in the sample line to the gas analyzer checks the gas decay tank activity inventory each time a sample is taken for hydrogen-oxygen analysis. An alarm warns the operator when the inventory limit is approached so that another tank may be placed in service.

Before a tank can be emptied to the environment, its contents must be sampled and analyzed to verify sufficient decay and to provide a record of the activity to be released, and only then discharged to the plant vent at a controlled rate through a radiation monitor in the vent. Samples are taken manually by opening the isolation valve to the gas analyzer sample line and permitting gas to flow to the gas analyzer where it can be collected in one of the sampling system gas sample vessels. After sampling, the isolation valve is closed. During release, a trip valve in the discharge line is closed automatically by a high activity level indication in the plant vent.

During operation, gas samples are drawn periodically from tanks discharging to the waste gas vent header as well as from the particular large gas decay tank being filled at the time, and automatically analyzed to determine their hydrogen and oxygen content. The hydrogen analysis is for surveillance since the concentration range will vary considerably from tank to tank. There should be no significant oxygen content in any of the tanks, and an alarm will warn the operator if any sample shows 2-percent by volume of oxygen. This allows time to isolate the tank before the combustible limit is reached. Another tank is placed in service while the operator locates and eliminates the source of oxygen. Discharged gases are released from the plant vent and diluted in the atmosphere due to the turbulence in the wake of the containment building in addition to the effects of normal dispersion.

The maximum expected annual gaseous release by isotope is given in the Annual Effluent Release and Waste Disposal Report.

11.1.2.1.3 Solids Processing

Solid waste processing is controlled by the Process Control Program in the ODCM.

Resin is normally stored in the spent resin storage tank for decay; this tank is described in section 11.1.2.2.6. Resin is removed from the storage tank to a high integrity container, which is dewatered and prepared for transportation in accordance with the Process Control Program. Spent filters can be placed in the high integrity containers.

Miscellaneous solid wastes such as paper, rags and glassware, are processed in accordance with the Process Control Program. When possible, solid waste is sent to a licensed incineration and volume reduction center, or to a material recovery center. This process is controlled by the Process Control Program.

The unit 1 containment has been modified for use as an interim onsite storage facility for dry active waste.

The Original Steam Generators (OSGs) are stored in the Original Steam Generator Storage Facility (OSGSF). Storage in this building is limited to the OSGs. The OSGSF is a reinforced concrete structure measuring approximately 150 feet by 54 feet (not including the labyrinth entryways). The building is located on the eastern side of the plant, between Electrical Tower 3 and the Buchanan Service Center access road. This location is within the Owner Controlled Area outside the Protected Area. The structure is constructed of cast-in-place concrete. Except for the South wall, which consists of pre-cast stackable concrete blocks. Use of pre-cast blocks provide access to install the OSGs and for removal of the OSGs at a later date. The roof is covered with a single-ply membrane roofing system.

The walls of the OSGSF are 3’-0" thick and the roof is tapered from 2’-6" in the center of the building to 2’-0" at the east and west walls. The slab is 3’-0" thick with a thickened perimeter that is 5’-0" thick. Personnel access doors with labyrinth entryways are provided at each end of the building to prevent radiation streaming through the door. The walls of the labyrinth entryway are 3’-0" thick with the roof over the labyrinth entryway tapered from 1’-2" to 1’-0". Two locked steel doors in each entryway will provide access to the building after the pre-cast concrete blocks are put in place, one in the exterior wall opening and one in the labyrinth wall.

The OSGSF is designed to contain contaminated materials and facilitate decontamination should such an action become necessary. Waterstops are used at all construction joints to prevent both the intrusion of water into the facility and the escape of contaminated water from the facility. The floor of the facility is sloped to provide adequate drainage to a sump. Protective coatings are applied to the floor slab and lower portion of the walls to ease decontamination, if required. A passive HEPA filter system is provided to allow venting of the OSGSF while containing any airborne contamination.

An electrical system provides interior and exterior lighting, 110-volt AC outlets, and a remote alarm system on each entryway. Two locked steel doors secure the building and a security fence is installed around the perimeter of the building.

11.1.2.2 Components

Codes applying to components of the waste disposal system are shown in Table 11.1-6. Component summary data is shown in Table 11.1-7. Waste disposal system components are located in the auxiliary building except for the reactor coolant drain tank, which is in the containment and the waste holdup tank, which is in the liquid holdup tank vault.

11.1.2.2.1 [Deleted]

11.1.2.2.2 Chemical Drain Tank

The chemical drain tank is a vertical cylinder of austenitic stainless steel and collects drainage from the chemistry sampling station. The tank contents are pumped to the waste holdup tanks.

11.1.2.2.3 Reactor Coolant Drain Tank

The reactor coolant drain tank is a horizontal cylinder with spherically dished heads. The tank is all welded austenitic stainless steel. This tank serves as a drain surge tank for the reactor coolant system and other equipment located inside the reactor containment. The water collected in this tank is transferred to the chemical and volume control system holdup tanks, the refueling water storage tank, or the waste holdup tank.

11.1.2.2.4 Waste Holdup Tank

The waste holdup tank is the central collection point for radioactive liquid waste. The tank is stainless steel of welded construction.

11.1.2.2.5 Sump Tank and Sump Tank Pumps

The sump tank serves as a collecting point for waste discharged to the basement level drain header. It is located at the lowest point in the auxiliary building. Floor drains enter this tank through a loop seal to prevent back flow of gas from the tank. Two horizontal centrifugal pumps transfer liquid waste to the waste holdup tank. All wetted parts of the pumps are stainless steel. The tank is all-welded austenitic stainless steel.

11.1.2.2.6 Spent Resin Storage Tank

The spent resin storage tank retains resin discharged from the primary plant demineralizers. Normally, resins are stored in the tank for decay of short-lived isotopes. However, the contents can be removed at any time, if sufficient shielding is provided for the spent resin shipping vessel. A layer of water is maintained over the resin surface as a precaution against resin degradation due to heat generation by radioactive decay. Resin is removed from the tank by first sparging with nitrogen to loosen the resin and then pressurizing the tank with nitrogen to approximately 60 psig to force the resin slurry out of the tank. If desired, the primary water supply can be used instead of nitrogen for agitating the resin before discharging it from the tank. The tank is all-welded austenitic stainless steel.

11.1.2.2.7 Gas Decay Tanks

Four large (525-ft^3) welded, vertical, carbon steel tanks are provided to hold radioactive waste gases for decay. This arrangement is adequate for operation with 1-percent fuel defects (as discussed in Section 14.2.3). Four tanks are provided so that during normal operation, sufficient time is available for decay but release is allowed at any time providing the activity is within limits. Normally one of the large gas decay tanks will be in service receiving waste gas while a second tank will be selected to provide backup. When the pressure in the tank receiving gas reaches a predetermined pressure, the fill valve on the tank in service will close and the fill valve on the standby tank will open. A connection is provided on the bottom the tank to allow any water collected in the tank to be removed to the drain header. A nitrogen supply is available for purging the tank.

The large gas decay tanks are sampled periodically by the gas analyzer. Only the tank in the process of being filled will be sampled; the other tanks will be bypassed. A radiation monitor in the gas analyzer line will indicate its reading in the Central Control Room. An alarm is provided so the operator can stop the filling operation before the 6000 Ci limit on the tank is reached. The Offsite Dose Calculation Manual provides the methodologies used to determine the alarm setpoint of the radiation monitor. An administrative maximum of 6000 Ci of equivalent Xe-133 is allowed in any one tank to minimize impacts of accidental release from equipment or tank failure and is well below the ODCM limit.

Gas held in the decay tanks can either be returned to the chemical and volume control system holdup tanks, or discharged to the atmosphere if the activity concentration is suitable for release. The header arrangement at the tank inlet gives the operator freedom to fill, reuse, or discharge gas to the environment simultaneously without restriction by operation of the other tanks.

Six small (40-ft^3), welded carbon steel, vertical tanks are provided to hold waste gases released during degassing of the reactor coolant prior to a cold shutdown.

A connection is provided on the bottom of the tank to allow any water collected in the tank to be removed to the drain header. A nitrogen supply is available for purging the tank.

The small gas decay tanks have the same administrative activity limit, 6000 Ci, as the large tanks. Since the activity of the gases collected during the degassing operation will be much higher than that collected during normal operation, a smaller tank volume is required to stay below the limit of 6000 Ci. This is the reason the tanks provided to collect the gas from the degassing operation are smaller than the tanks provided for normal operation and why the large gas decay tanks cannot be used for this degassing operation.

No sampling connections are provided on the small tanks. Prior to degassing the reactor coolant system, the total gaseous activity of the coolant should be determined. The fission gas activity inventory will be distributed equally among the six tanks through a common inlet header. With this arrangement, assuming typical coolant concentrations, the activity inventory in any one tank will be less than the normal administrative limit of 6000 Ci of equivalent Xe-133 (as discussed in Section 14.2.3). Assuming operation with up to 1% fuel defects, the inventory in each small gas decay tank would be greater than this but less than the ODCM limit.

11.1.2.2.8 Compressors

Two compressors are provided for continuous removal of gases from equipment discharging to the plant vent header. These compressors are of the water-sealed centrifugal displacement type. Operation of each of the compressors is controlled by a selector switch allowing one compressor to operate at any one time. Construction is cast iron, bronze fitted. A mechanical seal is provided to maintain outleakage of compressor seal-water at a negligible level.

11.1.2.2.9 Waste Evaporator Package

Waste Evaporator Package has been retired.

11.1.2.2.10 Distillate Storage Tanks

Two distillate storage tanks are provided.

The tanks are horizontal, cylindrical type with standard flanged and dished heads. Each tank is provided with heaters for cold weather temperature control.

11.1.2.2.11 Waste Condensate Tanks

Two 1000-gal waste condensate tanks are provided to collect liquid wastes that are suitable for direct release to the river. The tanks are vertical, cylindrical types with one standard flanged and dished head and one flat head. They are located on the 80-ft elevation of the primary auxiliary building and are constructed of austenitic stainless steel.

11.1.2.2.12 Baler

The balers have been retired and removed from the facility.

11.1.2.2.13 Nitrogen Manifold

Nitrogen, used as cover gas in the vapor space of various components, is supplied from a dual manifold. Pressure control valves automatically switch from one manifold to the other, to ensure a continuous supply of gas.

11.1.2.2.14 Hydrogen Manifold

Hydrogen is supplied to the volume control tank to maintain the hydrogen concentration in the reactor coolant. The hydrogen is supplied from a dual manifold. Pressure control valves automatically switch from one manifold to the other to ensure a continuous supply of gas.

11.1.2.2.15 Gas Analyzer

An automatic gas analyzer with a nominal 1-hr recycle time is provided to monitor the concentrations of oxygen and hydrogen in the cover gas of tanks discharging to the radiogas vent header. Upon indication of a high oxygen level, an alarm sounds to alert the operator.

11.1.2.2.16 Pumps

Pumps used throughout the system for draining tanks and transferring liquids are shown on Figure 11.1-1 sheets 1 and 2.

The wetted surfaces of all pumps are stainless steel.

11.1.2.2.17 Piping

Piping carrying liquid wastes is stainless steel while all gas piping is carbon steel. Piping connections are welded except where flanged connections are necessary to facilitate equipment maintenance.

11.1.2.2.18 Valves

All valves exposed to gases are carbon steel. All other valves are stainless steel.

Stop valves are provided to isolate each piece of equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay.

Relief valves are provided for tanks containing radioactive waste if the tanks might be over-pressurized by improper operation or component malfunction. Tanks containing wastes, which contain oxygen and are normally of low activity concentrations are vented into the auxiliary building exhaust system.

11.1.3 Design Evaluation

11.1.3.1 Liquid Wastes

Liquid wastes are primarily generated by plant operations. The Annual Effluent and Waste Disposal Report provides the total liquid effluent activity released by isotope.

Appendix 11B presents the results of an original plant preoperational assessment of river water dilution factors between the Indian Point site and the nearest public drinking water intake and is being retained for historical purposes.

11.1.3.2 Gaseous Wastes

Gaseous wastes consist primarily of hydrogen stripped from coolant discharged to the chemical and volume control system holdup tanks during boron dilution, nitrogen and hydrogen gases purged from the chemical and volume control system tank when degassing the reactor coolant, nitrogen from the closed gas blanketing system, and controlled depressurization of the containment atmosphere. The gas decay tanks will permit decay of waste gas before discharge in accordance with the ODCM. The annual gaseous release to atmosphere is given in the Annual Effluent Release and Waste Disposal Report.

Compliance of gaseous effluent releases to regulatory requirements is reflected in the plant's Technical Specifications.

11.1.3.3 Solid Wastes

Solid wastes consist of solidified waste liquid concentrates and sludges, spent resins and filters, and miscellaneous materials such as paper and glassware.

Waste liquid concentrates and sludges are solidified in liners. Spent resins and plant filters are also packaged in liners, which are placed in waste casks for removal to a burial facility. Miscellaneous wastes are packaged in 52 or 55-gal drums. When possible, solid waste is sent to a licensed incinerator, volume reduction center, or material recovery center. Preparation of solid radwastes for shipment and offsite disposal is conducted in accordance with a process control program. Certain activities such as inspections and verifications are considered to be Quality Control activities.

Changes to operations and design were implemented during 1981 to reduce the amount of solid radioactive waste packaged at the plant. The solid radwaste associated with liquid radwaste processing has been reduced by a significant factor since 1981. This was accomplished by using sluicable ion exchange demineralizers instead of evaporators and solidification of concentrate bottoms. It is intended to continue with the use of demineralizers as the prime method of liquid waste processing with evaporation and solidification as the backup method.

Sandblasters are available to remove fixed radioactivity from non-compressible items such as gas bottles, I-beams, angle irons, steel plates, and various tools and equipment. A very low volume of contaminated sand (grit) is being generated. This sand is used to fill voids in non-compactable waste containers.

To further reduce solid waste volumes a liquid abrasive bead decontamination unit, an ultrasonic unit and a solvent degreaser unit have been installed in 1985 to remove loose and fixed contamination from equipment. This equipment can then be reused in the controlled area or released for uncontrolled use. Also, offsite supercompaction and licensed incineration methods are available and used to reduce total burial volumes.

11.1.4 Minimum Operating Conditions

Minimum operating conditions for the waste disposal system are enumerated in the ODCM.

TABLES 11.1-1 through 11.1-5

DELETED

TABLE 11.1-6
Waste Disposal System Components Code Requirements

Component	Code
Chemical drain tank	No code
Reactor coolant drain tank	ASME III,[1] Class C
Sump tank	No code
Spent resin storage tanks	ASME III,[1] Class C
Gas decay tanks	ASME III,[1] Class C
Waste holdup tank	No code
Water condensate tank	No code
Distillate storage tank No code	
Waste filter	No code
Piping and valves	USAS-B31.1,[2] Section 1

Notes:
1. ASME III, American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section IV, Nuclear Vessels.
2. USAS-B31.1, Code for pressure piping, U.S. American Standards Association and special nuclear cases where applicable.

TABLE 11.1-7 (Sheet 1 of 2)
Component Summary Data

Tanks	**Quantity**	**Type**	**Volume**	**Design Pressure**	**Design Temperature F°**	**Material**
Reactor Coolant drain	1	H	350 gal	25 psig	267	ss
Chemical drain	1	V	375 gal	Atm	180	ss
Sump	1	V	375 gal	Atm	150	ss
Waste holdup	1	H	3300-ft^3	Atm	150	ss
Spent resin Storage	1	V	300-ft^3	100 psig	150	ss
Waste condensate	2	V	1000 gal	Atm	180	ss
Distillate storage	2	H	25000 gal	17 psig	250	cs
Gas decay (large)	4	V	525-ft^3	150 psig	150	cs
Gas decay (small)	6	V	40-ft^3	150 psig	150	cs

Pumps	**Quantity**	**Type**	**Flow gpm**	**Head ft**	**Design Pressure psig**	**Design Temperature F°**	**Material** [1]
Reactor coolant drain (A)	1	H, CC	50	175	100	267	ss
Reactor coolant drain (B)	1	H, CC	150	175	100	267	ss
Chemical drain	1	H, C_2	20	100	100	180	ss

TABLE 11.1-7 (Sheet 2 of 2)
Component Summary Data

Pumps	**Quantity**	**Type**	**Flow gpm**	**Head Ft**	**Design Pressure psig**	**Design Temperature F^o**	**Material$_1$**
Sump tank	2	H, C_2	20	100	150	180	ss
Waste condensate	2	H, C_2	20	100	150	180	ss
Waste evaporator feed	1	H, C_2	20	100	150	180	ss
Waste transfer	1	H, C_2	30	215	105	70	ss
Distillate recirculation	2	H, C_2	200	100	43_3	120_4	ss
Reactor cavity pit (2RCPP)	1	Sub-merge V, C	100	50	150	120	ss
Reactor cavity pit (1RCPP)	1	Sub-merge V, C	20	62	150	120	ss

Miscellaneous	Quantity	Capacity	Type
Waste gas compressors	2	48 f^3/min	H, C_2

Key:

H = Horizontal	C = Centrifugal	CC = Carbon Steel
V = Vertical	CC = Centrifugal canned	SS = Stainless Steel

Notes:
1. Wetted surfaces only.
2. Mechanical seal provided.
3. 43 psig is the operating differential pressure of the pump.
4. 120^{o}F is the maximum operating temperature of the pump

TABLE 11.1-8
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11.1 FIGURES

Figure No.	Title
Figure 11.1-1 Sh. 1	Waste Disposal System Process Flow Diagram, Sheet 1, Replaced with Plant Drawing 9321-2719
Figure 11.1-1 Sh. 2	Waste Disposal System Process Flow Diagram, Sheet 2. Replaced with Plant Drawing 9321-2730

11.2 RADIATION PROTECTION

11.2.1 Design Bases

Radiation protection at Indian Point 2 incorporates a program for maintaining radiation exposures as low as reasonably achievable (ALARA). The ALARA program is part of all normal and special work processes. Procedures, designs, modifications, work packages, inspections, surveillances, maintenance activities and plant betterment activities are subjected to ALARA reviews to ensure dose reduction actions are taken. Operational and design ALARA training programs are provided to station and support engineering and technical groups. ALARA is taught in Radiation Worker Qualification courses

11.2.1.1 Monitoring Radioactivity Releases

Criterion: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (GDC 17)

The containment atmosphere, the plant vent, the containment fan cooler service water discharge, the waste disposal system liquid effluent, the condenser air ejectors, and steam generator blowdown are monitored for radioactivity during normal operations, from anticipated transients, and from accident conditions.

All gaseous effluent from possible sources of accidental releases of radioactivity external to the reactor containment (e.g., the spent-fuel pit and waste handling equipment) will be exhausted from the plant vent, which is monitored. Any contaminated liquid effluent discharged to the condenser circulating water canal is monitored. For the case of leakage from the reactor containment under accident conditions the plant area radiation monitoring system supplemented by portable survey equipment to be kept in the Health Physics office area should provide adequate monitoring of accident releases. The details of the procedures and equipment to be used in the event of an accident are specified in Section 11.2.5, the plant procedures, and the plant emergency plan. The formulation of these details considers the requirements for notification of plant personnel, the utility load dispatcher, and local authorities.

11.2.1.2 Monitoring Fuel and Waste Storage

Criterion: Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels. (GDC 18)

Monitoring and alarm instrumentation are provided for fuel and waste storage and handling areas to detect inadequate cooling and to detect excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release operation, but the permanent record of activity releases is provided by radiochemical analysis of known quantities of waste.

The spent fuel pit temperature and level are monitored to assure proper operation, as discussed in Section 9.3.3.2.3.

A controlled ventilation system removes gaseous radioactivity from the atmosphere of the fuel storage and waste treating areas of the auxiliary building and discharges it to the atmosphere via the plant vent. Radiation monitors are in continuous service in these areas to actuate high-activity alarms on the control board annunciator, as described in Section 11.2.3.

11.2.1.3 Fuel and Waste Storage Radiation Shielding

Criterion: Adequate shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities. (GDC 68)

Auxiliary shielding for the waste disposal system and its storage components is designed to limit the dose rate to levels not exceeding 0.75 mrem/hr in normally occupied areas, to levels not exceeding 2.0 mrem/hr in intermittently occupied areas, and to levels not exceeding 15 mrem/hr in limited occupancy areas.

Gamma radiation is continuously monitored in the auxiliary building. A high-level signal is alarmed locally and annunciated in the control room.

11.2.1.4 Protection Against Radioactivity Release From Spent Fuel and Waste Storage

Criterion: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (GDC 69)

All waste handling and storage facilities are contained and equipment designed so that accidental releases directly to the atmosphere are monitored and will not exceed applicable limits; refer also to Sections 11.1.2, 14.2.2, and 14.2.3. The components of the waste disposal system are designed to the pressures given in Table 11.1-7 and the codes given in Table 11.1-6. Hence, the probability of a rupture or failure of the system is exceedingly low.

11.2.2 Shielding

11.2.2.1 Design Basis

Radiation shielding is designed for reactor operation at maximum calculated thermal power and to limit the normal operation radiation levels at the site boundary below those levels allowed for continuous non-occupational exposure. The plant is capable of continued safe operation with 1-percent fuel element defects (as discussed in Section 14.2.3).

In addition, the shielding provided ensures that in the event of a hypothetical accident, the integrated offsite exposure due to the contained activity does not result in any offsite radiation exposures in excess of applicable limits.

Operating personnel at the plant are protected by adequate shielding, monitoring, and operating procedures. When additional shielding is suggested, and permitted as a function of reactor operating mode, it will be evaluated in the context of the station ALARA program and temporary shielding procedures. Modifications to existing structures or shields, which may alter personnel or equipment qualification dose will be evaluated in the design review process. The permanent large and significant shielding arrangement is shown on Figures 1.2-5, 5.1-3, 5.1-4, 5.1-6 and 5.1-7. Shielding arrangements may be altered consistent with the radiation protection plan and the ALARA program station administration orders.

Detailed and periodic surveys of all restricted area radiation levels are performed. All high radiation areas are appropriately marked and access controlled in accordance with 10 CFR 20 and other applicable regulations and station procedures as well as the Technical Specifications.

In accordance with NUREG-0737, Item II.B.2, each power reactor licensee was required to perform a radiation and shielding design review of spaces around systems that may, as a result of an accident, contain highly radioactive material. Additionally, each licensee was required to provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or postaccident procedure controls. Indian Point Unit 2 shielding design review and corrective action were reviewed during an NRC inspection in May 1983. The inspection report[1] and a safety evaluation report[2] concluded that the requirements of NUREG 0737, Item II.B.2 were met at Indian Point Unit 2.

The shielding is divided into five categories according to function. These functions include the primary shielding, the secondary shielding, the accident shielding, the fuel transfer shielding, and the auxiliary shielding.

11.2.2.1.1 Primary Shield

The primary shield is designed to:

1. Reduce the neutron fluxes incident on the reactor vessel to limit the radiation induced increase in nil ductility transition temperature.

2. Attenuate the neutron flux sufficiently to limit activation of plant components.

3. Limit the gamma fluxes in the reactor vessel and the primary concrete shield to avoid excessive temperature gradients or dehydration of the primary shield.

4. Reduce the residual radiation from the core, reactor internals, and reactor vessel to levels, which will permit access to the region between the primary and secondary shields after plant shutdown.

5. Reduce the contribution of radiation leaking to obtain optimum division of the shielding between the primary and secondary shields.

11.2.2.1.2 Secondary Shield

The main function of the secondary shielding is to attenuate the radiation originating in the reactor and the reactor coolant. The major source in the reactor coolant is the Nitrogen-16 activity (83 $\mu Ci/cm^3$ maximum), which is produced by neutron activation of oxygen during passage of the coolant through the core. The secondary shield will limit the full power dose rate outside the containment building to less than 0.75 mrem/hr.

11.2.2.1.3 Accident Shield

The main purpose of the accident shield is to ensure radiation levels outside the containment building are within applicable limits following a maximum credible accident.

11.2.2.1.4 Fuel Handling Shield

The fuel handling shield is designed to facilitate the removal and transfer of spent fuel assemblies and control rod clusters from the reactor vessel to the spent-fuel pit. It is designed to attenuate radiation from spent fuel, control clusters, and reactor vessel internals to less than 2.0 mrem/hr at the refueling cavity water surface and less than 0.75 mrem/hr in areas adjacent to the spent-fuel pit.

11.2.2.1.5 Auxiliary Shielding

The function of the auxiliary shielding is to protect personnel working near various system components in the chemical and volume control system, the residual heat removal system, the waste disposal system, the sampling system and the high radiation sampling system sentry panels. The shielding provided for the auxiliary building is designed to limit the dose rates to less than 0.75 mrem/hr in normally occupied areas, and at or below 2.0 mrem/hr in intermittently occupied areas during normal operation. Under accident conditions, samples are diverted to a shielded high radiation sampling system tank. Liquid can be pumped from this tank back into the containment.

An additional room has been constructed in the primary auxiliary building (elevation 98-ft) to provide additional shielding protection for operators. The walls are seismically qualified to avoid damage to the equipment in the room after a design-basis accident. In order to reduce personnel exposure during accident conditions, all gas sample lines to the gas analyzers have been provided with a nitrogen purge capability. This system purges all the sampled gases from the sample lines and returns them to their source.

11.2.2.2 <u>Shielding Design</u>

11.2.2.2.1 Primary Shield

The primary shield consists of the core baffle, water annuli, barrel-thermal shield (all of which are within the reactor vessel), the reactor vessel wall, and a concrete structure surrounding the reactor vessel.

The primary shield immediately surrounding the reactor vessel consists of an annular reinforced concrete structure extending from the base of the containment to an elevation of 69-ft. The lower portion of the shield is a minimum thickness of 6-ft of regular concrete ($q = 2.3\ g/cm^3$) and is an integral part of the main structural concrete support for the reactor vessel. It extends upward to join the concrete cavity over the reactor. The reactor cavity, which is approximately rectangular in shape, extends upward to the operating floor with vertical walls 4-ft thick, except in the area adjacent to fuel handling, where the thickness is increased to 6-ft. A shielding collar is provided at each point where the eight reactor coolant pipes penetrate the primary shield.

The primary concrete shield is air cooled to prevent overheating and dehydration from the heat generated by radiation absorption in the concrete. Eight "windows" have been provided in the primary shield for insertion of the ex-core nuclear instrumentation. Cooling for the primary shield concrete and the nuclear instrumentation is provided by 12,000 cfm cooling air.

The primary shield neutron fluxes and design parameters are listed in Table 11.2-2.

11.2.2.2.2 Secondary Shield

The secondary shield surrounds the reactor coolant loops and the primary shield. It consists of the annular crane support wall, the operating floor, and the reactor containment structure. The containment structure also serves as the accident shield.

The lower portion of the secondary shield above grade consists of the 4-ft 6-in. thick cylindrical portion of the reactor containment and a 3-ft concrete annular crane support wall surrounding the reactor coolant loops. The secondary shield will attenuate the radiation levels in the primary loop compartment from a value of 25 rem/hr to a level of less than 0.75 mrem/hr outside the reactor containment building. Penetrations in the secondary shielding are protected by supplemental shields.

The secondary shield design parameters are listed in Table 11.2-3.

11.2.2.2.3 Accident Shield

The accident shield consists of the 4-ft 6-in. thick reinforced concrete cylinder capped by a hemispherical reinforced concrete dome of a 3-ft 6-in. thickness. This shielding includes supplemental shields in front of the containment penetration.

The equipment access hatch is shielded by a 3-ft 6-in. thick concrete shadow shield and 1-ft 6-in. thick concrete roof to reduce scattered dose levels in the event of loss of reactor coolant accident accompanied by a complete core meltdown.

The accident shield design parameters are listed in Table 11.2-4.

11.2.2.2.4 Fuel Handling Shield

The refueling cavity, flooded to approximately elevation 93.7-ft during refueling operations, provides a temporary water shield above the components being withdrawn from the reactor vessel. The water height during refueling is approximately 24.50-ft above the reactor vessel flange. This height ensures that a minimum of 10.50-ft of water will be above the active fuel of a withdrawn fuel assembly. Under these conditions, the dose rate is less than 2.0 mrem/hr at the water surface.

The fuel transfer canal is a passageway connected to the reactor cavity extending to the inside surface of the reactor containment. The canal is formed by two concrete walls each 6-ft thick, which extends upward to the same height as the reactor cavity. During refueling, the canal is flooded with borated water to the same height as the reactor cavity.

The spent fuel assemblies and control rod clusters are remotely removed from the reactor containment through the horizontal spent fuel transfer tube and placed in the spent fuel pit. Concrete, 6-ft thick, shields the spent fuel transfer tube. This shielding is designed to protect personnel from radiation during the time a spent fuel assembly is passing through the main concrete support of the reactor containment and the transfer tube. Radial shielding during fuel transfer is provided by the water and concrete walls of the fuel transfer pit. An equivalent of 6-ft of regular concrete is provided to ensure a maximum dose value of 0.75 mrem/hr in the areas adjacent to the spent fuel pit.

Spent fuel is stored in the spent fuel pit, which is located adjacent to the containment building. Shielding, above grade elevation, for the spent fuel storage pit is provided by concrete walls 6-ft thick and is flooded to a level such that the water height is greater than 13-ft above the spent fuel assemblies.

The refueling shield design parameters are listed in Table 11.2-5.

11.2.2.2.5 Auxiliary Shield

The auxiliary shield consists of concrete walls around certain components and piping, which process reactor coolant. In some cases, the concrete block walls are removable to allow personnel access to equipment during maintenance periods. Periodic access to the auxiliary building is allowed during reactor operation. Each equipment compartment is individually shielded so that compartments may be entered without having to shut down and, possibly, to decontaminate the adjacent system.

The shielding material provided throughout the auxiliary building is regular concrete ($r = 2.3\ g/cm^3$). The principal auxiliary shielding provided is tabulated in Table 11.2-6.

11.2.3 Radiation Monitoring System

11.2.3.1 Design Bases

The radiation monitoring system is designed to perform two basic functions:

1. Warn of any radiation health hazard, which might develop.
2. Give early warning of a plant malfunction, which might lead to a health hazard or plant damage.

Instruments are located at selected points in and around the plant to detect, compute, and record the radiation levels. In the event the radiation level should rise above a desired setpoint, an alarm is initiated in the control room. The automatic radiation monitoring system operates in conjunction with regular and special radiation surveys and with chemical and radio-chemical analyses performed by the plant staff. Adequate information and warning is thereby provided for the continued safe operation of the plant and assurance that personnel exposure does not exceed 10 CFR 20 limits.

11.2.3.2 Radiation Monitoring Betterment Program

A new system has been installed to replace the original process radiation monitoring system. Each of the original monitors is removed from service after installation and testing of the new monitor. The new system is described below as it currently exists.

The process radiation monitoring system is a digital system with the following major components: individual radiation monitoring units for each monitored process line; a minicomputer unit located in the technical support center; a CRT display and printer located in the central control room; and annunciators located in the central control room.

The minicomputer unit includes a console with CRT and typer, disk drive and magnetic tape drive. It communicates digitally with the individual radiation monitoring units, and processes, records, and displays data.

Table 11.2-7 shows the process streams monitored by the individual radiation monitor units, along with the normal maximum channel output. Each monitor unit monitors a sample of the process fluid, which is piped through a bypass loop. The sample is cooled if required. To facilitate maintenance and calibration, the bypass loop can be isolated and purged.

The liquid and airborne monitors utilize an off-line sampler(s) and a gamma or beta scintillation detectors to measure radioactivity present in a sample. Each monitor has a micro-processor, which communicates with the minicomputer.

Each monitor will activate an annunciation alarm in the event of failure, high radiation, or high temperature where applicable.

The minicomputer and the CRT/printer unit are powered from a battery-backed inverter. As discussed below, several monitor units receive power from MCC-26A and MCC-26BB, which are powered by an emergency diesel generator in the event of loss of other power sources.

Information on specific monitors is given in the following sections.

11.2.3.2.1 Service Water from Component Cooling Heat Exchangers Monitors

Monitors R39 and R40 monitor the service water from component cooling heat exchangers 21 and 22, respectively. Radioactivity in these streams would indicate a component cooling heat exchanger leak when there is radioactivity in the component cooling loop. These monitors are powered from MCC-26A. They are wired to a control room annunciator, independent of their communications loop through the minicomputer.

11.2.3.2.2 Containment Air Monitors

Monitors R41 and R42 monitor the containment atmosphere for particulate and gaseous activity, respectively. These monitors are seismically qualified, and their power supplies are class IE. Either monitor, on detection of a high activity level, will initiate containment ventilation isolation, consisting of closure of the two containment purge supply valves, the two containment purge exhaust valves, and the containment pressure relief valves. Although IP2 plant design has always included isolation of these valves upon detection of high radioactivity in the containment atmosphere, this function has also been analyzed and credited for IP2 compliance with

NUREG-0737, Item II.E.4.2.7 (Reference 24). Their signals are provided to control room indicators and recorders and to the safety assessment system.

11.2.3.2.3 Plant Vent Air Monitors

R43 monitors the air in the plant vent for particulate and iodine activity, while R44 monitors for gaseous activity. They are seismically qualified, and their power supplies are class IE. On detection of a high activity level, R44 initiates containment ventilation isolation as described in the preceding section, and also initiates closure of the gas discharge valve in the waste gas disposal system. Their signals are provided to control room indicators and recorders and to the safety assessment system. Additionally, an indicator for monitor R44 is located at the waste disposal panel.

11.2.3.2.4 Condenser Air Ejector Discharge Monitor

The gas removed from the condenser by the air ejector is monitored for gaseous radioactivity (which is indicative of steam generator tube leakage) by monitor R45. On the detection of high radiation, the condenser exhaust gas is diverted from the atmospheric discharge to the containment. A control room alarm is provided independent of the communications loop. The monitor, which receives power from a highly reliable source backed up by the emergency diesel generators, is capable of functioning after a steam generator tube rupture coincident with loss of offsite power.

11.2.3.2.5 Service Water Return from Containment Fan Cooler Units

Two redundant monitors, R46 and R53, monitor the service water return from all containment fan cooler units. Small bypass flows from each of the heat exchangers and from the fan motor coolers are mixed in a common header and monitored. During a loss of coolant accident, radioactivity at this point would indicate a leak from the containment atmosphere into the cooling water. Upon indication of a high radiation level, each heat exchanger is sampled to determine, which unit is leaking. Each of these channels is hardwired to a safety-related display unit, a recorder and an annunciator, all in the control room. The communications link through the minicomputer is isolated from each of these channels by an isolation device. The channels receive power from MCC-26A. These monitors, the display units and the connecting piping are designed to be capable of functioning after a safe shutdown earthquake.

11.2.3.2.6 Component Cooling Radiation Monitor

This channel, R47, monitors the component cooling loop for radioactivity, which would indicate a leak of reactor coolant from the reactor coolant system and/or the residual heat removal loop. An interlock initiates closure of a valve in the component cooling surge tank vent line in the event a high radiation level is detected. Closure of this valve will prevent gaseous activity release. Component cooling activity is recorded and displayed in the control room, and high activity initiates a control room annunciator. The display unit, recorder and annunciator are independent of the minicomputer communications loop. The monitor is isolated from the communications loop by an isolation device. This monitor is powered from MCC-26A, and is designed to be capable of functioning after a safe shutdown earthquake.

11.2.3.2.7 Waste Condensate Tank Discharge Line

This channel, R48, monitors liquid releases from the Waste Condensate Tanks. Automatic valve closure is initiated by this monitor to prevent further release after a high radiation level is detected. This monitor is hardwired to a control room chart recorder. It receives power from MCC-26A.

11.2.3.2.8 Steam Generator Blowdown Monitor

This monitor, R49, monitors the liquid blowdown from the secondary side of the steam generators. Radioactivity in this stream would indicate a primary-to-secondary leak, providing information to back up the condenser air removal gas monitor. Samples from the bottoms of all four steam generators are mixed in a common header and the common sample is monitored. Upon indication of high activity, an interlock from monitor R49 closes all steam generator blowdown containment isolation valves and the city water supply to the steam generator blowdown tank spray. Each steam generator is individually sampled to determine the source. Due to the location of monitor R49, the sample travel time from the sample point to the monitor is 90 seconds to 2 minutes (as discussed in Section 14.2.4). The sample point is downstream of the blowdown line containment isolation valves, which close on Phase A containment isolation signal. The signal from R49 is one of the parameters available to the operator to diagnose a steam generator tube rupture backing up the indication from the condenser air ejector monitor. Initiation of safety injection and Phase A isolation, in response to a steam generator tube rupture, could prevent R49 from seeing the increase in activity resulting from the steam generator tube rupture. R49 is not a primary indication to the operator of steam generator tube rupture, thus the ability of the operator to respond to steam generator tube rupture will not be adversely affected.

Monitor R49 receives power through MCC-26BB and is designed to be capable of operating after a safe shutdown earthquake. It will annunciate in the control-room independent of its communication loop through the minicomputer. The monitor is hardwired to a recorder in the control room.

11.2.3.2.9 Waste Gas Decay Tank

This monitor, R50, indicates activity in the waste gas decay tanks. It is hardwired to a recorder in the control room and also annunciates in the control room, independent of the communication loop through the minicomputer. It receives power from MCC-26A.

11.2.3.2.10 Secondary Boiler Blowdown Purification System

This monitor, R51, indicates activity in the system effluent and the Unit 1 North Curtain Drain sump discharge. It enables plant operators to take corrective action in the event of high activity. It is powered from a Unit 1 motor control center. It alarms in the control room independent of its communications loop through the minicomputer.

11.2.3.2.11 Steam Generator Blowdown Purification System Cooling Water Monitor

This monitor, R52, monitors the cooling water from the Unit 1 secondary boiler blowdown purification system, which can be used to process steam generator blowdown effluents from Unit 2. It actuates an alarm in the control room. It is not required to function in the event of an earthquake.

11.2.3.2.12 Liquid Waste Distillate Radiation Monitor

This monitor, R54, is powered from a Unit 1 motor control center. It alarms in the central control room independent of the communications loop through the minicomputer. This monitor terminates the distillates tank discharges upon detecting high activity.

11.2.3.2.13 Steam Generator Secondary System Monitors

There are four monitors (R55A, R55B, R55C, and R55D) for activity in the secondary systems of the steam generators. A small flow from each is cooled and depressurized, and then monitored.

11.2.3.2.14 Effluent Discharge to ENIP3

This monitor, R57, is not required to function to mitigate any postulated accident. It monitors the contents of the sewage ejector pit, located in Unit 1 and trips the ejector pumps if high activity is detected. A central control room alarm is provided, independent of the communications loop. Power to monitor R57 is supplied from a Unit 1 source. This monitor terminates sewage transfer upon detecting high activity.

11.2.3.2.15 House Service Boilers

This monitor, R59, is powered from a Unit 1 motor control center. It indicates any activity that may be present in the condensate return. It alarms in the control room.

11.2.3.2.16 Stack Radiation Monitor

R60 has monitors for gaseous, particulate, and iodine activity in the air in the stack.

11.2.3.2.17 Maintenance and Outage Building Ventilation Exhaust

The air exhausted from elevation 95' of the Maintenance and Outage Building is monitored by R-5976 for particulates and gases. This monitor is integrated into the process monitoring system.

11.2.3.2.18 Sphere Foundation Sump Liquid Effluent

Monitor R-62 monitors the activity of the liquid discharge from the Unit 1 Sphere Foundation Sump drainage. This monitor alarms of the common process radiation monitor panel for high radiation.

11.2.3.2.19 Main Steam/Steam Generator Tube Leakage

Nitrogen-16 monitors R-61A, R-61B, R-61C, and R-61D are located near the main steam lines in the Auxiliary Boiler Feed Pump Building and when a steam generator tube leaks sufficiently the N-16 monitor will alarm.

11.2.3.3 Original Radiation Monitoring System

11.2.3.3.1 Control Room Cabinet

Most of the control room system equipment is centralized in three cabinets. High reliability and ease of maintenance are emphasized in the design of this system. Sliding channel drawers are used for rapid replacement of units, assemblies, and entire channels. It is possible to remove the various chassis completely from the cabinet after disconnecting the cables from the rear of these units.

Radiation recorders and associated preamplifiers for channels R-11, R-12, R-13, R-14, R-15, R-16, R-17, R-18, R-19, R-20, and R-23 have been installed in a new radiation recorder panel SA-1, which is adjacent to Panel SA in the central control room. This installation allows for continuous monitoring and trending of these channels during emergencies. The new panel includes a 36-point annunciator panel and eleven recorders, one for each parameter indicated above.

11.2.3.3.2 Monitor Channel Output

The maximum channel output of the radiation monitors is given in Table 11.2-7.

11.2.3.3.3 Operating Conditions

Where fluid temperature is too high for the monitor, a cooling device with temperature indication is included. The different operating temperature ranges are within the design limits of the sensors.

The relation of the radiation monitoring channels to the systems with which they are associated is given in the sections describing those systems. Routine test and recalibrations will ensure that the channels operate properly.

The components of the radiation monitoring system are designed according to the following environmental conditions:

1. Temperature - an ambient temperature range of 40°F to 120°F.

   [***Note*** *- Equipment located in the control room area may be specified for smaller temperature and humidity ranges because of the controlled environment provided by the heating and ventilating system.*]

2. Humidity - 0 to 100-percent relative humidity.

   [***Note*** *- Equipment located in the control room area may be specified for smaller temperature and humidity ranges because of the controlled environment provided by the heating and ventilating system.*]

3. Pressure - components in the auxiliary building and control room are designed for normal atmospheric pressure. Area monitoring system components inside the containment are designed to withstand test pressure.

4. Radiation - process and area radiation monitors are of a nonsaturating design so that they "peg" full-scale if exposed to radiation levels up to 100 times full scale indication. Process monitors are located in areas where the normal and postaccident background radiation levels will not affect their usefulness.

The radiation monitoring system is divided into the following subsystems:

1. The process radiation monitoring system, which monitors various fluid streams for indication of increasing radiation levels.

2. The area monitoring system, which monitors area radiation in various parts of the plant.

3. Environmental radiation monitoring system, which monitors radiation in the area surrounding the plant.

Portable alarming area radiation monitors and continuous area monitors are used in the Unit 1 area utilized for interim storage of dry active waste.

11.2.3.3.4 Original Process Radiation Monitoring System

This system monitors radiation levels in various plant operating systems. The output from each channel detector is transmitted to the radiation monitoring system cabinets located in the control room area where the radiation level is indicated by a meter and recorded by a multipoint recorder. High radiation level alarms are annunciated on the main control room board and indicated on the radiation monitoring system cabinets.

The installed monitoring systems are not designed to determine the nature and amount of radioactivity in the systems being monitored, but are designed to detect the concentrations of the isotopes in their respective streams or areas as indicated in Table 11.2-7. These systems monitor gross activity and are designed to generate an alarm under abnormal conditions and in most cases generate automatic responses. Isotopic identification and concentrations are determined by grab sample analysis.

Each channel contains a completely integrated modular assembly, which includes the following:

1. Level amplifier

   Amplifies the energy of the radiation pulse to provide a discriminated output to the log level amplifier.

2. Log level amplifier

   Accepts the shaped pulse of the level amplifier output, performs a log integration, (converts total pulse rate to a logarithmic analog signal) and amplifies the resulting output for suitable indication and recording.

3. Power supplies

   Power supplies are contained in each drawer for furnishing the positive and negative voltages for the transistor circuits, relays and alarm lights, and for providing the high voltage for the detector.

4. Test-calibration circuitry

   These circuits provide a precalibrated analog signal to perform channel test, and a solenoid-operated radiation check source to verify the operation of the channel. An annunciator light on the main control board indicates when the channel is in the test-calibrate mode.

5. Radiation level meter

   This meter, mounted on the drawer, has a scale calibrated logarithmically in counts per minute from 10^1 to 10^4, and 10^1 to 10^6. The level signal is also recorded by the recorder.

6. Indicating lights

   These lights indicate high-radiation alarm levels and circuit failure. An annunciator on the main control board is actuated on high radiation.

7. Bistable circuits

   Two bistable circuits are provided, one to alarm on high radiation (actuation point may be set at any level within the range of the instruments), and one to alarm on loss of signal (circuit failure).

8. A remotely-operated long-half-life radiation check source is furnished in each channel. The energy emission ranges are similar to the radiation energy spectra being monitored. The source strength is sufficient to cause approximately mid-range indication of the detector unit.

The process radiation monitoring system consists of the radiation monitoring channels, which are discussed in the following pages.

11.2.3.3.4.1 Containment and Plant Vent Air Particulate Monitors (R-11 and R-13)

These monitors are no longer functional.

11.2.3.3.4.2 Containment Radioactive Gas Monitor (R-12)

Information in this paragraph is being retained for historical perspective. During normal plant operation, the tritium level in the reactor coolant will be limited to a sufficient level to ensure an acceptable tritium activity in the refueling water. With a containment purge rate of 40,000 cfm, the maximum concentration of tritium in the containment air will be less than 1/5 of MPC. The basis for this concentration is determined from the assumption that the refueling water evaporation rate is 100 1b/hr, the containment is purged for 2 hr at the rate of 40,000 cfm prior to access, and that the purge continues during the refueling operation at 40,000 cfm.

During normal plant operation, grab samples from the containment and auxiliary building area will be analyzed for tritium as required.

11.2.3.3.4.3 Plant Vent Gas Monitor (R-14)

This monitor is no longer functional.

11.2.3.3.4.4 Condenser Air Ejector Gas Monitor (R-15)

This monitor is no longer functional.

11.2.3.3.4.5 Containment Fan Cooling Water Monitors (R-16 and R-23)

These monitors are no longer functional.

11.2.3.3.4.6 Component Cooling Loop Liquid Monitor (R-17)

This monitor is no longer functional.

11.2.3.3.4.7 Waste Disposal System Liquid Effluent Monitor (R-18)

This monitor is no longer functional.

11.2.3.3.4.8 Waste Disposal System Gas Analyzer Monitor (R-20)

This monitor has been replaced by R-50.

11.2.3.3.4.9 Steam Generator Liquid Sample Monitor (R-19)

This monitor is no longer functional.

11.2.3.3.4.10 Gross Failed Fuel Detector

This detector is no longer functional.

11.2.3.3.4.11 Iodine-131 Monitors

These monitors are no longer functional

11.2.3.3.4.12 Calibration of Process and Effluent Monitors

Liquid and gaseous sources, similar to those expected during normal plant operation, will not be used to verify proper installation and operating capability of the detectors. A check source, installed in the sampler, will be used to verify that the detectors are operating and properly installed.

A primary calibration was performed on a one-time basis in the vendor's design verification test. Further primary calibrations are not required since the geometry cannot be significantly altered within the sampler. The design verification test utilizes typical isotopes of interest to determine proper detector response.

Secondary standard calibrations are performed with a radiation source of known activity. These single point calibrations are used to verify the original vendor calibration. Cesium sources are used for both gaseous and liquid effluent monitors. The secondary standard calibrations are performed by removing the detector and placing the source on the sensitive area of the detector. The secondary standard calibrations are performed at each refueling outage.

An additional secondary calibration of each monitor is performed periodically by manually sampling the system involved and analyzing for composition and activity using gamma spectrometry. The knowledge of the isotopes present is then used for proper instrument calibration.

There are no specific routine maintenance procedures for the radiation monitoring system monitors. If background buildup is observed, decontamination procedures will be performed.

11.2.3.3.5 Original Area Radiation Monitoring System

The Unit 1 area radiation monitoring system consists of five channels, which monitor radiation levels in various Unit 1 locations. These area are listed below:

Channel	Area Monitor
ARM-1	Drum Storage Area Corridor
ARM-2	Pedestrian Tunnel
ARM-3	Nuclear Service Building SBBPS HX Room
ARM-4	Evaporator Bottom Pumps Room Corridor
ARM-5	Fuel Handling Floor

Channels ARM-1 through ARM-5 consist of a fixed position gamma sensitive sodium iodide detector. The detector output is amplified and shaped locally, and displayed both locally and in the control room. Both local and control room logarithmic meters span the range from 0.1 mR/hr to 1000 mR/hr. The control room annunciator is common to all five units.

The Unit 2 area radiation monitoring system consists of six channels, which monitor radiation levels in various areas of Unit 2. These areas are listed as follows:

Channel	Area Monitor
R-1	Control Room
R-2	Containment
R-4	Charging pump room
R-5	Spent fuel building
R-6	Sampling room
R-7	Incore instrument area

Channels R-1, R-2 and R-4 through R-7 consist of a fixed position gamma sensitive Geiger-Mueller tube detector. The detector output is amplified and the log count-rate is determined by the integral amplifier at the detector. The radiation level is indicated locally at the detector and at the radiation monitoring system (RMS) cabinets. The RMS signals are also logged and trended (recorded) by the plant computer. High radiation alarms are displayed on the main annunciator, the radiation monitoring cabinets, and at the detector location. When radiation levels drop below the high level alarm setpoint, the "high" alarms on the monitors are reset automatically. The automatic reset procedure also exists for the "low" alarms.

The control room annunciator provides a single window, which alarms for any channel detecting high radiation. Verification of which channel has alarmed is done at the radiation monitoring system cabinets. A remotely-operated, long half-life radiation check source is provided in each channel. The source strength is sufficient to produce indication of detector response.

A meter is mounted on the front of each computer-indicator module and is calibrated logarithmically from 0.1 mrem/hr to 10 rem/hr.

A remote meter calibrated logarithmically from 0.1 mrem/hr to 10 rem/hr, is mounted at the detector assembly.

Radiation monitoring system cabinet alarms consist of a red indicator light for high radiation and an amber light to annunciate detector or circuit failure. The remote meter and alarm assembly at the detector contains a red indicator light and a buzzer type alarm annunciator actuated on high radiation.

11.2.3.4 <u>NUREG-0737 Monitors</u>

The following monitors were installed in conformance with NUREG-0737, "Clarification of TMI Action Plan Requirements":

11.2.3.4.1 Containment High Range Radiation Monitors (R-25 and R-26)

Installed within the containment building are two ion chamber type radiation detectors. These detectors are wired to receiving units located on the accident assessment panel. Analog type ratemeters display rem/hr values from 10^0 to 10^7. These values will be continuously recorded on separate strip chart recorders. Computer outputs are also provided as well as alarm output contacts for annunciation of high radiation inside of the containment building. A check feature is also provided for periodic system verification. Pushbuttons for check initiation and reset are provided on the front of each ratemeter.

One of the high-range radiation detectors is installed at the top of the pressurizer and the other on the steam generator wall in such a way that they can monitor dose rates within the containment building. These monitors are intended to provide information about the imminence or extent of a breach of a fission-product barrier.

No control features are provided with this system.

11.2.3.4.2 High-Range, Noble Gas Monitor (R-27)

The high-range noble gas monitor is installed in the boric acid evaporator building on the 84-ft elevation along with a sample station. The monitor is intended to provide information about the magnitude of releases of radioactive materials, should they occur.

The monitor is skid-mounted and fixed in place by anchor bolts; the various parts of the sample station are similarly secured to the wall and floor. Connections have been installed for data processors and displays and to supply electrical power and a nitrogen purge capability. The display for this monitor is located on the accident assessment panel in the common Units 1 and 2 central control room.

11.2.3.4.3 Main Steam Line Radiation Monitors (R-28, R-29, R-30, and R-31)

Each of the four steam lines is monitored for gross activity by an individual Geiger-Mueller detector assembly, which is positioned next to the lines upstream of the pressure relief valves. The readouts for these detectors are located in the control room on the accident assessment panel. The sensitivity of these monitors is from 10^{-1} to 10^{3} $\mu Ci/cm^3$. Each meter has an alarm output for high radiation. The four separate outputs are wired to independent alarms for each main steam line radiation monitor located on the accident assessment panel in the common Units 1 and 2 control room. Each meter also has recorder output, which is wired to a common multipoint recorder. These monitors are used in combination with the total steam flow from the low range flow meter as a backup method of determining the magnitude of the estimated releases through the atmospheric dump valves and the steam generator safety valves.

Each detector assembly includes a constant depleted uranium source giving a fixed readout. This feature takes the place of the usual electrically activated check source mechanism.

No control features are provided with this system.

11.2.3.4.4 Dual Channel Gas and Particulate Monitor [Deleted]

11.2.3.4.5 PAB Breaker Service Access Area Radiation Monitor R-5987

Area Monitor channel R-5987 is provided to indicate habitability of the primary auxiliary building area between motor control centers 26AA and 26BB. Post-accident access to this area may be required to service accident mitigation equipment. The monitor, which uses a Geiger-Mueller detector, has a range of 0.1 mrem/hr to 10 rem/hr. It provides indication and alarm both locally and in the central control room, and provides input data to the plant computer. It receives power from an instrument bus and is designed to the category 3 criteria of regulatory guide 1.97, rev. 2.

11.2.3.4.6 Post Accident Sampling System Monitors

There are three area radiation monitors, R-37-1, R-37-2, R-37-3, installed for the Post Accident Sampling System. The detectors are Ionization Chambers with readout/alarms located on one of the local Sampling System control panels. There are no control features associated with these monitors.

11.2.3.4.7 Control Room Air Intake

Process radiation monitors R-38-1 and R-38-2 are installed near the intake ducts in the northern and southern sections of the Control Room's fan room. The southern detector is located on the intake air stream for the Unit 1 area of the Control Building excluding the Control Room. The northern detector is near the Unit 2 intake duct where the duct penetrates the north wall of the fan room. If a high radiation condition is sensed entering from either south or north of the Control Building the Control Room Ventilation will switch to the “Incident – Outside Air Filtered Pressurization Mode (Mode 2).”

11.2.4 Environmental Monitoring Program

Environmental monitoring is discussed in section 2.8 and requirements are set forth in the ODCM. The environmental monitoring program and results are described in the Annual Radiological Environmental Operating Report.

11.2.5 Radiation Protection and Medical Programs

In response to an Order Modifying License[18], Con Edison developed a comprehensive action plan[19,20] to upgrade station radiological controls. The action plan was approved by the NRC in Reference 21. Con Edison's plan to maintain program effectiveness was submitted to the NRC in Reference 22. The NRC determined in 1986 that the implementation of the action plan was thorough and complete, and all terms of the order have been satisfactorily completed (Reference 23).

11.2.5.1 Personnel Monitoring

The official and permanent record of accumulated external radiation exposure received by individuals is obtained principally from a thermoluminescent dosimeter (TLD). Direct reading dosimeter provides day-by-day indication of external radiation exposure.

Special or additional TLDs are issued as may be required under unusual conditions. These devices are issued as directed by the environmental health and safety personnel.

The TLDs are processed on a routine basis, usually at monthly intervals.

Annual reports of personnel monitoring are submitted to the NRC in accordance with 10 CFR 20.2206 and Technical Specifications.

11.2.5.2 Personnel Protective Equipment

All personnel are required to wear appropriate protective clothing as specified by a radiation work permit. The nature of the work to be done is the governing factor in the selection of protective clothing to be worn by individuals. The most common protective apparel available is shoe covers, head covers, gloves, and coveralls. Additional items of specialized apparel such as plastic suits, face shields, and respirators are available. In all cases, radiation protection personnel evaluate the radiological conditions and specify the required items of protective clothing to be worn. Respiratory protective devices are available in any situation arising from plant operations in which an airborne radioactive area exists or is expected to exist in excess of applicable limits. In such cases, the airborne concentrations are monitored by radiation protection personnel and the necessary protective devices are specified according to concentration and type of airborne contaminants present.

Respiratory devices available for use include:

1. Full-face respirator (filter or gas canister, negative pressure).
2. Atmosphere supplying respirators (pressure demand, or continuous flow).
3. Airhood.
4. Self-contained breathing apparatus.

Self-contained breathing apparatus will be used in any situation involving oxygen deficient atmospheres.

The appropriate type of respiratory protection equipment required will be determined from 10 CFR, 20.1701-1704.

11.2.5.3 Facilities and Access Provisions

The radiologically controlled area is a portion of an area to which access is limited and additional steps are applied for purposes of occupational dose control and loose radioactive material control. A Radiation Area is an area accessible to personnel in which there exists radiation at such levels that a major portion of the body could receive in any 1 hr a dose in excess of 5.0 mrem at 30 cm from the source. The Radiologically Controlled Areas of IP2 are established, identified, and controlled through plant procedures.

Any area in which radioactive material and radiation are present shall be surveyed, classified, and conspicuously posted with the appropriate radiation caution sign as specified in 10 CFR 20.1902.

The general arrangement of the control point facilities is designed to provide access control to the RCA and it also provides a change location for personal clothing.

Friskers and/or Personnel Contamination Monitors are located at all authorized personnel exits from the radiologically controlled area. All personnel will survey themselves before leaving the controlled area.

Personnel decontamination equipment is available in the controlled area decontamination and first aid rooms.

Administrative and physical security measures are employed to prevent unauthorized entry of personnel to any high radiation area. These measures include the following:

1. Areas in which radiation levels are so high that individuals might receive doses in excess of 100 mrem at 30 cm in 1 hr shall be barricaded and conspicuously posted as "high radiation areas." Administrative controls require the issuance of a radiation work permit prior to entry to any high radiation area.

2. Locations where the above value exceeds 1 rem at 30 cm in 1 hr are conspicuously posted, and in addition, locked doors are provided to prevent unauthorized entry. Keys to these doors are kept under special administrative control. The locks and administrative controls on these doors are arranged so that personnel cannot be prevented from leaving high radiation areas.

11.2.5.4 Radiation Instrumentation

Laboratory facilities are provided for the radiation protection and chemistry sections. These facilities include both laboratory and calibration rooms. A health physics control station is equipped to analyze routine air samples and contamination swipe surveys. The control station also serves as a central location for portable radiation survey instruments.

"Friskers" and other type personnel monitors are located at appropriate plant locations as dictated by the plant radiation protection program.

A beta-gamma portal monitor is located at all authorized personnel exits from the radiologically controlled area as a final check on personnel leaving the controlled area.

The types of portable radiation survey instruments available for routine monitoring functions are controlled and placed by Health Physics and governed by procedures.

Survey instruments are included in a formal maintenance program to ensure that they are normally calibrated. Calibration and maintenance records are provided for each instrument.

Portable radiation survey instruments are available for use offsite during and following any possible accidental release of radioactivity from the facility. The equipment available and required are controlled by the Emergency Plan and Health Physics procedures.

11.2.5.5 Onsite Treatment Facilities, Equipment and Supplies

Onsite treatment facilities consist of a Decontamination Room and an Examination Room located in the Unit 1 Nuclear Services Building adjacent to the Containment Sphere but outside the external concrete biological shield. An alternate location for the treatment of injured and/or contaminated personnel and for the storage of supplies is the Medical Bureau Examination Room located in the Buchanan Service Center.

Onsite equipment and supplies for the treatment of injured and/or contaminated personnel are controlled by Health Physics Procedures and the Emergency Plan and its Implementing Procedures.

11.2.5.6 Treatment Procedures and Techniques

The procedure and techniques used to treat injured and/or contaminated personnel are addressed by Health Physics procedures and the Emergency Plan and its Implementing Procedures.

11.2.5.7 Qualifications of Medical Personnel

Arrangements with local hospitals with qualified personnel to provide medical services for injured and/or contaminated personnel are included in the Emergency Plan and its Implementing Procedures.

Onsite Emergency Medical Technicians are certified by New York State. First Aid responders are certified by the American Red Cross, the American Heart Association or other certified First Aid / CPR training association. Health Physics technicians receive personnel decontamination training.

11.2.5.8 Transport of Injured Personnel

Arrangements for ambulance service to transport injured and/or contaminated personnel to local hospitals are included in the Emergency Plan and its Implementing Procedures.

11.2.5.9 Hospital Facilities

Arrangements with local hospitals with qualified personnel to provide medical services for injured and/or contaminated personnel are included in the Emergency Plan and its Implementing Procedures.

11.2.6 Evaluation of Radiation Protection

In the event of an accident involving a major release of core activity to the containment (e.g., the large break Loss-of-Coolant Accident with core degradation), the shielding provided by the containment protects the personnel in the control room from receiving excessive doses from the activity inside the containment. The dose to control room operators following the postulated large break LOCA includes the dose from the activity entering the control room, the direct dose from the cloud of activity outside the control room, and the direct dose from the radiation emanating from the containment. The control room doses are discussed in Section 14.3.6.5.

Liquid Waste Release

All liquid waste releases will be assayed for radioactivity to comply with the limits (one-tenth of 10 CFR 20) for unrestricted areas specified.

11.2.7 Tests and Inspections

Complete radiation surveys were made throughout the plant containment and auxiliary building during initial phases of plant startup. Survey data were taken and compared to design levels at power levels of 10-percent, 50-percent, and 100-percent of rated full power. Survey data were reviewed for conformance to design levels before increasing to the next power range.

The gas and particulate effluent monitors shall be tested at each refueling shutdown with calibrated sources and normal response of each monitor shall be tested daily using a remotely-operated test source to verify the instruments response. Liquid effluent monitors shall be tested at each refueling shutdown with calibrated sources and normal response of each monitor shall be tested daily using a remotely-operated test source to verify the instruments response.

11.2.8 Handling and Use of Sealed Special Nuclear, Source and By-Product Material

A. Tests for leakage and / or contamination shall be performed as follows:

1. Each sealed source, with a half-life greater than thirty days, shall be tested for leakage and / or contamination at intervals not to exceed six months (see 11.2.8.A.2 for testing of sealed sources that are stored and not being used).

*[**Note** - Does not apply to startup sources subject to core flux, tritium, and material in gaseous form.]*

2. Sealed sources that are stored and not being used shall be tested for leakage prior to any use or transfer to another user unless they have been leak tested within six months prior to the date of use or transfer. In the absence of a certificate indicating that a test has been made within six months prior to the transfer, sealed sources shall not be put into use until tested.

3. Startup sources shall be leak tested prior to being subjected to core flux and following repair or maintenance to the source.

B. Sealed sources are exempt from 11.2.8.A when the source contains:

1. Less than or equal to 100 microcuries of beta and / or gamma emitting material, or
2. Less than or equal to 5 microcuries of alpha emitting material.

C. The leakage test shall be capable of detecting the presence of 0.005 microcuries of radioactive material on the test sample.

D. If the leakage test reveals the presence of 0.005 microcuries or more of removable contamination, the sealed source shall immediately be withdrawn from use and either decontaminated and repaired, or be disposed of in accordance with USNRC regulations.

E. If the leakage test reveals the presence of 0.005 microcuries or more of removable contamination, a special report shall be prepared and submitted to the Commission within 30 days.

REFERENCES FOR SECTION 11.2

1. Letter from W. Starostecki, NRC, to J. D. O'Toole, Con Edison, Subject: Inspection 50-247/83-14, dated July 5, 1983.

2. Letter from S. A. Varga, NRC, to J. D. O'Toole, Con Edison, Subject: Indian Point Unit 2 - NUREG 0737, Item II.B.2.2, Corrective Actions for Access to Vital Areas, dated October 26, 1983.

3. Deleted

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11. Deleted

12. Not Used

13. Deleted

14. Deleted

15. Deleted

16. Deleted

17. Deleted

18. Letter from R. C. DeYoung, NRC, to A. Hauspurg, Con Edison, Subject: Notice of Violation and Order Modifying License (NRC Inspection Nos.50-247/84-13 and 50-247/84-22), dated September 27, 1984.

19. Letter from J. D. O'Toole, Con Edison, to T. E. Murley, NRC, Subject: Response to Order Modifying License - Radiation Protection Plan Improvements, dated November 21, 1984.

20. Letter from J. D. O'Toole, Con Edison, to T. E. Murley, NRC, Subject: Revised Radiation Protection Oversight Committee Charter, dated February 14, 1985.

21. Letter from T. E. Murley, NRC, to J. D. O'Toole, Con Edison, Subject: Approval of Radiation Protection Action Plan, dated April 12, 1985.

22. Letter from M. Selman, Con Edison, to T. E. Murley, NRC, Subject: Plan for Maintaining Effectiveness of Radiation Protection Upgrade Programs, dated January 8, 1986.

23. Letter from T.E. Murley, NRC, to A. Hauspurg, Con Edison, Subject: Completion of Requirements of Order Modifying License, dated August 18, 1986.

24. Letter from S. A. Varga, NRC, to J. D. O'Toole, Con Edison, Subject: Completion of Review of NUREG-0737, Item II.E.4.2.6 and II.E.4.2.7 (with attached Safety Evaluation Report), dated November 9, 1982.

BIBLIOGRAPHY FOR SECTION 11.2

Comprehensive Public Water Supply Study for the New York City of New York and County of Westchester, Report CPWS-27, (submitted by Metcalf and Eddy, Hazen and Sawyer, and Malcolm Pirnie Engineers to the New York State Department of Health), August 1967.

TABLE 11.2-1
DELETED

TABLE 11.2-2
Primary Shield Neutron Fluxes and Design Parameters

Calculated Neutron Fluxes

Energy Group	Incident Fluxes (n/cm^2- sec)	Leakage Fluxes (n/cm^2 - sec)
E > 1 MeV	7.2×10^8	2.6×10^2
5.3 KeV ≤ E ≤ 1 MeV	1.0×10^{10}	5.9×10^2
.625 eV ≤ E ≤ 5.2 KeV	5.3×10^9	1.1×10^3
E < .625 eV	1.5×10^9	8.8×10^4

Design Parameters

Core thermal power	3216 MWt
Active core height, in.	144
Effective core diameter, in.	132.7
Baffle wall thickness, in.	1.125
Barrel wall thickness, in.	2.25
Thermal shield wall thickness, in.	2.75
Reactor vessel I.D., in	173.0
Reactor vessel wall thickness, in.	8.625
Reactor coolant cold-leg temperature	555°F
Reactor coolant hot-leg temperature	613°F
Maximum thermal neutron flux exiting primary concrete	10^6 n/cm^2-sec
Reactor shutdown dose exiting primary concrete	< 15 mrem/hr

TABLE 11.2-3
Secondary Shield Design Parameters

Core power density	98.5 w/cm^3
Reactor coolant liquid volume	12,600-ft^3
Reactor coolant transit times (sec):	
Core	0.817
Core exit to steam generator inlet	2.001
Steam generator inlet channel	0.592
Steam generator tubes	3.220
Steam generator tubes to vessel inlet	2.758
Vessel inlet to core	2.167
Total out of core	10.738
Full power dose rate outside secondary shield	<0.75 mrem/hr

TABLE 11.2-4
Accident Shield Design Parameters

Core thermal power	3216 Wt
Minimum full power operating time	1000 days
Equivalent fraction of core melting	1.0
Fission product fractional releases:	
Noble gases	1.0
Halogens	0.5
Remaining fission product inventory	0.01
Cleanup rate following accident	0
Maximum integrated direct dose (1-wk exposure) in control room	<1.5 rem
Maximum integrated direct dose (1-wk exposure) at the site boundary	<350 mrem

TABLE 11.2-5
Refueling Shield Design Parameters

Total number of fuel assemblies	193
Minimum full power exposure	1000 days
Minimum time between shutdown and fuel handling	56 hours
Maximum dose rate adjacent to spent fuel pit	0.75 mrem/hr
Maximum dose rate at water surface	2.0 mrem/hr

TABLE 11.2-6
Principal Auxiliary Shielding

Component	Concrete Shield Thickness
Demineralizers	4-ft - 0-in.
Charging pumps	2-ft - 6-in.
Liquid waste holdup tank	2-ft - 6-in.
Volume control tanks	3-ft - 6-in.
Reactor coolant filter	3-ft - 6-in.
Gas stripper	2-ft - 6-in.
Gas decay tanks	3-ft - 6-in.
Gas compressor	2-ft - 0-in.
Waste evaporator	2-ft - 0-in.
High radiation sampling system sentry panels	1-ft - 6-in.[1]
Motor control centers and support equipment	1-ft – 0-in.

Design parameters for the auxiliary shielding include:

Core thermal power	3216 MWt
Fraction of fuel rods containing small cladding defects	0.01
Reactor coolant liquid volume	12,600-ft^3
Letdown flow (normal purification)	75 gpm
Effective cesium purification flow	7 gpm
Cut-in concentration deborating demineralizer	150 ppm
Dose rate outside auxiliary building	0.75 mrem/hr
Dose rate in the building outside shield walls	0.75 mrem/hr

Notes:
1. This represents shielding minimum for the panels. The panels themselves contain 7 in. lead shot shielding sandwiched between two steel plates. The base of the panels (up to a height of 2-ft 9-in.) is also shielded by lead shot shielding sandwiched between two steel plates.

TABLE 11.2-7 (Sheet 1 of 3)
Radiation Monitoring Channel Data

Effluent Monitors

Channel	Stream Monitored	Normal Maximum Channel Output
R-27*	High Range, Noble Gas	1.0×10^5 uCi/cc
R-39*	Service Water from	1.0×10^7 CPM
R-40*	Component Cooling Heat Exchangers	1.0×10^7 CPM
R-43*	Plant Vent Air Particulate	1.0×10^7 CPM
	Plant Vent Air Iodine	1.0×10^7 CPM
R-44	Plant Vent Air Gaseous	1.0×10^7 CPM
R-45	Condenser Air Ejector Discharge	1.0×10^5 uCi/cc
R-46	Service Water Returns from	1.0×10^7 CPM
R-53	Containment Fan Cooler Units	1.0×10^7 CPM
R-48	Waste Condensate Tank Discharge Line	1.0×10^7 CPM
R-49	Steam Generator Blowdown	1.0×10^7 CPM
R-50	Waste Gas Decay Tanks	5.0×10^4 uCi/cc
R-51	Secondary Boiler Blowdown Purification System	1.0×10^7 CPM
R-52*	Secondary Boiler Blowdown Purification System Cooling Water	1.0×10^7 CPM
R-54	Liquid Waste Distillate	1.0×10^7 CPM
R-55A*	Steam Generator Blowdown Secondary System	1.0×10^7 CPM
R-55B*		1.0×10^7 CPM
R-55C*		1.0×10^7 CPM
R-55D*		1.0×10^7 CPM
R-57	Sewage Effluent Discharge	1.0×10^7 CPM
R-60*	Stack Air Gaseous	1.0×10^7 CPM
	Stack Air Particulate*	1.0×10^7 CPM
	Stack Air Iodine*	1.0×10^7 CPM
R-62	Unit 1 Sphere Foundation Sump	1.0×10^7 CPM
R-5976*	Maintenance & Outage Building Gaseous	1.0×10^7 CPM
	Maintenance & Outage Building Particulate	1.0×10^7 CPM

TABLE 11.2-7 (Sheet 2 of 3)
Radiation Monitoring Channel Data

Process Monitors

Channel	Stream Monitored	Normal Maximum Channel Output
R-41	Containment Air Particulate	1.0×10^7 CPM
R-42	Containment Air Gaseous	1.0×10^7 CPM
R-47	Component Cooling Water	1.0×10^7 CPM
R-59	House Service Boiler Condensate	1.0×10^7 CPM
R-28*	Main Steam Line High Radiation	1.0×10^6 CPM
R-29*		1.0×10^6 CPM
R-30*		1.0×10^6 CPM
R-31*		1.0×10^6 CPM
R-38-1	Control Room Air Intake	1.0×10^3 mR/hr
R-38-2		1.0×10^3 mR/hr
R-61A*	Main Steam Line, N-16	1.0×10^4 CPM
R-61B*		1.0×10^4 CPM
R-61C*		1.0×10^4 CPM
R-61D*		1.0×10^4 CPM

TABLE 11.2-7 (Sheet 3 of 3)
Radiation Monitoring Channel Data

Area Monitors

Channel	Stream Monitored	Normal Maximum Channel Output
ARM-1	Unit 1 Drum Storage	1.0×10^3 mR/hr
ARM-2	Unit 1 Pedestrian Tunnel	1.0×10^3 mR/hr
ARM-3	Unit 1 Nuclear Services Building Valve Room	1.0×10^3 mR/hr
ARM-4	Unit 1 Evaporator Bottom Room	1.0×10^3 mR/hr
ARM-5	Unit 1 Fuel Handling Floor	1.0×10^3 mR/hr
R-1	Control Room	1.0×10^4 mR/hr
R-2	Containment by Personnel Hatch	1.0×10^4 mR/hr
R-4	Charging Pump Room / PAB Area	1.0×10^4 mR/hr
R-5	Spent Fuel Building	1.0×10^4 mR/hr
R-6	Sample Room	1.0×10^4 mR/hr
R-7	Incore Instrument Area in Containment	1.0×10^4 mR/hr
R-25* R-26*	Containment High Range Radiation	1.0×10^{10} mR/hr 1.0×10^{10} mR/hr
R-37-1 R-37-2 R-37-3	Post Accident Sampling System	1.0×10^7 mR/hr 1.0×10^7 mR/hr 1.0×10^7 mR/hr
R-5987	PAB Breaker Service Area	1.0×10^4 mR/hr

Note:

* This listing does not apply the requirements of the Technical Specifications, Technical Requirements Manual, or Offsite Dose Calculation Manual (ODCM) to any radiation monitor that was not installed as a result of an NRC requirement, but was installed as an enhancement or as a means of providing additional information to plant personnel, such as the R-61A through R-61D radiation monitors.

Radiation monitors listed as Effluent Radiation Monitors in UFSAR Table 11.2-7 and not specifically listed in Technical Requirements Manual Table 3.3.G-1, ODCM Table D 3.3.1-1, ODCM Table D 3.3.2-1, or Unit 1 Technical Specifications Section 5.2.5 will continue to maintain surveillance requirements imposed by ODCM Table D 3.3.1-1 or ODCM Table D 3.3.2-1 for daily, monthly, quarterly and refueling frequencies.

TABLE 11.2-7a
DELETED

TABLES 11.2-8 through 11.2-13
DELETED

11.2 FIGURES

Figure No.	Title
Figure 11.2-1	Deleted
Figure 11.2-2	Deleted
Figure 11.2-3	Deleted
Figure 11.2-4	Deleted
Figure 11.2-5	Deleted
Figure 11.2-6	Deleted

Appendix 11A
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Appendix 11B
DETERMINATION OF RIVER WATER DILUTION FACTORS BETWEEN THE INDIAN POINT SITE AND THE NEAREST PUBLIC DRINKING WATER INTAKES

LIST OF TABLES

Table and Title

LIST OF FIGURES

Figure and Title

Appendix 11B
DETERMINATION OF RIVER WATER DILUTION FACTORS BETWEEN THE INDIAN POINT SITE AND THE NEAREST PUBLIC DRINKING WATER INTAKES

The analytical techniques used to analyze the dispersion of continuous and burst releases of liquids are discussed in detail in "Transport of Contaminants in the Hudson River above Indian Point Station," which is referenced in Section 2.5.

There are two potential sources of drinking water in the Hudson River, namely, New York City's Chelsea Pumping Station and the Castle Point Veteran's Hospital. The city of New York's Chelsea Pumping Station is located about 1 mile north of Chelsea, New York, on the east bank of the Hudson River. The pumping station is 22 miles upriver from Indian Point measured along the centerline of the river. The Castle Point Veteran's Hospital is a relatively small intake located approximately 21 miles upriver from the proposed site.

Analyses have been conducted to determine the difference in concentration at Chelsea and Castle Point Veteran's Hospital. The difference in concentration is small; hence, the discussion of the potential intake, namely, Chelsea, is sufficient. (See Reference 3 of Section 2.5 for continuous and burst releases.)

The River drought conditions analyzed have been characterized in terms of salinity because the operation of the Chelsea Station is dependent on the level of salt at the station. Consider the following five drought conditions, i.e., salinities at Chelsea:

Salt Concentration in ppm		Runoff (cfs)	Dispersion Coefficient (Square miles/day)
At Chelsea	At Indian Point		
200	2300	5000	5.24
300	2800	4600	5.28
500	4000	4400	5.43
1000	5500	4000	6.00
2000	7000	3500	7.16

The first two drought conditions correspond to concentrations of salinity at Chelsea, at which the New York City Department of Water Resources would begin to be concerned about using Chelsea for New York City's water supply.

The third condition, a salinity of 500 ppm, corresponds to the "midthousand" level, which might constitute the maximum level at which Chelsea operation would be stopped. This also corresponds to the Public Health Service drinking water standard for total dissolved solids.

The fourth condition, a salinity of 1000 ppm, represents the maximum level at which Chelsea operation would be stopped.

The fifth condition, a salinity of 2000 ppm, corresponds to the highest levels of salinity known to have occurred at Chelsea and represents the most conservative river conditions used in this analysis. This concentration of salinity at Chelsea was reached in late November 1964 at the end of 6 months of Hudson River low flows. Support that the 1964 drought was the worst on record after regulation of the Hudson River is given in a recent report concerning the potential of the Hudson River supplementing New York City's water supply system.*

*[**Note** - "Comprehensive Public Water Supply Study for the New York City of New York and County of Westchester" - Report CPWS-27 submitted by Metcalf and Eddy, Hazen and Sawyer, and Malcolm Pirnie Engineers to the New York State Department of Health, August 1967.]*

The upstream movement of salt is the result of a rather delicate balance, which is struck between the salinity-induced density currents, which tend to drive the salt itself up the estuary, and fresh water flow, which tends to hold back the salt movement. The river's dispersion characteristics are strongly influenced by this phenomenon, so that salinity profiles become the chief means of estimating the longitudinal dispersion coefficient in the river.

Calculation of dispersion coefficients requires a knowledge of the salinity changes between two fixed points and the river's flow. The essential point, however, is that the behavior of a conservative substance is identical to the salt behavior, which is well-defined; hence, the salinity at Chelsea is an excellent indicator of the upstream movement of any pollutant introduced to the river below the station. This is explained as follows:

1. If salt is not present at Chelsea, then neither will any other pollutant, discharged many miles below Chelsea, be present at Chelsea.

2. When salt is present at Chelsea, the ratio between the salt concentrations at Indian Point and Chelsea is a measure of the "mechanical dilution," i.e., dilution due to the river's flow and dispersion characteristics for non-decaying pollutants.

Hence, for the five drought conditions cited above, the mechanical dilution factors between Indian Point Station and Chelsea may be obtained directly from the ratio of salinity at these two points and are as follows:

Runoff (cfs)	Mechanical Dilution
5000	11.5
4600	9.4
4400	8.0
4000	5.5
3500	3.5

To obtain the concentrations of decaying radionuclides at Chelsea, simple ratios of the salt concentrations at Indian Point and Chelsea are not used. Rather, a material balance on each isotope is struck over any segment of the river by considering the transport mechanisms of net flow and longitudinal dispersion, and the radioactive decay mechanism. The longitudinal dispersion coefficient is obtained from salt profiles. The approach is described in the reference cited above in Section 2.5.

To show how the significant parameters, namely, the salinity and the half-life affect the river's ability to reduce concentration of introduced pollutants, a study was made assuming a normalized continuous release rate for each isotope of 1 Ci/day and a normalized burst release for each isotope of 1 Ci. Since the concentrations at Chelsea are directly proportional to the source term, the normalized curves can be used to determine quickly the concentration at Chelsea due to a known burst or continuous release from Indian Point, or to determine dilution factors.

Continuous Release

A hypothetical case where primary coolant with 1-percent failed fuel being released directly to the discharge canal was considered so that the behavior of all isotopes of possible concern in the river could be presented. The activity is released at a constant rate, the value of which is set so that the MPC of the mix will not be exceeded in the discharge water. The most severe drought conditions have been utilized; for the continuous release, these consist of a long-term steady upstream runoff of 3500 cfs, which causes the salt concentration at Chelsea to reach 2000 ppm.

Other pertinent river parameters used in the analysis are as follows:

1. Longitudinal dispersion coefficient, "E" = 7.16 mi^2/day
2. Average cross-sectional area, "A" = 140,000-ft^2

The results of this analysis are presented in Table 11B-1 and the computational procedure follows:

1. Column 1 - Unit 3 PSAR, Column 2, Part B, Table 16 (E-3.1).
2. Column 2 - 0.693 divided by half-life in days.
3. Column 3 - allowable release rate based on MPC of mix in discharge canal.
4. Column 4 through 7 - computation procedure for continuos release, QL and M report to Con Edison on Chelsea concentrations (May 1966), and included in both Units 2 and 3 submittals. (Analyses appended to Section 2.5.)
5. Column 8 - concentration at Chelsea divided by concentration at Indian Point.

The minimum dilution factors for all isotopes of concern are given in column 8 of Table 11B-1.

For the effect of all three units at Indian Point releasing radioactivity to the river under the conditions described above, the corresponding Chelsea and Indian Point concentrations can be computed by multiplying the concentrations in these tables by 1,960,000/840,000 or 2.34, the ratio of the total condenser flow to the Units 2 or 3 condenser flow. This assumes that the mix distribution from each unit is the same.
Burst Release

The results of the normalized burst release studies are presented in Figures 11B-1 through 11B-5. They are based on a 1 Ci burst release of each isotope. The following conclusions can be reached from these Figures.

1. Referring to Figure 11B-1, the peak concentrations at Chelsea and Castle Point are for the purpose of this discussion essentially the same.

2. Referring to Figure 11B-2, variations in drought conditions, i.e., changes in low runoff values do not appreciably affect the peak concentrations at Chelsea.

3. Referring to Figure 11B-5, the runoff does not appreciably affect the time for an isotope to reach a peak concentration at Chelsea; the time to the peak is a weak function of half-life for isotopes with half-lives less than 100 days, and the time to the peak is not sensitive to half-life for isotopes with half-lives greater than 100 days.

4. Referring to Figures 11B-3 and 11B-4, short-lived (less than 1 day) isotopes will not reach Chelsea; peak concentrations of intermediate isotopes (1 day to 100 days) are strongly dependent on the half life.

The river dilution factor between Indian Point and Chelsea for the burst release is a nonapplicable concept. When the maximum radioactivity effect of each isotope occurs at Chelsea, the corresponding concentration of that isotope at Indian Point will be very low. Furthermore, Chelsea will not see the maximum concentration of each isotope at the same time. For these reasons, for the burst release, the concentration in the Hudson River is considered for Indian Point one-half day after the release and at Chelsea at the time when the concentration of the given isotope is maximum at that point. Zero time cannot be used at Indian Point because the equations used will yield infinity for the concentration at $x = 0$, $t = 0$. One-half day later was used because this corresponds to one tidal cycle, the minimum time necessary to provide the river mixing, which these equations presume.

Based on the above definition of dilution factor for the burst release, the minimum dilution factors for the burst release were determined for the drought condition resulting in 2000 ppm of salt at Chelsea. The hypothetical case where the entire primary coolant with fission product inventory due to operation with 1-percent failed fuel was dumped into the river was used to arrive at the dilution factors for all isotopes of concern. The results of this analysis are given in Table 11B-2 and the computational procedure is as follows:

1. Columns 1 and 2 - Taken from Table 9.2-5 (Unit No. 3 PSAR), entitled "Reactor Coolant System Equilibrium Activities," and computed using a primary coolant volume of 3.56×10^8 ml. Tritium activity of 890 Ci added later.

2. Columns 3 through 7 - Computation procedure for accidental release, QL and M report to Con Edison on Chelsea, May 1966, and included in Units 2 and 3 submittals (as appended to Section 2.5).

3. Column 8 - Based on burst release dilution factor definition cited above.

TABLE 11B-1 (Sheet 1 of 2)
Concentrations of Primary Coolant Isotopes in the
Hudson River at Indian Point and Chelsea

Hypothetical Continuous Release, One Percent Failed Fuel

MPC in Discharge Canal

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			Behavior At				
			Indian Point		Chelsea		
Isotope	Decay Rate (day^{-1})	Discharge Rate (µCi/day)	Concentration (µCi/ml)	Fraction of MPC	Concentration (µCi/ml)	Fraction of MPC	River Dilution Between Indian Point - Chelsea
Mn-54	2.3×10^{-3}	1.54×10^{2}	15.25×10^{-12}	1.5×10^{-7}	3.99×10^{-12}	3.99×10^{-8}	3.82
Mn-56	6.3	3.33×10^{4}	118.5×10^{-12}	1.2×10^{-6}	5.5×10^{-20}	5.5×10^{-16}	2.16×10^{9}
Co-58	0.97×10^{-2}	4.62×10^{3}	332×10^{-12}	3.3×10^{-6}	6.35×10^{-11}	5.35×10^{-7}	5.22
Fe-59	1.5×10^{-2}	1.07×10^{2}	6.77×10^{-12}	1.1×10^{-7}	1.05×10^{-12}	1.75×10^{-8}	6.45
Co-69	3.6×10^{-4}	5.45×10^{2}	61.8×10^{-12}	1.2×10^{-6}	1.73×10^{-11}	3.45×10^{-7}	3.58
Br-84	3.15×10^{-3}	1.63×10^{4}	1530×10^{-12}	-	-	-	-
Rb-88	5.6×10^{-3}	1.54×10^{4}	1.28×10^{-7}	-	-	-	-
Rb-89	6.48×10^{-3}	3.56×10^{4}	2870×10^{-12}	-	-	-	-
Sr-89	1.37×10^{-2}	1.20×10^{3}	76.4×10^{-12}	2.5×10^{-5}	1.25×10^{-11}	4.28×10^{-6}	6.11
Sr-90	0.69×10^{-4}	0.81×10^{2}	9.35×10^{-12}	3.1×10^{-5}	2.68×10^{-12}	8.92×10^{-6}	3.49
Y-90	2.6×10^{-4}	1.66×10^{2}	2.88×10^{-12}	1.4×10^{-7}	2.24×10^{-14}	1.12×10^{-9}	352
Sr-91	1.73	7.82×10^{2}	5.32×10^{-12}	0.8×10^{-7}	6.1×10^{-17}	8.70×10^{-13}	8.72×10^{4}
Y-91	1.2×10^{-2}	3.56×10^{2}	23.9×10^{-12}	8×10^{-7}	4.27×10^{-12}	1.34×10^{-7}	5.60
Mo-99	2.5×10^{-1}	1.96×10^{6}	3.47×10^{-8}	1.7×10^{-4}	2.84×10^{-10}	1.42×10^{-6}	122

TABLE 11B-1 (Sheet 2 of 2)
Concentrations of Primary Coolant Isotopes in the
Hudson River at Indian Point and Chelsea

Hypothetical Continuous Release, One Percent Failed Fuel

MPC in Discharge Canal

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			Behavior At				
			Indian Point		Chelsea		
	Decay Rate	Discharge Rate	Concentration	Fraction	Concentration	Fraction	River Dilution Between
Isotope	(day^{-1})	(µCi/day)	(µCi/ml)	of MPC	(µCi/ml)	of MPC	Indian Point - Chelsea
I-131	$8.62x10^{-2}$	$1.04x10^{6}$	$3.07x10^{-8}$	$1x10^{-1}$	$1.35x10^{-9}$	$4.5x10^{-3}$	22.7
Te-132	$0.9x10^{-2}$	$1.10x10^{5}$	$8.08x10^{-9}$	$2.7x10^{-4}$	$2.38x10^{-12}$	$7.94x10^{-7}$	3400
I-132	7.2	$3.56x10^{5}$	$1.18x10^{-9}$	$1.5x10^{-4}$	$1.63x10^{-19}$	$2.03x10^{-14}$	$7.25x10^{9}$
I-133	0.81	$8.05x10^{5}$	$7.97x10^{-9}$	$8x10^{-3}$	$2.82x10^{-12}$	$2.82x10^{-6}$	2830
Te-134	23	$1.16x10^{4}$	$21.6x10^{-12}$	-	-	-	-
I-134	19	$2.12x10^{5}$	$4.34x10^{-10}$	$2.2x10^{-5}$	$7.70x10^{-26}$	$3.85x10^{-21}$	$5.64x10^{15}$
Cs-134	$0.93x10^{-3}$	$1.36x10^{5}$	$1.47x10^{-8}$	$1.6x10^{-3}$	$4.01x10^{-9}$	$4.46x10^{-4}$	3.67
I-135	2.39	$8.05x10^{5}$	$4.58x10^{-9}$	$1.1x10^{-3}$	$5.88x10^{-15}$	$1.47x10^{-9}$	$7.8x10^{5}$
Cs-136	$5.14x10^{-2}$	$1.32x10^{4}$	$4.95x10^{-10}$	$6x10^{-6}$	$3.49x10^{-11}$	$3.88x10^{-7}$	14.2
Cs-137	$6.3x10^{-4}$	$5.76x10^{5}$	$6.34x10^{-8}$	$3.2x10^{-3}$	$1.91x10^{-8}$	$9.55x10^{-4}$	3.32
Cs-138	32	$2.62x10^{4}$	$41.8x10^{-12}$	-	-	-	-
Ba-140	$5.4x10^{-2}$	$3.56x10^{2}$	$12.1x10^{-12}$	$4x10^{-7}$	$9.09x10^{-13}$	$3.03x10^{-8}$	13.3
La-140	0.415	$3.70x10^{2}$	$5.1X10^{-12}$	$2.5X10^{-7}$	$1.33X10^{-14}$	$6.65X10^{-10}$	384
Ce-144	$2.44x10^{-3}$	$1.25x10^{3}$	$122.5x10^{-12}$	$1.2x10^{-5}$	$3.05x10^{-11}$	$3.05x10^{-6}$	4.02
Pr-144	$5.13x10^{-2}$	$1.37x10^{6}$	$5.13x10^{-8}$	-	-	-	-
Tritium		$1.49x10^{6}$	$1.74x10^{-7}$	$5.8x10^{-5}$	$4.75x10^{-8}$	$1.59x10^{-5}$	3.66
	Total	$9.15x10^{6}$					

TABLE 11B-2 (Sheet 1 of 2)
Concentrations of Radioisotopes the Hudson River at Indian Point and Chelsea

Accidental Loss of Entire Primary Coolant (One Percent Failed Fuel) in a Burst Release

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Equilibrium Activity in the Primary Coolant	River Concentrations at Indian Point One-Half Day After Release		Time for Maximum Concentrations to Reach Chelsea	Maximum River Concentrations at Chelsea		River Dilution Between Indian Point - Chelsea
Isotope	(Ci)	µCi/ml	Fractions of MPC	(days)	µCi/ml	Fractions of MPC	
Mn-54	0.092	5.83×10^{-9}	5.83×10^{-5}	20.4	2.22×10^{-11}	2×10^{-7}	2.9×10^{2}
Mn-56	19.9	2.26×10^{-10}	2.26×10^{-6}	1.4	2.68×10^{-16}	3×10^{-12}	7.5×10^{5}
Co-58	2.78	1.76×10^{-10}	1.76×10^{-6}	17.6	4.75×10^{-12}	5×10^{-8}	3.7×10^{1}
Fe-59	0.064	4.05×10^{-10}	6.75×10^{-6}	16.2	1.21×10^{-12}	2×10^{-7}	3.4×10^{1}
Co-60	0.29	1.84×10^{-9}	3.68×10^{-5}	21.4	8.18×10^{-11}	2×10^{-6}	1.8×10^{1}
Br-84	9.65	6.1×10^{-8}	-	0.7	2.87×10^{-26}	-	2.1×10^{18}
Rb-88	920	5.81×10^{-6}	-	0.5	2.3×10^{-30}	-	2.5×10^{24}
RB-89	1.95	2.39×10^{-8}	-	0.5	3.89×10^{-34}	-	6.2×10^{25}
Sr-89	0.91	5.73×10^{-9}	1.91×10^{-3}	16.5	1.94×10^{-10}	6×10^{-5}	6.2×10^{1}
Sr-90	0.049	3.1×10^{-10}	1.0×10^{-3}	21.6	1.2×10^{-11}	4×10^{-5}	2.5×10^{1}
Y-90	0.099	4.84×10^{-10}	2.42×10^{-4}	6.3	2.11×10^{-12}	1×10^{-7}	2.4×10^{2}
Sr-91	0.469	1.25×10^{-9}	1.79×10^{-5}	2.7	4.25×10^{-14}	6×10^{-10}	3×10^{4}
Y-91	19.9	1.20×10^{-7}	4.0×10^{-3}	17.0	4.01×10^{-9}	1×10^{-4}	4×10^{1}
Mo-99	1170	6.56×10^{-6}	3.28×10^{-2}	6.4	2.61×10^{-8}	1×10^{-4}	3.3×10^{2}

TABLE 11B-2 (Sheet 2 of 2)
Concentrations of Radioisotopes in the Hudson River at Indian Point and Chelsea

Accidental Loss of Entire Primary Coolant (One Percent Failed Fuel) in a Burst Release

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Equilibrium Activity in the Primary Coolant	River Concentrations at Indian Point One-Half Day After Release		Time for Maximum Concentrations to Reach Chelsea	Maximum River Concentrations at Chelsea		River Dilution Between Indian Point - Chelsea
Isotope	(Ci)	μCi/ml	Fractions of MPC	(days)	μCi/ml	of MPC	
I-131	622	3.8×10^{-6}	12.2	9.8	4.99×10^{-8}	1.7×10^{-1}	7.2×10^{1}
Te-132	65.7	4.14×10^{-7}	1.88×10^{-2}	18+	1.3×10^{-8}	4×10^{-4}	3.5×10^{1}
I-132	195	3.35×10^{-8}	4.18×10^{-3}	1.3	9.7×10^{-16}	1×10^{-10}	4.2×10^{7}
I-133	485	2.06×10^{-6}	2.06	3.8	8.03×10^{-10}	8×10^{-4}	2.6×10^{3}
Te-134	6.94	6.73×10^{-13}	-	0.8	5.6×10^{-24}	-	1.2×10^{11}
I-134	127	6.04×10^{-11}	3.02×10^{-6}	0.8	3.45×10^{-21}	2×10^{-16}	1.5×10^{10}
Cs-134	81.5	5.17×10^{-7}	574	21.1	2.01×10^{-8}	2.2×10^{-3}	2.6×10^{6}
I-135	485	9.3×10^{-7}	2.3×10^{-1}	2.2	6.62×10^{-12}	1.6×10^{-6}	1.4×10^{5}
Cs-136	7.9	5.0×10^{-8}	5.55×10^{-4}	11.5	8.98×10^{-10}	1×10^{-5}	5.6×10^{1}
Cs-137	348	2.20×10^{-6}	1.10×10^{-1}	21.6	8.73×10^{-8}	4.4×10^{-3}	2.5×10^{1}
Cs-138	15.7	1.09×10^{-15}	-	0.7	5.23×10^{-26}	-	2.1×10^{10}
Ba-140	0.212	1.35×10^{-9}	4.50×10^{-5}	11.5	2.3×10^{-11}	8×10^{-8}	5.6×10^{2}
La-140	0.22	1.15×10^{-9}	5.75×10^{-5}	5.2	1.95×10^{-12}	1×10^{-7}	5.8×10^{2}
Ce-144	0.075	4.74×10^{-10}	4.75×10^{-5}	20.3	1.78×10^{-11}	2×10^{-7}	2.4×10^{2}
Pr-144	0.082	5.19×10^{-10}	-	11.7	9.65×10^{-12}	-	5.4×10^{1}
Tritium	890	5.36×10^{-6}	1.79×10^{-3}	21.8	2.22×10^{-7}	8×10^{-4}	2.2×10^{0}

11B FIGURES

Figure No.	Title
Figure 11B-1	Iodine-131 Concentration vs Days After Burst Release From Indian Point for 1 Curie Release
Figure 11B-2	Iodin-131 Concentration vs Chelsea vs Days After Burst Release From Indian Point for 1 Curie Release
Figure 11B-3	Maximum Concentration vs Distance Upstream for 1 Curie Release
Figure 11B-4	Maximum Concentration at Chelsea vs Half-Life for 1 Curie Release
Figure 11B-5	Time to Reach Peak Concentration at Chelsea vs Half-Life for 1 Curie Release

Appendix 11C
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Appendix 11D
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TABLE 11D-1
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11D FIGURES

Figure No.	Title
Figure 11D-1	Deleted
Figure 11D-2	Deleted

Appendix 11E
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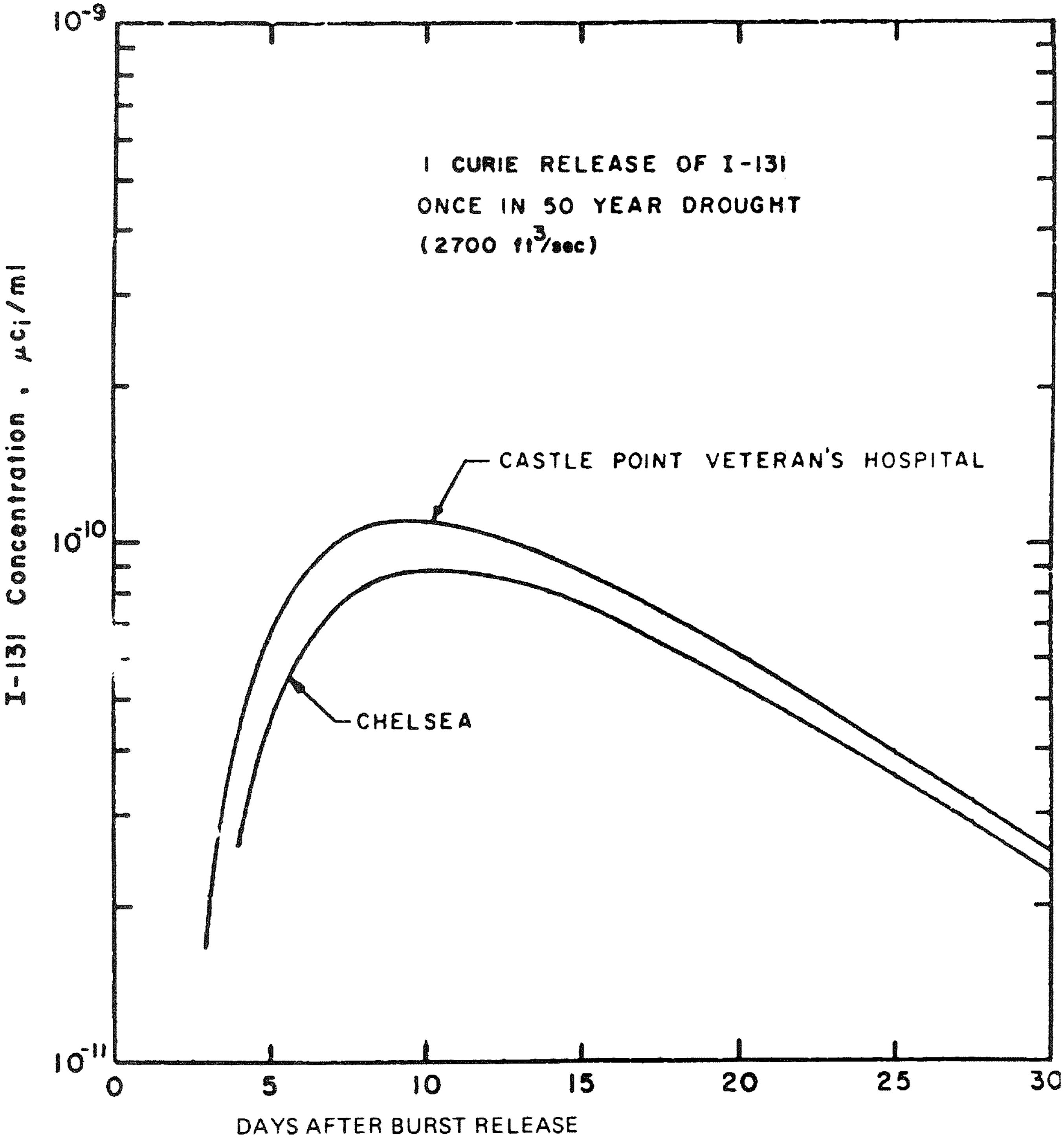
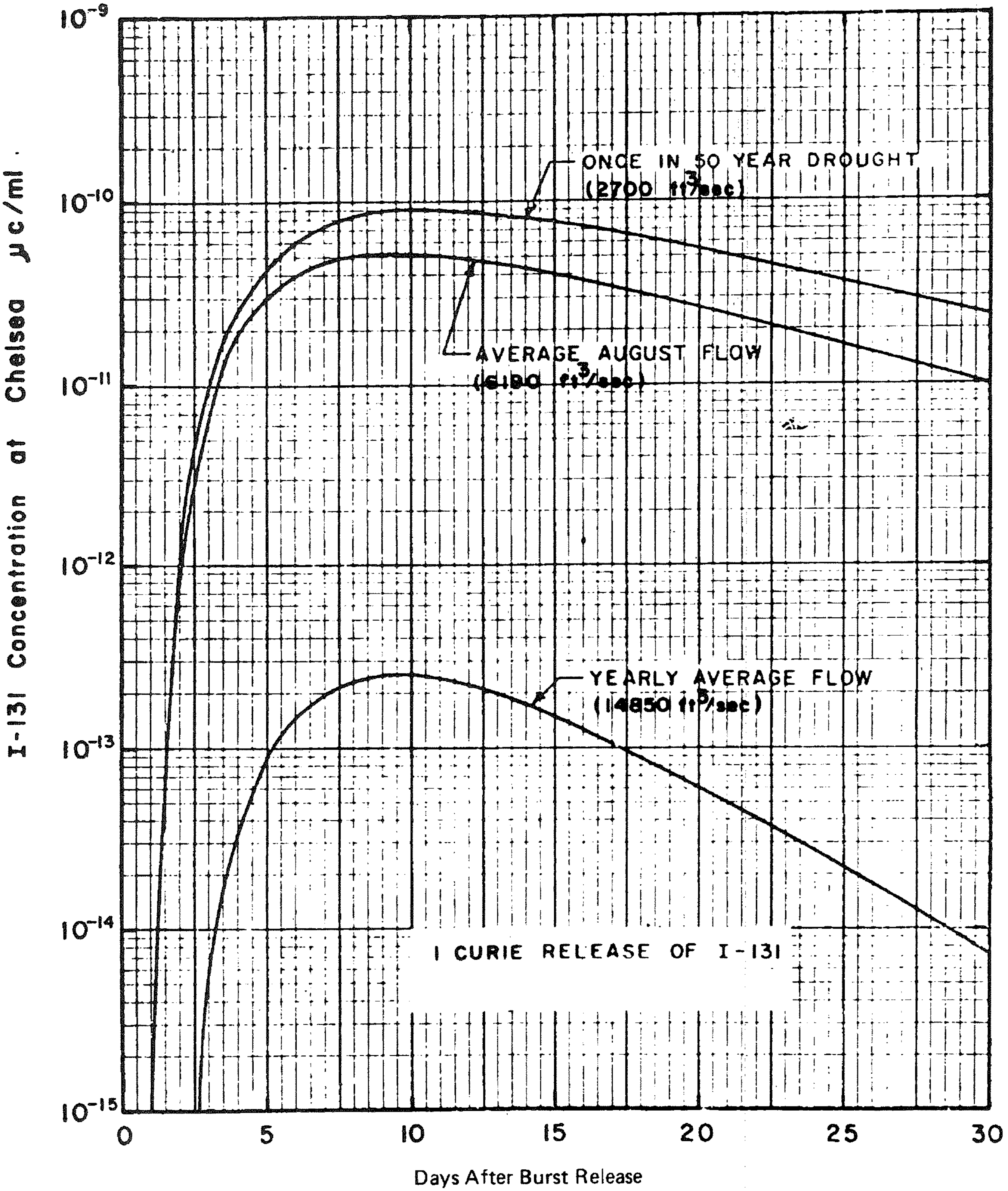
11E FIGURES

Figure No.	Title
Figure 11E-1	Deleted
Figure 11E-2	Deleted



INDIAN POINT UNIT No. 2	
UFSAR FIGURE 11B-1 IODINE-131 CONCENTRATION VS DAYS AFTER BURST RELEASE FROM INDIAN POINT FOR 1 CURIE RELEASE	
MIC. No. 1999MC3945	REV. No. 17A

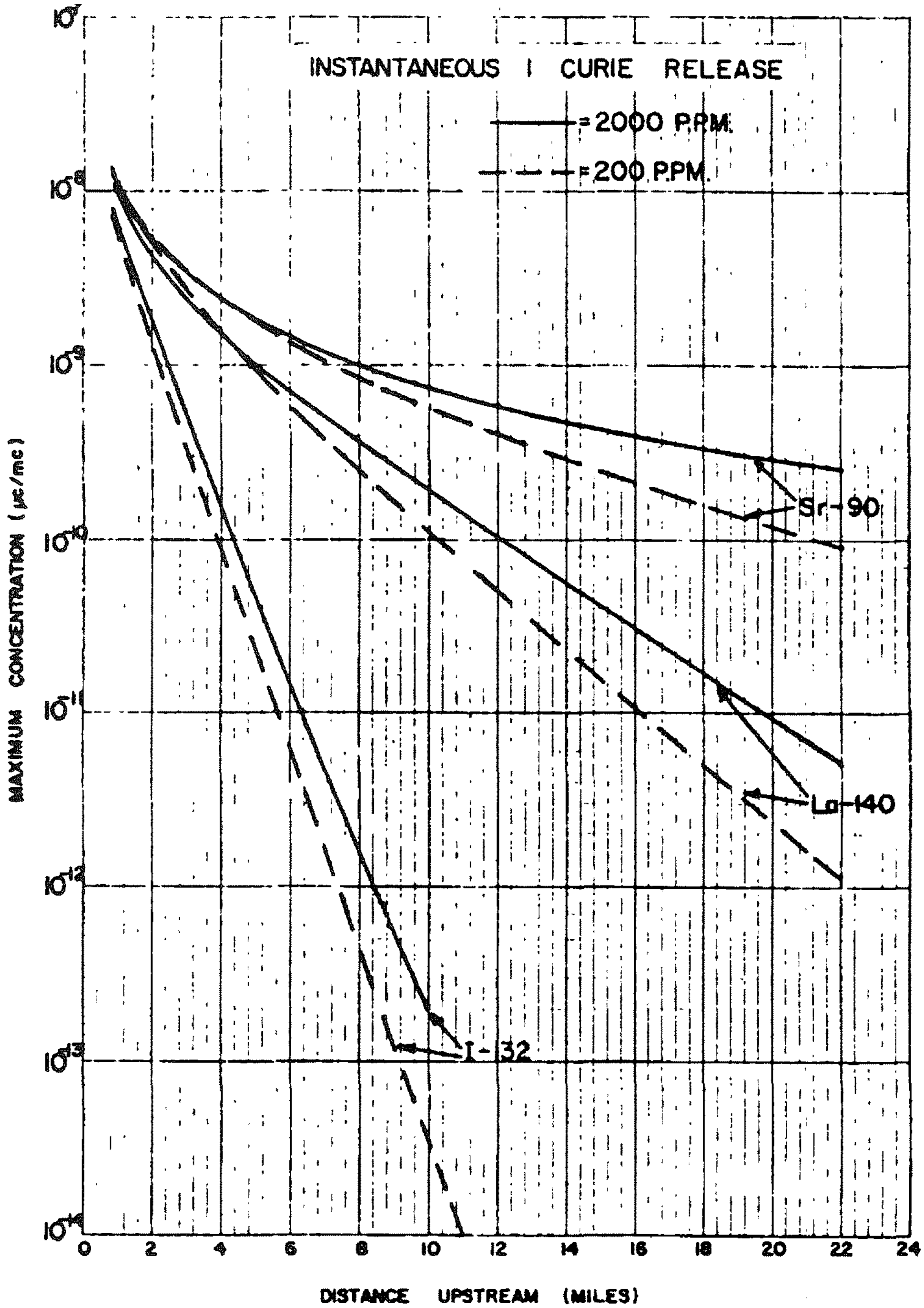


INDIAN POINT UNIT No. 2

UFSAR FIGURE 11B–2

IODINE–131 CONCENTRATION AT CHELSEA vs DAYS AFTER BURST RELEASE FROM INDIAN POINT FOR 1 CURIE RELEASE

MIC. No. 1999MC3946	REV. No. 17A

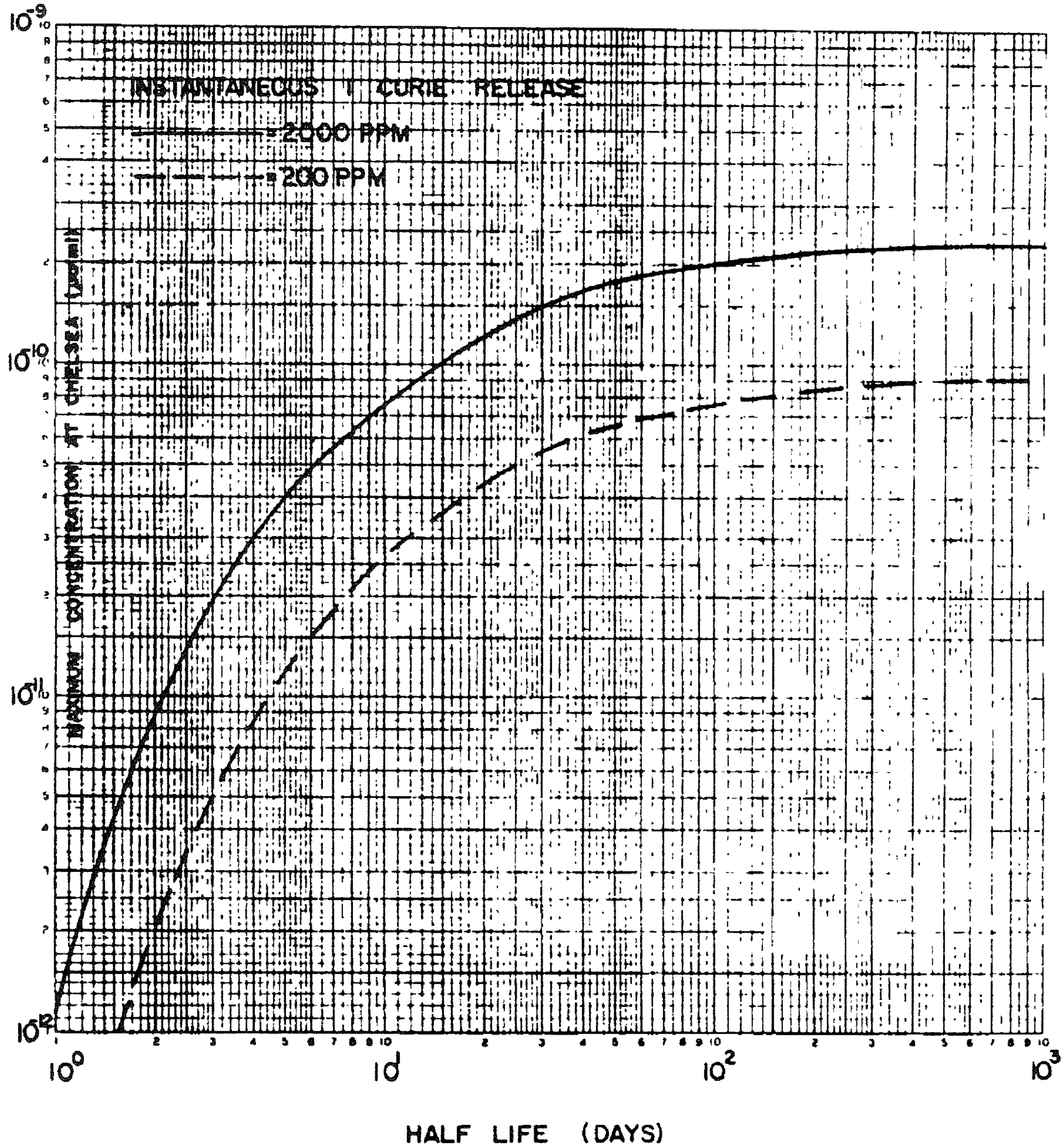


INDIAN POINT UNIT No. 2

UFSAR FIGURE 11B-3

MAXIMUM CONCENTRATION vs DISTANCE UPSTREAM FOR 1 CURIE RELEASE

MIC. No. 1999MC3947	REV. No. 17A

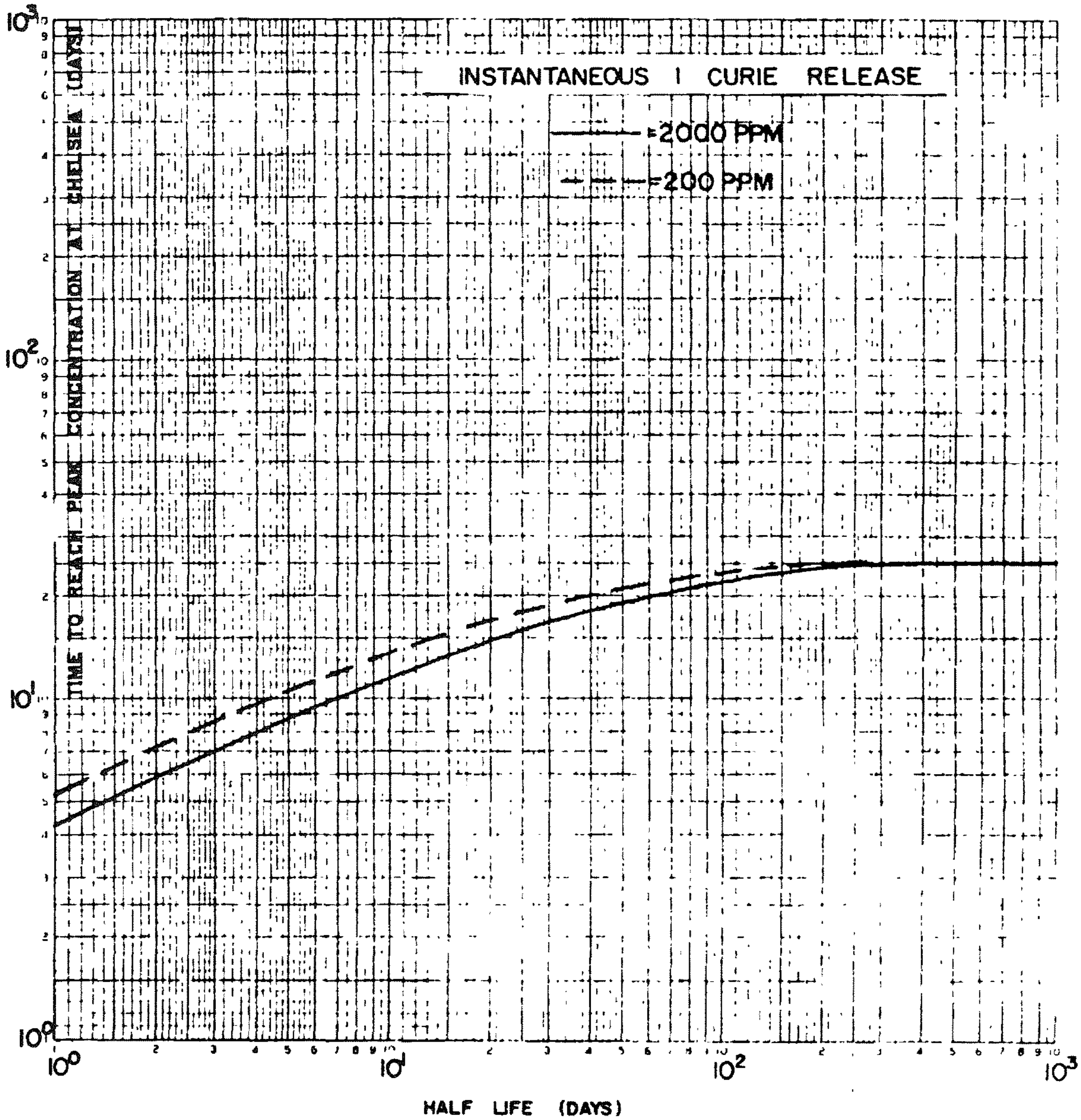


INDIAN POINT UNIT No. 2

UFSAR FIGURE 11B-4

MAXIMUM CONCENTRATION AT CHELSEA vs HALF-LIFE FOR 1 CURIE RELEASE

MIC. No. 1999MC3948	REV. No. 17A

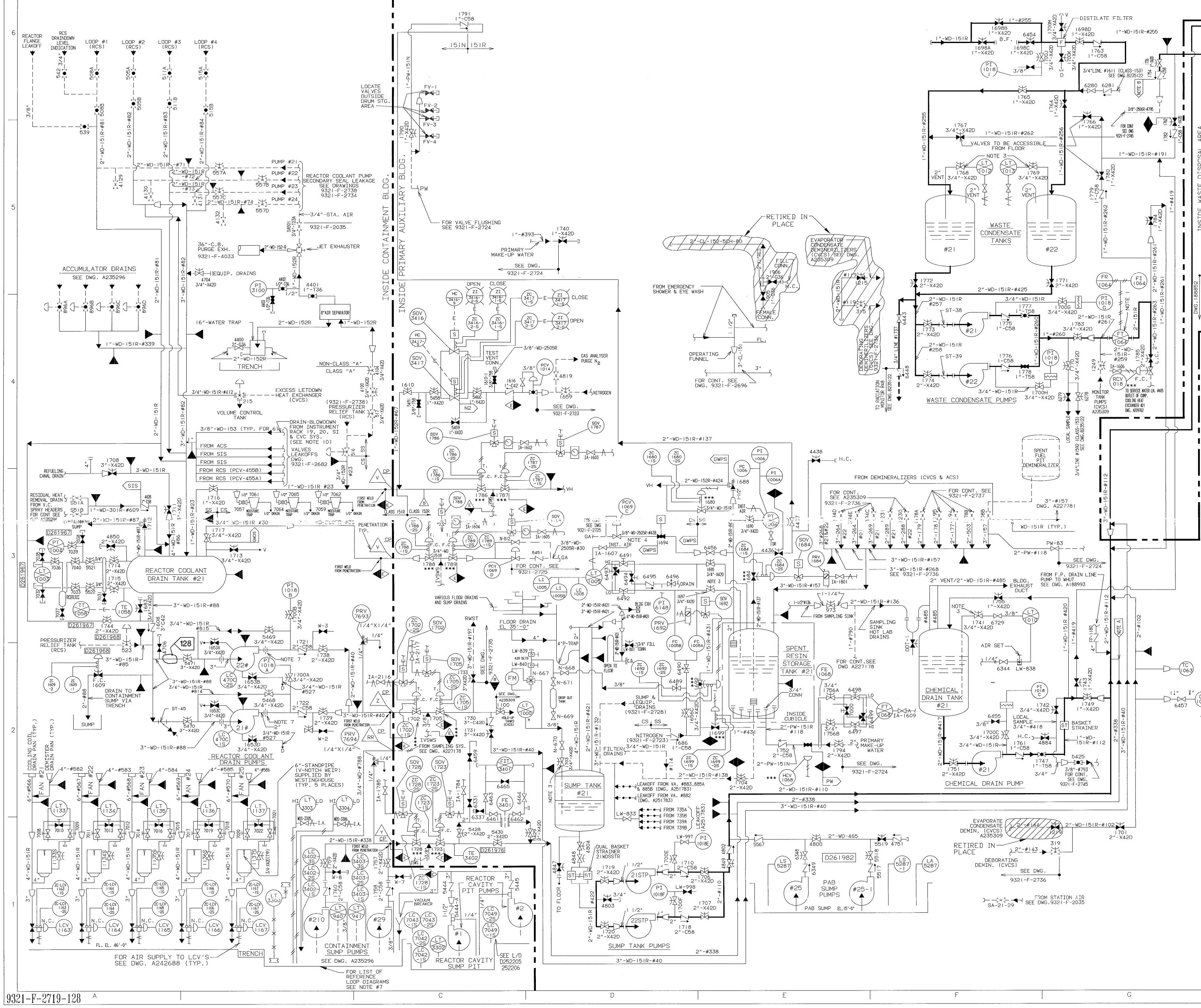


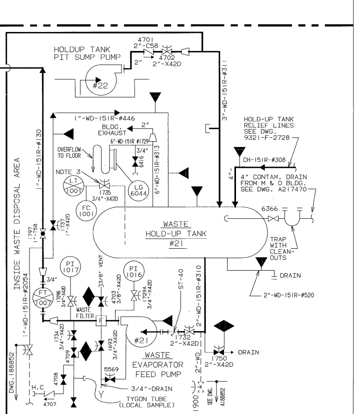
INDIAN POINT UNIT No. 2

UFSAR FIGURE 11B-5

TIME TO REACH PEAK CONCENTRATION AT CHELSEA vs HALF-LIFE FOR 1 CURIE RELEASE

MIC. No. 1999MC3949	REV. No. 17A





REV	DESCRIPTION	DATE	BY	CHK'D	APP.
128	INCORPORATED DRN-04-04579, ER-IP2-04-34741	12/16/04	GH		

REVISIONS

REVISION
USE .1 SIZE TEXT ONLY

REFERENCES

1. PROCESS FLOW DIAGRAM (W) DWG. 540 F 896.
2. DEFINITION OF SYMBOLS (W) E. SPEC. G675176 REV. 2
3. INSTRUMENTATION & CONTROL STANDARDS (W) SYMBOL & APPLICATIONS FOR INSTRUMENT DIAGRAMS. SECTION 1.1 ISSUED AUG. 12TH, 1966 (W) INSTRUMENT INSTALLATION SECTION 3.0 ISSUED NOV. 16TH, 1966
4. MATERIAL SPEC. & FITTINGS (W) E. SPEC. G569866 REV. 2 (W) E. SPEC. G676398 REV. 0

REFERENCE DRAWINGS

RCS - 9321-F-2738 - REACTOR COOLANT SYS.
ACS { 9321-F-2720 - AUXILIARY COOLANT SYS. / A227781
CVCS { 9321-F-2736 - CHEMICAL & VOLUME CONTROL SYS. / 9321-F-2737 - CHEMICAL & VOLUME CONTROL SYS. / A208168 - CHEMICAL & VOLUME CONTROL SYS.
SIS - 9321-F-2735 - SAFETY INJECTION SYS.
SS { 9321-F-2745 - SAMPLING SYS. / A227178
IVSWS-9321-F-2726 - ISOLATION VALVE SEAL WATER SYS.
PW - 9321-F-2724 - PRIMARY WATER SYS.
WDS { 9321-F-2730 - WASTE DISPOSAL SYS. / A188852 - INTEGRATED WASTE DISPOSAL SYS.
N2 - 9321-F-2723 - NITROGEN TO NUCLEAR EQUIP.
9321-F-2728 - NUCLEAR EQUIP. DRAIN
A209762 - SERVICE WATER SYS.
9321-C-2016 -FLOW DIAGRAM SYMBOLS

EVERYTHING ON THIS DRAWING (EXCLUDING THOSE PORTIONS SHOWN WITH DASH LINES) IS PART OF THE LIQUID WASTE PROCESSING SYSTEM (LWPS) LISTED IN EXHIBIT A.CI-240-1, EXCEPT AS SPECIFICALLY INDICATED HEREIN

N2 NITROGEN SUPPLY SYSTEM
PW PRIMARY WATER SYSTEM
GWPS GASEOUS WASTE PROCESSING SYSTEM
SIS SAFETY INJECTION SYSTEM
NOTE A BOUNDS THE CONTAINMENT SUMP SYS. AS LISTED IN EXHIBIT A, CI-240-1
NOTE B BEYOND THIS POINT LINE IS THE PART OF SAMPLING SYSTEM NOT LISTED IN CI-240-1

NOTES

1. FOURTEEN DIAMETERS OF STRAIGHT PIPE REQUIRED BETWEEN FLOW METER AND UP-STREAM TEE.
2. SCREEN SUPPLIED TO PREVENT RESIN BACKFLOW, 2"X 1" SW END, APPROX. 12" OVERALL LENGTH AND MOUNTED IN VERTICAL OREINTATION IN DRUMMING ROOM.
3. BUBBLER TUBE 3/4" CLASS 153, FOLLOWING VALVES REQUIRED FIELD INSTALLED 3/4" TUBE BY 3/4" PIPE INSERTS TO MATCH, 1741, 1703, 1695, 1735, 1697, 1768 & 1769
4. VALVE ACTUATED BY GAS ANALYZER, I & C CHANNEL AC-1067
5. WDS BUBBLERS OPERATE ON INSTRUMENT AIR EXCEPT SPENT RESIN STORAGE TANK CHANNEL LT-1005 WHICH USES NITROGEN (SEE SHEET 2, WDS).
6. ORIFICE PLATE AND FLANGE SUPPLIED WITH PUMP AND STAMPED WITH CORRESPONDING ITEM NUMBER.
7. SEE DWG'S D226016, D226020, D226074, D260110 & D260111.
8. *** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT & IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL DWG. 9321-F-7056.
9. THE QUALITY GROUP A,B,C, & SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN
10. ISOLATION VALVE FOR RACK 20 BLOWDOWN DRAIN IS VALVE #563.

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN ENTERGY AS
"CLASS A" ITEMS
PER THE QAPD

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

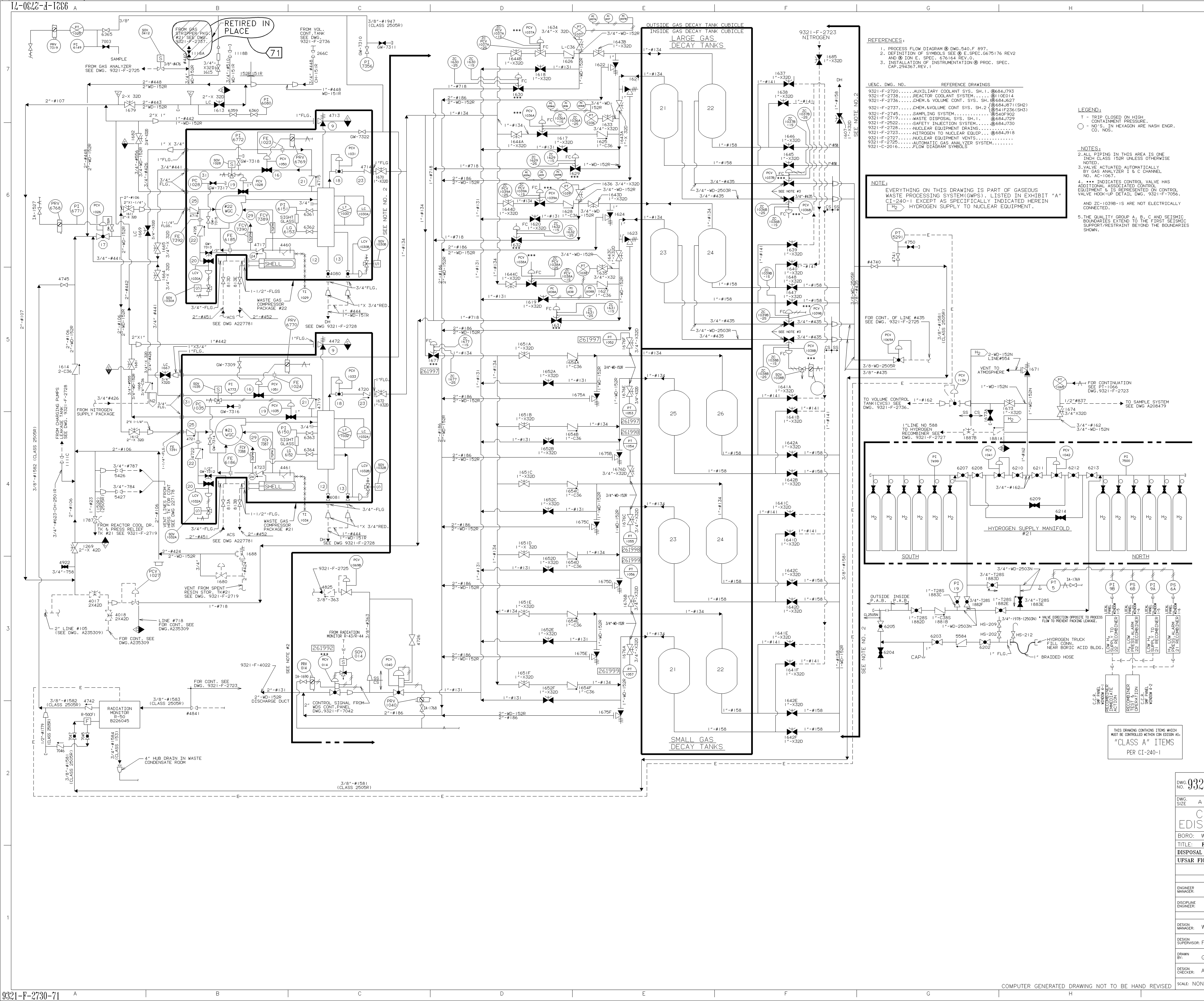
REVISION SIGNATURES

REV	DES	ENG

DWG. NO. 9321-F-2719-128
DWG. SIZE A | DWG. TYPE COMPANY
CON EDISON | STATION INDIAN POINT
BORO: WESTCHESTER
TITLE: FLOW DIAGRAM
WASTE DISPOSAL SYSTEM
- UFSAR FIGURE No. 11.1-1 (SHT. 1)

APPROVALS
ENGINEERING
ENGINEER MANAGER:
DISCIPLINE ENGINEER:
DESIGN
DESIGN MANAGER: W.J.KING 10-26-87
DESIGN SUPERVISOR: F.A. 10-26-87
DRAWN BY: B.JOHN 10-26-87
DESIGN CHECKER: E.D. 10-26-87
SCALE: NONE | DISCIPLINE CODE: MY

9321-F-2719-128



REFERENCES:

1. PROCESS FLOW DIAGRAM Ⓦ DWG.540.F 897.
2. DEFINITION OF SYMBOLS SEE Ⓦ E.SPEC.G675176 REV2 AND Ⓦ ION E. SPEC. 676164 REV.0.
3. INSTALLATION OF INSTRUMENTATION Ⓦ PROC. SPEC. CAP.294367.REV.1

UE&C. DWG. NO.	REFERENCE DRAWINGS
9321-F-2720	AUXILIARY COOLANT SYS. SH.1. Ⓦ684J793
9321-F-2738	REACTOR COOLANT SYSTEM...... Ⓦ110E014
9321-F-2736	CHEM.& VOLUME CONT. SYS. SH.1 Ⓦ684J627
9321-F-2737	CHEM.&VOLUME CONT SYS. SH.2 Ⓦ684J871(SH2) Ⓦ541F236(SH3)
9321-F-2745	SAMPLING SYSTEM............ Ⓦ540F902
9321-F-2719	WASTE DISPOSAL SYS. SH.1. Ⓦ684J729
9321-F-2522	SAFETY INJECTION SYSTEM...... Ⓦ684J730
9321-F-2728	NUCLEAR EQUIPMENT DRAINS............
9321-F-2723	NITROGEN TO NUCLEAR EQUIP... Ⓦ684J918
9321-F-2727	NUCLEAR EQUIPMENT VENTS.............
9321-F-2725	AUTOMATIC GAS ANALYZER SYSTEM........
9321-C-2016	FLOW DIAGRAM SYMBOLS

NOTE:

EVERYTHING ON THIS DRAWING IS PART OF GASEOUS WASTE PROCESSING SYSTEM(GWPS). LISTED IN EXHIBIT "A" CI-240-1 EXCEPT AS SPECIFICALLY INDICATED HEREIN
H2 HYDROGEN SUPPLY TO NUCLEAR EQUIPMENT.

LEGEND:

T - TRIP CLOSED ON HIGH CONTAINMENT PRESSURE.
⬡ - NO'S. IN HEXAGON ARE NASH ENGR. CO. NOS.

NOTES:

2. ALL PIPING IN THIS AREA IS ONE INCH CLASS 152R UNLESS OTHERWISE NOTED.
3. VALVE ACTUATED AUTOMATICALLY BY GAS ANALYZER I & C CHANNEL NO. AC-1067.
4. *** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT & IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL DWG. 9321-F-7056.

AND ZC-1039B-1S ARE NOT ELECTRICALLY CONNECTED.

5. THE QUALITY GROUP A, B, C AND SEISMIC BOUNDARIES EXTEND TO THE FIRST SEISMIC SUPPORT/RESTRAINT BEYOND THE BOUNDARIES SHOWN.

REVISION
USE .1 SIZE TEXT ONLY

71
THIS REVISION IS NON CLASS PER CI-240-1. UPDATED DRAWING TO SHOW RETIRED BORON RECOVERY EQUIPTMENT PER CRS #199806527. RELEASED AS CONSTRUCTED P.N. 69901-AF.
D.B./Y.J. 02/09/01

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS:
"CLASS A" ITEMS
PER CI-240-1

REVISION SIGNATURES

REV	DES	ENG
71		G. BHALLA 02/09/2001

DWG. NO. 9321-F-2730-71

DWG. SIZE A | DWG. TYPE COMPANY

CON EDISON | STATION: INDIAN POINT

BORO: WESCHESTER

TITLE: **FLOW DIAGRAM WASTE DISPOSAL SYSTEM SHT. No. 2**

UFSAR FIG. No. 11.1-1 (SHT. 2)

APPROVALS

ENGINEERING

ENGINEER MANAGER:

DISCIPLINE ENGINEER:

DESIGN

DESIGN MANAGER: W.J. KING/G.C. 1-13-88

DESIGN SUPERVISOR: F.A. 1-13-88

DRAWN BY: GIBBS & HILL

DESIGN CHECKER: A.G. 1-13-88

SCALE: NONE | DISCIPLINE CODE: MY

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

9321-F-2730-71

CHAPTER 12
CONDUCT OF OPERATIONS

12.1 ORGANIZATION AND RESPONSIBILITY

Operation and maintenance of the Indian Point Unit 2 facility is the responsibility of the Entergy Nuclear organization. The management organization and functional responsibilities as they relate to the operation and maintenance of the Indian Point facility are discussed in Section 1.10.3 and in the Quality Assurance Program Manual (QAPM).

12.1.1 Facility Staff

The corporate officer with direct responsibility for the plant shall be responsible for overall facility activities and shall delegate in writing the succession to this responsibility during his absence.

The Plant Manager is responsible for overall unit safe operation and has control over those onsite activities necessary for safe operation and maintenance of the plant.

The facility organization, duty shift composition, control room occupancy, and other requirements for reactor operational and refueling personnel are in accordance with the Technical Specifications.

A fire brigade is maintained on the site at all times. The organization, operation and training of the fire brigade is discussed in the document under separate cover entitled, "IPEC Fire Protection Program Plan."

12.1.2 Facility Staff Qualifications

Each member of the facility staff meets or exceeds the minimum qualifications of ANSI / ANS-3.1-1978 for comparable positions, except for (1) the Operations Manager and the Assistant Operation Manager's SRO license requirement which shall be in accordance with Technical Specification 5.2.2.e, and (2) the Radiation Protection Manager who meets or exceeds the minimum qualifications of Regulatory Guide 1.8, September 1975.

The Plant Manager meets or exceeds the minimum qualifications specified for Plant Manager in ANSI / ANS-3.1-1978.

Each Watch Engineer has a bachelor's degree or equivalent in a scientific or engineering discipline with specific training in plant design, and response and analysis of the plant for transients and accidents.

TABLE 12.1-1
DELETED

12.1 FIGURES

12.2 TRAINING

A retraining and replacement training program for the facility staff is maintained under the direction of the Nuclear Training Manager and meets or exceeds the requirements and recommendations of Section 5.5 of ANSI / ANS-3.1-1978, 10 CFR Part 55 and the requirements of the Technical Specifications.

Other areas of operator training are included in the overall plant training program. These specific areas are the training or retraining of plant personnel on specific procedures in accordance with the TMI Lessons Learned implementation schedule and the modification of reactor operator qualifications relating to experience and training. Details of these additional areas of training are included in References 1 and 2.

The training program for the fire brigade is described in the document under separate cover entitled, "IPEC Fire Protection Program Plan."

An emergency plan training program is maintained to cover licensee and non-licensee individuals or groups assigned to the various functional areas of emergency activity.

Radiation protection training is given to personnel requiring unescorted access to controlled areas of the plant.

The initial and requalification training programs for reactor operators and senior reactor operators include instruction in heat transfer, fluid flow, thermodynamics, and mitigation of accidents involving a degraded core as required by NUREG-0737.

Operating personnel from the Plant Manager through the operations chain to the reactor operators and watch engineers receive training in the use of installed systems to control or mitigate accidents that severely damage the core as required by NUREG-0737.

Training requirements for the security force are set forth in the "Security Force Training and Qualification Plan, Indian Point Units 1 and 2."

REFERENCES FOR SECTION 12.2

1. Letter from P. Zarakas, Con Edison, to H Denton, NRC, Subject: Actions Taken To Comply With 30 Day Requirement in the NRC Confirmatory Order of February 11, 1980, dated March 11, 1981.

2. Letter from J. D. O'Toole, Con Edison, to D. G. Eisenhut, NRC, Subject: RC Interim Staffing Criteria, dated January 7, 1981.

12.3 WRITTEN PROCEDURES

Written procedures and administrative policies are established, implemented, and maintained in accordance with the Quality Assurance Program Manual (QAPM).

12.3.1 Emergency Operating Procedures

Emergency operating procedures (EOPs) in use at Indian Point 2 were systematically developed through a program, which included phases of validation, verification, training and operator feedback. This program met the requirements of NUREG-0737 and utilized the guidance of NUREG-0899, NRC Standard Review Plan 13.5.2, and the Westinghouse Owners Group (WOG) Emergency Response Guidelines. These generic WOG Emergency Response Guidelines were evaluated by the NRC in a December 26, 1985 Supplemental Safety Evaluation Report[1]. The resulting EOPs are symptom oriented and based upon acceptable technical guidelines derived from approved analyses of transients and accidents. Implementation of the procedure development program included analyses of the operator's tasks to identify the instrumentation and controls necessary for the operator to perform the functions specified in the technical guidelines. A writer's guide ensured a consistent method of preparing EOPs to satisfy objectives of being usable, accurate, complete, readable and acceptable to control room personnel. Validation and verification assured they are technically correct and usable, follow the writer's guide, correspond to the control room and plant hardware, and are compatible with the minimum number, qualifications, training and experience of the operating staff. The training and operator feedback phases resulted in the understanding by the operators of the philosophy behind the approach to the EOPs, their mitigative strategy and technical bases. These phases also ensured that the operators are capable of executing the EOPs under expected conditions. EOP training program includes guidance against misuse or misapplication of the EOPs during normal operating events.

In accordance with NRC Generic Letter 82-33, Supplement 1 to NUREG-0737 and NUREG-0899, each licensee is required to have plant specific Procedures Generation Package (PGP) for preparing, implementing and maintaining upgraded Emergency Operating Procedures (EOPs). The PGP is to embody the programmatic elements of the EOP maintenance program including plant specific technical guidelines, a writer’s guide, the verification and validation programs, the EOP training program, and maintenance of the EOPs consistent with updated generic WOG Emergency Response Guidelines. Con Edison described the Indian Point Unit No. 2 PGP processes and procedures in submittals to the NRC[2,3]. The NRC provided their review and recommendations by NRC Safety Evaluation dated October 16, 1989[4].

REFERENCES FOR SECTION 12.3

1. Letter from T. Novak (NRC) to D. Butterfield (WOG) dated December 26, 1985 forwarding “Supplemental Safety Evaluation Report by the Office of Nuclear Reactor Regulation in the Matter of Westinghouse Owners Group Emergency Response Guidelines”.

2. Letter from J. O’Toole (Con Edison) to D. Eisenhut (NRC), dated June 4, 1984

3. Letter from M. Selman (Con Edison) to Document Control Desk (NRC), dated February 11, 1987

4. Letter from D. Brinkman (NRC) to S. Bram (Con Edison) dated October 16, 1989 forwarding “Safety Evaluation Regarding the Procedures Generation Package for Indian Point Unit 2 (TAC No. 44309).”

12.4 RECORDS

Records concerning facility operations are maintained in the form of logbooks, charts, and other such internal reports as may be needed to document pertinent operating conditions.

The principal logs to be maintained are those in the central control room, in the senior watch supervisor's office, by the shift chemist, and by the shift health physics technician. These logs include descriptions of the operating conditions that exist at the time, descriptions of significant operational efforts accomplished during the shift, and such operating events or circumstances as are deemed pertinent to maintain proper continuity of knowledge and understanding of such matters as responsibility in those areas is passed on from shift to shift.

A record of radiation safety conditions, internal and environmental, is maintained in the form of appropriate log entries, and continuous recording chart information in those functional systems and areas provided with radiation survey instruments. In addition, Radiation Work Permit survey information provides the necessary record of radiation exposure conditions prior to job commencement. Actual personnel radiation exposure information is maintained. Records of controlled radiation releases to the environment are maintained by the station chemical and health physics groups, and all necessary information describing specific radioactivity concentrations, total volumes released, along with any dilution requirements, are entered on the Radioactive Waste Release Permit prepared for each release.

All abnormal occurrences that occur during the course of facility operations are recorded in the senior watch supervisor's logbook and, where appropriate, in the logbooks maintained by the licensed operator in the main control room, the shift chemist, and the shift health physics technician.

Plant modification records (e.g., procedures, drawings, specifications) are maintained on file.

Detailed records of total uranium, U-235, Pu-239, and Pu-241 for all fuel in use or in storage are maintained. Records of fuel transfers are maintained via proper execution of NRC forms. Specific locations for all fuel assemblies in the reactor core or in the fuel storage pools are maintained on appropriate core or fuel storage pool arrangement drawings.

Record maintenance and retention is in accordance with the requirements of the Quality Assurance Program Manual (QAPM). Records are maintained on paper, microfilm/aperture cards, or optical disk storage media. Procedures for maintenance of optical disk records comply with the guidance of NRC Generic Letter 88-18 “Plant Record Storage on Optical Disks.”

12.5 REVIEW AND AUDIT OF OPERATIONS

Matters such as design changes to the facility which require a license amendment, changes to operating procedures, or changes to the Technical Specifications, are conducted in accordance with the requirements of 10 CFR 50 and the Quality Assurance Program Manual (QAPM). To assist in this function, Entergy has chartered two committees specifically for the review of safety-related items. These committees (i.e., the On-Site Safety Review Committee and the Safety Review Committee) function in accordance with the requirements of the Quality Assurance Program Manual (QAPM).

A continuing review of facility operations is performed by the station operating staff and at the executive level.

12.5.1 On-Site Safety Review Committee (OSRC)

The On-Site Safety Review Committee functions to advise on all matters related to nuclear safety in accordance with the requirements of the Quality Assurance Program Manual (QAPM).

12.5.2 Safety Review Committee (SRC)

The Safety Review Committee functions to provide independent review and audit of designated activities and plant operations in accordance with the requirements of the Quality Assurance Program Manual (QAPM).

12.5.3 Qualification of Inspection, Examination, Testing, and Audit Personnel

Entergy's commitments and exceptions related to the qualification of inspection, examination, testing, and audit personnel are described in the Quality Assurance Program Manual (QAPM).

REFERENCES FOR SECTION 12.5

1. Letter from Con Edison to NRC, Subject: Con Edison Response to Generic Letter 81-01, dated July 31, 1981.

2. Letter from S.A. Varga, NRC, to J.D. O'Toole, Con Edison, Subject: NRC Review of Con Edison's Response to Generic Letter 81-01, dated September 27, 1982.

12.6 PLANT SECURITY

The program for ensuring the physical security of the Indian Point Unit 2 station has been reviewed by the NRC and found acceptable.[1] The fully implemented security plan provides the protection needed to meet the general performance requirements of 10 CFR 73.55(a) and the objectives of the specific requirements of 10 CFR 73.55, paragraphs (b) through (h), without impairing the ability to operate the plant safely. The approved plant security program, titled "Indian Point, Physical Security, Training and Qualification, Safeguards Contingency Plan, and ISFSI", is addressed in the facility operating license. The approved security plan documents and the NRC Security Plan Evaluation Report have been withheld from public disclosure pursuant to 10 CFR 2.790(d).

Access to Indian Point Unit 1, 2 and 3 areas for all persons is controlled under approved procedures administered by the Station Security Section.

REFERENCES FOR SECTION 12.6

1. Letter from John A. Nakoski, NRC, to Fred Dacimo, Entergy, regarding Indian Point revised Design Basis Threat (DBT) and revisions to Physical Security Plan, Training and Qualification Plan, and Safeguards Contingency Plan, (TAC Nos. MC29292 and MC2930), dated October 28, 2004.

12.7 EMERGENCY PREPAREDNESS

12.7.1 Emergency Plan

In accordance with 10 CFR 50.54(q), a document titled Indian Point Energy Center Emergency Plan was submitted by Entergy to the NRC.[1]

12.7.2 Emergency Response Facilities

The emergency response facilities concept is part of the implementation plan for Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability," as requested by Generic Letter 82-33.

The Emergency Operations Facility provides for the management of overall emergency response, coordination of radiological and environmental assessments, and determination of recommended public protective actions. An alternate Emergency Operations Facility is located outside of the 10-mile emergency planning zone.

The Emergency News Center is a separate facility located at the Hudson Valley Traffic Management Center in Hawthorne, N.Y. The Emergency News Center will be used for information dissemination to the public via the news media.

The Technical Support Center is an onsite facility located adjacent to the control room that would provide plant management and technical support to the reactor operating personnel located in the control room during emergency conditions.

The Operational Support Center is an onsite area, separate from the control room and the Technical Support Center, where support personnel would assemble in an emergency.

In developing the facilities, NRC guidance in regard to facilities, location, space requirements, environmental control, radiological monitoring, reliable communications, site status data, records, and staffing was taken into consideration.

The emergency response facilities became fully functional on March 8, 1983. Their functional capability was initially demonstrated on March 9, 1983, at a full-scale Federal Emergency Management Agency exercise.

REFERENCES FOR SECTION 12.7

1. Letter from J.T. Herron, Entergy, to NRC, Document Control Desk, Subject: Combined Emergency Plan for the Indian Point Energy Center, dated September 26,2002.

CHAPTER 13
TESTS AND OPERATIONS

13.0 INTRODUCTION

[Historical Information] The testing and startup operation of the plant systems prior to full power operation of the unit included tests made prior to the initial reactor fuel loading, precritical tests, zero power tests, and power level escalation, plus tests made as part of the zero power and power ascension program inherent with each core loading cycle and periodic test requirements of the Technical Specifications.

The purpose of the program has been to test and operate the reactor and its various systems (1) to make certain that the equipment has been installed and will operate in accordance with the design requirements, (2) to provide procedures for safe initial fuel loading or fuel reloading and to determine zero power values of core parameters significant to the design and operation, and (3) to bring the unit to its rated capacity in a safe and orderly fashion.

Prior to initial full-power operation of Indian Point Unit 2, the plant underwent a thorough, systematic testing program that successively demonstrated the capability and safety of the plant to proceed to each following stage of testing until full power was achieved and maintained. WEDCO, a wholly owned subsidiary of Westinghouse, had the overall responsibility for engineering, construction management, and initial startup testing. The initial startup tests were subdivided into several stages, each to be completed before the next stage was undertaken. Following the startup and testing program, periodic system and plant performance tests are performed as described in the Technical Specifications.

Detailed procedures stating the test purpose, conditions, precautions, and limitations are prepared for each test. The procedures include a delineation of administrative procedures and test responsibility, equipment clearance procedures, and an overall sequence of startup operations. The procedures specify the sequence of tests and measurements to be conducted and conditions under which each is to be conducted to ensure both safety of operation and the relevancy and consistency of the results obtained. If significant deviations from design predictions should exist, unacceptable behavior be revealed, or apparent anomalies develop, testing is suspended and the situation reviewed by the licensee and technical advisors as appropriate to determine whether a question of safety is involved and what corrective action is to be taken prior to resumption of testing. The ultimate responsibility for these determinations rests with the licensee.

The test objectives incorporate testing of redundant equipment where it is involved. Abnormal plant conditions may be simulated during testing when such conditions do not endanger personnel or equipment, or contaminate clean systems. Where predicted emergency or abnormal conditions are involved in the testing program, the detailed operation is provided in the test procedure.

Acceptance criterion for all components and systems is that the test results are acceptable when the test objectives are met within the design specification limits and within the applicable Technical Specifications.

The test program described in the following sections is based upon the reference plant design and experience gained during startup of other units. The detailed procedures include expected values and acceptance criteria that demonstrate the degree to which the facility does meet design criteria.

13.1 TESTS PRIOR TO INITIAL REACTOR FUEL LOADING [Historical Information]

The first stage of the initial tests was a comprehensive testing program, which ensured that equipment and systems performed in accordance with design criteria prior to fuel loading. As the installation of individual components and systems was completed, they were tested and evaluated according to predetermined and approved written testing techniques, procedures, or checkoff lists. Field and engineering analyses of test results were made to verify that systems and components were performing satisfactorily and to recommend corrective action, if necessary.

The program included tests, adjustments, calibrations, and system operations necessary to ensure that initial fuel loading and subsequent power operation could be safely undertaken. In general, the types of tests were classified as installation, flushing, hydrostatic, hot functional, and preoperational tests. These tests were aimed at verifying that the system or equipment was capable of performing the function for which it was designed.

Where practical, preoperational tests involved actual operation of the system and equipment under design or simulated design conditions. In addition, the reactor protection and safeguards instrumentation systems were performance tested prior to initial core loading.

The reactor coolant system vibration testing program overlapped the plant testing program. Data for this particular program were taken during cold hydro and hot functional testing prior to fuel loading and also during the low-power physics tests that followed initial fuel loading (refer to Section 13.5).

The list below is the sequence of major startup tests and operations performed to place all equipment in the specified system in service for the initial reactor fueling. Table 13.1-1 describes the objectives of the tests. Con Edison, in cooperation with Westinghouse/WEDCO, prepared detailed test procedures prior to the scheduled initial testing of systems and determination of reactor physics parameters. The tests conducted on the engineered safety systems are included under the safety injection system, the containment spray system, and the containment air recirculation cooling and filtration system:

1. Switchgear system.
2. Voice communication systems.
3. Service water system.
4. Fire protection system.
5. Instrument and service air systems.
6. Nitrogen storage system.
7. Reactor coolant system cleaning.
8. Reactor containment air recirculation and filtration system.
9. Feedwater and condensate circulation systems.
10. Auxiliary coolant system.
11. Chemical feed system.
12. Chemical and volume control system.
13. Containment spray system.
14. Safety injection system.
15. Fuel handling system.

16. Containment isolation and isolation valve seal-water systems.
17. Containment penetration and weld channel pressurization system.
18. Reactor containment high-pressure test.
19. Cold hydrostatic tests.
20. Radiation monitoring system.
21. Nuclear instrumentation system.
22. Radioactive waste disposal system.
23. Sampling system.
24. Instrument calibration.
25. Hot functional tests.
    a. Reactor coolant system.
    b. Chemical and volume control system.
    c. Sampling system.
    d. Auxiliary coolant system.
    e. Safety injection system.
    f. Radioactive waste disposal system.
    g. Ventilation system.
26. Primary and secondary systems safety valves tests.
27. Turbine steam seal and blowdown systems.
28. Emergency diesel electric system.

TABLE 13.1-1
(Sheet 1 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading [Historical Information]

System or Test	Test Objective
1. Switchgear system (electrical tests)	To ensure continuity, circuit integrity, and the correct and reliable functioning of electrical apparatus. Electrical tests were performed on transformers, switchgear, turbine generator, motors, cables, control circuits, excitation switchgear, dc system, annunciator systems, lighting distribution switchboard, communication system, and miscellaneous equipment. Special attention was directed to the following tests: a. 480-V switchgear breaker interlock test. b. Station loss of voltage auto-transfer test. c. Critical power transfer test. d. Tests of protective devices. e. Equipment automatic start tests. f. Check exciter for proper voltage buildup.
2. Voice communication systems	To verify proper communication between all intraplant stations, for interconnection to commercial phone service, and to balance and adjust amplifiers and speakers.
3. Service water system	To verify, prior to critical operations, the design head capacity characteristics of the service water pumps; that the system would supply design flow rate through all heat exchangers; and would meet the specified requirements when operated in the safeguards mode.
4. Fire protection system	To verify proper operation of the system by ensuring that the design specifications would be met for the fire service booster pump and fire service pumps, checking that automatic start functions operate as designed, and that level and pressure controls meet specifications.
5. Instrument and service air systems	To verify the operation of all compressors to design specifications, the manual and automatic operation of controls at design setpoints, design air-dryer cycle time and moisture content of discharge air, and proper air pressure to each instrument served by the system.
6. Nitrogen storage system	To verify system integrity, valve operability, regulating and reducing station performance, and the ability to supply nitrogen to interconnecting systems as required.

TABLE 13.1-1
(Sheet 2 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
7. Reactor coolant system cleaning	To flush and clean the reactor coolant and related primary systems to obtain the degree of cleanliness required for the intended service. Provisions to maintain cleanliness, integrity, and protection from contamination sources were made after system cleaning and acceptance. The system, component, or section of a system was considered clean when the flush cloth showed no grindings, filings or insoluble particulate matter larger than 40 µm (lower limit of naked eye visibility). After systems were flushed clean of particulate matter within the limit specified, the cleanliness integrity of the system was maintained filled with water, which met the system cold chemistry requirements. After fill and pressurization and prior to hot operation, cold chemistry requirements were maintained. Oxygen was analyzed and brought into specification prior to exceeding 200°F.
8. Reactor containment air recirculation and filtration system	To verify, prior to critical operation, the fan capacities, and the remote and automatic operation of system louvers and valves in accordance with the design specifications.
9. Feedwater and condensate circulation systems	To verify proper operation of feedwater and circulating water pumps according to specifications, valve and control operability and setpoints, flushing and hydro as applicable, inspection for completeness and integrity. Functional testing was performed when the steam supply became available.

TABLE 13.1-1
(Sheet 3 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
10. Auxiliary coolant system	To verify component cooling flow to all components and to verify proper operation of instrumentation, controllers, and alarms. Specifically, each of the three loops, that is, the component cooling loop, the residual heat removal loop, and the spent fuel pit cooling loop, were tested to ensure that: a. All manual and remotely operated valves were operable manually and/or remotely. b. All pumps performed according to manufacturer's specifications. c. All temperature, flow, level, and pressure controllers functioned to control at the required setpoint when supplied with appropriate signals. d. All temperature, flow, level, and pressure alarms functioned at the required locations when the alarm setpoint was reached and cleared when the reset point was reached. e. Design flow rates were established through heat exchangers.
11. Chemical feed system	To verify valve and control operability and setpoints, flushing and hydro as applicable, inspection for completeness and integrity. Functional testing was performed when the steam supply became available.

TABLE 13.1-1
(Sheet 4 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
12. Chemical and volume control system	To verify, prior to critical operation, that the chemical and volume control system would function as specified in the system description and appropriate technical manuals. More specifically that: a. All manual and remotely operated valves were operable manually and/or remotely. b. All pumps performed to manufacturer's specifications. c. All temperature, flow, level, and pressure controllers functioned to control at the required setpoint when supplied with appropriate signals. d. All temperature, flow, level, and pressure alarms functioned at the required locations when the alarm setpoint was reached and cleared when the reset point was reached. e. The reactor makeup control accomplished blending, dilution, and boration as designed. f. The design seal-water flow rates were attainable at each reactor coolant pump. g. The boric acid evaporator package functioned as specified in the manufacturer's technical manual.
13. Containment spray system	To verify performance of the containment spray pumps.

TABLE 13.1-1
(Sheet 5 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
14. Safety injection system	To verify, prior to critical operation, response to control signals and sequencing of the pumps, valves, and controllers of this system as specified in the system description and the manufacturer's technical manuals, and check the time required to actuate the system after a safety injection signal is received. More specifically that: a. All manual and remotely operated valves were operable manually and/or remotely. b. All pumps performed their design functions satisfactorily. c. For each pair of valves to redundant flow paths, disabling one of the valves would not impair remote operation of the other. d. The proper sequencing of valves and pumps occurred on initiation of a safety injection signal. e. The fail position on loss of power for each remotely operated valve was as specified. f. Valves requiring coincidence signals of safety injection and high containment pressure operated when supplied with these signals. g. All level and pressure units were set at the specified points and provided alarms at the required location(s), and reset at the specified point. h. The time required to actuate the system was within the design specifications.

TABLE 13.1-1
(Sheet 6 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
15. Fuel handling system	To show that the system design would be capable of providing a safe and effective means of transporting and handling fuel from the time it reaches the plant until it leaves the plant. In particular, the tests were designed to verify that: a. The major structures required for refueling such as the reactor cavity, refueling canal, spent fuel storage pool, and decontamination facilities were in accordance with the design specifications. b. The major equipment required for refueling such as the manipulator crane, spent fuel pit bridge, and fuel transfer system would operate in accordance with the design specifications. c. All auxiliary equipment and instrumentation would function properly.
16. Containment isolation and isolation valve seal water systems	To verify the capability for reliable operation and to demonstrate the manual and automatic operation of the system. To demonstrate the operation and proper sequence of isolation valve closure and seal-water addition. To demonstrate function of isolation valve seal-water system independent of other systems. To demonstrate the operation and system response time induced by an isolation signal. Manual valves were manipulated to ensure proper operation of the seal-gas injection portion of the system.
17. Containment penetration and weld channel pressurization system	To verify the air system and nitrogen backup system integrity, operate valves, check flow-meters and pressure gauges as required to ensure that pressure differentials would meet design specifications.
18. Reactor containment high-pressure test	To verify, prior to critical operation, the structural integrity and leaktightness of the containment.
19. Cold hydrostatic tests	To verify the integrity and leaktightness of the reactor coolant system and related primary systems with the performance of a hydrostatic test at the specified test pressure with no visible leakage or distortion.

TABLE 13.1-1
(Sheet 7 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
20. Radiation monitoring system	To verify the calibration, operability, and alarm setpoints of all radiation level monitors, air particulate monitors, gas monitors, and liquid monitors that are included in the operational radiation monitoring system and the area radiation monitoring system.
21. Nuclear instrumentation system	To ensure that the instrumentation system is capable of monitoring the reactor leakage neutron flux from source range through 120-percent of full power and that protective functions are operating properly. In particular the tests were designed to verify that: a. All system equipment, cabling, and inter-connections were properly installed. b. The source range detector and associated instrumentation would respond to neutron level changes and that the source range protection (high flux level reactor trip) as well as alarm features and audible count rate would operate properly. c. The intermediate range instrumentation reactor protection and control features (high-level reactor trip and high-level rod stop signals) would operate properly and that permissive signals for blocking source range trip and source range high-voltage-off would operate properly. d. The power range instrumentation would operate properly and that the protective features such as the overpower trips and permissive and dropped-rod functions would operate with the required redundancy and separation through the associated logic matrices, and nuclear power signals to other systems were available and operating properly. e. All auxiliary equipment such as the comparator and startup rate channel, recorders, and indicators were operating as specified. f. All instruments were properly calibrated and all setpoints and alarms properly set.

TABLE 13.1-1
(Sheet 8 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
22. Radioactive waste disposal system	To verify satisfactory flow characteristics through the equipment, to demonstrate satisfactory performance of pumps and instruments, to check for leaktightness of piping and equipment, and to verify proper operation of alarms, instrumentation, and controls. More specifically that: a. All piping and components were properly installed as per design specifications. b. All manual and automatic valves were operable. c. All instrument controllers were operating to control processes at required values. d. All process alarms were operable at required locations. e. All pumps performed to manufacturer's specifications. f. All pump indications and controls were operable at designated stations. g. The waste gas compressors packages operated as specified in manufacturer's technical manual. h. The gas analyzer operated as specified in manufacturer's technical manual. i. The waste evaporator operated as specified in manufacturer's technical manual. j. The hydrogen and nitrogen supply packages were sufficient for all modes of operation.
23. Sampling system	To verify that a specified quantity of representative fluid could be obtained safely and at design conditions from each sampling point. In particular the tests were designed to verify that: a. All system piping and components were properly installed. b. All remotely and manually operated valving operated in accordance with the design specifications. c. All sample containers and quick-disconnect couplings functioned properly and as specified.

TABLE 13.1-1
(Sheet 9 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
24. Instrument calibration	Instrumentation and control devices were checked to ensure their accuracy. Primary sensing elements, transducers, transmitters, receivers, recorders and indicators were thoroughly inspected and adjusted for accuracy of their setpoint characteristics. Interconnecting piping and wiring were checked for continuity and functional requirements. Each device was tested in accordance with established test procedures. Limit switches used for initiating indicating lights, alarms, and interlock functions were checked under actual or simulated operating conditions. Control devices were exercised to ensure proper operation with the required accuracy and response characteristics. Setpoints for devices were checked and adjusted to their specified values. Each individual circuit of the reactor and turbine protection systems was tested to verify that appropriate signals initiate reactor and turbine trips. As a signal level corresponding to the particular condition was reached, trip or cutback functions would annunciate as provided in the particular channel under test.

TABLE 13.1-1
(Sheet 10 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
25. Hot functional tests	The reactor coolant system was tested to check heatup (using pump heat) and cooldown procedures; to demonstrate satisfactory performance of components prior to installation of the core; to verify proper operation of instrumentation, controllers, and alarms; and to provide operating conditions for checkout of auxiliary systems. The chemical and volume control system was tested to determine that water could be charged at rated flow against normal reactor coolant system pressure, to check letdown flow against design rate for each pressure reduction station, to determine the response of the system to changes in pressurizer level, to check procedures and components used in boric acid batching and transfer operations, to check operation of the reactor makeup control, to check operation of the excess letdown and seal-water flowpath, and to verify proper operation of instrumentation, controllers, and alarms. The sampling system was tested to determine that a specified quantity of representative fluid could be obtained safely and at design conditions from each sampling point. The auxiliary coolant system was tested to evaluate its ability to remove heat from reactor coolant, to verify component cooling flow to all components, and to verify proper operation of instrumentation, controllers, and alarms. The safety injection system was tested to check the time required to actuate the system after a safety injection signal is received, to check that pumps and motor-operated valves were properly sequenced, and to verify proper operation of instrumentation, controllers, and alarms. The radioactive waste disposal system was tested to verify satisfactory flow characteristics through the equipment, to demonstrate satisfactory performance of pumps and instruments, to check for leaktightness of piping and equipment, and to verify proper operation of alarms. The ventilation system was tested to adjust proper flow characteristics of ducts and equipment; to demonstrate satisfactory performance of fans, filters, and coolers; and to verify proper operation of instruments and alarms.

TABLE 13.1-1
(Sheet 11 of 11)
Objectives of Tests Prior to Initial Reactor Fuel Loading

System or Test	Test Objective
26. Primary and secondary systems safety valves tests	To test pressurizer and boiler safety and relief valves to ensure that each valve was operable.
27. Turbine steam seal and blowdown systems	To verify valve and control operability and setpoints, flushing and hydro as applicable, inspection for completeness and integrity. Functional testing was performed when a steam supply became available.
28. Emergency diesel electric system	To demonstrate that the system was capable of providing power for operation of vital equipment under power failure conditions. In particular the tests were designed to verify that: a. All system components were properly installed. b. The emergency diesels function according to the design specification under emergency conditions. c. The emergency units are capable of supplying the required power to vital equipment under emergency conditions. d. All redundant features of the system function according to the design specifications.

13.2 FINAL PLANT PREPARATION [Historical Information]

13.2.1 Core Loading

[Historical Information] Fuel loading did not begin until the prerequisite system tests and operations as defined in the detailed core loading procedures were satisfactorily completed and the facility operating license was obtained. Upon completion of fuel loading, the reactor upper internals and pressure vessel head were installed and additional mechanical and electrical tests were performed. The purpose of these activities was to prepare the system for nuclear operation and to establish that all design requirements necessary for operation had been achieved.

The overall responsibility and direction for initial core loading was exercised by the general superintendent. During the initial core-loading operation, the WEDCO refueling manager was in charge of the Westinghouse activities. The process of initial core loading was, in general, directed from the operating floor of the containment structure. Standard procedures for the control of personnel and the maintenance of containment security were established prior to fuel loading. The core configuration was specified as part of the core design studies conducted well in advance of station startup and as such was not subject to change at startup. The core was assembled in the reactor vessel, submerged in water containing sufficient quantities of boric acid to maintain the fully loaded core substantially subcritical. Core-loading procedures specify alignment of fluid systems to prevent inadvertent dilution of the boron in the reactor coolant, restrict the movement of fuel to preclude the possibility of mechanical damage, prescribe the conditions under which loading may proceed, identify chains of responsibility and authority, and provide for continuous and complete fuel and core component accountability.

The core-loading procedure documents included a detailed tabular check sheet that prescribed and verified the successive movements of each fuel assembly and its specified inserts from its initial position in the storage racks to its final position in the core. Multiple checks were made of component serial numbers and types at successive transfer points to guard against possible inadvertent exchanges or substitutions of components. The results of each loading step were evaluated by the Con Edison licensed senior reactor operator and the WEDCO refueling manager before the next prescribed step was started.

Core moderator chemistry conditions (particularly boron concentration) were prescribed in the core-loading procedure document and were verified by chemical analysis of moderator samples every 8 hr during core-loading operations.

The reactor coolant system was isolated and applicable tagging and administrative procedures used to prevent unauthorized change in the boron concentration. The boric acid tank was filled with concentrated boric acid solution and the residual heat removal system placed in service and available to provide moderator mixing and temperature control, if required. A detailed preloading checkoff list was followed to ensure that all systems, equipment and conditions affecting the loading operation were met. Periodically, the checkoff list was reviewed to ensure that systems and equipment continued to meet requirements of the core-loading operation.

The core-loading sequence followed a step-by-step procedure to ensure at each loading step that:

1. Fuel assemblies of the correct enrichments were installed in the proper locations.

2. Rod cluster control assemblies were inserted into the proper fuel assemblies prior to loading the assemblies into the core.

3. Neutron sources and neutron detectors were properly located in the core during fueling. Continuous radiation monitoring was provided at the core-loading stations during fuel-handling and core-loading operations.

Core-loading instrumentation consisted of two permanently installed plant source range (pulse-type) nuclear channels and two temporary incore source range channels plus a third temporary channel to be used as a spare. The permanent channels were monitored in the control room by licensed plant operators; the temporary channels were installed in the containment and were monitored by technical specialists of Westinghouse and by licensed senior reactor operators of Con Edison. At least one plant channel and one temporary channel were equipped with audible count range indicators. Both plant channels and both regular temporary channels displayed neutron count rate on count rate meters and strip chart recorders. Two artificial neutron sources, each rated at approximately 200 Ci of Po-210 alpha activity, were introduced into the core at appropriate specified points in the core-loading program to ensure a neutron population large enough for adequate monitoring of the core.

Fuel assemblies together with inserted control components (rod cluster control units or burnable poison inserts) were added to the core one at a time according to a previously established and approved sequence that had been developed to provide reliable core monitoring with minimum possibility of core mechanical damage. The core-loading procedure documents included a detailed tabular check sheet that prescribed and verified the successive movements of each fuel assembly and its specified inserts from the initial position in the storage racks to the final positions in the core.

An initial nucleus of eight fuel assemblies, the first of which included an activated neutron source, was determined to be the minimum source-fuel nucleus that would permit subsequent meaningful inverse count rate monitoring. This initial nucleus is known by calculation and previous experience to be markedly subcritical (k_{eff} = 0.90) under the required conditions of loading.

Subsequent fuel additions were made one assembly at a time with detailed inverse count rate ratio monitoring after each addition. The results of each loading step were evaluated by both Westinghouse technical specialists and licensed Con Edison operations personnel; concurrent approval to proceed had to be granted before the next prescribed step was started.

Criteria for safe loading required that loading operations stop immediately if:

1. The neutron count rates on all responding nuclear channels doubled during any single loading step.

2. The neutron count rate on any individual nuclear channel increased by a factor of 5 during any single loading step.

A containment evacuation alarm was coupled to the plant source range channels to provide automatic indication of high count rate during fuel addition.

In the event that an unacceptable increase in count rate was observed on any or all responding nuclear channels, special procedures involving fuel withdrawal from the core, detector relocation and charging of additional boric acid into the moderator could have been invoked by Westinghouse technical specialists with the approval of licensed operational personnel of Con Edison.

13.2.2 Precritical Tests [Historical Information]

Upon completion of core loading and installation of the reactor upper internals and the reactor vessel head, certain mechanical and electrical tests were performed prior to initial criticality. The electrical wiring for the rod drive circuits, the rod position indicators, primary and secondary trip circuits, and the incore thermocouples were tested. Final operational tests were repeated on these electrical items.

Mechanical and electrical tests were performed on the rod cluster control unit drive mechanisms. Tests included a complete operational checkout of the mechanisms. Checks were made to ensure that the rod position indicator coil stacks were connected to their proper position indicators. Similar checks were made on the rod cluster control unit drive coils.

After filling and venting was completed, the final hydro tests were conducted.

Tests were performed on the reactor trip circuits to test manual trip operation. Actual rod cluster control unit drop times were measured for each rod cluster control at operating temperature, pressure, and flow. By use of dummy signals, the various plant abnormalities that require tripping were simulated and accurate trip delay times were measured for the control and protection system circuitry.

A complete electrical and mechanical check was made on the incore nuclear flux mapping system at the operating temperature and pressure.

The incore thermocouple tests checked circuit continuity and compared the thermocouple readings for their relative errors (offsets) in the isothermal condition.

13.3 INITIAL TESTS IN THE OPERATING REACTOR [Historical Information]

After satisfactory completion of fuel loading and final precriticality tests, nuclear operation of the reactor was initiated. This final stage of startup and testing included initial criticality, low-power testing, and power level escalation. The purposes of these tests were to establish the operational characteristics of the unit and core, to verify design prediction, to demonstrate that license requirements were being met, and to ensure that the next prescribed step in the test sequence could be safely undertaken. Reactor control setpoint verification was also performed during this stage of startup testing.

Tests that were performed from the initial core loading to rated power are summarized in Table 13.3-1.

13.3.1 Initial Criticality [Historical Information]

Initial criticality was established by withdrawing the shutdown and control banks of rod cluster control units from the core, leaving the last withdrawn control bank inserted far enough to provide effective control when criticality was achieved, and then slowly and continuously diluting the heavily borated reactor coolant until the chain reaction was self-sustaining.

Successive stages of rod cluster control bank withdrawal and of boron concentration reduction were monitored by observing change in neutron count rate as indicated by the regular plant source range nuclear instrumentation as functions of rod cluster control bank position and, subsequently, of primary water addition to the reactor coolant system during dilution.

The inverse count rate ratio was monitored as an indication of the nearness and rate of approach to criticality of the core during rod cluster control bank withdrawal and during reactor coolant boron dilution. The rate of approach toward criticality was reduced as the reactor approached extrapolated criticality to ensure that effective control was maintained at all times.

Relevant procedures specified alignment of fluid systems to allow controlled start and stop and adjustment of the rate of approach to criticality, indicated values of core conditions under which criticality would be expected, and identified chains of responsibility and authority during reactor operations.

13.3.2 Zero-Power Testing

Upon establishment of criticality a prescribed program of reactor physics measurements was undertaken to verify that the basic static and kinetic characteristics of the core were as expected and that the values of kinetic coefficients assumed in the safeguards analysis were indeed conservative.

Measurements made at zero power and primarily at or near operating temperature and pressure included verification of calculated values of rod cluster control group and unit worths, isothermal temperature coefficients under various core conditions, differential boron concentration worth, and critical boron concentrations as a function of rod cluster control group configuration. Preliminary checks on relative power distribution were made in normal and abnormal rod cluster control unit configurations.

Concurrent tests were conducted on the plant instrumentation including the source and intermediate range nuclear channels. Rod cluster control unit operation and the behavior of the associated control and indicating circuits were demonstrated.

Detailed procedures specified the sequence of tests and measurements to be conducted, and the conditions under which each was to be performed to ensure the relevancy and consistency of the results obtained. These tests covered a series of prescribed control rod configurations with intervening measurements of differential control rod worths and boron worth during boron dilution or boron injection. As the successive configurations were established, the measurement techniques used were:

1. Dynamic temperature coefficient measurements – Differential moderator coefficient measurement made by continuously increasing or decreasing the moderator average temperature and observing the resultant change in core reactivity.

2. Dynamic control rod worth measurements - Control rod differential worth measurements made by monotonically withdrawing or inserting selected control rods or groups of rods and part-length [*Note - Subsequent to initial plant*

operation (during the Cycle 2/3 refueling outage), the part-length rod cluster control assemblies were removed from the reactor.] rods and observing the resultant change in core reactivity.

3. Dynamic boron worth measurements - Differential boron worth measurements made by monotonically increasing or decreasing main coolant boron concentration and observing the resultant change in core reactivity.

13.3.3 Power Level Escalation

In order to ensure that operation of the core would be as expected in all respects, and that achievement of rated power was under carefully controlled conditions, a power escalation test program was established to carry the plant from completion of zero-power physics testing through full-power operation. The power escalation test program provided for stepwise achievement of full power, with careful review of significant core parameters at each step, to ensure that fuel and control rod mechanical performance, flux distribution, temperature distribution hot channel factors and reactivity control worths were acceptable before additional escalation was undertaken.

The power escalation test program provided for measurements to be made at convenient power levels in the vicinity of minimum self-sustaining power, discrete levels approaching 100-percent, and at rated power. In each case, progression to higher levels was contingent upon acceptable core performance.

Additional reactor physics measurements were made and the ability of the reactor control and protection system to respond effectively to signals from primary and secondary instrumentation under a variety of conditions encountered in normal operations was verified. At prescribed power levels, the dynamic response characteristics of the reactor coolant and the steam systems were evaluated.

The sequence of tests, measurements, and intervening operations is prescribed in the power escalation procedures together with specific details relating to the conduct of the several tests and measurements. The measurement and test operations during power escalation are similar to those during normal operation.

The preparation for power escalation is described below. In order to monitor performance, the following analytical results were on hand before power escalation was undertaken:

1. Expected values for local power ratios in each of the incore flux-detector thimbles.

2. Expected values for relative power in each fuel assembly and in individual fuel rods of interest in various control group configurations.

3. Expected values of power peaking factors.

4. Combined power and programmed temperature reactivity defect as a function of primary power level at expected boron concentrations.

5. Equilibrium xenon reactivity defect as a function of primary power level.

6. Identification and integral reactivity worth of the most significant single rod cluster control assemblies in the control group, when fully withdrawn, with

various operating control rod configurations, for both full- and part-length rods.

7. Identification and integral reactivity worth of the most significant single rod cluster control assemblies among all groups, for both full- and part-length rods.

Other conditions that were to be met before commencement of the power escalation test program were as follows:

1. The following plant conditions were established:

   a. The zero-power reactor physics test program had been successfully completed as prescribed. Experimental values of zero power reactivity parameters had been deduced and were available for guidance in the elevated power program.

   b. Discrepancies between analytically predicted and experimentally measured values of physics parameters had been identified and appropriate revisions had been made in the values of expected primary coolant boron concentrations and rod cluster control group positions listed in the power escalation test sequence.

   c. The reactor coolant system and all required components of the secondary coolant system were fully assembled, mechanically tested, and ready for service as required.

   d. All control, protection, and safety systems were fully installed; all required preoperational tests satisfactorily completed; and all components ready for service as required.

   e. The reactor coolant was at required temperature, pressure, and lithium and boron concentration.

   f. Demineralized water was available in adequate quantity for extensive boron dilution.

   g. Concentrated boric acid solution was available in sufficient quantity to permit increases in main coolant boron concentration as required.

   h. All special equipment and instrumentation required for the power escalation test program was installed and calibrated and available for service as specified.

   i. Thermocouple correction constants derived from the hot, isothermal calibrations.

   j. Reactor coolant flow coastdown measured and found acceptable.

2. A pretest checkoff list indicating the required status of all systems and auxiliary equipment affecting the power escalation test program was available. The pretest checkoff list included, but was not limited to, provisions for verification and certification of all items specified in item 1, above.

3. Experimental procedures, suitable for executing the power escalation test sequence, were available for distribution to all personnel concerned with the power escalation test program.

4. The procedure, schedule, and personnel assignments and responsibilities were thoroughly discussed with and understood by the operational and experimental personnel.

The following tests were conducted during the power escalation test program:

1. Electrical trip testing - Electrical tripping relays that are initiated by plant on-power malfunctions were retested and the consequent trip sequence rechecked under operating conditions for correct operation and sequence.

2. Turbine trip testing - The turbine protection system was checked to confirm that the appropriate initiation would either trip the turbine through the main trip solenoid or would mechanically trip the turbine. As the various setpoints or status conditions were reached, the trip or runback functions were verified.

3. Elevated power reactivity coefficient evaluation - During the approach to full power and during initial operation at power, a sequence of reactor physics measurements was carried out to determine experimentally the power and temperature coefficients and power defects at various power levels, differential (full- and part-length) control rod worth and boron worths during boron dilutions, and xenon worth during initial operation. Measurements techniques were:

   a. Dynamic differential power coefficient - Differential power coefficient measurements were made at elevated power over a limited range in power level by initiating a small power level change. The change in core reactivity associated with the compensating control rod motion is related to the net change in power level.

   b. Elevated power transient response evaluation - As the power level was increased during the initial power escalation, a series of transient response measurements was made to determine plant response to load changes. The test technique in each case consisted of establishing the transient change in plant conditions and closely monitoring the system response during and after the transient period. The responses of system components were measured for 10-percent loss of load and recovery, loss of load with steam dump, turbine trip, loss of reactor coolant flow, and trip of single rod cluster control units. Reactor coolant coastdown was also measured.

   c. Elevated power determination of power distribution - At successive power levels and in prescribed control rod configurations (full- and part-length), measurements of flux and power distributions within the core were made and nuclear hot channel factors evaluated. Use was made of the miniature incore flux detector system and of the incore thermocouples to determine the nuclear power and thermal and hydraulic conditions within the core. Ex-core nuclear instrumentation was calibrated to indicate actual incore axial power distribution.

d. Determination of primary coolant flow rate - Primary coolant flow rate was evaluated by measuring primary coolant pump power and elbow tap pressure differential.

e. Verification of remote control stations - After the plant was certified to operate at elevated power levels, the capability for manually taking the plant to hot shutdown from stations remote from the control room was verified. This test demonstrated that controls and information available in the local control stations were functioning properly and were sufficient to permit the operators to trip the plant, control heat removal, and borate in an orderly manner to reach and maintain the reactor in a hot shutdown status should the control room ever become uninhabitable.

TABLE 13.3-1 (Sheet 1 of 5)
Initial Testing Summary [Historical Information]

Test	Conditions	Objectives	Acceptance Criteria
RCC_1 unit drop tests	1. Cold shutdown 2. Hot shutdown	To measure the scram time of RCC units under full flow and no flow conditions	Droptime less than value assumed in safety analysis
Thermocouple/RTD intercalibration	Various temperatures during system heatup at zero power	To determine in—place isothermal correction constants for all core exit thermocouples and reactor coolant RTDs	RTDs verify that RTD system meets setpoint requirements of Technical Specifications
Nuclear design check tests	All two dimensional RCC control group configurations at hot, zero power	To verify that nuclear design predictions for endpoint boron concentrations, isothermal temperature coefficient, and power distributions are valid	FFD and SAR_2 limiting values for $\delta\rho/\delta T$, $F_\Delta H$
RCC control group calibration	All RCC control groups at hot, zero power	To verify that nuclear design predictions for control group differential worths with and without part—length RCC units are valid	FFD and SAR limiting values for $\delta\rho/\delta h$, $\Delta\rho/h$
Power coefficient measurement	0-percent to 100-percent of full power	To verify that nuclear design predictions for differential power coefficient are valid	FFD and SAR limiting values for $\delta\rho/\delta q$
Automatic control system checkout	Approximately 20-percent	To verify the control system response characteristics for the: a. Steam generator level control system b. RCC automatic control system c. Turbine control system	No safety criteria applicable

TABLE 13.3-1 (Sheet 2 of 5)
Initial Testing Summary

Test	Conditions	Objectives	Acceptance Criteria
Power range instrumentation calibration	During static and/or transient conditions at: 30-percent 70-percent 90-percent 100-percent	To verify all power range instrumentation consisting of: power range nuclear channels, in—core flux mapping system, core exit thermocouple system, and reactor coolant RTDs are responsive to changes in reactor power level and power distribution, and to intercalibrate the several systems	Verify that setpoints cited in Technical Specifications are met
Load swing test	± 10-percent steps at: ~40-percent to 50-percent ~100-percent	To verify reactor control system performance	No safety criteria applicable
Plant trip	Full load rejection from: ~50-percent ~100-percent	To verify reactor control performance	Proper operation of steam dump and feedwater overrides.
Pressurizer effectiveness test	Hot, shutdown	To verify that pressurizer pressure can be reduced at the required rate by pressurizer spray actuation	No safety criteria applicable
Minimum shutdown verification	Hot, zero power	To verify the nuclear design prediction of the minimum shutdown boron concentration with one “stuck” RCC unit	Verify stuck rod shutdown criteria
Psuedo ejection test	Hot, zero power	To verify nuclear design predictions of effects on core reactivity and power distribution of ejection of one RCC unit from a fully inserted control group	FFD and SAR limiting values for $F_{\Delta H}$, reactivity insertion

TABLE 13.3-1 (Sheet 3 of 5)
Initial Testing Summary

Test	Conditions	Objectives	Acceptance Criteria
Pseudo ejection test	~30-percent of rated power	To verify nuclear design predictions of effects on core reactivity and power distribution of ejection of one RCC unit from typical operating configuration.	FFD and SAR limiting values for $F_{\Delta H}$, reactivity insertion
Loss of flow test	Hot shutdown	Measure reactor coolant flow coastdown following trip of reactor coolant pumps	Flow coastdown no faster than FFD and SAR curves
Power redistribution follow	~70-percent of rated power	To verify that ex—core nuclear instrumentation adequately monitors changes in core power distribution under transient xenon conditions	FFD and SAR symmetric offset F_Q correlation
Static RCC drop test	~50-percent of rated power	To verify that a single RCC unit inserted fully or part way below the control bank can be detected by ex—core nuclear instrumentation and core exit thermocouples under typical operating conditions and to provide bases for adjustment of protection system setpoints	Inserted rod detectable with instrumentation
RCC insertion test	~50-percent of rated power	To determine the effect of a single fully inserted RCC unit on core reactivity and core power distribution under typical operating conditions as bases for setting turbine runback limits	See next test

TABLE 13.3-1 (Sheet 4 of 5)
Initial Testing Summary

Test	Conditions	Objectives	Acceptance Criteria
Dynamic RCC drop test	~70-percent of rated power	To verify automatic detection of dropped rod, and subsequent automatic rod stop and turbine cutback	Required power reduction and rod withdrawal block accomplished
Load reduction test	~50-percent reduction from ~70-percent ~50-percent reduction from 100-percent	To verify reactor control system	No safety criteria applicable
Part—length group operational maneuvering	~90-percent	To verify that the part—length RCC maneuvering scheme is effective in containing and suppressing spatial xenon transients	FFD and SAR limiting values for F_Q , $F_{\Delta H}$
Load cycle test	~40-percent ~85-percent	To verify that all plant systems are capable of sustaining load follow operations without encountering unacceptable operational limits through a typical weekly cycle	FFD and SAR limiting values for F_Q , $F_{\Delta H}$, shutdown margin
Turbine—generator startup tests	Pre— and Post—synchronization	To verify that the turbine—generator unit and associated controls and trips are in good working order and ready for service	Successful completion of all mechanical and electrical and control functional checks

TABLE 13.3-1 (Sheet 5 of 5)
Initial Testing Summary

Test	Conditions	Objectives	Acceptance Criteria
Turbine—generator	Power level sufficient for turbine auxiliaries to be operating	To verify normal trouble free performance of the turbine—generator at low power	Performance within manufacturers limitations
Control valve tests	~70-percent of rated power	To verify capability of exercising control valves at significant load and evaluate function of valves and controls	Normal trouble free operation
Acceptance test run	100 hours at rated full power	To verify reliable steady state full power capability	100 hours reliable equilibrium plant operation at full power

Notes:
1. Rod cluster control.

2. Final facility description and safety analysis report.

13.4 OPERATING RESTRICTIONS

13.4.1 Safety Precautions

[Historical Information] Measurements and test operations during zero-power and power escalation phases are always performed under several active trip functions. Any verification program is concluded by several trip functions if the program attempts to violate any of the criteria of the protective circuitry. Furthermore, to ensure that transients are concluded early in the life of the transient, several of the setpoints of the trip functions are reduced, as referenced in Chapter 7.

Measurements are made at various points in the power escalation program as power level is increased. Considerations are made of the instrument accuracy and extrapolations are made for these parameters before proceeding in the program, including both instrument inaccuracies and uncertainties. A continuing verification is then made that the reactor parameters are no more limiting than those assumed in the accident analysis, which are the most limiting values.

Each power step is relatively small, so that a high degree of certainty is associated with the prediction of plant parameters. The accuracy of the prediction obtained for each power level is a major factor in determining further power escalation.

The reactor protection system ensures that the public safety is further protected, as stated above.

13.4.2 Initial Operation Responsibilities

Ultimate responsibility for the facility rested with the holder of the operating license. During the transition from a construction oriented project to a commercial power-producing plant, equipment and systems were tested to prove their capability in accordance with design criteria. Test procedures for the initial startup program were written and approved by both Westinghouse and Con Edison prior to plant testing. Post-core-load test procedures were prepared by Westinghouse and reviewed prior to performance by Con Edison through the Nuclear Facilities Safety Committee. Pertinent safety comments from the committee were factored into the procedures prior to performance. All tests and test procedures were under the control of the general superintendent of the plant to ensure that proper emphasis was placed on safety by all during these acceptance tests (i.e., each test was reviewed by all responsible parties, initial plant conditions and pre-requisites to the test had been met, and proper personnel were available and understood the test procedures and precautions). Westinghouse provided technical direction for these tests.

As part of the precautions, all licensed senior reactor operators and manufacturer's representatives whose equipment was being tested were instructed to stop a test or a portion of a test if the test was not being performed safely or in accordance with the written test procedures. The test would be promptly continued only if minor modifications to the test procedure were required and the test was approved by the general superintendent or his representative and the Westinghouse representative. If substantial revisions were required, however, the general superintendent would review the change with the same approach as that taken with a new test procedure before the test could be continued.

The Joint Test Group (consisting of responsible WEDCO and Con Edison personnel) reviewed and concurred in the release of test procedures for implementation. Technical responsibility for each individual phase of actual startup resided with the functional group most directly concerned with the results of the test. WEDCO and Westinghouse had onsite representatives of supporting functional groups to provide technical advice, recommendations, and assistance in planning and executing the respective stages of unit startup.

All system operations in the testing program were performed by station operators in accordance with the approved written procedures. These procedures included such items as delineation of administrative procedures and test responsibilities, equipment clearance procedures, test purpose, conditions, precautions, limitations, and sequence of operations. Procedural changes were made only in accordance with an approved standard operating procedure that required review and approval of the changes by experienced supervisory personnel.

Test procedures stating the test purpose, conditions, precautions, limitations, and criteria for acceptance were prepared for each test by WEDCO and/or Westinghouse technical advisors. All such procedures were reviewed and concurrence given by the Joint Test Group in accordance with approved standard operating procedures prior to implementation.

All test results received a preliminary review and evaluation by Con Edison site personnel. Cognizant WEDCO/Westinghouse startup engineers and technical advisors determined the adequacy of test data for verification of design objectives. Detailed analyses of test results and issuance of final test reports were performed by WEDCO site startup and/or Westinghouse engineering and design personnel with input from Con Edison where appropriate. Con Edison reviewed all final test results to determine that design objectives and criteria had been met and gave final approval as to the acceptability of plant components, systems, and operating characteristics of the facility.

13.5 REACTOR COOLANT SYSTEM VIBRATION TESTING PROGRAM [Historical Information]

Two test programs were performed on the Indian Point Unit 2 reactor coolant system to measure the dynamic behavior of the reactor coolant system. The two programs were (1) reactor coolant system impedance test and (2) reactor internals and reactor coolant system loop vibration test under steady-state and transient conditions.

13.5.1 Reactor Coolant System Impedance Test

The purpose of the impedance test was to determine the natural frequencies, mode shapes, and damping of the main components of the reactor coolant system. These tests were performed with the reactor coolant system filled with water and were performed prior to the installation of the core and control rods. The reactor coolant and charging pumps were not in operation during this test.

Electromagnetic shakers were attached at several points on one of the reactor coolant system loops so that normal modes of the structure could be excited. Accelerometers were used to measure the response of the structure. The mode shape and damping at the natural frequencies were then deduced from acceleration measurements made at several points on the structure while vibrating at a natural frequency. The shaker was attached at selected locations on the steam generator, reactor coolant pumps, and loop piping; the test plans called for the following locations:

1. Steam generator 21, approximately 65-ft elevation, circumferentially (i.e., tangential to the wall of the vapor container).

2. Steam generator 21, between the 100-ft elevation and the 120-ft elevation.
3. Main coolant pump 21, approximately 62-ft elevation, circumferentially.
4. Main coolant pump 21, approximately 83-ft elevation, circumferentially.
5. Main coolant pump 21, approximately 83-ft elevation, radially.
6. Intermediate leg, loop 21, approximately 54-ft elevation, radially.

Thirteen monitoring accelerometers were attached to the structure at the locations specified in Table 13.5-1 under external transducers. In addition, hand-held accelerometers were moved from point to point to establish the exact mode shape. All shakers and accelerometer cables were routed to a readout station from which the excitation was controlled and response measured.

An initial impedance plot was obtained by exciting the structure at a constant, low force level from a frequency not less than 1 Hz to a frequency not greater than 300 Hz. This was followed by additional sweeps at higher force levels to facilitate detection of natural frequencies that have relatively low response. A determination of the mode shape at each natural frequency of interest was made by measuring the amplitude and phase of the acceleration response at a large number of points relative to the drive point.

Data from which damping could be deduced were obtained by suddenly opening the electrical input of the shaker while driving at a natural frequency and recording the resulting decrement.

13.5.2 Steady-State and Transient Internals and Loop Vibration Measurements

The objectives of the instrumentation program for the second program of testing were:

1. To obtain data that provided increased confidence in the adequacy of the internals structures by establishing the design margins at key locations on the structure. The strain gauge and maximum displacement indicators were used primarily for this purpose.

2. To obtain data that could be used to develop improved analytical tools for the prediction of internals vibrations. Comparison with the 1/7 scale model data and establishing model validity were part of this objective.

Instrumentation was provided for the reactor coolant system major components, that is, reactor vessel, reactor internals, reactor coolant piping, reactor coolant pumps, and steam generators.

13.5.2.1 Reactor Vessel and Loop Piping

Six accelerometers were located on the vessel, three on the vessel head studs and three on the bottom of the vessel. The six vessel transducers were arranged so that the rigid body motion of the vessel could be measured. The loop piping was instrumented with pressure transducers installed in temperature wells on an inlet and outlet leg. In addition, the data from the external transducers were correlated with the internals data to establish remote estimation of internals motions.

13.5.2.2 Steam Generators

One of the steam generators was instrumented in the same manner as described in Section 13.5.1 and its gross motion measured. The dynamic analysis performed on the steam generator tube bundle is described in Chapter 4.

13.5.2.3 Reactor Coolant Pumps

One of the reactor coolant pumps was equipped with three accelerometers mounted at the top of the motor support stand (see Table 13.5-1). They were mounted in a horizontal plane to pick up circumferential and radial vibrations of the pump. Prior to vibration testing (during preoperational tests), the reactor coolant pumps were checked to ensure that they were within limits. The balance and alignment were adjusted if they were not within limits initially (see Chapter 4 for further description).

13.5.2.4 Reactor Internals

The reactor internals were monitored with strain gauges, accelerometers, pressure transducers, and maximum-displacement indicators. There were 46 strain gauges, 14 accelerometers, 5 pressure transducers, and 14 maximum-displacement indicators.

The instrumentation was used as follows:

1. Guide Tubes - The instrumentation used on the guide tubes was the same as that used on the Zorita and Ginna reactors. Three guide tubes were instrumented with strain gauges. The central guide tube was selected because it would have no set cross flow velocity during four-pump operation; a guide tube near the outlet nozzle at approximately 150 degrees was selected because it was expected to have the highest cross flow velocity with the initial complement of guide tubes. A guide tube near the opposite outlet nozzle at approximately 330 degrees was selected because it was expected to have the highest cross flow velocity for plutonium recycle operation. In the 1/7 scale model tests for Indian Point Unit 2, the guide tube located at about 150 degrees was similarly instrumented. These data were used to compare the scale model with the actual plant.

   The response of the guide tubes over the expected range of vibration frequencies was measured with strain gauges and accelerometers to provide strain versus amplitude data and to ensure that the proper location for the strain gauges had been chosen prior to installation in the reactor vessel.

2. Upper Core Barrel - Strain was measured at two locations on the core barrel: (1) just below the core barrel flange and (2) at the upper to lower core barrel weldment, which is a reduced cross-section elevation (see Table 13.5-1). In addition, an axial strain gauge was placed on the outside surface of the barrel, radially inward from the centerline of an inlet nozzle. This gauge was used to obtain an indication of the stress due to the ram effect of the inlet flow against the core barrel and to compare with previous data taken at this location on the 1/7 scale Indian Point Unit 2 model, the 1/13 ENEL/SENA model, and the Obrigheim plant.

   Accelerometers were located on the upper core barrel to determine the vibration of the upper core barrel in its shell modes. This information contributed significantly to understanding the upper barrel strain gauge readings.

Accelerometers were also placed on two thermal shield support blocks to obtain information on the vibration of the core barrel in its ring modes and beam modes. Data were available from the 1/7 scale model at similar locations.

3. Thermal Shield - The measurement of the maximum stress in the thermal shield with a reasonable number of strain gauges was impossible because of the number and nonuniform spacing of supports and the flexibility of the core barrel. The most highly strained bolt that fastens the top of the shield to the core barrel was instrumented with four strain gauges. One of the four gauges was redundant so that loss of one gauge would not result in the loss of all information from this location. To measure the desired strains, the gauges were in a vertical plane passing through the core centerline when the final torque on the bolt was reached (see Table 13.5–1).

   Three flexures were instrumented. The locations of the gauges were 0 degrees, 90 degrees, and 240 degrees. These gauges provided the data needed to determine the forces in each of the instrumented flexures.

   Three accelerometers were located at the mid-elevation of the shield and one near the bottom to provide data to assist in the interpretation of the strain gauge results and to compare with 1/7 scale model data. Supporting data were obtained from model and full-scale impedance tests.

   Pressure measurements were made at the inside and outside wall of the thermal shield. Four pressure transducers to measure the fluctuating static pressure were located near the top (82.5 degrees) and bottom (28 degrees) of the thermal shield.

   Fourteen maximum displacement indicators were installed into the thermal shield snubber holes, which were not occupied by pressure transducers (eleven at the upper end and three at the lower end).

   The maximum decrease in the proximity of the thermal shield to the core barrel and the vibratory motion of the thermal shield relative to the core barrel were obtained from these indicators by interpretation of styli scratches.

4. Upper Core Plate - Four accelerometers on the upper core plate were used to define the horizontal motion of the upper core plate. This information was used to determine the degree to which base motion excites the guide tubes and support columns (refer to Table 13.5-1).

5. Top Support Plate - A pressure transducer was mounted on the top support plate to be sensitive to vertical pressure fluctuations in the upper plenum. In addition to providing pressures in the upper plenum it was useful in relating the other pressure transducer signals to each other. A pressure transducer was placed in a similar location in the Obrigheim reactor.

13.5.2.5 Instrumentation Description

Transducers measuring strain, acceleration, and pressure as well as maximum displacement indicators were used.

1. Strain gauges - The strain gauges were integral lead gauges similar to those used for the Zorita and Ginna experiments. The minimum sensitivity was greater than 3 μin./in. from 0 to 1000 Hz.

2. Accelerometers - Piezoelectric accelerometers having a sensitivity of approximately 200 pc/g were used with resolution greater than 0.005 g from 5 Hz (± 0.002-in.) to 1000 Hz.

3. Pressure transducers - Piezoelectric pressure transducers were used, which had a resolution of 0.2 psi. The diaphragms of the pressure transducers were flush with the surface where pressure was measured.

4. Maximum-displacement indicators - The maximum-displacement indicators were similar to those used in the Zorita and Ginna experiments. The internal spring-loaded plunger within the displacement pin was designed to follow the relative cyclic motion between the thermal shield and core barrel, thus causing the two stationary spring-loaded styli to leave small markings on the plunger. These marks provided a direct indication of the magnitude of the vibratory motion. The displacement indicators consisted of a cylindrical pin held by means of a clamping fit within a housing block mounted on the thermal shield. The pin was assembled and adjusted within the block so that it was tight against the outer diameter of the core barrel. Sufficient clamping force was exerted on the pin to ensure that the pin would move within the housing block only by a relative motion of the thermal shield toward the core barrel. This created a gap between the end of the pin and the core barrel that was measured during the post hot functional inspection. These measured gaps provided an indication of the total relative motion between the thermal shield and core barrel resulting from thermal differential expansion, hydraulic forces, and vibration.

13.5.2.6 Test Conditions

For these tests the following conditions were required:

1. During cold hydrostatic testing, data were taken at one primary coolant temperature (less than 150°F). This temperature was established by the temperature that existed when time for the testing occurred in the schedule. The temperature was kept within ±20°F during the testing.

2. During the hot functional tests, data were taken at a low temperature (less than 150°F) and at the maximum test temperature. Again, the main coolant temperature was kept within ±20°F while data was being taken. During heatup, a selected number of instruments were monitored continuously.

3. At the completion of hot functional testing, all instruments were removed except six strain gauges on two guide tubes, three strain gauges on the core barrel, one pressure transducer on the top support plate, and the thirteen

accelerometers on the outside structure. These instruments were monitored during precritical testing after the core was loaded. The measurements were made on these instruments for steady-state and transient conditions. Data were taken during control rod exercising, with and without moving the rods in the instrumented guide tube at the same temperature conditions as specified in items 1 and 2, above. For the above tests, data were recorded during startup transients, shutdown transients, and steady flow with several combinations of reactor coolant pumps running including each pump operating individually and all four pumps operating simultaneously. At the first refueling, the internal transducers were removed.

This reactor coolant system testing program, when coupled with experience from offsite testing, model testing, and data from other testing programs on operating plants provided assurance that inservice vibration monitoring instrumentation is not required. (See Chapter 4 for a discussion on the metal impact monitoring system installed since the original test program.)

Table 13.5-1 (Sheet 1 of 4)
[Historical Information]
Transducer Locations for Vibration Experiments

Structure	Outer Wall	Inner Wall	Elevation	Angle, Degrees	Dir. Of Sensitivity	Accelerometer	Pressure Transducer	Strain Gage
Core Barrel	X	X	Upper Core Barrel	0	A			2
	X	X	Below Flange	90	A			2
	X	X	Weldment	270	A			2
	X		Behind Inlet Nozzle	67-1/2	A			1
	X	X	Weldment Upper	0	A			2
	X	X	Lower Core Barrel	0	C			2
	X	X		90	A			2
	X	X		90	C			2
		X	Nozzle Elevation	0	R	1		
	X			45	R	1		
		X		90	R	1		
		X		270	R	1		
	X			22-1/2	R	1		
	X		On Thermal Shield Support Blocks	112-1/2	R	1		

A = AXIAL
C = CIRCUMFERENTIAL
R = RADIAL

Table 13.5-1 (Sheet 2 of 4)

Transducer Locations for Vibration Experiments

Structure	Outer Wall	Inner Wall	Elevation	Angle, Degrees	Dir. Of Sensitivity	Accelerometer	Pressure Transducer	Strain Gage
Thermal Shield	X	X	Snubber Pin Holes Top	82.5	R		2	
	X	X	Snubber Pin Holes Bottom	28	R		2	
	X		Mid Elevation	0	R	1		
				90	R	1		
			Flexures	0	R			6
				90	R			6
				240	R			6
			Top Support Bolt	67-1/2	R			4
	X		Mid Elevation	270	R	1		
	X		Near Bottom	90	R	1		
Upper Core Plate			Top Surface	0	R	1		
				0	C	1		
				180	R	1		
				180	C	1		
Top Support Plate			Bottom Surface		A		1	

Table 13.5-1 (Sheet 3 of 4)

Transducer Locations for Vibration Experiments

Structure	Outer Wall	Inner Wall	Elevation	Angle, Degrees	Dir. Of Sensitivity	Accelerometer	Pressure Transducer	Strain Gage
Guide Tube			Near Top Support Plate					3
			Pos. D-14 (Plut. Recycle)					2
			H-8 (Center)					4
			K-2 (Max. Vel.)					
Vessel	X		Vessel Head Studs	0	C	1[a]		
	X			0	R	1[a]		
	X			180	C	1[a]		
	X		Bottom Of Vessel	-	R	1[a]		
	X				C	1[a]		
	X				A	1[a]		
	X		Inlet Leg (21, 22 & 24)				3	
	X		Outlet Leg (21)				1	
Steam Generator No. 21			~65 Feet (Support Pad Elev.)		C	1[a]		
			~120 Feet (Near Top)		C	1[a]		
					R	1[a]		

Table 13.5-1 (Sheet 4 of 4)

Transducer Locations for Vibration Experiments

Structure	Outer Wall	Inner Wall	Elevation	Angle, Degrees	Dir. Of Sensitivity	Accelerometer	Pressure Transducer	Strain Gage
Main Coolant Pump No. 21			~62 Feet (Support Pad Elev.)		C	1[a]		
			~83 Feet (Top Motor Flange)		C R	1[a] 1[a]		
Intermediate Leg (Loop 21)			~54 Feet (Center of Pipe)		R	1[a]		
Containment Floor			~6 Feet		R C	1 1		

[a] These instruments in addition to portable accelerometers were used during the impedance test to determine mode shapes

13.6 TESTS FOLLOWING REACTOR REFUELING

During the initial return to power following a refueling shutdown or following a cold shutdown where fuel assemblies have been handled (inspection for example), a series of tests are carried out on the new core. The objectives of these tests are:

1. To demonstrate that the core performance during reactor operation will not exceed safety analysis and Technical Specification limits.

2. To verify the nuclear design calculations.

3. To provide the bases for the calibration of reactor instrumentation.

13.6.1 Reload Startup Physics Test Program

A typical reload startup physics test program may include, but is not limited to, the following:

1. Precriticality tests

   Calibration check of the incore thermocouples and reactor coolant resistance temperature detectors.

2. Hot zero power and beginning of core life condition tests

   a. Determination of the isothermal temperature coefficients and all rods out condition and boron end points for the following conditions:
      (1) All rods out of core.

   b. Determination of the differential and integral rod worths for the following banks of control rods:

      (1) Control bank D.
      (2) Control bank C with control bank D inserted.
      (3) Control bank B with control banks C and D inserted.
      (4) Control bank A with control banks B, C and D inserted.

      -OR-

      Determination of the integral rod worth for each individual Control and Shutdown Bank.

   c. Movable incore detector flux map performed at a power level less than or equal to 30-percent.

3. Power ascension tests

   a. Movable incore detector flux maps performed at various power levels.
   b. Overpower ΔT and overtemperature ΔT setpoint determination.
   c. Ex-core/incore instrumentation calibration.
   d. Heat balance/thermal power measurements.
   e. Reactor coolant flow measurements.

Core loading verification is carried out by monitoring the movement of each assembly during actual core loading. The location of each assembly as it is loaded into the core is verified using a detailed procedure prepared from the reload loading pattern. A final loading verification is carried out visually upon the completion of core loading to verify the as-loaded core against the design loading pattern.

Cold, zero-power physics testing is not included for reload core heatup, initial criticality, and power ascension. Since reactor operations in the initial cold condition are nonexistent, and initial warmup can be accomplished without nuclear heat (pump heat only), no meaningful information could be gained from such cold, zero-power testing.

Hot Testing

Hot, zero-power physics testing is used to verify that the reactor core can be safely operated and that it meets its design objectives. Hot, zero-power physics testing is accomplished with the reactor coolant system temperature and pressure at the no-load conditions.

Initial Criticality

The core conditions are established at their no-load values with all rod cluster controls inserted. A "1/M" plot is maintained during all periods of rod withdrawal and boron dilution.

Determination of Zero Power Flux Level

The ideal flux level for conduct of zero-power physics testing is one in which the flux level is sufficiently high enough to give a signal-to-noise ratio and at the same time sufficiently low enough to avoid the reactivity feedback associated with nuclear heating.

All-Rods-Out Boron Concentration

Although this test applies to the all-rods-out condition, it may be employed to determine endpoints of other control configurations.

Moderator Temperature Coefficient

The moderator temperature coefficient is determined from the measured all rods out isothermal temperature coefficient to assure that Technical Specification requirements are satisfied.

Differential Rod Worth

Differential rod worth is measured by incrementally moving the rods from one endpoint to another and measuring the reactivity addition per increment of movement. The endpoints used are generally the fully inserted and fully withdrawn core configuration for each control bank. Normally, bank overlap is not used at this time. In order to keep the flux level within the selected span for physics testing, boron is traded for rod position so that the overall reactivity status core and the flux level remain relatively constant.

Integral Rod Worth

The integral rod worth curves are developed by integrating the differential rod worth curve as a function of rod height. An alternate measurement technique Dynamic Rod Worth (DRWM), can also be used to measure the integral rod worth provided the technique, evaluation criteria, and remedial actions identified in Attachment 4 of Reference 1 are followed. The NRC documented their acceptance of this technique in a Safety Evaluation Report[2].

Power Ascension
The power ascension program involves slow increase in power level up to 100-percent power accompanied by testing to verify that the core is operating within the required limits.

In particular, movable detector flux traces are run at various power levels to ensure that the fuel was properly loaded and that the power distribution is within design limits. Reactor coolant system flow is determined to ensure that the total reactor coolant system flow exceeds the required minimum rate.

For the low-power physics test to measure control rod worth and shutdown margin the reactor may be critical with all but one control rod inserted [Historical Information].

13.6.2 Test Results

Test results are compared against nuclear design results; in all cases acceptance criteria are in accordance with Technical Specification limits. If the cycle reload is such that it falls within the conditions specified below for preparation and submittal of a startup physics test report to the NRC, such a report summarizing the results of the startup tests is so prepared and submitted.

Startup Report

A summary report of the plant startup and power escalation testing shall be submitted following (1) amendments to the license involving a planned increase in power level, (2) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (3) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant. The report shall address each of the appropriate tests identified in the UFSAR and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described.

Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the startup report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

REFERENCES FOR 13.6

1. Letter from Nicholas J. Liparulo, Westinghouse to NRC, Document Control Desk, October 10, 1995.

2. Letter from Robert C. Jones, NRC to Nicholas J. Liparulo, Westinghouse, dated January 5, 1996.

CHAPTER 14
SAFETY ANALYSIS

14.0 INTRODUCTION

This chapter evaluates the safety aspects of the plant and demonstrates that the plant can be operated safely and that exposures from credible accidents do not exceed the applicable limits.

14.0.1 Accident Classification

This chapter is divided into four sections, each dealing with a different behavior category:

1. Core and Coolant Boundary Protection Analysis, Section 14.1 -The incidents presented in Section 14.1 generally have no offsite radiation consequences.

2. Standby Safeguards Analysis, Section 14.2 –The accidents presented in Section 14.2 are more severe and may cause the release of radioactive material to the environment.

3. Rupture of a Reactor Coolant Pipe, Section 14.3 - The accident presented in Section 14.3, the rupture of a reactor coolant pipe, is the worst-case accident and is the primary basis for the design of engineered safety features. It is shown that even this accident meets the applicable limits.

4. Anticipated Transients Without Scram, Section 14.4 -The accidents presented in Section 14.4 were assumed to occur without the benefit of tripping the reactor. While the failure to trip is unlikely, several accidents were evaluated for which credit was not taken for a reactor trip. The results showed that gross fuel clad damage would not occur if the reactor failed to trip.

14.0.2 General Assumptions

Parameters and assumptions that are common to various accident analyses are described below to avoid repetition in subsequent sections. Reactor characteristics are reviewed at the start of each operating cycle to assure that they are within the bounds assumed in the accident analyses.

14.0.2.1 Steady-State Errors

For most accidents which are DNB limited, nominal values of initial conditions are assumed. The allowances on power, temperature, and pressure are determined on a statistical basis and are included in the limit DNBR, as described in Reference 1. This procedure is known as the "Revised Thermal Design Procedure" (RTDP) and these accidents utilized the WRB-1 DNB correlation for both the 15x15 VANTAGE+ fuel design and the upgraded fuel design. The initial conditions for other key parameters are selected in such a manner to maximize the impact to DNBR. Minimum measured flow is used in all RTDP transients. This flow allows for up to 7.9-percent allowance for calorimetric uncertainty.

For accidents which are not DNB limited, or for which the Revised Thermal Design Procedure is not employed, the initial conditions are obtained by applying the maximum steady state errors to rated values in such a manner to maximize the impact on the limiting parameters and conditions.

The following conservative steady state errors are considered:

1.	Core Power	± 2-percent allowance for calorimetric error
2.	Average Reactor Coolant System Temperature	± 7.5 ^{o}F allowance for controller deadband and measurement error
3.	Pressurizer Pressure	+28/-37 psi allowance for steady state fluctuations and measurement error
4.	Reactor Coolant Flow	Thermal Design Flow of 80,700 gpm/loop is assumed and no steady state errors are applied.

For all accidents initiated from full power, a nominal full power vessel average temperature ranging between a minimum and maximum of 549^{o}F to 572.0^{o}F was conservatively chosen for the analysis to bound operation at full power within this temperature range.

14.0.2.2 Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of fuel assemblies, control rods, and operating instructions. Power distribution may be characterized by the radial factor ($F_{\Delta H}$) and the total peaking factor (F_Q). The peaking factor limits are given in the Core Operating Limits Report (COLR).

For transients which may be DNB limited, the radial peaking factor is of importance. The radial peaking factor increases with decreasing power level due to rod insertion. This increase in $F_{\Delta H}$ is included in the core limits illustrated in Figure 7.2-19. All transients that may be DNB limited are assumed to begin with a $F_{\Delta H}$ consistent with the design thermal power level defined in the Technical Specifications.

For transients which may be overpower limited, the total peaking factor (F_Q) is of importance. All transients that may be overpower limited are assumed to begin with plant conditions including power distributions which are consistent with reactor operation as defined in the Technical Specifications.

The incore instrumentation system is employed to verify that actual hot channel factors are, in fact, no higher than those specified in the COLR.

14.0.2.3 Reactor Trip

A reactor trip signal acts to open the two series trip breakers feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the control rods, which then fall by gravity into the core. There are various instrumentation delays associated with each tripping function, including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall.

The time delay assumed for each tripping function is as follows:

Tripping Function	Time Delay (sec)
Overpower (nuclear)	0.5
Overtemperature ΔT	2.0
Overpower ΔT	2.0
Low pressurizer pressure	2.0
High pressurizer pressure	2.0
High pressurizer level	2.0
Low reactor coolant flow	
- loop flow detectors	1.0
- reactor coolant pump undervoltage	1.5
- reactor coolant pump underfrequency trip	1.0
Turbine trip	2.0
Low-low steam-generator water level	2.0

The trip levels used in the following analyses are maximum values including the trip setpoint and the error allowance. The trip setpoints are established based on Allowable Values set forth in the Technical Specifications.

The maximum nuclear overpower trip point assumed for the analysis is 116-percent. The trips are calibrated at power such that the calibration error is the calorimetric error of 2-percent. The design allowance for nonrepeatable errors is 6-percent. Nonrepeatable errors include both instrument drift and errors due to process changes such as control rod motion since both are observable as an error between the indicated signal and the known power from calorimetric measurements. In summary, the trip setpoints are less than the trip value assumed in the analyses to ensure that trip occurs within the assumed value when including the design error allowance.

The negative reactivity insertion following a reactor trip is a function of the position versus time of the control rods and the variation in rod worth as a function of rod position. With respect to accident analyses, the critical parameter is the time of insertion up to the dashpot entry or approximately 85-percent of the control rod travel.

The reactivity insertion versus time assumed in accident analyses is shown in Figure 14.0-1. The control rod insertion time to dashpot entry is taken as 2.4 seconds. This control rod drop time requirement is specified in the plant Technical Specifications.

REFERENCES FOR SECTION 14.0

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

2. Deleted

14.0 FIGURES

Figure No.	Title
Figure 14.0-1	Reactivity Insertion vs. Time for Reactor Trip

14.1 CORE AND COOLANT BOUNDARY PROTECTION ANALYSIS

For the following plant abnormalities and transients, the reactor control and protection systems are relied upon to protect the core and reactor coolant boundary from damage:

1. Uncontrolled rod cluster control assembly withdrawal from a subcritical condition.
2. Uncontrolled rod cluster control assembly withdrawal at power.
3. Rod cluster control assembly drop.
4. Chemical and volume control system malfunction.
5. Loss of reactor coolant flow.
6. Startup of an inactive reactor coolant loop.
7. Loss of external electrical load.
8. Loss of normal feedwater.
9. Reduction in feedwater enthalpy incident.
10. Excessive load increase incident.
11. Loss of all normal ac power to the station auxiliaries.
12. Likelihood and consequences of turbine-generator overspeed.

All reactor protection criteria are met presupposing the most reactive rod cluster control assembly is in its fully withdrawn position. Trip is defined for analytical purposes as the insertion of all full-length rod cluster control assemblies, except the most reactive assembly, which is assumed to remain in the fully withdrawn position. This is to provide margin in shutdown capability against the remote possibility of a stuck rod cluster control assembly condition existing at a time when shutdown is required.

Instrumentation is provided for continuously monitoring all individual rod cluster control assemblies together with their respective group position. This is in the form of a deviation alarm system. If a rod should deviate from its intended position, the reactor can be shut down in an orderly manner and the condition corrected. [***Note*** *- See Technical Specifications, Section 3.1, for permissible variances.*] Such occurrences are expected to be extremely rare on the basis of operation and test experience to date.

In summary, reactor protection is designed to prevent cladding damage in all transients and abnormalities listed above. The most probable modes of failure in each protection channel result in a signal calling for the protective trip. The coincidence of two-out-of-three (or two-out-of-four) signals is required where single-channel malfunction could cause spurious trips while at power. A single component or channel failure in the protection system itself coincident with one stuck rod cluster control assembly is always permissible as a contingent failure and does not cause a violation of the protection criteria. The reactor protection systems are designed in accordance with the IEEE "Standard for Nuclear Plant Protection Systems."

14.1.1 Uncontrolled Rod Cluster Control Assembly Withdrawal From A Subcritical Or Low Power Startup Condition

A rod cluster control assembly (RCCA) withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by withdrawal of rod cluster control assemblies resulting in a power excursion. This could occur with the reactor subcritical, at hot zero power, or at power. The "at power" case is discussed in Section 14.1.2. The low power startup condition assumed in this section (1×10^{-9} of nominal power) is less than the power level expected for any shutdown condition.

Although the reactor is normally brought to power from a subcritical condition by means of RCCA withdrawal, initial startup procedures with a clean core call for boron dilution. The maximum rate of reactivity increase in the case of boron dilution is less than that assumed in this analysis (see Section 14.1.5).

The RCCA drive mechanisms are wired into preselected bank configurations, which are not altered during reactor life. The drive mechanisms being wired into preselected bank configurations prevent the RCCAs from being manually withdrawn in other than their respective banks. Power supplied to the banks is controlled such that no more than two banks can be withdrawn at the same time and in their proper withdrawal sequence. The RCCA drive mechanisms are of the magnetic latch type and coil actuation is sequenced to provide variable speed travel. The maximum reactivity insertion rate analyzed in the detailed plant analysis is that occurring with the simultaneous withdrawal of the combination of two sequential control banks having the maximum combined worth at maximum speed, which is well within the capability of the protection system to prevent core damage.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast rise terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the power excursion is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous RCCA withdrawal accident occur, the transient will be terminated by the following automatic features of the reactor protection system:

1. Source range flux level trip - actuated when either of two independent source range channels indicates a flux level above a preselected, manually adjustable value. This trip function may be manually bypassed when either of two intermediate range flux channels indicates a flux level above the source range cutoff power level.

2. Intermediate range flux level trip - actuated when either of two independent intermediate range channels indicates a flux level above a preselected, manually adjustable value. This trip function is manually bypassed when two-out-of-four power range channels are reading above approximately 10-percent power and automatically reinstated when three-out-of-four channels indicate a power level below this value. To prevent unnecessary reactor trips during power reductions prior to shut down, operating procedures allow these trips to be manually bypassed until they have reset to the untripped condition and the reset has been verified.

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

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

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

NOTE: Automatic Rod Withdrawal Has Been Physically Disabled At Indian Point Unit 2.

14.1.1.1 Method of Analysis

The analysis of the uncontrolled RCCA bank withdrawal from subcritical accident is performed in three stages: (1) an average core nuclear power transient calculation, (2) an average core heat transfer calculation, and (3) the DNBR calculation. The average core nuclear calculation is performed using spatial neutron kinetics methods in TWINKLE[18] to determine the average power generation with time, including the various total core feedback effects (i.e., Doppler reactivity and moderator reactivity). The average heat flux and temperature transients are determined by performing a fuel rod transient heat transfer calculation in FACTRAN[19]. The average heat flux with appropriate peaking factors is next used in VIPRE[23] for departure from nucleate boiling ratio calculations.

This accident is analyzed using Standard Thermal Design Procedures. Plant characteristics and initial conditions are discussed in Section 14.0.2.1. In order to give conservative results for a startup accident, the following assumptions are made:

1. Since the magnitude of the power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler defect, conservatively low values as a function of power are used.

2. Contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time between the fuel and the moderator is much longer than the neutron flux response time. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. A highly conservative value is used in the analysis to yield the maximum peak heat flux.

3. The reactor is assumed to be just critical at hot zero power (no load) T_{avg} (547°F). This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler coefficient, all of which tend to reduce the Doppler feedback effect thereby increasing the neutron flux peak. The initial effective multiplication factor is assumed to be 1.0 since this results in the worst nuclear power transient.

4. Reactor trip is assumed to be initiated by power range high neutron flux (low setting). The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and rod cluster control assembly release, is taken into account. A 10-percent increase is assumed for the power range flux

trip setpoint raising it from the nominal value of 25-percent to 35-percent. Since the rise in the neutron flux is so rapid, the effect of errors in the trip setpoint on the actual time at which the rods are released is negligible. In addition, the reactor trip insertion characteristic is based on the assumption that the highest worth rod cluster control assembly is stuck in its fully withdrawn position.

5. The maximum positive reactivity insertion rate assumed (75 pcm/sec) is greater than that for the simultaneous withdrawal of the combination of two sequential control banks having the greatest combined worth at maximum speed (45-in./min). Control rod drive mechanism design is discussed in Section 3.2.3.4.

6. The most limiting axial and radial power shapes, associated with having the two highest combined worth banks in their high worth position, is assumed in the departure from nucleate boiling analysis.

7. The initial power level was assumed to be below the power level expected for any shutdown condition (10^{-9} of nominal power). This combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.

8. Two reactor coolant pumps are assumed to be in operation. This is conservative with respect to departure from nucleate boiling. No single active failure in any system or equipment available to mitigate the effects of the accident will adversely affect the consequences of the accident.

14.1.1.2 Results

Figures 14.1-1 through 14.1-4 show the transient behavior for the uncontrolled RCCA bank withdrawal incident, with the accident terminated by reactor trip at 35-percent of nominal power. The reactivity insertion rate used is greater than that calculated for the two highest worth sequential control banks, both assumed to be in their highest incremental worth region. Figure 14.1-1 shows the nuclear power transient.

The energy release and the fuel temperature increases are relatively small. The thermal flux response, of interest for departure from nucleate boiling considerations, is shown in Figure 14.1-2. The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux much less than the full power nominal value. There is a large margin to departure from nucleate boiling during the transient since the rod surface heat flux remains below the design value, and there is a high degree of subcooling at all times in the core. Figures 14.1-3 and 14.1-4 show the response of the hot-spot fuel average temperature and the hot-spot clad temperature. The average fuel temperature increases to a value lower than the nominal full power value. The minimum departure from nucleate boiling ratio at all times remains above the limit value.

The calculated sequence of events and summary of the results for this accident are shown in Table 14.1-1. With the reactor tripped, the plant returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

The operating procedures would call for operator action to control reactor coolant system boron concentration and pressurizer level using the chemical and volume control system, and to maintain steam generator level through control of the main or auxiliary feedwater system.

Any action required of the operator to maintain the plant in a stabilized condition will be in a time frame in excess of 10 min following reactor trip.

14.1.1.3 Radiological Consequences

There are no radiological consequences associated with an uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low power startup condition event since radioactivity is contained within the fuel rods and the reactor coolant system is maintained within design limits. This is demonstrated by showing that the minimum departure from nucleate boiling ratio remains above the limit DNBR.

14.1.1.4 Conclusions

In the event of a RCCA withdrawal accident from the subcritical condition, the core and the reactor coolant system are not adversely affected, since the combination of thermal power and the coolant temperature result in a DNBR greater than the limit value. Thus, no fuel or clad damage is predicted as a result of departure from nucleate boiling.

14.1.2 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal At Power

An uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power results in an increase in the core heat flux. Since the heat extraction from the steam generator lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power increase and resultant coolant temperature rise could eventually result in DNB. Therefore, in order to avert damage to the fuel clad, the Reactor Protection System is designed to terminate any such transient before the DNBR falls below the safety analysis limit values.

This event is classified as an ANS Condition II incident (an incident of moderate frequency).

The automatic features of the Reactor Protection System which prevent core damage following the postulated accident include the following:

1. Power range neutron flux instrumentation actuates a reactor trip if two-of-four channels exceed an overpower setpoint.

2. Reactor trip is actuated if any two-out-of-four ΔT channels exceed an Overtemperature ΔT setpoint. This setpoint is automatically varied with axial power imbalance, coolant temperature and pressure to protect against DNB.

3. Reactor trip is actuated if any two-out-of-four ΔT channels exceed an Overpower ΔT setpoint. This setpoint is automatically varied with coolant temperature to ensure that the allowable heat generation rate (kW/ft) is not exceeded.

4. A high pressurizer pressure reactor trip is actuated from any two-out-of-three pressure channels which is set at a fixed point. This set pressure is less than the set pressure for the pressurizer safety valves.

5. A high pressurizer water level reactor trip is actuated from any two-out-of-three level channels when the reactor power is above approximately 10-percent (Permissive P-7).

In addition to the above listed reactor trips, there are the following RCCA withdrawal blocks:

1. High neutron flux (one-out-of-four power range)
2. Overpower ΔT (one-out-of-four)
3. Overtemperature ΔT (one-out-of-four)

The manner in which the combination of the overpower and overtemperature ΔT trips provide protection over the full range of RCS conditions is described in Chapter 7.

14.1.2.1 Method of Analysis

The transient is analyzed by the RETRAN Code.[21A] This code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. The code computes pertinent plant variables, including temperatures, pressures, and power level.

This accident is analyzed using the Revised Thermal Design Procedure. [22] Initial reactor power, RCS pressure, and temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 22 of Chapter 14.1.

In performing the analysis, the following assumptions are made to assure bounding results are obtained for all possible normal operational conditions:

1. Reactivity Coefficients - Two cases are analyzed:
   a. Minimum Reactivity Feedback. A least-negative moderator density coefficient of reactivity is assumed, corresponding to the beginning of core life. A variable Doppler power coefficient with core power is used in the analysis. A conservatively small (in absolute magnitude) value is assumed.

   b. Maximum Reactivity Feedback. A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler power coefficient are assumed.

2. The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 116-percent of nominal full power. The ΔT trips include all adverse instrumentation and setpoint errors; the delays for trip actuation are assumed to be the maximum values.

3. The trip reactivity is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position.

4. A range of reactivity insertion rates is examined. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the two control banks having the maximum combined worth at maximum speed.

5. A range of initial power levels from 10% to 100% power is considered.

The effect of the axial core power distribution is accounted for by causing a decrease in the Overtemperature ΔT trip setpoint proportional to the decrease in margin to DNB.

14.1.2.2 Results

Figures 14.1-5, 14.1-6 and 14.1-7 show the transient response for a rapid RCCA withdrawal incident starting from full power. Reactor trip on high neutron flux occurs shortly after the start of the accident. Since this is rapid with respect to the thermal time constants of the plant, small changes in T_{avg} and pressure result and margin to DNB is maintained.

The transient response for a slow RCCA withdrawal from full power is shown in Figures 14.1-8, 14.1-9 and 14.1-10. Reactor trip on Overtemperature ΔT occurs after a longer period and the rise in temperature is consequently larger than for rapid RCCA withdrawal. Again, the minimum DNBR is greater than the safety analysis limit values.

Figure 14.1-11 shows the minimum DNBR as a function of reactivity insertion rate from initial full power operation for minimum and maximum reactivity feedback. It can be seen that two reactor trip channels provide protection over the whole range of reactivity insertion rates. These are the high neutron flux and Overtemperature ΔT channels. The minimum DNBR is never less than the safety analysis limit values.

Figures 14.1-12 and 14.1-13 show the minimum DNBR as a function of reactivity insertion rate for RCCA withdrawal incidents starting at 60 and 10-percent power, respectively, for minimum and maximum reactivity feedback. The results are similar to the 100-percent power case, except as the initial power is decreased, the range over which the Overtemperature ΔT trip is effective is increased. In all cases the DNBR does not fall below the safety analysis limit value.

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

For transients initiated at 60% power it is noted that:

1. For reactivity insertion rates above approximately 10 pcm/sec reactor trip is initiated by the high neutron flux trip for the minimum reactivity feedback cases. The neutron flux level in the core rises rapidly for these insertion rates while core heat flux lags behind due to the thermal capacity of the fuel and coolant system fluid. Thus, the reactor is tripped prior to significant increase in heat flux or water temperature with resultant high minimum DNB ratios during the transient. As reactivity insertion rate decreases, core heat flux can remain more nearly in equilibrium with the neutron flux. Minimum DNBR during the transient thus decreases with decreasing insertion rate.

2. The Overtemperature ΔT reactor trip circuit initiates a reactor trip when measured coolant loop ΔT exceeds a setpoint based on measured Reactor Coolant System average temperature and pressure. It is important to note that the average temperature contribution to the circuit is lead lag compensated to decrease the effect of the thermal capacity of the RCS in response to power increases.

3. For reactivity insertion rates below10 pcm/sec the Overtemperature ΔT trip terminates the transient.

   For reactivity insertion rates from 10 pcm/sec to approximately 2 pcm/sec the effectiveness of the Overtemperature ΔT trip increases (in terms of increased minimum DNBR) due to the fact that with lower insertion rates the power increase rate is slower, the rate of rise of average coolant temperature is slower and the system lags and delays become less significant.

4. For reactivity insertion rates less than 2 pcm/sec, the rise in the reactor coolant temperature is sufficiently high so that the steam generator safety valve setpoint is reached prior to trip. Opening of these valves, which acts as a heat sink on the Reactor Coolant System and results in increased heat removal from the Reactor Coolant System, sharply decreases the rate of increase of the Reactor Coolant System average temperature.

The effect described in item 4 above, which results in the sharp peak in minimum DNBR at approximately 2 pcm/sec, does not occur for transients initiated at 100% power since the steam generator safety valves are not actuated prior to trip (Figure 14.1-11).

Since the RCCA withdrawal at power incident is an overpower transient, the fuel temperatures rise during the transient until after reactor trip occurs. For high reactivity insertion rates, the overpower transient is fast with respect to the fuel rod thermal time constant, and the core heat flux lags behind the neutron flux response. Due to this lag, the peak core heat flux does not exceed 116-percent of its nominal value (i.e., the high neutron flux trip setpoint assumed in the analysis). Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature will still remain below the fuel melting temperature.

For slow reactivity insertion rates, the core heat flux remains more nearly in equilibrium with the neutron flux. The overpower transient is terminated by the Overtemperature ΔT reactor trip before a DNB condition is reached. The peak heat flux again is maintained below 116-percent of its nominal value. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature will remain below the fuel melting temperature.

Since the DNBR is not violated at any time during the RCCA withdrawal at power transient, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient. The calculated sequence of events for this accident is shown on Table 14.1-2 for large and small reactivity insertion rates. These sequences of events are for the cases initiated from full power assuming minimum reactivity feedback conditions. With the reactor tripped, the plant eventually returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

14.1.2.3 Conclusions

The high neutron flux and Overtemperature ΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates, i.e., the minimum value of DNBR is always larger than the safety analysis limit values.

14.1.3 Incorrect Positioning Of Part-Length Rods

Part-length rods were employed in the original design to improve the axial power distributions as well as to control potential axial xenon oscillations. Subsequent to initial plant operations, however, (during the Cycle 2/3 refueling outage), the part-length rod cluster control assemblies were removed from the reactor.

14.1.4 Rod Cluster Control Assembly Drop

The dropping of a rod cluster control assembly could occur from deenergizing a drive mechanism. It would result in a power reduction and a possible increase in the hot-channel factor. If no protective action occurred, the reactor coolant system would attempt to restore the power to the level that existed before the incident occurred. This would lead to a reduced safety margin or possibly departure from nucleate boiling, depending upon the magnitude of the hot-channel factor.

If a rod cluster control assembly should drop into the core during power operation, this would be detected by the rod bottom signal device, which provides an individual position indication signal for each rod cluster control assembly. The initiation of this signal is independent of lattice location, reactivity worth, or power distribution changes inherent with the dropped rod cluster control assembly. Further indication of a rod cluster control assembly drop would be obtained by independent means, using the out-of-core power range channel signals.

A rod drop signal from any rod position indication channel, or from one or more of the four power range channels, initiates protective action by reducing turbine load by a preset adjustable amount. Bypass switches have been installed which are in the DEFEAT position, so as to bypass the runback. The automatic rod control system has been modified and currently utilizes only the automatic rod insertion feature (the automatic rod withdrawal feature has been disabled by this modification). This action prevents core damage. The automatic turbine runback functionality has been administratively deleted. The rod stop is also redundantly actuated. Rod drop protection is discussed in Section 7.2.

14.1.4.1 Method of Analysis

The transient response following a dropped RCCA event is calculated using a detailed digital simulation of the plant. A dropped RCCA or dropped RCCA Bank causes a step decrease in reactivity and the resulting core power generation is determined using the LOFTRAN computer code [21]. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, rod control system, steam generators, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. Since LOFTRAN employs a point neutron kinetics model, a dropped rod event is modeled as a negative reactivity insertion corresponding to the reactivity worth of the dropped RCCA(s), regardless of the actual configuration of the rod(s) that drop.

A dropped rod cluster control assembly results in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly. Following a dropped rod cluster control assembly with turbine runback and automatic rod withdrawal disabled, the plant will establish a new equilibrium condition. Depending on the worth of the dropped RCCA(s), power may be reestablished by reactivity feedback.

When reactivity feedback does not offset the worth of the dropped RCCA(s), a cooldown condition exists until a low pressurizer pressure reactor trip signal is reached. When reactivity feedback is large enough to offset the worth of the dropped RCCA(s), reactor power is reestablished at a new equilibrium condition.

To capture the transient response, dropped rod statepoints designed to bound possible operation without a turbine runback were evaluated. The dropped rod/bank statepoints are based on generic dropped rod analyses performed as part of the Westinghouse Owners Group (WOG) dropped rod protection modification program.[27] The WOG dropped rod protection modification program was specifically performed to support elimination of turbine runback on dropped rod (for Westinghouse plants with this system) and deletion of the negative flux rate trip (for Westinghouse plants without turbine runback on dropped RCCA) for conditions with and without automatic rod withdrawal block. The incident is analyzed using the Revised Thermal Design Procedure and assumes nominal initial conditions as described in Section 14.0.2.1

14.1.4.2 Results

Figures 14.1-14 through 14.1-16 illustrate a typical transient response when reactivity feedback does not offset the worth of the dropped RCCA(s). In this case, BOL conditions are shown with a small negative moderator temperature coefficient (MTC) of -5 pcm/ºF for a dropped RCCA worth of 400 pcm. As a result of the negative reactivity insertion of the dropped rod cluster control assembly, a cooldown condition of the RCS exists. The nuclear power reaches a level lower than that which existed before the incident and the RCS temperature and pressure continue to decrease until a low pressurizer pressure reactor trip signal is reached.

Figures 14.1-17, 14.1-18, and 14.1-19 illustrate a typical transient response when reactivity feedback is large enough to offset the worth of the dropped RCCA(s). In these figures EOL conditions are shown with a large negative moderator temperature coefficient (MTC) of -35 pcm/ºF for a dropped rod cluster control assembly worth of 400 pcm. With a large reactivity feedback, a new equilibrium condition is reached without a reactor trip. The nuclear power returns to nearly the initial power level that existed before the incident while the RCS temperature and pressure are reduced to a slightly lower condition.

The evaluation of the generic WOG dropped rod/bank statepoints considered to bound possible operation without turbine runback show the applicable licensing basis acceptance criteria is met. Specifically, the evaluations performed using the WOG dropped rod/bank statepoints verified that the DNBR licensing basis acceptance criterion is met assuming no turbine runback following a dropped RCCA event for single or multiple dropped RCCAs from the same group of a given bank with rod withdrawal block. It should be noted that no evaluation of single dropped RCCA worths with automatic rod control functioning was performed to confirm the acceptability of the dropped RCCA event for a single failure of a rod-on-bottom signal which automatically blocks rod withdrawal. This is because automatic rod withdrawal has been physically disabled at Indian Point Unit 2 which precludes such occurrences.

For all cases analyzed, the DNBR does not fall below the limit value.

14.1.4.3 Conclusions

Based on the DNBR results for all of the cases analyzed, it has been demonstrated that the DNBR criterion is met, and therefore, it is concluded that dropped RCCAs do not lead to conditions that cause core damage and that all applicable safety criteria is satisfied for this event.

14.1.5 Chemical And Volume Control System Malfunction

14.1.5.1 Introduction

Reactivity can be added to the core with the chemical and volume control system by feeding reactor makeup water into the reactor coolant system via the reactor makeup control system. Boron dilution is a manual operation. A boric acid blend system is provided to permit the operator to match the concentration of reactor coolant makeup water to that existing in the coolant at the time. The chemical and volume control system is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

There is only a single, common source of dilution water to the blender from the primary water makeup system; inadvertent dilution can be readily terminated by isolating this single source. The operation of the primary water makeup pumps that take suction from the primary water storage tank (PWST) provides the non-borated supply of makeup water to the blender. The boric acid from the boric acid storage tank(s) is blended with the reactor makeup water in the blender, and the composition is determined by the preset flow rates of boric acid and reactor makeup water on the reactor makeup control. The operator must switch from the automatic makeup mode to the dilute mode and move the start-stop switch to start, or, alternatively, the boric acid flow controller could be set to zero. Since these are deliberate actions, the possibility of inadvertent dilution is very small. In order for this dilution water to be added to the reactor coolant system, the charging pumps must be running in addition to the primary water makeup pumps. Also, any diluted water introduced into the volume control tank (VCT) must pass through the charging pumps to be added to the reactor coolant system.

Thus, the rate of addition of diluted water to the reactor coolant system from any source is limited to the capacity of the charging pumps. This addition rate is 294 gpm for all three charging pumps. This is the maximum delivery rate based on a pressure drop calculation comparing the pump curve with the system resistance curve. Normally, only one charging pump is operating while the others are on standby.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of pumps in the chemical and volume control system. Alarms are actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of system malfunction. Boron dilution during refueling, startup, and power operation are considered in this analysis.

14.1.5.2 Method of Analysis and Results

14.1.5.2.1 Dilution During Refueling

During refueling the following conditions exist:

1. One residual heat removal pump providing a minimum flow rate of 1000 gpm is normally running except during short time periods as allowed by the technical specifications.

2. The chemical and volume control system and/or safety injection system are aligned so that there is at least one flow path to the core for boric acid injection when there is fuel in the reactor, as required by the Technical Specifications.

3. The minimum boron concentration of the refueling water is at least 2050 ppm or higher to maintain a shutdown of at least 5-percent $\Delta k/k$ with all control rods in; periodic sampling ensures that this concentration is maintained.

4. Neutron sources are installed in the core and detectors connected to instrumentation giving audible count rates are installed outside or within the reactor vessel to provide direct monitoring of the core.

A minimum water volume in the reactor coolant system of 3257-ft^3 is considered. This corresponds to the volume necessary to fill the reactor vessel to mid-loop. The maximum dilution flow of 294 gpm and uniform mixing are also considered. The operator has prompt and definite indication of any boron dilution from the audible count rate instrumentation. High count rate is alarmed in the reactor containment and the main control room. The count-rate increase is proportional to the multiplication factor.

The boron concentration must be reduced from 2050 ppm to approximately 1390 ppm before the reactor will go critical. This would require more than 30 minutes. This is ample time for the operator to recognize the audible high count-rate signal and isolate the reactor makeup source by closing valves and stopping the primary water makeup pumps and/or charging pumps. The Refueling Operation Surveillance Procedure requires values which are potential sources of un-borated water be tagged closed, and the possibility of inadvertent dilution during refueling is very small. In addition, there could be a source of water from Indian Point Unit 1. Procedures call for isolation of that source should there be an unintended dilution.

14.1.5.2.2 Dilution During Startup

In this mode, the plant is being taken from one long-term mode of operation, Hot Standby, to another, Power Operation. Typically, the plant is maintained in the Startup mode only for the purpose of startup testing at the beginning of each cycle. During this mode of operation rod control is in manual. All normal actions required to change power level, either up or down, require operator initiation.

Conditions assumed for the analysis are:

1. Dilution flow is the maximum capacity of the charging pumps, 294 gpm.

2. A minimum RCS water volume of 8567-ft^3. This corresponds to the active RCS volume taking into account 10% uniform steam generator tube plugging minus the pressurizer and the reactor vessel upper head.

3. The initial boron concentration is assumed to be 1800 ppm, which is a conservative maximum value for the critical concentration at the condition of hot zero power, rods to insertion limits, and no Xenon.

4. The critical boron concentration following reactor trip is assumed to be 1550 ppm, corresponding to the hot zero power, all rods inserted (minus the most reactive RCCA), no Xenon condition. The 250 ppm change from the initial condition noted above is a conservative minimum value.

This mode of operation is a transitory operational mode in which the operator intentionally dilutes (borates) and withdraws control rods to take the plant critical. During this mode, the plant is in manual control with the operator required to maintain a high awareness of the plant status. For a normal approach to criticality, the operator must manually initiate a limited dilution (boration) and subsequently manually withdraw the control rods, a process that takes several hours. The Technical Specifications require that the operator assure that the reactor does not go critical with the control rods below the insertion limits. Once critical, the power escalation must be sufficiently slow to allow the operator to manually block the source range reactor trip nominally set at 2.3 E5 CPS after receiving P-6 from the intermediate range. Too fast a power escalation (due to an unknown dilution) would result in reaching P-6 unexpectedly, leaving insufficient time to manually block the source range reactor trip. Failure to perform this manual action results in a reactor trip and immediate shutdown of the reactor.

However, in the event of an unplanned approach to criticality or dilution during power escalation while in the Startup mode, the plant status is such that minimal impact will result. The plant will slowly escalate in power to a reactor trip on the power range neutron flux - high, low setpoint (nominal 25-percent power). From initiation of the event, there are greater than 15 minutes available for operator action prior to return to criticality.

14.1.5.2.3 Dilution at Power

In this mode, the plant may be operated in either automatic or manual rod control. Conditions assumed for the analysis are:

1. Dilution flow is the maximum capacity of the charging pumps, 294 gpm.

2. A minimum RCS water volume of 8567-ft^3. This corresponds to the active RCS volume (with 10% uniform steam generator tube plugging) minus the pressurizer and reactor vessel upper head.

3. The initial boron concentration is assumed to be 1800 ppm, which is a conservative maximum value for the critical concentration at the condition of hot full power, rods to insertion limits, and no Xenon.

4. The critical boron concentration following reactor trip is assumed to be 1450 ppm, corresponding to the hot zero power, all rods inserted (minus the most reactive RCCA), no Xenon condition. The 350 ppm change from the initial condition noted above is a conservative minimum value.

With the reactor in automatic rod control, the power and temperature increase from boron dilution results in insertion of the control rods and a decrease in the available shutdown margin. The rod insertion limit alarms (LOW and LOW-LOW settings) alert the operator more than 15 minutes prior to losing the required minimum shutdown margin. This is sufficient time to determine the cause of dilution, isolate the reactor water makeup source, and initiate boration before the available shutdown margin is lost.

With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature rise will cause the reactor to reach the Overtemperature ΔT trip setpoint resulting in a reactor trip. The boron dilution transient in this case is essentially the equivalent to an uncontrolled RCCA bank withdrawal at power. The maximum reactivity insertion rate for a boron dilution is conservatively estimated to 1.24 pcm/sec, which is within the range of insertion rates analyzed. Thus, the effects of dilution prior to reactor trip are bounded by the uncontrolled RCCA bank withdrawal at power analysis (Section 14.1.2). Following reactor trip there are greater than 15 minutes prior to criticality. This is sufficient time for the operator to determine the cause of dilution, isolate the reactor water makeup source, and initiate boration before the available shutdown margin is lost.

14.1.5.3 Conclusions

Because of the procedures involved in the dilution process requiring operator action, an erroneous dilution is considered very unlikely. Nevertheless, if an unintentional dilution of boron in the reactor coolant does occur, numerous alarms and indications are available to alert the operator to the condition. The maximum reactivity addition due to changes in dilution are slow enough to allow the operator to determine the cause of the addition and take corrective action before shutdown margin is lost.

14.1.6 Loss Of Reactor Coolant Flow

14.1.6.1 Description

A loss-of-coolant-flow incident may result from a mechanical or electrical failure in one or more reactor coolant pumps, or from a fault in the power supply to these pumps. If the reactor is at power at the time of the incident, the immediate effect of loss-of-coolant flow is a rapid increase in coolant temperature. This increase could result in departure from nucleate boiling with subsequent fuel damage if the reactor is not tripped promptly. The following trip circuits provide the necessary protection against a loss-of-coolant-flow incident and are actuated by:

1. Low voltage on pump power supply bus (above P-7 permissive).

2. Pump circuit breaker opening (one-out-of-four above P-8 permissive, two-out-of-four above P-7 permissive).

3. Low reactor coolant flow (one-out-of-four above P-8 permissive, two-out-of-four above P-7 permissive).

Each pump circuit breaker is automatically tripped on an undervoltage of its associated bus or an underfrequency on any two-out-of-four pump buses.

These trip circuits and their redundancy are further described in Section 7.2.

The most severe partial and complete loss of reactor coolant flow accidents are analyzed to ensure that the reactor trip together with flow sustained by the inertia of the coolant and rotating pump parts will be sufficient to prevent departure from nucleate boiling. Therefore, the fuel will not be damaged as a result of the most severe credible loss-of-coolant-flow accident.

14.1.6.2 Method of Analysis

The following loss of flow cases were analyzed:

1. Loss of four pumps from full power during four-loop operation.
2. Loss of one pump from full power during four-loop operation.

The normal power supplies for the pumps are the four buses connected to the generator, each of which supplies power to one of the four pumps. When a turbine trip occurs, the pumps are automatically transferred to the buses supplied from an external power line, and the pumps will continue to supply coolant flow to the core. The simultaneous loss of power to the four reactor coolant pumps is a highly unlikely event. Since the pumps are on separate buses, a single bus fault would result in the loss of only one pump.

These transients are analyzed with two computer codes. First, the RETRAN[21a] computer code is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE[23] computer code is then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS flow from RETRAN.

The calculation of DNBR during the transient is made using the nucleate boiling correlations as described in Section 3.2.2.1.2. In addition, the following assumptions were made in the calculations.

14.1.6.2.1 Initial Operating Conditions

The initial operating conditions used for the analysis are consistent with the use of the Revised Thermal Design Procedure (RTDP).[22] These assumptions include the following full power initial operating conditions; nominal value of power, nominal steady state pressure, and maximum steady state average programmed temperature.

14.1.6.2.2 Reactivity Coefficients

A conservatively large absolute value of the Doppler-only power coefficient is used. The least negative moderator temperature coefficient (minimum moderator density coefficient) is assumed (0.0 pcm/^{o}F), since this results in the maximum core power during the initial part of the transient, when the minimum DNBR is reached.

14.1.6.2.3 Reactor Trip

For the one-pump loss-of-flow incidents, the reactor trip is assumed to be actuated by the redundant flow monitoring channel (two-out-of-three), since this results in the largest delay to reactor trip. For the four-pumps loss of flow incident, two cases are considered; reactor trip actuated by redundant bus undervoltage or breaker trip (one-out-of-four or one-out-of-three) and reactor trip on bus underfrequency (two-out-of-four). For the analysis of the four-pump loss-of-flow incident actuated by a bus undervoltage or breaker trip, the loss of flow is assumed to occur at the initiation of the event (i.e., t=0). Hence, with respect to the safety analysis, the undervoltage trip setpoint is irrelevant. However, for the analysis of the four-pumps loss-of-flow incident actuated by a bus underfrequency, the reactor is assumed to trip after an underfrequency reactor coolant pump trip at 57 Hz following a frequency decay of 5 Hz/sec from an initial frequency of 60 Hz. The trip is conservatively modeled to occur at 1.6 seconds, which includes a maximum reactor trip time delay of 1.0 seconds. Following reactor trip, the reactor coolant pumps will continue to coast down, and natural circulation flow will eventually be established. With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

The low-flow trip setting is 92-percent of full flow; the trip signal is assumed to be initiated at 85.0-percent of full flow, allowing 7.0-percent for margin and instrumentation uncertainty. Upon reactor trip, it is assumed that the most reactive rod cluster control assembly is stuck in its fully withdrawn position, hence resulting in a minimum insertion of negative reactivity. The negative reactivity insertion upon trip is conservatively assumed to be 4% Δk.

A conservative shape of trip reactivity insertion versus time (based on a RCCA drop time of 2.4 seconds to the dashpot) was also used.

14.1.6.2.4 Heat Transfer Coefficient

The overall heat conductance between the fuel and water regions varies considerably during the transient mostly as a result of the change of fuel gap conductance. The larger heat transfer coefficients calculated at several different power levels, using EOL fuel temperatures, are used. This assumption produces a fast fuel thermal response and maximizes the positive reactivity inserted by Doppler feedback as the core is shutdown.

14.1.6.2.5 Flow Coastdown

Reactor coolant flow coastdown curves are shown in Figure 14.1-21 for the one-pump loss of flow and in Figures 14.1-24 and 14.1-27, for the four-pumps loss of flow accident on bus undervoltage and bus underfrequency, respectively. These curves are based on high estimates of loop pressure losses and include the effect of inertia from the pump flywheels.

14.1.6.3 <u>Results</u>

The time sequence of events and summary of the results for the complete (four-pumps) loss of flow and for the partial (one-pump) loss of flow accidents are shown in Tables 14.1-3 and 14.1-4, respectively.

Figure 14.1-20 shows the nuclear power and heat flux transients for the partial loss of flow from full power operation. Figure 14.1-22 shows the DNBR as a function of the time for this case. The minimum DNBR is reached at about 3.4 seconds after the initiation of the accident. For this case, the DNBR also always remains above the safety limit value.

Figure 14.1-23 shows the nuclear power and heat flux transients for the complete loss of flow from full power operation following a reactor trip on bus undervoltage. Figure 14.1-25 shows the DNBR as a function of time for this case. The minimum DNBR is reached at about 3.3 seconds from the start of the accident and the DNBR always remains above the safety limit value.

Figure 14.1-26 shows the nuclear power and hot channel heat flux transients for the complete loss of flow from full power operation following a reactor trip on bus underfrequency. Figure 14.1-28 shows the DNBR as a function of time for this case. The minimum DNBR is reached at about 3.6 seconds from the start of the accident and the DNBR always remains above the safety limit value.

14.1.6.4 Conclusions

Since the applicable safety analysis DNBR limit is met for the loss of flow cases considered, there is no cladding damage and no release of fission products into the reactor coolant. Therefore, all applicable safety criteria is met for the loss of flow events.

14.1.6.5 Locked Rotor Accident

A transient analysis was performed for the postulated instantaneous seizure of a reactor coolant pump rotor. Flow through the reactor coolant system is rapidly reduced, leading to a reactor trip on a low-flow signal. Following the trip, heat stored in the fuel rods continues to pass into the core coolant, causing the coolant to expand. The rapid expansion of the coolant in the reactor core, combined with the reduced heat transfer to the secondary system, causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the power-operated relief valves, and eventually opens the pressurizer safety valves, in that sequence. The two power-operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, their pressure-reducing effect is not included in the analysis.

14.1.6.5.1 Method of Analysis

As was the case for the loss of flow accident previously analyzed, the locked rotor analysis was performed assuming a full power initial condition with all four loops in operation and the same two computer codes are used to analyze this transient. The RETRAN[21a] computer code is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE[23] computer code is then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS flow from RETRAN.

The following effects of the locked rotor event were investigated:

1. Primary pressure transient.
2. Fuel clad temperature transient (this is calculated assuming film boiling in order to give the worst possible results).
3. DNB transient (for determining the amount of rods in DNB for the offsite dose release calculations).

14.1.6.5.1.1 Initial Conditions

Except for the DNB evaluation, performed using the Revised Thermal Design Procedure, the locked rotor accident was analyzed assuming that at the beginning of the postulated event (at the time the shaft in one of the reactor coolant pumps is assumed to seize), the plant is in operation under the most adverse steady-state operating conditions; i.e., 102% of the NSSS design thermal power, with maximum steady-state pressurizer pressure and level, and maximum steady-state coolant average temperature.

14.1.6.5.1.2 Evaluation of the Pressure Transient

For the peak pressure evaluation, the initial pressure is conservatively estimated as 28 psi above nominal pressure (2250 psia) to allow for errors in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. To obtain the maximum pressure in the primary side, conservatively high loop pressure drops are added to the calculated pressurizer pressure.

After pump seizure, the neutron flux is rapidly reduced by control rod insertion. Rod motion is assumed to begin 1 second after the flow in the affected loop reaches 85.0-percent of nominal flow. No credit is taken for the pressure-reducing effect of the pressurizer relief valves, pressurizer spray, steam dump, or controlled feedwater flow after plant trip. Although these operations are expected to occur and would result in a lower peak pressure, an additional degree of conservatism is provided by ignoring their effect.

The safety valves start operating at 2485 psig and their combined capacity for steam relief is 42-ft^3/sec.

14.1.6.5.1.3 Evaluation of Fuel Rod Thermal Transient

The evaluation of fuel rod thermal transient is performed at the hot spot. Results obtained from analysis of this "hot spot" condition represent the upper limit with respect to clad temperature and zirconium-water reaction.

In the evaluation, the rod power at the hot spot is conservatively assumed to be at least 2.5 times the average rod power (i.e., F_Q = 2.5) at the initial core power level.

14.1.6.5.1.4 Film Boiling Coefficient

The film boiling coefficient is calculated in the VIPRE program [23] using the Bishop-Sandberg-Tong film-boiling correlation. The fluid properties are evaluated at film temperature (average between wall and bulk temperatures). The program calculates the film coefficient at every time step, based upon the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and mass flowrate as a function of time are used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient since they are the most conservative with respect to clad temperature response. For conservatism, film boiling was assumed to start at the beginning of the accident.

14.1.6.5.1.5 Fuel Clad Gap Coefficient

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

14.1.6.5.1.6 Zirconium-Steam Reaction

The zirconium-steam reaction can become significant above 1800°F (clad temperature). The Baker-Just parabolic rate equation shown below is used to define the rate of the zirconium-steam reaction.

$$\frac{d\left(w^2\right)}{dt} = 33.3x10^6 \exp\left(-\frac{45{,}500}{1.986T}\right)$$

where:

w = amount reacted (mg/cm^2).

t = time (seconds).

T = temperature (°Kelvin).

The reaction heat is 1510 cal/g.

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

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

The evaluation of the number of rods in DNB has been performed using the Revised Thermal Design Procedure.

Nominal values for power, core pressure and core inlet temperature were assumed in the analysis, consistent with the use of the RTDP.

Calculation of the extent of the DNB in the core during the transient has been performed using the VIPRE[23] program.

14.1.6.5.2 Results

Figures 14.1-29 through 14.1-30a show the transient results for one locked rotor with four loops in operation (with loss of offsite power). The results of these calculations and the time sequence of events are also summarized in Table 14.1-5. The peak RCS pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits of the ASME code, Section III. Also the clad peak temperature is considerably less than 2700°F. It should be noted that the clad temperature was conservatively calculated assuming that DNB (i.e., film boiling) occurs at the initiation of the transient even if DNB is not expected.

14.1.6.5.3 Fission Product Release

As a result of the accident, fuel clad damage may occur. Due to the potential for leakage between the primary and secondary systems, radioactive reactor coolant is assumed to leak from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere through either the atmospheric relief valves or the main steam safety valves. Iodine and alkali metals group activity is assumed to be contained in the secondary coolant prior to the accident, and some of this activity is also released to the atmosphere as a result of steaming the steam generators following the accident.

There are no rods in DNB as a result of the locked rotor. In determining the offsite doses following the locked rotor accident, it is conservatively assumed that 5% of the fuel rods in the core suffer sufficient damage that all of their gap activity is released. The core activity is provided in Table 14.3-43 and it is assumed that the damaged fuel rods have all been operating at a peaking factor of 1.70. The gap fractions from Table 3 of Regulatory Guide 1.183 (Reference 37) are used. These are 8% for I-131, 10% for Kr-85, 5% for other iodines and noble gases, and 12% for alkali metals. Per the model in Regulatory Guide 1.183, these are the only nuclide groups considered for gap activity.

A pre-existing iodine spike in the reactor coolant is assumed to have increased the primary coolant iodine concentration to 60 μCi/gm of dose equivalent 1-131 prior to the locked rotor accident. The alkali metals and noble gas activity concentrations in the RCS at the time the accident occurs are based on operation with a fuel defect level of one percent. The iodine activity concentration of the secondary coolant at the time the locked rotor ejection accident occurs is assumed to be 0.15 μCi/gm of dose equivalent I-131.

Regulatory Guide 1.183 (Reference 37) specifies that the iodine released from the fuel is 95% particulate (cesium iodide), 4.85% elemental, and 0.15% organic. However, iodine in solution is considered to be all elemental and after it is released to the environment the iodine is modeled as 97% elemental and 3% organic.

The primary to secondary steam generator tube leak used in the analysis is 150 gpd per steam generator (total of 600 gpd).

No credit for iodine removal is taken for any steam released to the condenser prior to reactor trip and concurrent loss of offsite power. All noble gas activity carried over to the secondary side through steam generator tube leakage is assumed to be immediately released to the outside atmosphere. The residual heat removal system is assumed to be placed in service at 30 hours after the accident and there are no further releases to the environment after this point in time.

An iodine partition factor in the steam generators of 0.01 curies/gm steam per curies/gm water is used. The partition factor for the alkali metal activity in the steam generators is 0.0025 and is based on moisture carryover.

The resultant 2 hour site boundary dose is 0.24 rem TEDE. The 30 day low population zone dose is 0.54 rem TEDE. These doses are calculated using the meteorological dispersion factors discussed in Section 14.3.6.2.1.

The offsite doses resulting from the accident are less than 2.5 rem TEDE, which is 10-percent of the limit value of 10 CFR 50.67 and is the dose acceptance limit from Regulatory Guide 1.183.

The accumulated dose to control room operators following the postulated accident was calculated using the same release, removal and leakage assumptions as the offsite doses, using the control room model discussed in Section 14.3.6.5 and Tables 14.3-50 and 14.3-51. The calculated control room dose is presented in Table 14.3-52 and is less than the 5.0 rem TEDE control room dose limit values of 10 CFR 50.67.

14.1.6.5.4 Conclusions

1. The peak pressure of 2553 psia for the worst case ensures that the integrity of the primary coolant system is not endangered and can be considered as an upper limit, considering the conservative assumptions used in the study.

2. The DNBR always remains above the safety limit value. Hence there are no rods in DNB.

3. The peak clad average temperature of 1813°F, calculated for the hot spot, includes the effect of the zirconium-steam reaction (which is still quite small at that temperature). It can be considered an upper limit since:
   a. The hot spot was assumed to be in departure from nucleate boiling from time zero regardless if DNB occurs.
   b. A high gap coefficient (10000 Btu/hr-ft^2 - °F) was used.
   c. No credit was taken for transition boiling. The heat transfer coefficient for fully developed film boiling was used from time zero.
   d. The nuclear heat released in the fuel at the hot spot was based on a zero moderator coefficient.

4. The radiological consequences of this event are within the limit values.

Based on this, it can be concluded that all the applicable safety criteria for the locked rotor accident are met.

14.1.7 Startup Of an Inactive Reactor Coolant Loop

Technical Specifications require that all 4 reactor coolant pumps be operating for reactor power operation and preclude operation with an inactive loop (except for testing or repair and not to exceed the time specified). This event was originally included in the FSAR licensing basis when operation with a loop out of service was considered. Based on the current Technical Specifications which prohibit at power operation with an inactive loop as indicated above and the changes to the Technical Specifications which deleted all references to three loop operation, this event has been deleted from the updated FSAR.

14.1.8 Loss Of External Electrical Load

14.1.8.1 Description

A major load loss on the plant can result from either a loss of external electrical load or from a turbine trip. For either case, offsite power is normally available for the continued operation of plant components such as the reactor coolant pumps, unless the 6.9 KV fast bus transfer does not take place. The specific case of loss of all ac power to station auxiliaries is discussed in Section 14.1.12. The case of RCP overspeed following a turbine mechanical overspeed trip is addressed in Section 4.2.2.4.

A turbine trip will cause a reactor trip based on a signal derived from the turbine autostop oil pressure unless the reactor is below approximately 20-percent power (P-8). The automatic steam dump system accommodates the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere. Additionally, main feedwater flow would be lost if the turbine condenser were not available. For this situation, steam generator level would be maintained by the auxiliary feedwater system.

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

In the event the steam dump valves fail to open following a large loss of load or in the event of a complete loss of load with steam dump operating, the steam generator safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, the low steam generator level signal, or the overtemperature/overpower ΔT signals. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly. However, the pressurizer safety valves and steam generator safety valves are sized to protect the RCS and steam generator against overpressure for all load losses without assuming the operation of the steam dump system. The RCS and main steam supply relieving capacities were designed to ensure safety of the unit without requiring the automatic rod control, pressurizer pressure control and/or steam bypass control systems.

14.1.8.2 Method of Analysis

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

In addition to the specific analysis discussed above for a complete loss of steam load from full power, the acceptability of a loss of steam load without direct reactor trip on turbine trip below 35% of 3230.0 MWt NSSS full power was also evaluated.

The total loss of load transients were analyzed with the RETRAN computer program (Reference 21a). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

This accident was analyzed using the Revised Thermal Design Procedure (RTDP) (Reference 22) for DNB concerns (case with pressure control) and for overpressure concerns (case without pressurizer pressure control) using the Standard Thermal Design Procedure (STDP). With the RTDP, the initial conditions assumed for reactor power, RCS pressure and temperature are assumed to be at their nominal values as described in Section 4.0.2.1.

Major assumptions are summarized below:

1. Initial Operating Conditions

   The initial reactor power, RCS pressure, and RCS temperatures are assumed at their nominal values consistent with steady state full power operation for the DNB case analyzed using RTDP. For the peak RCS pressure case, uncertainties are applied in the most limiting directions to the initial core power, reactor coolant pressure and reactor coolant temperature.

2. Moderator and Doppler Coefficients of Reactivity

   The turbine trip is analyzed with minimum reactivity feedback. The minimum feedback cases assume a minimum moderator temperature coefficient and the least negative Doppler coefficient.

3. Reactor Control

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

4. Steam Releases

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

5. Pressurizer Spray and Power-operated Relief Valves

   Two cases with minimum reactivity feedback conditions were analyzed:

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

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

6. Feedwater Flow

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

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

14.1.8.3 Results

The transient responses for a total loss of load from full power operation are shown on Figures 14.1-31 to 14.1-33 and Figures 14.1-37 through 14.1-39 for two cases; one case with pressure control, one case without pressure control, both assuming minimum reactivity feedback conditions. Previously, four cases were analyzed; two cases at BOL minimum reactivity feedback conditions and two cases at EOL reactivity feedback conditions. Since the Loss of Load/ Turbine Trip event results in a primary system heatup, the analysis conservatively assumed minimum reactivity feedback conditions for both, with and without pressurizer pressure control which bounds the event with EOL reactivity feedback conditions.

Figures 14.1-31 through 14.1-33 show the transient responses for the total loss of steam load assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped by the high pressurizer pressure trip channel.

The minimum DNBR is well above the limit value. The pressurizer power operated relief valves are actuated for this case and maintain system pressure below 110-percent of the design value. The steam generator safety valves open and limit the secondary steam pressure increase.

The total loss of load event was also analyzed assuming the plant to be initially operating at full power [Deleted] conditions with no credit taken for the pressurizer spray, pressurizer power-operated relief valves, or steam dump. The reactor is tripped on the high pressurizer pressure signal. Figures 14.1-37 through 14.1-39 show the transients without credit for pressurizer spray or power-operated relief valves. The neutron flux remains essentially constant at full power until the reactor is tripped. The DNBR increases throughout the transient. In this case the pressurizer safety valves are actuated and maintain the system pressure below 110-percent of the design value.

Table 14.1-6 summarizes the sequence of events for the various transients considered for the total loss of load cases presented above.

The results of the complete loss of steam load from full power evaluation concluded that a loss of steam load without direct reactor trip on turbine trip below 35% of full power is bounded by the complete loss of flow event described in Section 14.1.6 with respect to the minimum DNBR condition reached during the transient and bounded by the loss of load (turbine trip) event from full power conditions with respect to peak overpressure RCS conditions.

14.1.8.4 Conclusions

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

14.1.9 Loss Of Normal Feedwater

14.1.9.1 Description

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

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

A. As the steam pressure rises following the trip, the steam generator power-operated relief valves are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the steam generator power-operated relief valves are not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and reactor coolant pumps plus the residual decay heat produced in the reactor.

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

Following the occurrence of a loss of normal feedwater, the reactor may be tripped by any of the following reactor protection system trip signals:

a. Low-low steam generator water level
b. Over-Temperature ΔT
c. High pressurizer pressure
d. High pressurizer water level
e. RCP undervoltage (if coincident with a LOOP signal)
f. Steam flow-feedwater flow mismatch in coincidence with low water level in any steam generator.

Auxiliary Feedwater (AFW) is supplied by actuation of two motor-driven auxiliary feedwater pumps, which are initiated by any of the following signals:

a. Low-low water level in any steam generator.
b. Automatic trip (not manual) of any main feed pump turbine.
c. Any safety injection signal.
d. Manual actuation.
e. Loss of offsite power concurrent with unit trip.

In addition, one turbine driven auxiliary feedwater pump starts on the following actuation signals although no automatic delivery of water to the steam generators occurs:

a. Low-low level in any two steam generators.

b. Loss of offsite power concurrent with unit trip and no safety injection signal.
c. Manual actuation.

The motor-driven auxiliary feedwater pumps are powered by the emergency diesel generators. The pumps take suction from the condensate storage tank for delivery to the steam generators. Each motor-driven pump is designed to supply the minimum required flow within 60 seconds of the initiating signal. The turbine-driven AFW pump is valved out during normal operation. Therefore, although it is automatically actuated, it is not available to deliver flow to the steam generators until an operator action is taken to align the turbine-driven train.

Backup in equipment and control logic is provided to ensure that reactor trip and automatic auxiliary feedwater flow will occur following any loss of normal feedwater, including that followed by loss of offsite power. An analysis of the system transient is presented below to show that following a loss of normal feedwater, the auxiliary feedwater system is capable of removing the stored and residual heat plus reactor coolant pump waste heat, thus preventing either overpressurization of the RCS or loss of water from the reactor core, and the plant returning to a safe condition.

14.1.9.2 Method of Analysis

A detailed analysis using the RETRAN computer code (Reference 21a) is performed to determine the plant transient following a loss of normal feedwater. The code simulates the core neutron kinetics, reactor coolant system, pressurizer, pressurizer power operated relief valves and safety valves, pressurizer heaters and spray, steam generators, main steam safety valves, and the auxiliary feedwater system, and computes pertinent variables, including pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

Assumptions made in the analysis are:

1. Initial steam generator level is at the nominal programmed value plus 10% narrow range span (NRS). Reactor trip occurs on steam generator low-low level at 0% of narrow range span.

2. The plant is initially operating at 102-percent of the NSSS power (3230 MWt) which bounds a nominal pump heat of 14MWt.

3. Conservative core residual heat generation based on long-term operation at the initial power level preceding the trip is assumed. The 1979 decay heat standard (ANS 5.1) plus 2 sigma uncertainty was used for calculation of residual decay heat levels.

4. The worst single failure in the AFW system occurs, i.e., failure of one of the motor-driven auxiliary feedwater pumps. The Auxiliary Feedwater System is assumed to automatically supply a total of 380 gpm to two steam generators from one motor-driven pump. Additional flow from the turbine-driven auxiliary feedwater pump is assumed available only following an operator action to align the turbine-driven pump.

5. The pressurizer sprays, heaters, and power operated relief valves are assumed operable. This maximizes the peak transient pressurizer water volume. If these

control systems did not operate, the pressurizer safety valves would maintain peak RCS pressure at or below the actuation setpoint throughout the transient.

6. Secondary system steam relief is achieved through the steam generator safety valves. No credit is taken for the operation of steam dumps or power-operated relief valves.

7. Cases are analyzed assuming initial hot full power reactor vessel average coolant temperatures at the upper and lower ends of the uprated operating range with uncertainty applied in both the positive and negative direction. The vessel average temperature assumed at the upper end of the range is 572°F with an uncertainty of ±7.5°F. The average temperature assumed at the lower end of the range is 549°F with an uncertainty of ±7.5°F. Results for the limiting case are presented.

8. Initial pressurizer pressure is assumed to be 2250 psi with an uncertainty of +28/-37 psi. Cases are considered with the pressure uncertainty applied in both the positive and negative directions to conservatively bound potential operating conditions. Results for the limiting case are presented.

9. Cases are analyzed assuming initial feedwater temperatures at the upper and lower ends of the uprated operating feedwater temperature window (436.2°F and 390°F, respectively).

10. The high T_{avg} program cases assumes an initial pressurizer level of 71-percent (65% + 6% uncertainty). For the low T_{avg} program cases, an initial pressurizer level of 43-percent (37% + 6% uncertainty) is considered.

11. The enthalpy of the auxiliary feedwater is assumed to be 90.77 Btu/lbm corresponding to a condensate storage tank temperature of 120 ^oF.

12. Analyses with both minimum (0%) and maximum (10%) steam generator tube plugging were performed to conservatively bound potential operating conditions.

13. An auxiliary feedwater line purge volume of 268.8 ft^3 is assumed.

The loss of normal feedwater analysis is performed to demonstrate the adequacy of the reactor protection and engineered safeguards systems (i.e., the auxiliary feedwater system). The analysis demonstrates the capability of the AFW system to remove long term decay heat, thus preventing RCS overpressurization or loss of RCS water by overfilling the pressurizer.

As such, the assumptions used in this analysis are designed to minimize the energy removal capability of the system and to maximize the possibility of water relief from the coolant system by maximizing the coolant system expansion, as noted in the assumptions listed above.

For the loss of normal feedwater transient, the reactor coolant volumetric flow remains at its normal value and the reactor trips via the low-low steam generator level trip. The reactor coolant pumps may be manually tripped at some later time to reduce heat addition to the RCS.

Normal reactor control systems are not required to function in this analysis. The reactor protection system is required to function following a loss of normal feedwater as analyzed herein. The auxiliary feedwater system is required to deliver a minimum auxiliary feedwater flow rate and no single active failure will prevent operation of any system required to function.

14.1.9.3 Results

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to the reduction of steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat. Sixty seconds following the initiation of the low-low level trip, at least one motor-driven auxiliary feedwater pump is automatically started and supplying the minimum required flow to reduce the rate of decrease in steam generator water level.

The capacity of one motor driven auxiliary feedwater pump is such that the rate of decrease of the water level in the steam generator being fed AFW flow is sufficiently slowed to provide an allowable time for the operator to align the turbine-driven train and prevent water relief from the RCS relief or safety valves.

The calculated sequence of events for this accident is listed in Table 14.1-7. Figure 14.1-43 (Sheet 1 through Sheet 5) shows the significant plant parameters following a loss of normal feedwater. The Figures show that the plant approaches a stabilized condition following reactor trip and auxiliary feedwater initiation. Figure 14.1-43 Sheet 1 shows the pressurizer water volume transient. As shown in Figure 14.1-43 Sheet 3, RCS subcooling is maintained since the RCS never reaches saturated conditions. Plant procedures may be followed to further stabilize and cool down the plant.

14.1.9.4 Conclusions

Results of the analysis show that, for a loss of normal feedwater event, all safety criteria are met. The AFW capacity is sufficient to prevent pressurizer filling and any subsequent water relief through the pressurizer relief and safety valves. This assures that the RCS is not overpressurized.

14.1.10 Excessive Heat Removal Due To Feedwater System Malfunctions

14.1.10.1 Description

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

An example of a feedwater control system malfunction that results in a decrease in feedwater enthalpy would be an inadvertent opening of the feedwater bypass valve which diverts flow around the low pressure feedwater heaters. The feedwater bypass valve was retired in place when operating experience proved that it was not required for its intended purpose of providing sufficient suction pressure at the feed pumps. The description of this event, however, including the method of analysis, results and conclusions, is being retained herein for informational purposes. For this event, there would be a sudden reduction in inlet feedwater temperature to the steam generator. The increased subcooling of the secondary side would create a greater load demand on the primary side which can lead to reactor trip conditions.

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

14.1.10.2 Method of Analysis

The excessive heat removal due to feedwater system malfunction transients were analyzed using the RETRAN code (Reference 21a).

The decrease in feedwater enthalpy event is conservatively assumed to occur at hot full power initial conditions. As a result of opening the feedwater bypass valve and diverting the flow around the low-pressure feedwater heaters, the feedwater temperature at the inlet of the steam generator in the affected loop decreases from 430°F to 420°F. This results in a decrease in the feedwater enthalpy of less than 11 Btu/lbm. An evaluation shows that the reduction in feedwater enthalpy by 11 Btu/lbm is significantly less than that for excessive load increase events described in Section 14.1.11. Therefore, excessive load increase events (cases with manual reactor control at BOL and with automatic reactor control at EOL) bound the feedwater enthalpy cases as previously described.

For the excessive feedwater addition due to a control system malfunction or operator error that allows a feedwater control valve to open fully, three cases were analyzed as follows:

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

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

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

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

1. For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction, resulting in a step increase to 130% of nominal feedwater flow to one steam generator.

2. For the feedwater control valve accident at zero load conditions, a feedwater valve malfunction occurs that results in a ramp increase in flow to one steam

generator from zero flow at time zero to 210% of the nominal full load value for one steam generator at 5 seconds.

3. For the zero load condition, a conservatively low feedwater enthalpy corresponding to a feedwater temperature of 100^{o}F is assumed.

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

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

14.1.10.3 Results and Conclusions

For the feedwater enthalpy reduction event, the reduction in feedwater enthalpy is less than the equivalent reduction in feedwater enthalpy from the excessive load increase incident as described in Section 14.1.11. Therefore, the results for the excessive load increase incident, which show considerable margin to the DNBR limit exist under these same conditions, bound the feedwater enthalpy reduction cases.

In the case of excessive feedwater flow resulting from an accidental full opening of one feedwater control valve with the reactor at zero power and the above mentioned assumptions, the resulting transient is similar to, but less severe than the hypothetical steamline break transient described in Section 14.2.5. Because the excessive feedwater flow cases with the reactor at zero power is bounded by the analysis presented in Section 14.2.5, no transient results are given in this section. It should be noted that if the incident occurs with the unit just critical at no-load, the reactor may be tripped by the power range neutron flux trip (low setting).

For the full power cases, the results with automatic rod control are nearly identical to those with manual rod control assumed. This is because the small increase in feedwater flow (30% above nominal) results in a very small increase in RCS temperature. The rod control system actuates but rod movement is minimal due to the small RCS temperature change.

Transient results showing the core heat flux, pressurizer pressure, T_{avg}, and DNBR, as well as the increase in nuclear power and loop ΔT associated with the increased thermal load on the reactor are given in Figure 14.1-45 for the full power case with manual rod control. Steam generator water level rises until the feedwater is terminated as a result of the high-high steam generator water level trip. The DNBR does not fall below the safety analysis DNBR limit. The calculated sequence of events for the full power cases are shown in Table 14.1-8.

14.1.11 Excessive Load Increase Incident

14.1.11.1 Description

An excessive load increase incident is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10% step-load increase or a 5% per minute ramp load increase in the range of 15 to 100% of full power (the elimination of the automatic control rod withdrawal function could require the use of manual rod control to have the reactor respond to the turbine load change and to restore the coolant average temperature to the programmed value). Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system.

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

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

14.1.11.2 Method of Analysis

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

1. Reactor control in manual with beginning-of-life minimum moderator reactivity feedback.
2. Reactor control in manual with end-of-life maximum moderator reactivity feedback.
3. Reactor control in automatic with beginning-of-life minimum moderator reactivity feedback.
4. Reactor control in automatic with end-of-life maximum moderator reactivity feedback.

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

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

This accident was analyzed using the Revised Thermal Design Procedure (RTDP).[22] Initial reactor power, RCS pressure, and temperature were assumed to be at their nominal values. Uncertainties in initial conditions were included in the limit DNBR as described in Section 14.0.2.1.

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

The cases which assume automatic rod control were analyzed to ensure that the worst case with respect to minimum DNBR is presented. The automatic rod control function is not required to mitigate the consequences of this event. The automatic control rod withdrawal feature in plant operation has been physically disabled, allowing only the automatic control rod insertion mode to be in effect when rod control is in automatic.

Given the non-limiting nature of this event with respect to the DNBR safety analysis criterion, an explicit analysis was not performed as part of the Stretch Power Uprate program. Instead, a detailed evaluation of this event was performed. The evaluation model consists of the generation of statepoints based on generic conservative data. The statepoints are then compared to the core thermal limits to ensure that the DNBR limit is not violated. Since automatic rod withdrawal has been disabled at Indian Point Unit 2, only cases assuming manual rod control are evaluated.

These cases are:

- Reactor in manual rod control with EOL (maximum moderator) reactivity feedback.

14.1.11.3 Results and Conclusions

An evaluation of this event was performed to support the Stretch Power Uprate program. The evaluation determined that the DNB design basis for a 10% step load increase continues to be met.

14.1.12 Loss of all AC Power to the Station Auxiliaries

14.1.12.1 Description

A complete loss of non-emergency AC power may result in the loss of all power to the plant auxiliaries: i.e., the RCPs, condensate pumps, etc. The loss of power may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip at the station, or by a loss of the onsite non-emergency AC distribution system.

The first few seconds of the transient would be almost identical to the four pump loss-of-flow case presented in Section 14.1.6 where the pump coastdown inertia along with the reactor trip prevent reaching the DNBR limit. After the trip, decay heat will be accommodated by the auxiliary feedwater system. This portion of the transient would be similar to that presented in Section 14.1.9 for the Loss of Normal Feedwater event.

The events following such a condition are described in the sequence listed below:

1. Plant vital instruments are supplied by emergency power sources (See Chapter 8).

2. As the steam system pressure rises following the trip, the steam system power-operated relief valves are automatically opened to the atmosphere. Steam bypass to the condenser is not available because of loss of the circulating water pumps. If the power-operated relief valves are not available, the steam generator self-actuated safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.

3. As the no-load temperature is approached, the steam system power-operated relief valves (or the self-actuated safety valves, if the power-operated relief valve are not available) are used to dissipate the residual heat and to maintain the plant at the hot standby condition.

4. The emergency diesel generators are started on loss of voltage on the plant emergency buses and begin to supply plant vital loads.

The auxiliary feedwater system is started automatically as discussed in Section 14.1.9 for the loss of normal feedwater analysis. The two motor-driven AFW pumps are supplied by power from the emergency diesel generators. The pumps take suction directly from the condensate storage tank for delivery to the steam generators. Each motor-driven pump is designed to supply the minimum required flow within 60 seconds of the initiating signal. Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant loops aided by the auxiliary feedwater in the secondary system. The analysis here will show that following a loss of AC power event, the natural circulation flow in the RCS is sufficient to remove residual heat from the core.

14.1.12.2 Method of Analysis

A detailed analysis using the RETRAN computer code (Reference 21a) is performed to determine the plant transient following a loss of AC power to the station auxiliaries. The code simulates the core neutron kinetics, reactor coolant system including natural circulation, pressurizer, pressurizer power operated relief valves and safety valves, pressurizer heaters and spray, steam generators, main steam safety valves, and the auxiliary feedwater system, and computes pertinent variables, including pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

Major assumptions differing from those in a loss of normal feedwater presented in Section 14.1.9 are:

1. No credit is taken for immediate response of control rod drive mechanisms caused by a loss of offsite power.
2. A heat transfer coefficient in the steam generator associated with RCS natural circulation is assumed following the reactor coolant pump coastdown.
3. The plant is initially operating at 102-percent of the NSSS power (3230 MWt). A nominal RCP heat of 14 MWt was assumed.

The complete loss of non-emergency AC power analysis is performed to demonstrate the adequacy of the reactor protection and engineered safeguards systems (i.e., the auxiliary feedwater system). The analysis demonstrates the capability of the AFW system to remove long term decay heat, thus preventing RCS overpressurization or loss of RCS water by overfilling the pressurizer.

As such, the assumptions used in this analysis are designed to minimize the energy removal capability of the system and to maximize the possibility of water relief from the coolant system by maximizing the coolant system expansion, as discussed in Section 14.1.9 for the assumptions in the loss of normal feedwater analysis.

14.1.12.3 Results

Figure 14.1-50 (Sheet 1 through Sheet 5) shows the plant parameters following a loss of offsite power to the station auxiliaries. The time sequence of events for this accident is given in Table 14.1-10.

After the reactor trip, stored and residual heat must be removed to prevent damage to either the RCS or the core. The RETRAN results show that the natural circulation flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

14.1.12.4 Conclusions

Results of the analysis show that, for the loss of offsite power to the station auxiliaries event, all safety criteria are met. The AFW capacity is sufficient to prevent water relief through the pressurizer relief and safety valves; this assures that the RCS is not overpressurized.

The analysis also demonstrates that sufficient long-term heat removal capability exists by the natural circulation capability of the RCS following reactor coolant pump coastdown to prevent fuel or clad damage.

14.1.13 Likelihood And Consequences of Turbine-Generator Unit Overspeed

The assessment of turbine-generator overspeed prepared and submitted in the original 1968 Indian Pont Unit 2 FSAR (as part of the initial license application) assumed that all turbine missiles (i.e., fragments of turbine rotor disks) would be contained within the turbine casing. Subsequent to that submittal, a 1970 study was prepared by Westinghouse to document the results of additional analytical and experimental work performed regarding the likelihood and consequences of turbine overspeed. (See Reference 30). In response to an AEC request for further information, this study was provided as Appendix 14A in Supplement 12 to the original FSAR prior to initial plant operation. The results showed that the original position on the containment of low pressure turbine disk fragments within the turbine casing could no longer be maintained and a completely independent turbine electric overspeed detection and valve trip initiation system (i.e., IEOPS) was incorporated into the original Indian Point Unit 2 design.

In the late 1980s, Westinghouse and the Westinghouse Owners Group proposed and the NRC approved the generic application of a revised probabilistic methodology for turbine missile generation likelihood and the appropriate frequencies for inspection, testing, and maintenance of turbine rotors and control systems (See References 28, 31, 32, 33). The NRC concluded that maintaining a small probability of turbine missile generation through testing and inspection is a reliable means of ensuring safety-related structures, systems, and components are adequately protected from such missiles and that the revised approach simplifies and improves procedures for evaluation of turbine missile risks by eliminating from consideration factors such as missile trajectory and damage probability. The NRC's revised acceptance criteria for total turbine missile generation probabilities was established as less than 1E-4 per year for a favorably oriented turbine and less than 1E-5 per year for an unfavorably oriented turbine.

By letter dated February 8, 1994 (Reference 34), the NRC issued Amendment No. 168 to the Indian Point Unit 2 Operating License which approved the application of the revised generic methodology to Indian Point Unit 2, a revised surveillance interval for testing turbine stop and control valves, and the deletion of Technical Specification limiting conditions for operation and surveillance requirements for the Independent Electrical Overspeed Protection System (IEOPS). The IEOPS has been disabled and is out of service. This approval was based on the application of the generic methodology and data of Reference 28 as supplemented by Reference 29, and the Consolidated Edison commitment contained in Reference 35 to review and re-evaluate the turbine valve testing frequency probabilistic analysis any time major changes in the turbine system have been made or a significant upward trend in the valve failure rate is identified. This commitment included the incorporation of information on valve failure rates in the UFSAR and the updating of that information at least once every three years (See Section 14.1.13.2).

14.1.13.1 Turbine Control and Protection

The likelihood of a turbine-generator unit overspeed condition is remote because of the reliability and redundancy of the turbine control and protection systems.

The turbine control and protection system is completely hydraulic. There are two low-pressure oil control systems: the auxiliary governor system and the emergency trip system. These two systems and the 300-psi system are interconnected through orifices. The control and protection system is fail-safe; any loss of oil pressure causes closure of the steam valves.

The main governor normally controls the unit. Should an overspeed take place, the auxiliary governor system will be actuated first, the auxiliary governor dome valve will open, the 300-psi pressure oil will drain, and the control valve will close.

Should the unit overspeed reach the mechanical overspeed trip setpoint, the overspeed trip valve will open, the 300-psi pressure oil will drain, and the throttle valves will close. At the same time, a second drain path will be provided for the 300-psi oil system that controls the first set of valves, so that the control valves will trip too, in case they did not trip.

Assuming, for the purpose of analysis, that a control valve and stop valve in the same steam path fail to close, a turbine runaway would occur.

Besides the provisions in the design of the turbine control and protection system during plant operation, valves are exercised on a periodic basis to preclude the possibility of a valve stem sticking. Analyses of oil samples are performed as required.

The turbine is periodically given an overspeed check to verify the trip speed. The remaining tripping devices are periodically checked.

14.1.13.2 Analysis and Results

Reference 28 documents the probabilistic analysis performed to determine the annual turbine missile ejection probability, as a function of turbine valve test frequency, for a group of nuclear power plants with Westinghouse turbines. Testing of turbine valves affects the probability that the valves will be incapable of closing given that the load on the turbine is lost. The failure or unavailability of the turbine valves contributes to the probability that the turbine will overspeed and eject a missile.

The analysis of turbine overspeed included a thorough identification of all faults and contributors to overspeed. Specific plant data was collected from the turbine owners in the effort. In addition, other systems which interface with the turbine were investigated to determine whether they have any impact on the probability of overspeed. The study quantified the total risk of turbine missile ejection at destructive overspeed (approximately 180-percent of rated turbine speed) and at lower speeds in the range of 120 to 136-percent at rated speed. The lower speeds were evaluated in two categories: design overspeed and intermediate overspeed.

The analysis performed used fault trees to determine the annual probability of overspeed for each of the three overspeed events. Failures of turbine valves and overspeed protection components were modeled in the fault trees as a function of the valve test intervals as appropriate. The probability of overspeed was calculated for various test intervals. The probabilities of missile generation for the design and intermediate overspeed conditions were determined based on plant-specific low pressure rotor design information. The probability of missile generation for the destructive overspeed event was assumed to be 1.0. For each overspeed event, the probability of the overspeed event was combined with the probability of missile generation for that event. The resulting annual probabilities of missile generation for each event, for a given test interval, were summed to provide the total.

Subsequent to the issuance of Reference 28, a subgroup of plants with Westinghouse BB-95/96 turbines evaluated more recent valve failure data and modes. Reference 29 modeled the revised failure rates and modes using a fault tree for the destructive overspeed event. The destructive overspeed probability was calculated for various turbine valve test intervals. An allowance was defined for the missile ejection contributions of the design and intermediate overspeed. Reference 29 provided revised guidance for determining appropriate turbine valve test intervals. Using the destructive overspeed results in conjunction with the allowance, the results may be used to determine an appropriate turbine valve test interval which meets the NRC acceptance criterion of 1.0E-5 per year. Reference 36 contains the most recent assessment of turbine valve failure data and covers a period from January 1986 through December 1999. The valve failure data is presented in Figures 14.1-62 through 14.1-66, and the turbine valve test interval currently recommended by the vendor is presented in Figure 14.1-67.

Indian Point Unit No. 2 has fully integral low pressure turbine rotors. The fully integral design eliminates the disk bores and keyways of the earlier design, reducing peak stresses and transferring the location of peak stresses to the blade fastening locations on the rotor. Reference 16 (submitted to the NRC by Westinghouse) discusses the probabilities of crack initiation and missile generation. The probability of creating a disk-segment missile is significantly lower for the fully integral design than for the previous design. Based on the conclusions in Reference 16, Consolidated Edison notified the NRC (Reference 17) that periodic in-service inspections of the fully integral low pressure turbine rotors will not be required.

Because of the very large margin between the high pressure spindle bursting speed and the maximum speed at which the steam can drive the unit with all admission valves full open, the probability of spindle failure is practically zero. Therefore, no harmful missile is expected from the high pressure turbine rotor in case of a turbine runaway.

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27. Haessler, R. L., et al., "Methodology for the Analysis of the Dropped Rod Event," WCAP-11394-P-A (Proprietary) and "WCAP-11394 (Non-proprietary), January 1990

28. Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," WCAP-11525, June 1987

29. Letter from S.B.Bram, Consolidated Edison, to Document Control Desk, NRC, dated November 8, 1993, Attachment A: Summary of Westinghouse Owners Group Turbine Valve Test Frequency Subgroup Final Report "Update of BB-95/96 Turbine Valve Failure Rates and Effects on Destructive Overspeed Probabilities."

30. Fox, J.N., Westinghouse Electric Corporation, "Likelihood and Consequences of Turbine Overspeed at the Indian Point Nuclear Generating Unit No. 2," July, 1970

31. Letter from C. E. Rossi, NRC, to J. A. Martin, Westinghouse, dated February 2, 1987 forwarding an NRC Safety Evaluation Report on generic Westinghouse licensing topical reports regarding the probability of turbine overspeed and missile generation.

32. Letter from A. C. Thandani, NRC, to D. M. Musolf, Northern States Power Company, dated November 2, 1989, forwarding an NRC Safety Evaluation and Supplemental Safety Evaluation regarding use of WCAP-11525 in future license amendment requests by Westinghouse Owners Group (Turbine Valve Test Frequency Subgroup Members).

33. Letter from D. S. Brinkman to S. B. Bram, Consolidated Edison, dated November 30, 1989, regarding approval for referencing of WCAP-11525 by members of the Westinghouse Owners Group (Turbine Valve Test Frequency Evaluation Subgroup).

34. Letter from F.J. Williams, Jr., NRC, to S.B. Bram, Consolidated Edison, forwarding License Amendment No. 168 to Facility Operating License No. DPR-26 and associated Safety Evaluation.

35. Letter from S.B. Bram, Consolidated Edison, to Document Control Desk, NRC, "Proposed Amendment to Technical Specifications Regarding Turbine Valve Test Frequency and Electrical Overspeed Protection System", dated August 9, 1991.

36. Letter from R. Sisk, Westinghouse Owners Group, to Turbine Valve Test Frequency Evaluation Subgroup, dated October 16, 2000, forwarding "Final Update and Evaluation of BB-95/96 Turbine Valve Failure Data Base – September 29, 2000."

37. Regulatory Guide 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” July 2000.

TABLE 14.1-1
Uncontrolled RCCA Withdrawal From a Subcritical Condition
Time Sequence of Events

Event	Time (Seconds)
Start of the accident	0.0
High Neutron Flux Reactor Trip Setpoint (Low Setting) reached	9.8
Rods begin to fall	10.3
Minimum DNBR occurs	11.8
Peak Clad Average Temperature occurs	12.0
Peak Fuel Average Temperature occurs	12.3
Peak Fuel Centerline Temperature occurs	13.2

SUMMARY OF THE RESULTS

Peak Clad Average Temperature (°F)	701
Peak Fuel Average Temperature (°F)	1927
Peak Fuel Centerline Temperature (°F)	2286

TABLE 14.1-2
Uncontrollable RCCA Bank Withdrawal at Power
Time Sequence of Events

Accident	Event	Time (Sec)
Uncontrollable RCCA bank withdrawal at power		
1. Case A	Initiation of uncontrollable RCCA withdrawal at a high reactivity insertion rate (70 pcm/sec)	0
	Power range high neutron flux high trip point reached	1.6
	Rods begin to fall into core	2.1
	Minimum DNBR occurs	3.0
2. Case B	Initiation of uncontrollable RCCA withdrawal at a small reactivity insertion rate (1 pcm/sec)	0
	Overtemperature ΔT reactor trip signal initiated	100.2
	Rods begin to fall into core	102.2
	Minimum DNBR occurs	103.0

TABLE 14.1-3
Complete Loss of Flow (Undervoltage)
Time Sequence of Events

Event	Time (Seconds)
All the pumps begin to coastdown	0.
Reactor coolant pump undervoltage trip point reached at	0.
Rods begin to fall	1.5
Minimum DNBR occurs	3.3
Maximum RCS pressure occurs	15.0

SUMMARY OF THE RESULTS
COMPLETE LOSS OF FLOW (Undervoltage)

Maximum RCS Pressure (psia)	2349

Complete Loss of Flow (Underfrequency)
Time Sequence of Events

Event	Time (Seconds)
Frequency decay of 5 Hz/sec begins	0.
Reactor coolant pump underfrequency trip point reached and all the pumps begin to coastdown	0.6
Rods begin to fall	1.6
Minimum DNBR occurs	3.6
Maximum RCS pressure occurs	15.2

SUMMARY OF THE RESULTS
COMPLETE LOSS OF FLOW (Underfrequency)

Maximum RCS Pressure (psia)	2366

TABLE 14.1-4
Partial Loss of Flow
Time Sequence of Events

Event	Time (Seconds)
One pump begins to coastdown	0.
Reactor coolant low-flow trip setpoint (85%) reached	1.6
Rods begin to fall	2.6
Minimum DNBR occurs	3.4
Maximum RCS pressure occurs	14.4

SUMMARY OF THE RESULTS
PARTIAL LOSS OF FLOW

Maximum RCS Pressure (psia)	2331

TABLE 14.1-5
Locked Rotor Event – Hot Spot
Time Sequence of Events

Event	Time (Seconds)
Rotor in one pump seizes	0.
Reactor coolant low flow trip setpoint reached at	0.10
Rods begin to fall	1.10
Maximum clad temperature occurs	3.8
Maximum RCS pressure occurs	5.1

SUMMARY OF THE RESULTS
LOCKED ROTOR EVENT – HOT SPOT

Maximum Reactor Coolant System Pressure (psia)	2553
Maximum Clad Average Temperature (°F)	1813
% Zirconium Reacted	0.31%

TABLE 14.1-6
Loss of External Electrical Load
Time Sequence of Events

Event	Time of event, sec With Pressurizer Control – DNB Case	Without Pressurizer Control – RCS Overpressurization Case
Loss of electrical load/turbine trip	0.0	0.0
Initiation of steam release from SG safety valves	11.97	8.30
High pressurizer pressure reactor trip point reached	9.81	6.33
Rods begin to fall	11.81	8.33
Minimum DNBR occurs (min. DNBR = 2.06)	13.10	N/A
Peak RCS pressure occurs (peak RCS pres. = 2676.83 psia)	N/A	8.69
Peak MSS pressure occurs (peak MSS pres. = 1158.68 psia)	N/A	15.67

TABLE 14.1-7
Loss of Normal Feedwater
Time Sequence of Events

Event	Time of event, sec
Main feedwater flow stops	20.0
Low-low steam generator water level reactor trip setpoint reached	64.0
Rods begin to drop	66.0
Automatic auxiliary feedwater from one motor driven auxiliary feedwater pump initiated	124.0
Operator action to establish auxiliary feedwater flow to remaining steam generators	666.0
Peak water level in the pressurizer occurs	925.0

TABLE 14.1-8
Feedwater Malfunction Event
Time Sequence of Events

Event	Time of event, sec	
	With Automatic Rod Control	Manual Rod Control
Feedwater flow to one SG increases to 130% of nominal	0.0	0.0
Peak pressurizer pressure occurs	99.5	100.0
Peak nuclear power occurs	98.0	98.0
Minimum DNBR occurs	97.5	98.0

TABLE 14.1-9
DELETED

TABLE 14.1-10
Loss of All AC Power to the Station Auxiliaries
Time Sequence of Events

Event	Time of event, sec
Main feedwater flow stops	20.0
Low-low steam generator water level reactor trip setpoint reached	64.0
Rods begin to drop	66.0
Reactor coolant pumps begin to coast down	68.1
Automatic auxiliary feedwater from one motor driven auxiliary feedwater pump initiated	124.0
Operator action to establish auxiliary feedwater flow to remaining steam generators	666.0
Peak water level in the pressurizer occurs	720.0

TABLE 14.1-11
DELETED

TABLE 14.1-12
DELETED

TABLE 14.1-13
DELETED

TABLE 14.1-14
DELETED

TABLE 14.1-15
DELETED

TABLE 14.1-16
DELETED

TABLE 14.1-17
DELETED

TABLE 14.1-18
DELETED

TABLE 14.1-19
DELETED

TABLE 14.1-20
DELETED

TABLE 14.1-21
DELETED

14.1 FIGURES

Figure No.	**Title**
Figure 14.1-1	Uncontrolled RCCA Withdrawal From A Subcritical Condition Nuclear Power vs. Time
Figure 14.1-2	Uncontrolled RCCA Withdrawal From A Subcritical Condition Heat Flux vs. Time, Avg. Channel
Figure 14.1-3	Uncontrolled RCCA Withdrawal From A Subcritical Condition Fuel Average Temperature vs. Time At Hot Spot
Figure 14.1-4	Uncontrolled RCCA Withdrawal From a Subcritical Condition Clad Inner Temperature vs. Time At Hot Spot
Figure 14.1-5	Uncontrolled RCCA Bank Withdrawal From Full Power With Minimum Reactivity Feedback (70 pcm/sec Withdrawal Rate)
Figure 14.1-6	Uncontrolled RCCA Bank Withdrawal From Full Power With Minimum Reactivity Feedback (70 pcm/sec Withdrawal Rate)
Figure 14.1-7	Uncontrolled RCCA Bank Withdrawal From Full Power With Minimum Reactivity Feedback (70 pcm/sec Withdrawal Rate)

Figure 14.1-45 Sh. 2	Feedwater System Malfunction Excessive Feedwater Flow - HFP Conditions Manual Rod Control Pressurizer Pressure and DNBR vs. Time
Figure 14.1-45 Sh. 3	Feedwater System Malfunction Excessive Feedwater Flow - HFP Conditions Manual Rod Control, Loop Delta - T, and Core T_{avg} vs. Time
Figure 14.1-46 Sh. 1	Deleted
Figure 14.1-46 Sh. 2	Deleted
Figure 14.1-47 Sh. 1	Deleted
Figure 14.1-47 Sh. 2	Deleted
Figure 14.1-48 Sh. 1	Deleted
Figure 14.1-48 Sh. 2	Deleted
Figure 14.1-49 Sh. 1	Deleted
Figure 14.1-49 Sh. 2	Deleted
Figure 14.1-50 Sh. 1	Loss of all AC Power, High T_{avg} Program, Pressurizer Pressure and Water Volume vs. Time
Figure 14.1-50 Sh. 2	Loss of all AC Power, High T_{avg} Program, Nuclear Power and Core Heat Flux vs. Time
Figure 14.1-50 Sh. 3	Loss of all AC Power To The Station Auxiliaries, High T_{avg} Program, Loop 21 Temperature and Loop 23 Temperature
Figure 14.1-50 Sh. 4	Loss of all AC Power To The Station Auxiliaries, High T_{avg} Program, Steam Generator 21 Pressure and Steam Generator 23 Pressure
Figure 14.1-50 Sh. 5	Loss of all AC Power To The Station Auxiliaries, High T_{avg} Program, Total RCS Flow and Pressurizer Relief vs. Time
Figure 14.1-51 Sh. 1	Deleted
Figure 14.1-51 Sh. 2	Deleted
Figure 14.1-51 Sh. 3	Deleted
Figure 14.1-51 Sh. 4	Deleted
Figure 14.1-51 Sh. 5	Deleted
Figure 14.1-52 Through 14.1-57	Deleted
Figure 14.1-58	Deleted
Figure 14.1-59 Sh. 1	Deleted
Figure 14.1-59 Sh. 2	Deleted
Figure 14.1-60	Deleted
Figure 14.1-61	Deleted
Figure 14.1-62	Tracking BB-95/96 Stop Valve (SV) Type 1 Failures Stop Valve Disc Fails
Figure 14.1-63	Tracking BB-95/96 Stop Valve (SV) Type 2 Failures Stop Valve Spring Fails
Figure 14.1-64	Tracking BB-95/96 Stop Valve (SV) Type 3 Failures Stop Valve Sticks Open
Figure 14.1-65	Tracking BB-95/96 Control Valve (CV) Type 4 Failures CV Spring Bolt Fails
Figure 14.1-66	Tracking BB-95/96 Control Valve (CV) Type 5 Failures Control Valve Sticks Open
Figure 14.1-67	Annual Frequency of Destructive Overspeed for Various BB-95/96 Turbine Valve Test Interval

14.2 STANDBY SAFETY FEATURES ANALYSIS

Adequate provisions have been included in the design of the plant and its standby engineered safety features to limit potential exposure of the public to below the applicable limits for situations that could conceivably involve uncontrolled releases of radioactive materials to the environment. The following situations have been considered:

1. Fuel-handling accidents.
2. Accidental release of waste liquid.
3. Accidental release of waste gases.
4. Rupture of a steam-generator tube.
5. Rupture of a steam pipe.
6. Rupture of a control rod drive mechanism housing - rod cluster control assembly ejection.

14.2.1 Fuel-Handling Accidents

The possibility of a fuel-handling incident is very remote because of the many administrative controls and physical limitations imposed on fuel-handling operations. All refueling operations are conducted in accordance with prescribed procedures under direct surveillance of a supervisor technically trained in nuclear safety. Before any refueling operations begin, a verification of complete rod cluster control assembly insertion is obtained by opening the reactor trip breakers and observing the rod position indicators. Boron concentration in the coolant is raised to the refueling concentration and verified by sampling.

After the vessel head is removed, the rod cluster control drive shafts are disconnected from their respective assemblies using the manipulator crane and the shaft unlatching tool. A spring scale is used to indicate that the drive shaft is free of the control cluster as the lifting force is applied. The fuel-handling manipulators and hoists are designed so that fuel cannot be raised above a position that provides adequate shield water depth for the safety of operating personnel. This safety feature applies to handling facilities in both the containment and in the spent fuel pit area. In the spent fuel pit, the design of storage racks and manipulation facilities is such that:

1. Fuel at rest is positioned by positive restraints in an eversafe, always subcritical, geometrical array. Even if an assembly is not placed in the correct region, sub-criticality is ensured because a minimum boron concentration of 2000 ppm is required at all times in the pool.

2. Fuel can be manipulated only one assembly at a time.

3. Violation of procedures by placing one fuel assembly in juxtaposition with any group of assemblies in racks will not result in criticality.

In addition, administrative controls do not permit the handling of heavy objects above the fuel racks under conditions specified in the Technical Requirements Manual.

Adequate cooling of fuel during underwater handling is provided by convective heat transfer to the surrounding water. The fuel assembly is immersed continuously while in the refueling cavity or spent fuel pit.

Even if a spent fuel assembly becomes stuck in the transfer tube, the fuel assembly is completely immersed and natural convection will maintain adequate cooling to remove the decay heat. The fuel-handling equipment is described in detail in Section 9.5.

Two nuclear instrumentation system source range channels are continuously in operation and provide warning of any approach to criticality during refueling operations. This instrumentation provides a continuous audible signal in the containment and will annunciate a local horn and a horn and light in the plant control room if the count rate increases above a preset low level.

Refueling boron concentration is sufficient to maintain the clean, cold, fully loaded core subcritical by at least 5-percent with all rod cluster control assemblies inserted. The refueling cavity is filled with water meeting the same boric acid specifications.

Special precautions are taken in all fuel-handling operations to minimize the possibility of damage to fuel assemblies during transport to and from the spent fuel pit and during installation in the reactor. All handling operations on irradiated fuel are conducted under water. The handling tools used in the fuel-handling operations are conservatively designed, and the associated devices are of a fail-safe design.

In the fuel storage area, the fuel assemblies are spaced in a pattern that prevents any possibility of a criticality accident. As required by 10 CFR 50.68, “Criticality Accident Requirements,” if the spent fuel pit takes credit for soluble boron, then “the k-effective of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with borated water, and the k-effective must remain below 1.0 (subcritical), at a 95 per cent probability, 95 percent confidence level, if flooded with unborated water.” NET-173-01, “Criticality Analysis for Soluble Boron and Burnup Credit in the Con Edison Indian Point Unit 2 Spent Fuel Storage Racks” and NET-173-02, “Indian Point Unit 2 Spent Fuel Pool (SFP) Boron Dilution Analysis,” determined that 10 CFR 50.68(b)(4) will be met during normal SFP operation and all credible accident scenarios (including affects of boraflex degradation) if: a) spent fuel pit boron concentration is maintained within the Technical Specification limits and, b) fuel assembly storage location within the spent fuel pit is restricted based on the fuel assembly’s initial enrichment, burnup, decay of Pu^{241} (i.e., cooling time) and number of Integral Fuel Burnable Absorbers (IFBA) rods.

Northeast Technology Corporation report NET-173-01 evaluated non-accident conditions in the SFP including the affects of the projected boraflex degradation through the year 2006. Based upon BADGER testing in calendar years 2003 and 2006 and RACKLIFE code projections, the validity of the criticality and boron dilution analysis documented in NET-173-01 and NET-173-02 can be extened through the end of the current license (September 30, 2013), provided BADGER testing is performed by August 2010 and again in calendar year 2012 to confirm the progression of localized Boraflex dissolution. This report determined that if storage location requirements in the Technical Specifications are met then the SFP will have a keff of ≤0.95 if filled with a soluble boron concentration of ≥786 ppm and will have a keff of <1.0 if filled with unborated water.

Northeast Technology Corporation report NET-173-01 also evaluated credible abnormal occurrences in accordance with ANSI/ANS-57.2-1983. This evaluation considered the effects of the following: a) a dropped fuel assembly or an assembly placed alongside a rack; b) a misloaded fuel assembly; and, c) abnormal heat loads. Northeast Technology Corporation report NET-173-01 determined that the SFP will maintain a keff of ≤0.95 under the worst-case accident scenario if the SFP is filled with a soluble boron concentration of ≥ 1495 ppm.

Therefore, Northeast Technology Corporation report NET-173-01 confirmed that the requirements in 10 CFR 50.68, "Criticality Accident Requirements," will be met for both normal SFP operation and credible abnormal occurrences if:

a) Spent Fuel Pit boron concentration is maintained within the limits Technical Specifications, and;
b) Fuel assembly storage location within the spent fuel pit is restricted in accordance with Technical Specifications based on the fuel assembly's initial enrichment, burnup, decay of Plutonium-241 (i.e. cooling time), and number of Integral Fuel Burnable Absorbers (IFBA) rods.

Northeast Technology Corporation report NET-173-02 evaluated postulated unplanned SFP boron dilution scenarios assuming an initial SFP boron concentration within the Technical Specification limit. The evaluation considered various scenarios by which the SFP boron concentration may be diluted and the time available before the minimum boron concentration necessary to ensure subcriticality for the non-accident condition (i.e. it is not assumed an assembly is misloaded concurrent with the spent fuel pit dilution event). Northeast Technology Corporation report NET-173-02 determined that an unplanned or inadvertent event that could dilute the SFP boron concentration from 2000 ppm to 786 ppm is not a credible event because of the low frequency of postulated initiating events and because the event would be readily detected and mitigated by plant personnel through alarms, flooding, and operator rounds through the SFP area.

Northeast Technology Corporation report NET-173-01 and NET-173-02 are based on conservative projections of amount of Boraflex absorber panel degradation assumed in each sub-region. These projections are valid through the end of the year 2006. Based upon BADGER testing in calendar years 2003 and 2006 and RACKLIFE code projections, the validity of the criticality and boron dilution analysis documented in NET-173-01 and NET-173-02 can be extened through the end of the current license (September 30, 2013), provided BADGER testing is performed by August 2010 and again in calendar year 2012 to confirm the progression of localized Boraflex dissolution. These compensatory measures for boraflex degradation in the SFP were evaluated by the NRC in Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 227 to Facility Operating License No. DPR-26, May 29,2002. The design of the facility is such that it is not possible to carry heavy objects, such as a spent fuel transfer case, over the fuel assemblies in the storage racks. The design is such that only one fuel assembly can be handled at a given time.

The motions of the cranes that move the fuel assemblies are limited to a low maximum speed. Caution is exercised during fuel handling to prevent a fuel assembly from striking another fuel assembly or structures in the containment or fuel storage building.

The fuel-handling equipment suspends the fuel assembly in the vertical position during fuel movements, except when the fuel is moved through the transport tube.

All these safety features and precautions make the probability of a fuel handling incident very low. Nevertheless, since it is possible that a fuel assembly could be dropped during the handling operations, the radiological consequences of such an incident were evaluated.

Sections 14.2.1.1 through 14.2.1.3 specifically address evaluations performed for the following accidents:

1. Fuel-handling accident in the fuel-handling building.
2. Refueling accident inside containment.
3. Fuel-handling cask drop accident.

14.2.1.1 Fuel-Handling Accident in Fuel-Handling Building

As a design basis for equipment in the fuel-handling area, consideration has been given to the perforation of all rods in one assembly resulting from a dropped fuel assembly during refueling.

Provisions have been included in the fuel-handling building to give further assurance that the consequences of this fuel-handling accident involving a spent fuel assembly will be acceptable.

To show that the radiological consequences of the postulated accident in which all rods in an assembly are breached are acceptable, an investigation was made to determine what the expected situation would be in terms of iodine available for release to the spent fuel pool water, the retention of iodine in the pool water, and the resulting doses at the site boundary. These analyses do not take credit for either building holdup of the iodines or removal by charcoal filters. The activity released from the damaged assembly is assumed to be released to the environment over a two hour period.

The consequences of an accident in which all rods in an assembly are breached under water have been analyzed. This is a conservative design-basis case, in which factors are introduced to allow for uncertainties.

In the analysis, conservative assumptions regarding fission product inventories and species distribution were made as summarized in Table 14.2-2. The maximum offsite doses are 4.2 rem total effective dose equivalent (TEDE) at the site boundary and 2.0 rem TEDE at the low population zone. Thus the consequences of the postulated fuel-handling accident are well within (i.e., less than 25-percent of) the limits of 10 CFR 50.67 which is the dose acceptance limit identified in Regulatory Guide 1.183 (Reference 20). All reasonable measures are employed in the handling of irradiated fuel to ensure against the occurrence of fuel damage and the associated radiological hazard.

The accumulated dose of the control room operators following the postulated accident was calculated using the same release, removal and leakage assumptions as the offsite dose, using the control room model discussed in Section 14.3.6.5 and Tables 14.3-50 and 14.3-51. The calculated control room dose is presented in Table 14.3-52 and is less than the 5.0 rem TEDE control room dose limit values of 10 CFR 50.67.

14.2.1.1.1 Basis for Assumptions

The fuel handling accident considers the release of all fuel-to-clad gap activity from one fuel assembly. The radial peaking factor ($F\Delta H$) applied to this assembly is 1.7.

A value of 285 for the pool elemental iodine decontamination factor was conservatively assumed. A decontamination factor of 1.0 is modeled for organic iodine and noble gases. The iodine released from the assembly gap is assumed to be 99.85% elemental and 0.15% organic. The overall pool decontamination factor for iodine is 200.

No credit is taken for removal of iodine by filters nor is credit taken for isolation of the release path. The Fuel Storage Building Ventilation System will remain in operation and discharge through the plant stack as approved by Technical Specification Amendment 211. Although the containment purge will be automatically isolated on a purge line high radiation alarm, isolation is not modeled in the analysis. The analysis assumes that the equipment hatch and airlock doors will be open (no credit is given for the requirement to maintain outage management administrative controls in place for re-establishing containment closure consistent with plant conditions). The activity released from the damaged assembly is assumed to be released to the environment over a two hour period. Since no filtration or containment isolation is modeled, this analysis supports refueling operations in either the containment or the fuel handling building.

The decay time prior to fuel movement assumed in the fuel handling accident radiological consequences analysis is 84 hours.

14.2.1.1.2 Calculation of Offsite Exposure

In calculating offsite exposure, it is assumed that the incident occurs in either the spent fuel pit or in the containment building and that the activity is discharged to the atmosphere at the ground level.

The dispersion of this activity is computed using the Gaussian plume dispersion formula and taking credit for building wake dilution as included in the 2 hr dispersion factor developed in Section 14.3.

The dose calculations were performed for a two hour release of the fuel assembly gap activity to the spent fuel pit water. The dispersion factors (Χ/Q) used in the calculations are for the site boundary, and the low population zone.

The Total Effective Dose Equivalent (TEDE) dose is the sum of Committed Effective Dose Equivalent (CEDE) dose and Effective Dose Equivalent (EDE) dose for the duration of the exposure to the cloud.

14.2.1.1.2.1 Iodine Committed Effective Dose Equivalent (CEDE) Dose

A delay of at least 84 hours is required after shutdown before fuel movement. The iodine activity remaining in the fuel assembly gap at the end of this 84 hours is used as input to the calculation. The following equation is used to obtain the integrated CEDE dose at the site boundary or low population zone for each of the iodine isotopes.

$$D_I = \left[A_I \times \left(\frac{1}{DF} \right) \times DCF_I \times \frac{\chi}{Q} \times B \right]$$

where

A_I = activity of the Iodine isotope in fuel assembly gap after 100 hours of decay (Ci)

DF = decontamination factor for iodine in water

DCF_I = CEDE dose conversion factor for the Iodine isotope from EPA-520/1-88-020 (Reference 21) (rem/Ci) *[Note: See Table 14.2-2]*

χ/Q = atmospheric dilution factor (sec/m^3)

B = breathing rate (m^3/sec)

14.2.1.1.2.2 Effective Dose Equivalent (EDE) Dose

On an isotopic basis, the equations for the integrated doses at the site boundary or low population zone are given by:

$$D_I = 0.25\left[A_I \times \left(\frac{1}{DF}\right) \times E_I \times \frac{\chi}{Q}\right]$$

$$D_I = \left[A_I \times DCF_I \times \frac{\chi}{Q}\right]$$

where

A_I = activity of the isotope in fuel assembly gap after 84 hours of decay (Ci)

DF = pool decontamination factor (200 for iodines and 1.0 for noble gases)

DCF_I = EDE dose conversion factor for the nuclide from EPA 402-R-93-081 (Reference 22) (rem-m^3/Ci-sec) [*Note - **See Table 14.2-2*]

χ/Q = atmospheric dilution factor (sec/m^3)

14.2.1.2 Refueling Accident Inside Containment

Since no filtration or isolation of the release path is modeled in the analysis for the accident occurring in the fuel handling building, the analysis presented above (Section 14.2.1.1) is applicable to the accident occurring in containment.

14.2.1.3 Fuel Cask Drop Accident

Performing an evaluation using the analysis assumptions for the fuel-handling accident shows that even with damage to a full core of recently discharged fuel assemblies by a fuel cask dropped into the spent fuel pool, the calculated fuel-handling accident doses would not be exceeded if 90 days had elapsed after shutdown. As outlined below, the accident is extremely improbable. In addition, Technical Requirements Manual Section 3.9.C precludes movement of a spent fuel cask over any region of the spent fuel pit.

During normal operation, if a spent fuel cask were placed in or removed from its position in the spent fuel pit, mechanical stops incorporated on the bridge rails would make it impossible for the bridge of the crane to travel further north than a point directly over the spot reserved for the cask in the pit.

It is extremely improbable that the cask would be inadvertently or otherwise dropped during the process of transfer. This is due to the following provisions:

1. Conservative design margins used for the cask-related handling equipment (crane, rigging, hooks, etc.).
2. Periodic nondestructive equipment tests and inspection procedures.
3. Use of qualified crane operator and riggers.
4. Use of approved operating and administrative procedures.

These provisions will be rigorously met so that the inadvertent drop of the cask into the pool is highly improbable. However, should such a highly unlikely accident occur, the basic assumptions for analysis are as follows:

1. The drop would be from the highest position of the cask, which is 5-ft above the water surface and 43-ft above the bottom of the pool.
2. The cask is fully loaded and weighs 40 tons.

The results of the analysis indicate that the cask would hit the bottom of the pit with a velocity of approximately 40-ft/sec, assuming a conservative drag coefficient of 0.5. In comparison, the cask would have reached a velocity of 52-ft/sec if dropped through 43-ft in air.

Using the Ballistic Research Laboratories formula for the penetration of missiles in steel, the depth of penetration of the cask into the 1-in. wear plate covering the 1/4-in. pit liner plate would be 0.35-in., assuming the cask struck the wear plate while in a perfectly vertical position. In the event that the cask falls through the water at an angle, terminal velocity of the cask would be somewhat less because of the increased drag. However, the cask would strike the wear plate with an initial line contact and would penetrate the wear plate and the pit liner plate, causing some cracking of the concrete below. This reinforced concrete is a minimum of 3-ft thick and rests on solid rock.

Water would initially flow through the punctured liner plate and fill the cracks in the concrete. Since the pit is founded on solid rock and since the bottom of the pit is approximately 24 feet below the surrounding grade, very little water can be lost from the pit. The capacity of the makeup demineralized water supply to the pit is 150 gpm. In addition, the spent fuel pit cooling system piping has a 4-in. blind flange connection for temporary cooling and/or makeup water.

Because the bottom of the spent fuel pit is 24-ft below grade and no equipment areas are in the vicinity, there can be no flooding of other areas with subsequent damage to equipment.

14.2.2 <u>Accidental Release-Recycle Of Waste Liquid</u>

Accidents that would result in the release of radioactive liquids are those which may involve the rupture or leaking of system pipe lines or storage tanks. The largest vessels are the three liquid holdup tanks of the chemical and volume control system, each sized to hold two-thirds of the reactor coolant liquid volume. The tanks are used to process the normal recycle of waste fluids produced. The contents of one tank will be passed through the liquid processing train while another tank is being filled.

All liquid waste components of the waste disposal system except the reactor coolant drain tank and the waste holdup tank are located in the auxiliary building, and any leakage from the tank or piping will be collected in the building sump to be pumped back into the liquid waste system. The waste holdup and the liquid holdup tanks are located in a thick concrete under-ground vault. The vault volume is sufficient to hold the full volume of any tank without overflowing to areas outside the vault. The reactor coolant drain tank is located in the containment building.

Holdup tanks are equipped with safety pressure relief and designed to accept the established seismic forces at the site. Liquids in the chemical and volume control system flowing into and out of these tanks are controlled by manual valve operation and governed by prescribed administrative procedures.

The volume control tank design philosophy is similar in many respects to that applied to the holdup tanks. Level alarms, pressure relief valves, and automatic tank isolation and valve control ensure that a safe condition is maintained during system operation. Excess letdown flow is directed to the holdup tanks via the reactor coolant drain tank.

Piping external to the containment running between the containment and the auxiliary building and between the auxiliary building and liquid holdup tank vault is run below grade in concrete trenches. Any liquid spillage from pipe rupture or leaks in these trenches would drain to the sump and be pumped to the sump tank and to the waste holdup tank.

The incipient hazard from these process or waste liquid releases is derived only from the volatilized components. The releases are described and their effects summarized in Section 14.2.3.

A river diffusion analysis was performed to determine the concentrations that would result at the Chelsea reservoir if a release of waste liquid to the river was assumed. The results of the analysis show that even the instantaneous release of the entire primary coolant system maximum activity corresponding to operation with 1-percent defects would not result in peak concentrations at Chelsea in excess of 10 CFR 20 MPC limits. Drought conditions were assumed to exist at the time of and for a period following the spill limiting the total runoff flow to 4000 cfs. The mean longitudinal diffusion coefficient corresponding to this flow was 8.74 mi^2 per day. These data represent a drought similar to conditions existing in late summer of 1964, which can be verified by data in Section 2.5.

The unlikely event of a loss of water from a spent resin storage tank actuates a low-level alarm to warn the operator. Resin contained in the tank can then be cooled by periodically flushing water from the primary water storage tank through the resin. Two pathways are available for the water: (1) through the primary water storage injection pipeline used when resin is removed from the tank, or (2) through the primary water pipeline used when resin is sluiced from the demineralizers into the tank.

The following conservative assumptions are made to determine the frequency of flushing to cool the resin:

1. The tank contains resin from the letdown line mixed-bed demineralizers discharged to the spent resin storage tank following the operation of the plant for one cycle with 1-percent fuel defects. This assumption yields the maximum heat generation rate per unit volume of resin in the tank and the maximum level of radioactivity in the tank.

2. There are no heat losses through the tank walls.

3. Water is lost immediately following the discharge of a mixed-bed resin into the spent-resin storage tank. This yields a maximum heat generation rate due to fission product decay.

4. The heat generation rate and resin bed temperature equations are developed based on one cubic foot of resin.

5. The mean heat capacity of the resin is 0.31 Btu/lb-°F.

6. Resin specific gravity is 1.14 with a void fraction of 0.4 giving a resin density of 43 lb/ft^3.

7. The amount of radioactivity in the resin is:

	$\mu Ci/cm^3$
Br-84	6.4E-1
I-131	1.4E4
I-132	1.7E2
I-133	2.4E3
Rb-88	3.1E1
Cs-134	3.7E4
Cs-136	1.3E3
Ba-137m	2.6E4
Cs-138	1.3E1
Co-60	1.5E2
La-140	3.1E1

(There is assumed to be sufficient Cs-137 on the resin to maintain the inventory of Ba-137m at the above value.)

These assumptions result in the following relationships:

1. The heat generation rate, q (Btu/hr per cubic foot of resin), due to fission product decay is approximated closely as a function of time, t (hr), by

$$q = 0.247e^{-0.0578t} + 0.869e^{-0.0144t} + 4.65e^{-0.00144t} + 41.95$$

where the first term is due to nuclides with half lives less than 12 hours, the second term is due to nuclides with half-lives between 12 hours and 2 days, the third term is due to nuclides with half-lives between 2 and 20 days, and the last term is due to nuclides with half lives >20 days.

2. The resin bed temperature, T (°F), as a function of time, t (hr), is

$$T = 0.32(1 - e^{-0.0578t}) + 4.52(1 - e^{-0.0144t}) + 242(1-e^{-0.00144t}) + 3.15t + T_o$$

where T_o is the initial resin temperature.

If T_o is assumed to be 90°F, it will take 14 hours for the resin temperature to rise to 140°F, the normal resin operating limit. At or below a temperature of 140°F, the radioactivity will not be released from the resin. The actual time to heat to 140°F will be greater than 14 hours because of the conservative assumptions made in the calculation. With 100 cubic feet of resin in the tank, the heat accumulated in the resin through the initial 14 hours will be 66,650 Btu. The resin can be maintained at 140°F or less by back flushing the resin with primary water at appropriate intervals. Flush water will be collected by the floor drain system and be pumped to the waste holdup tank. If a 10°F rise is taken in the flush water, the total quantity of water required will be about 810 gal per backflush operation to remove the 66,650 Btu accumulated in the resin.

Hence, the loss of water from the spent resin storage tank presents no hazard offsite or onsite because means are available both to detect the situation occurring and to keep the resin temperature under control until the resin can be removed to burial facilities.

14.2.3 Accidental Release - Waste Gas

The leakage of fission products through cladding defects can result in a buildup of radioactive gases in the reactor coolant. Based on experience with other operational, closed-cycle, pressurized-water reactors, the number of defective fuel elements and the gaseous coolant activity is expected to be low. The shielding and sizing of components such as demineralizers and the waste handling system are based on activity corresponding to 1-percent defective fuel which is at least an order of magnitude greater than expected. Tanks accumulating significant quantities of radioactive gases during operation are the gas decay tanks, the volume control tank, and the liquid holdup tanks.

The volume control tank accumulates gases over a core cycle by stripping action of the entering spray. Gaseous activity for the tank based on operation with 1-percent defective fuel is given in Table 14.2-5. During a refueling shutdown, this activity is vented to the waste gas system and stored for decay. A rupture of this tank is assumed to release all of the contained noble gases plus a small fraction of the iodine in the tank (a partition factor of 0.01 is used). Also, the noble gas activity and a fraction of the iodine activity contained in the letdown flow would be released. A maximum letdown flow of 120 gpm, plus ten percent for uncertainty, is assumed. The noble gas activity in the primary coolant is based on operation with one percent fuel defects (see Table 9.2-4) and the iodine concentration is assumed to be 60 µCi/gm. The iodine concentration is assumed to be reduced by a factor of ten by the demineralizer in the letdown line and ten percent of the remaining iodine activity is assumed to be released to the atmosphere. The letdown line is assumed to be isolated after 30 minutes.

The liquid holdup tanks receive reactor coolant, after passing through demineralizers, during the process of coolant purification. The contents of one tank are passed through the liquid processing train while another tank is being filled. In analyzing the consequence of rupture of a holdup tank, it is assumed that a single tank is filled to 80% of capacity using the letdown flow of 120 gpm (maximum purification flow) and the primary coolant noble gas concentrations are those for operation with one-percent fuel defects. The iodine concentration in the flow to the holdup tank is assumed to be 0.1 µCi/gm of dose-equivalent I-133 (this is ten-percent of the primary coolant equilibrium activity limit and this reduction is due to the 90% removal assumed to take place in the letdown line mixed-bed demineralizer). A major tank failure would be required to cause a release of all the contained noble gas. Since the tanks operate at low pressure, approximately 2 psig, a gas phase leak would result in an expulsion of approximately 12-percent of the contained gases and then the pressure would be in equilibrium with atmosphere. It is conservatively assumed that all of the contained noble gas activity and one-percent of the iodine activity are released. The tank pits are vented to the ventilation system so that any gaseous leakage would be discharged to the atmosphere by this route. Any liquid leaks from the tanks or piping will be collected in the tank sump pit to be pumped back into the liquid waste system.

The waste gas decay tanks receive the radioactive gases from the radioactive liquids from the various laboratories and drains processed by the waste disposal system. The maximum storage of waste gases occurs after a refueling shutdown, at which time the gas decay tanks store the radioactive gases stripped from the reactor coolant. A radiation monitor counts activity in a gas decay tank sample to the gas analyzer and an alarm is actuated if the activity approaches an administrative limit of 6000 Ci of dose-equivalent Xe-133. There is also an operating limit of 29,761 Ci of dose-equivalent Xe-133 in any tank. As discussed in Section 11.1, six shut-down gas decay tanks are provided in addition to the four gas decay tanks used during power operation to reduce the gaseous activity release as a result of an assumed rupture of one of the tanks during the decay period following a refueling shutdown.

The doses calculated for the tank failures are:

	Site Boundary WB Dose (rem)	Low Population WB Zone Dose (rem)	Control Room WB (rem)
Volume Control Tank	0.30	0.14	0.05
Gas Decay Tank	0.14	0.07	0.05
Holdup Tank	0.4	0.19	0.06

These doses are all less than 0.5 rem, whole body (RG 1.26).

[Deleted]

14.2.4 Steam-Generator Tube Rupture

Accident Description

The event examined is the complete severance of a single steam generator tube. The accident is assumed to take place during full power operation with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited amount of defective fuel rods. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the reactor coolant system. In the event of a coincident loss of offsite power, or failure of the condenser steam dump system, discharge of activity to the atmosphere takes place via the steam generator power operated relief valves (and safety valves if their setpoint is reached).

The activity that is available for release from the secondary system is limited by:

1. Activities in the steam generator secondary that are a consequence of operational leakage prior to the complete tube rupture.
2. The activity concentration in the reactor coolant.
3. Operator actions to isolate the mixed primary and secondary leakage to atmosphere.

The steam generator tube material is highly ductile and it is considered that the assumption of a complete severance is conservative. The more probable mode of tube failure would be one or more minor leaks of undetermined origin. Activity in the steam and power conversion system is subject to continuous surveillance and an accumulation of minor leaks that cause the activity to exceed the limits in the Technical Specifications is not permitted during reactor operation.

For small leaks which will not result in a safety injection signal or containment isolation signal, the air ejector radiation monitor will alarm in the presence of activity in the air ejector discharge line. The air ejector discharge is automatically diverted back to the containment. The steam-generator liquid monitor will then alarm after a delay of about 2 minutes and the steam-generator blowdown/sampling lines will be isolated automatically. The main steamline nitrogen-16 (N-16) monitors and other main steamline monitors will also detect the presence of activity in the secondary system. See Sections 11.2.3.2.4, 11.2.3.2.8, 11.2.3.2.13, 11.2.3.2.19 and 11.2.3.4.3 for further information on the secondary system monitors provided.

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

Assuming normal operation of the various plant systems, the following sequence of events is initiated by a tube rupture:

1. Pressurizer low pressure and low level alarms are actuated, and prior to reactor trip, charging pump flow is increased in an attempt to maintain pressurizer level. On the secondary side there is a steam flow/feedwater flow mismatch before trip, and feedwater flow to the affected steam generator is reduced due to the additional break flow which is being supplied to that steam generator.

2. The main steamline N-16 monitor and air ejector radiation monitor will alarm, indicating a sharp increase in radioactivity in the secondary system.

3. Decrease in reactor coolant system pressure due to a continued loss of reactor coolant inventory leads to a reactor trip signal on low pressurizer pressure or overtemperature ΔT. Resultant plant cool-down following reactor trip leads to a rapid decrease in pressurizer level and a safety injection signal, initiated by low pressurizer pressure, follows soon after reactor trip. The safety injection signal automatically terminates normal feedwater and initiates auxiliary feedwater.

4. The unit trip will automatically shut off steam flow through the turbine and will open steam bypass valves and bypass steam to the condenser if offsite power is available. In the event of a coincident loss of offsite power the steam dump valves would automatically close to protect the condenser. The steam generator pressure would rapidly increase, resulting in steam discharge to the atmosphere through the steam generator power operated relief valves (and the steam generator safety valves if their setpoint is reached).

5. Following reactor trip and safety injection actuation, the continued action of auxiliary feedwater supply and borated water injection flow provide a heat sink. Thus, steam bypass to the condenser, or in the case of a loss of offsite power,

steam relief to atmosphere, is attenuated during the time in which the recovery procedure leading to isolation is being carried out.

6. Safety injection flow results in stabilization of the reactor coolant system (RCS) pressure and pressurizer water level and, if not for the operator's recovery actions, the RCS pressure trends towards the equilibrium value where the safety injection flow rate equals the break flow rate.

Recovery

In the event of an SGTR, the plant operators must diagnose the SGTR and perform the required recovery actions to stabilize the plant and terminate the primary to secondary leakage. The operator actions for SGTR recovery are provided in the Emergency Operating Procedures (EOPs). The EOPs are based on guidance in the Westinghouse Owner's Group Emergency Response Guidelines which address the recovery from a SGTR with and without offsite power available. The major operator actions include: identification of the ruptured steam generator, isolation of the ruptured steam generator, cooldown of the reactor coolant system using the intact steam generators to ensure subcooling at the ruptured steam generator pressure, controlled depressurization of the reactor coolant system to the ruptured steam generator pressure, and subsequent termination of safety injection flow to stop primary to secondary leakage.

These operator actions are described below.

1. Identify the ruptured steam generator.

   High secondary side activity, as indicated by the secondary side radiation monitors will typically provide the first indication of an SGTR event. The ruptured steam generator can be identified by an unexpected increase in steam generator narrow range level or high activity in any steam generator sample. For an SGTR that results in a reactor trip at high power, the steam generator water level as indicated on the narrow range will decrease significantly for all of the steam generators. The auxiliary feedwater flow will begin to refill the steam generators, distributing approximately equal flow to each of the steam generators. Since primary to secondary leakage adds additional inventory to the ruptured steam generator, the water level will increase more rapidly in that steam generator. This response, as displayed by the steam generator water level instrumentation, provides confirmation of an SGTR event and also identifies the ruptured steam generator.

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

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

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

4. Depressurize the RCS to restore reactor coolant inventory.
   When the cooldown is completed, SI flow will tend to increase RCS pressure until break flow matches SI flow. Consequently, SI flow must be terminated to stop primary to secondary leakage. However, adequate reactor coolant inventory must first be assured. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after SI flow is stopped.

   The RCS depressurization is performed using normal pressurizer spray if the reactor coolant pumps (RCPs) are running. However, if offsite power is lost or the RCPs are not running, normal pressurizer spray is not available. In this event, RCS depressurization can be performed using a pressurizer power operated relief valve (PORV) or auxiliary spray.

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

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

<u>Results</u>

The analysis supports a Tavg window ranging from 549.0°F to 572.0°F. The analysis also supports a steam generator tube plug ranging from 0% to 10%. In estimating the mass transfer from the reactor coolant system through the broken tube, the following assumptions were made:

a. Plant trip occurs automatically as a result of low pressurizer pressure.

b. Following the safety injection signal, three high head safety injection pumps deliver flow for 30 minutes.

c. The ruptured steam generator pressure is maintained at the lowest steam generator safety valve reseat pressure of 885.4 psia (including 18% blowdown, which covers the 3% setpoint tolerance).

d. After reactor trip if the operators take no action to respond to the event the break flow will tend to equilibrate to the point where incoming safety injection flow is balanced by outgoing break flow as shown in Figure 14.2-0. In the accident analysis, this equilibrium break flow is assumed to persist from plant trip until 30 minutes after the accident initiation. The analysis does not require that the operators demonstrate the ability to terminate break flow within 30 minutes from the start of the event. It is recognized that the operators may not be able to terminate break flow within 30 minutes for all postulated SGTR events. The purpose of the calculation is to provide conservatively high mass-transfer rates for use in the radiological consequences analysis. This is achieved by assuming a constant break flow at the equilibrium flow rate for a relatively long time period. 30 minutes was selected for this purpose.

Sufficient indications and controls are provided at the control board to enable the operator to complete these functions satisfactorily within 60 minutes for the design-basis event even without offsite power. In order to demonstrate that releases calculated with the 30 minute equilibrium break flow assumption are indeed conservative, an evaluation was performed with a licensed thermal-hydraulic analysis code modeling the operator's response to the event. This evaluation modeled the operator's identification and isolation of the ruptured steam generator, cooldown of the RCS by dumping steam from the intact steam generators, depressurization of the RCS using the pressurizer PORV and subsequent termination of SI. This evaluation demonstrated that although break flow was terminated at 60 minutes, the mass transfer data calculated with the assumption of a constant break flow at the equilibrium value for 30 minutes from reactor trip is limiting as input to the radiological consequences analysis.

In addition to the above assumptions, it is conservatively assumed that all stored energy and decay heat is removed by steaming until 30 hours from the start of the event at which point heat removal would be provided by the Residual Heat Removal System. These assumptions lead to the determination of the following:

Time of reactor trip	290 sec
Steam releases prior to reactor trip	1075.6 lb/sec per SG
Steam releases from ruptured SG after reactor trip (trip – 30 minutes)	77,300 lb
Steam releases from intact SGs after reactor trip	
Trip – 2 hours	542,000 lb
2 – 8 hours	1,090,000 lb
8 – 30 hours	1,760,000 lb
Ruptured SG break flow	
0 – trip	29,000 lb
trip – 30 minutes	99,000 lb
Break flow flashing fraction	
0 – trip	0.21
trip – 30 minutes	0.13

Radiological Consequences

The radiological consequences analysis considers both a pre-accident iodine spike and an accident initiated iodine spike.

In the pre-accident iodine spike case it is assumed that a reactor transient has occurred prior to the SGTR and has raised the RCS iodine concentration to 60 μCi/gm of Dose Equivalent (DE) I-131 (60 times the assumed maximum coolant equilibrium concentration limit of 1.0 μCi/gm of Dose Equivalent I-131).

For the accident-initiated iodine spike case, the reactor trip associated with the SGTR creates an iodine spike in the RCS which increases the iodine release rate from the fuel to the RCS to a value 335 times greater than the release rate corresponding to the assumed maximum equilibrium RCS concentration of 1.0 μCi/gm of Dose Equivalent I-131. The duration of the accident-initiated iodine spike is limited by the amount of activity available in the fuel-cladding gap. Based on having 8-percent of the iodine in the fuel-cladding gap, the gap inventory would be depleted within 4 hours and the analysis assumed that the spike is terminated at that time.

The noble gas activity concentration in the RCS at the time the accident occurs is based on a one percent fuel defect level (see Table 9.2-4). The iodine activity concentration of the secondary coolant at the time the SGTR occurs is assumed to be equivalent to the Technical Specification limit of 0.15 μCi/gm of Dose Equivalent I-131.

The amount of primary to secondary steam generator tube leakage in the intact steam generators is assumed to be equal to 150 gpd per steam generator.

An iodine partition factor in the steam generators of 0.01 (curies iodine/gm steam) / (curies iodine/gm water) is used. Prior to reactor trip and concurrent loss of offsite power an iodine removal factor of 0.01 is taken for steam released to the condenser. All iodine contained in the fraction of the break flow that flashes to steam upon entering the secondary side of the steam generator is assumed to be immediately released to the outside atmosphere.

All noble gas activity carried over to the secondary side through steam generator tube leakage is assumed to be immediately released to the outside atmosphere.

At 30 hours after the accident, the Residual Heat Removal System is assumed to be capable of all decay heat removal and that there are thus no further steam releases to atmosphere from the secondary system.

The resultant site boundary doses are 3.3 rem TEDE for the pre-accident iodine spike and 1.2 rem TEDE for the accident-initiated iodine spike. The corresponding low population zone doses are 1.6 rem TEDE and 0.6 rem TEDE. These doses are calculated using the meteorological dispersion factors discussed in Section 14.3.6.2.1.

The offsite doses resulting from the accident with the assumed pre-accident iodine spike case are below than the limit values of 10 CFR 50.67 (25 rem TEDE) which is the dose acceptance limit identified in Regulatory Guide 1.183. The offsite doses resulting from the accident with the assumed accident-initiated iodine spike are less than 10-percent of the limit values of 10 CFR

50.67 (less than 2.5 rem TEDE) which is the dose acceptance limit identified in Regulatory Guide 1.183..

The accumulated doses to control room operators following the postulated accident were calculated using the same release, removal and leakage assumptions as the offsite doses, using the control room model discussed in Section 14.3.6.5 and Tables 14.3-50 and 14.3-51. The calculated control room doses are presented in Table 14.3-52 and are less than the 5.0 rem TEDE control room dose limit values of 10 CFR 50.67.

14.2.5 Rupture of a Steam Pipe

14.2.5.1 Description

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

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

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

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

1. Safety injection system actuation from any one of the following:
   [***Note*** *- The details of the logic used to actuate safety injection are discussed in Section 7.2.*]

   a. Two-out-of-three channels of low pressurizer pressure signals.

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

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

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

e. Manual actuation

2. The overpower reactor trips (nuclear flux and ΔT) and the reactor trip occurring upon actuation of the safety injection system.

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

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

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

Each main steam line has a fast-closing stop valve and a check valve. These eight valves prevent blowdown of more than one steam generator for any main steam line break location even if one valve fails to close. For example, for a main steam line break upstream of the stop valve in one line, a closure of either the check valve in that line or the stop valves in the other lines will prevent blowdown of the other steam generators.

Steam flow is measured by monitoring dynamic head in nozzles inside the steam pipes. The nozzles (16-in. ID versus a pipe diameter of 28-in. OD) are located inside the containment near the steam generators and also serve to limit the maximum steam flow for any break further downstream. In particular, the nozzles limit the flow for all breaks outside the containment and those inside the containment which are downstream of the flow-measuring nozzles. A schematic showing the location of the stop valves, check valves, and nozzles is shown in Figure 14.2-1. In addition a flow limiting device (integral flow restrictor) consisting of seven (7) low pressure drop venturis is located in the steam outlet nozzle of each steam generator. This limits the flow of the postulated steam line break at the outlet nozzle to $1.4 ft^2$ (flow restrictor area).

14.2.5.2 <u>Method of Analysis</u>

The analysis of the steam pipe rupture has been performed to determine:

1. The core heat flux and RCS temperature and pressure resulting from the cooldown following the steam line break. These conditions were determined using the RETRAN code.[4]

2. The thermal-hydraulic behavior of the core following a steam line break. A detailed thermal-hydraulic computer code, VIPRE[16] was used to determine if DNB occurs for the core conditions computed in the item 1 above.

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

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

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

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

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

5. The Moody curve for L/D = 0 reported in Figure 3 of Reference 6 was used to calculate the steam flow through a steam line break.

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

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

Case A - Steam pipe rupture of a 1.4ft^2 break size (integral flow restrictor area) in faulted main steam line with offsite power available.
Case B - Steam pipe rupture 1.4ft^2 break size (integral flow restrictor area) in faulted main steam line with a loss of offsite power.

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

In the case where offsite power is not available, an additional 7 seconds delay is assumed to start the diesels and to load the necessary SI equipment on line.

14.2.5.3 <u>Results</u>

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

1. Minimum shutdown margin equal to 1.3% delta-K
2. The most negative moderator temperature coefficient for the rodded core at end of life.
3. The most reactive RCCA stuck in its fully withdrawn position.
4. One safety injection pump fails to function as designed.

The Time Sequence of the Events for both cases analyzed is reported in Table 14.2-6

14.2.5.4 Core Power and Reactor Coolant System Transients

Case A - Steam pipe rupture of a 1.4ft^2 break size (integral flow restrictor area) in faulted main steam line with offsite power available.

Figure 14.2-2 shows the reactor coolant system transient and core heat flux following a steam pipe rupture (complete severance of a pipe) at the initial no-load conditions. Should the core be critical at near zero power when the rupture occurs, a reactor trip signal from the safety injection signal initiated on high differential pressure between steam lines or by high steam flow signals in coincidence with either low reactor coolant system temperature or low steam line pressure would trip the reactor.

The break assumed is the largest break that could occur, i.e., assuming a double-ended rupture of the steamline, limited to 1.4ft^2 at the SG nozzle restrictor. Offsite power is assumed available such that full reactor coolant flow is maintained. Steam release out the break from the three intact steam generators would be prevented by the reverse flow check valve in the faulted loop or by the automatic closing of the fast-acting stop valves in the steam lines on a high steam flow signal in coincidence with low reactor coolant system temperature or low steam line pressure. Even with the failure of one valve, release from the three intact steam generators while the fourth steam generator blows down would be limited to the time required to obtain an isolation signal and to actuate steam line isolation via the fast-acting stop valves. The steam line stop valves are designed to be fully closed in less than 5 seconds with no flow through them. With the high flow that exists during a steam line rupture, the valves would close considerably faster.

For this case, a high steam flow condition in all four loops occurs almost immediately. A low-low average loop temperature condition (i.e., less than 537 degree F) is reached in 2 of 4 loops at 12.9 seconds. Seven seconds later, at 19.99 seconds, signals to initiate SI, steam line isolation, and feedwater isolation are actuated. At 25.00 seconds, isolation of the 3 intact steam generators by closure of the main steam line isolation valves is completed. At 33.00 seconds, isolation of the main feedwater system is completed. The safety injection pumps which were started on the SI signal begin to deliver borated flow into the reactor core, after primary system pressure decreases below the SI pump head and the safety injection system lines are purged of unborated water.

As shown in Figure 14.2-2 the core becomes critical at 20.0 seconds. The peak core average heat flux of 15.5% of the nominal core power value (3216.0 MWt) is reached at 126.5 seconds.

Case B - Steam pipe rupture of a 1.4ft^2 break size (integral flow restrictor area) in faulted main steam line with a loss of offsite power.

For the case assuming a break with a loss of offsite power at time zero which results in a subsequent reactor coolant system flow coastdown, a high steam flow condition in all four loops occurs almost immediately. A low-low average loop temperature condition (i.e., less than 537°F) is reached in 2 of 4 loops at 14.65 seconds. Seven seconds later, at 21.65 seconds, signals to initiate SI, steam line isolation, and feedwater isolation are actuated. At 26.67 seconds, isolation of 3 intact steam generators is completed. At 34.67 seconds, isolation of the main feedwater system is completed. Following the appropriate safety injection system delay time required to start the safety injection pumps on the diesels, the safety injection pumps begin to deliver borated flow into the reactor core.

The peak core average heat flux of 9.20% of the nominal core power is reached at approximately 72 seconds.

14.2.5.5 Margin to Critical Heat Flux

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

14.2.5.6 Containment Peak Pressure for a Postulated Steam Line Break

The impact of steam line break mass and energy releases on containment pressure was addressed to assure the containment pressure remains below the design pressure of 47 psig. The LOFTRAN computer code was used to generate the mass and energy release to the containment for a large double-ended rupture at the discharge nozzle of the Model 44F replacement steam generator. A single failure of either the main or bypass feedwater control valve was assumed to occur concurrent with the break, which results in additional mass and energy release to containment from the feedwater system. The limiting case for the mass and energy releases is that which assumes offsite power is available at the hot full power conditions. The feedwater addition assumes a 2 second electronic delay, and a 5 second delay on tripping the main boiler feedwater pumps. The pumps are then assumed to coastdown in 10 seconds and the main boiler feedwater pump discharge valves (BFD-2) are assumed to close in 60 seconds. For the failure of the main feedwater control valve analysis, credit was taken for the main feedwater stop valves (BFD-5), with a closure time of 120 seconds. For the failure of the bypass feedwater control valve analysis, no credit was taken for the bypass feedwater stop valve (BFD-90).

An operator action to terminate auxiliary feed-water flow to the faulted steam generator was assumed at 15 minutes following receipt of the SI signal, which is more conservative than the 10 minute assumption previously used.

The COCO Code[17] was used to generate the containment response. The containment model was identical to that used for the Long Term LOCA Containment Integrity Analysis. The following assumptions were made:

-time dependent mass and energy release rates from LOFTRAN[5],
-an initial ambient pressure in the containment of 2 psig,
-an initial ambient temperature in the containment of 130°F,
-maximum safeguards of 5 fan coolers and two spray pumps.
-fan cooler initiation on SI signal with 60 second delay,
-containment spray initiation at 30 psig, with 60 second delay, and
-a containment spray temperature of 110°F.

The peak containment pressure was calculated to be 39.5 psig for failure of the main feedwater control valve, and 37.4 psig for failure of the bypass feedwater control valve. The calculated pressure time history is shown in Figure 14.2-7.

14.2.5.7 Dose Considerations

Assuming that a steam line break occurs when the steam generator is operating with a leak, the portion of reactor coolant activity discharged through the leak will be released to the steam generator. For the case in which the break is outside the containment and the leak occurs in the steam generator with the ruptured steam line, this activity is released to the atmosphere. In addition, the activity initially present in the steam generator will be released. Following the accident, the reactor coolant system would be cooled down and depressurized. The analysis assumes that the residual heat removal loop would be put into operation within 30 hours after the accident, and that there are no further steam releases to the atmosphere from the intact steam generators. Activity releases due to leakage of primary coolant to the faulted steam generator are assumed to continue until the primary coolant temperature is reduced to less than 212°F at 65 hours. At this point there would be no further release to the atmosphere. The radiological consequences analysis considers both a pre-accident iodine spike and an accident initiated iodine spike.

In the pre-accident iodine spike case it is assumed that a reactor transient has occurred prior to the event and has raised the RCS iodine concentration to 60 μCi/gm of Dose Equivalent (DE) I-131 (60 times the assumed maximum coolant equilibrium concentration limit of 1.0 μCi/gm of Dose Equivalent I-131).

For the accident-initiated iodine spike case, the depressurization and reactor trip associated with the event creates an iodine spike in the RCS which increases the iodine release rate from the fuel to the RCS to a value 500 times greater than the release rate corresponding to the assumed maximum equilibrium RCS concentration of 1.0 μCi/gm of Dose Equivalent I-131. The duration of the accident-initiated iodine spike is limited by the amount of activity available in the fuel-cladding gap. Based on having 8-percent of the iodine in the fuel-cladding gap, the gap inventory would be depleted within 3 hours and the analysis assumed that the spike is terminated at that time.

The noble gas activity concentration in the RCS at the time the accident occurs is based on a one percent fuel defect level (see Table 9.2-4). The iodine activity concentration of the secondary coolant at the time the steam line break occurs is assumed to be equivalent to the Technical Specification limit of 0.15 μCi/gm of Dose Equivalent I-131.

The amount of primary to secondary steam generator tube leakage in the steam generators is 150 gpd per steam generator.

The steam generator connected to the broken steam line is assumed to boil dry within the initial five minutes following the steamline break. The entire liquid inventory of this steam generator is assumed to be steamed off and all of the iodine initially in the steam generator is assumed to be released to the environment. Also, the iodine carried over to the faulted steam generator by tube leaks is assumed to be released directly to the environment with no credit taken for iodine retention in the steam generator.

For the intact steam generators an iodine partition factor in the steam generators of 0.01 (curies iodine/gm steam) / (curies iodine/gm water) is used. The concentration of iodine in the intact steam generators thus increases over the duration of the accident.

Prior to reactor trip and concurrent loss of offsite power an iodine removal factor of 0.01 could be taken for steam released to the condenser, but conservatively, the pre-trip condenser iodine removal is ignored.

All noble gas activity carried over to the secondary side through steam generator tube leakage is assumed to be immediately released to the outside atmosphere.

The resultant site boundary dose is 0.12 rem TEDE for both the pre-accident iodine spike case and the accident-initiated iodine spike case. The corresponding low population zone doses are 0.13 rem TEDE for the pre-accident spike and 0.33 rem TEDE for the accident-initiated spike. These doses are calculated using the meteorological dispersion factors discussed in Section 14.3.6.2.1.

The offsite doses resulting from the accident with the assumed pre-accident iodine spike case are below the limit values of 10 CFR 50.67 (25 rem TEDE) which is the dose acceptance limit identified in Regulatory Guide 1.183. The offsite doses resulting from the accident with the assumed accident-initiated iodine spike are less than 10-percent of the limit values of 10 CFR 50.67 (less than 2.5 rem TEDE) which is the dose acceptance limit identified in Regulatory Guide 1.183.

The accumulated doses to control room operators following the postulated accidents were calculated using the same release, removal and leakage assumptions as the offsite doses, using the control room model discussed in Section 14.3.6.5 and Tables 14.3-50 and 14.3-51. The calculated control room doses are presented in Table 14.3-52 and are less than the 5.0 rem TEDE control room dose limit values of 10 CFR 50.67.

14.2.6 Rupture of A Control Rod Mechanism Housing - Rod Cluster Control Assembly Ejection

14.2.6.1 Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing resulting in the ejection of a rod cluster control assembly and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

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

14.2.6.2 Mechanical Design

Mechanical design and quality control procedures intended to preclude the possibility of a rod cluster control assembly drive mechanism housing failure are listed below:

1. Each control rod drive mechanism housing was completely assembled and shop tested at 4100 psi.

2. Each mechanism housing was individually hydro tested to 3105 psig as it was installed on the reactor vessel head adapters and checked during the hydro test of the completed reactor coolant system.

3. Stress levels in the mechanism are not affected by system transients at power, or by thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress range specified by the ASME code, Section III, for Class A components.

4. The latch mechanism housing and rod travel housing are each a single length of forged type 304 stainless steel. This material exhibits excellent notch toughness at all temperatures that will be encountered. The joint between latch mechanism and head adapter is a threaded joint, reinforced using a canopy-type seal weld. The joint between the latch mechanism and rod travel housings is a Conoseal mechanical joint.

14.2.6.3 Nuclear Design

Even if a rupture of a rod cluster control assembly (RCCA) drive mechanism housing is postulated, the operation of a plant using chemical shim is such that the severity of an ejected RCCA is inherently limited. Reactivity changes caused by core depletion and xenon transients are compensated by boron changes. Further, the location and grouping of control RCCA banks are selected during the nuclear design to lessen the severity of a RCCA ejection accident. Therefore, should a RCCA be ejected from its normal position during full-power operation, only a minor reactivity excursion, at worst, could be expected to occur.

However, it may be occasionally desirable to operate with larger than normal insertions. For this reason, a rod insertion limit is defined as a function of power level. Operation with the RCCA's above this limit guarantees adequate shutdown capability and acceptable power distribution. The position of all RCCA's is continuously indicated in the control room. Alarms will occur if a bank of RCCA's approaches its insertion limit or if one RCCA deviates from its bank. Operating instructions require boration when a valid "APPROACHING ROD INSERTION LIMIT" alarm is received and emergency boration when a valid "ROD INSERTION LIMIT" alarm is received.

14.2.6.4 Reactor Protection

The protection for this accident is provided by high neutron flux trip (high and low setting).

14.2.6.5 Effects on Adjacent Housings

Disregarding the remote possibility of the occurrence of a rod cluster control assembly mechanism housing failure, investigations have shown that failure of a housing due to either longitudinal or circumferential cracking would not cause damage to adjacent housings. However, even if damage is postulated, it would not be expected to lead to a more severe transient since rod cluster control assemblies are inserted in the core in symmetric patterns, and control rods immediately adjacent to worst ejected rods are not in the core when the reactor is critical. Damage to an adjacent housing could, at worst, cause that rod cluster control assembly not to fall on receiving a trip signal; however, this is already taken into account in the analysis by assuming a stuck rod adjacent to the ejected rod.

14.2.6.6 Limiting Criteria

This event is classified as an ANS Condition IV incident. Due to the extremely low probability of a rod cluster control assembly ejection accident, some fuel damage could be considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold or significant conversion of the fuel thermal energy to mechanical energy have been carried out as part of the SPERT project by the Idaho Nuclear Corporation.[7] Extensive tests of UO_2 zirconium clad fuel rods representative of those in pressurized water reactor type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design have exhibited failures as low as 225 cal/gm. These results differ significantly from the TREAT results,[8] which indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreases by about 10-percent with fuel burnup. The clad failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure (large fuel dispersal, large pressure rise) even for irradiated rods, did not occur below 300 cal/gm. In view of the above experimental results, criteria are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are as follows:

1. Average fuel pellet enthalpy at the hot spot below 200 cal/gm.

2. Average clad temperature at the hot spot below 3000^{o}F and a Zirconium water reaction at the hot spot below 16%[23].

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

4. Fuel melting will be limited to less than 10-percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of criterion (1) above.

Criteria 2 is a Westinghouse internal criterion established to address clad melting and embrittlement. However Criterion 1 was identified (Reference 23) as the limit which ensures that core cool ability is maintained.

14.2.6.7 Method of Analysis

The calculation of the rod cluster control assembly ejection transient is performed in two stages, first an average core channel calculation and then a hot region calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients in the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient.

A detailed discussion of the method of analysis can be found in Reference 9.

14.2.6.7.1 Average Core Analysis

The spatial kinetics computer code, TWINKLE,[10] is used for the average core transient analysis. This code solves the 2 group neutron diffusion theory kinetic equation in 1, 2, or 3 spatial dimensions (rectangular coordinates) for 6 delayed neutron groups and up to 8000 spatial points. The computer code includes a detailed multi-region, transient fuel-clad-coolant heat transfer model for calculation of pointwise Doppler and moderator feed-back effects. In this analysis, the code is used as one-dimensional axial kinetics code since it allows a more realistic representation of the spatial effects of axial moderator feedback and rod cluster control assembly movement. However, since the radial dimension is missing, it is still necessary to employ very conservative methods (described in the following) for calculating the ejected rod worth and hot-channel factor.

14.2.6.7.2 Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal times the design hot-channel factor. During the transient, the heat flux hot-channel factor is linearly increased to the transient value in 0.1 sec, the time for full ejection of the rod. Therefore, the assumption is made that the hot spots before and after ejection are coincident. This is very conservative since the peak hot spot after ejection will occur in or adjacent to the assembly with the ejected rod, and before ejection the power in this region will necessarily be depressed.

The hot spot analysis is performed using the detailed fuel and cladding transient heat transfer computer code FACTRAN.[11] This computer code calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod and the heat flux at the surface of the rod, using as input the nuclear power versus time and the local coolant conditions. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A conservative pellet radial power distribution is used within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation[12] to determine the film boiling coefficient after DNB. The Bishop-Sandberg-Tong correlation is conservatively used assuming zero bulk fluid quality. The DNB ratio is not calculated; instead, the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted in order to force the full-power steady-state temperature distribution to agree with the fuel heat transfer design codes.

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The more important parameters are discussed below. Table 14.2-7 presents the parameters used in this analysis.

14.2.6.7.3 Ejected Rod Worths and Hot-Channel Factors

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

Power distribution before and after ejection for a "worst case" can be found in Reference 9. During plant startup physics testing, rod worths and power distributions are measured in the zero- and full-power rodded configurations and compared to values used in the analysis. It has been found that the worth and power peaking factors are consistently over-predicted in the analysis.

14.2.6.7.4 Reactivity Feedback Weighting Factors

The largest temperature rises, and hence the largest reactivity feedbacks, occur in the channel where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple channel analysis. Physics calculations have been carried out for temperature changes with a flat temperature distribution and with a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which when applied to single-channel feedbacks correct them to effective whole core feedbacks for the appropriate flux shape. In this analysis, since a one-dimensional (axial) spatial kinetics method is employed, axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension.

14.2.6.7.5 Moderator and Doppler Coefficient

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

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

14.2.6.7.6 Delayed Neutron Fraction, β

Calculation of the effective delayed neutron fraction (β_{eff}) yielded values no less than 0.500-percent at beginning-of-life and, 0.400-percent at end-of-life [Deleted].

14.2.6.7.7 Trip Reactivity Insertion

The trip reactivity insertion assumed includes the effect of one stuck rod cluster control assembly. These values are reduced by the ejected rod reactivity. The shutdown reactivity was simulated by dropping a rod of the required worth into the core. The start of rod motion occurred 0.5 sec after the high neutron flux trip point was reached. This delay is assumed to consist of 0.2 sec for the instrument channel to produce a signal, 0.15 sec for the trip breaker to open, and 0.15 sec for the coil to release the rods. A curve of trip rod insertion versus time was used, which assumed that insertion to the dashpot does not occur until 2.4 sec after the start of fall.

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

Depressurization calculations have been performed for a typical four-loop plant assuming the maximum possible size break (2.75-in. diameter) located in the reactor pressure vessel head. The results show a rapid pressure drop and a decrease in system water mass due to the break. The safety injection system is actuated by the low pressurizer pressure trip within 1 min after the break. The reactor coolant pressure continues to drop and reaches saturation (1100 to 1300 psi depending on the system temperature) in about 2 to 3 min. Because of the large thermal inertia of the primary and secondary system, there has been no significant decrease in the reactor coolant system temperature below no-load by this time, and the depressurization itself has caused an increase in shutdown margin by about 0.2-percent Δk due to the pressure coefficient. The cooldown transient could not absorb the available shutdown margin until more than 10 min after the break. The addition of highly borated (2000-ppm) safety injection flow starting 1 min after the break is more than sufficient to ensure that the core remains subcritical during the cooldown.

As discussed previously, reactor protection for a rod ejection is provided by high neutron flux trip (high and low setting). These protection functions are part of the reactor trip system. No single failure of the reactor trip system will negate the protection functions required for the rod ejection accident, or adversely affect the consequences of the accident.

14.2.6.8 Results

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

1. Beginning-of-Life, Full Power - Control bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot-channel factor were conservatively calculated to be 0.17-percent Δk and 6.80, respectively. The maximum hot-spot clad average temperature was 2199°F. The maximum hot-spot fuel center temperature was 4958°F.

2. Beginning-of-Life, Zero Power - For this condition, control bank D was assumed to be fully inserted, and banks B and C were at their insertion limits. The worst ejected rod is located in control bank D and has a worth of 0.65-percent Δk and a hot-channel factor of 12.0. The maximum hot-spot clad average temperature reached 1881°F and the maximum fuel center temperature was 2812°F.

3. End-of-life, Full Power - Control bank D was assumed to be inserted to its insertion limit. The ejected rod worth and hot-channel factors were conservatively calculated to be 0.20-percent Δk and 7.10, respectively. This resulted in a maximum clad average temperature of 2132°F. The maximum hot-spot fuel center temperature reached 4861°F.

4. End-of-Life, Zero Power - The ejected rod worth and hot-channel factor for this case were obtained assuming control bank D to be fully inserted and banks C and B at their insertion limits. The results were 0.80-percent Δk and 20.00,

respectively. The maximum clad average and fuel center temperatures were 2549°F and 3633°F, respectively.

A summary of the results for the cases presented above is given in Table 14.2-8. The nuclear power, fuel center, fuel average and clad temperature transients for all the cases are presented in Figures 14.2-11 through 14.2-18.
The calculated sequence of events for the rod ejection accident cases, are presented in Table 14.2-9. For all cases, reactor trip occurs very early in the transient, after which the nuclear power excursion is terminated. As discussed previously, the reactor will remain subcritical following a reactor trip.

The ejection of a rod cluster control assembly constitutes a break in the reactor coolant system boundary located in the reactor pressure vessel head. The effects and consequences of loss-of-coolant accidents are discussed in Section 14.3. Following the rod cluster control assembly ejection, the operator would follow the same emergency instructions as for any other loss-of-coolant accident to recover from the event.

14.2.6.9 Fission Product Release

As a result of the accident, fuel clad damage and a small amount of fuel melt are assumed to occur. Due to the pressure differential between the primary and secondary systems, radioactive reactor coolant is discharged from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere through either the atmospheric relief valves or the main steam safety valves. Iodine and alkali metals group activity is contained in the secondary coolant prior to the accident, and some of this activity is also released to the atmosphere as a result of steaming the steam generators following the accident. Finally, radioactive reactor coolant is discharged to the containment via the spill from the opening in the reactor vessel head. A portion of this radioactivity is released through containment leakage to the environment.

As a result of the rod ejection accident, less than 10% of the fuel rods in the core undergo DNB. In determining the offsite doses following the rod ejection accident, it is conservatively assumed that 10% of the fuel rods in the core suffer sufficient damage that all of their gap activity is released. Consistent with Regulatory Guide 1.183, a gap fraction of 10% is assumed for iodine and noble gas activity. Additionally, 12% of the alkali metal activity is assumed to be in the gap. The core activity is provided in Table 14.3-43 and it is assumed that the damaged fuel rods have all been operating at the maximum radial peaking factor of 1.70.

A small fraction of the fuel in the failed fuel rods is assumed to melt as a result of the rod ejection accident. This amounts to 0.25% of the core and the melting takes place in the centerline of the affected rods. Consistent with Regulatory Guide 1.183, for the containment leakage release pathway 25% of the iodine activity and 100% of the noble gas activity are assumed to enter the containment but for the secondary system release pathway 50% of the iodine activity and 100% of the noble gas activity are assumed. Additionally, for both pathways it is assumed that 100% of the alkali metal activity from the melted fuel is available for release.

The primary coolant iodine concentration is assumed to be at the equilibrium operating limit of 1.0 μCi/gm of dose equivalent 1-131 prior to the rod ejection accident. The alkali metals and noble gas activity concentrations in the RCS at the time the accident occurs are based on operation with a fuel defect level of one percent. The iodine activity concentration of the secondary coolant at the time the rod ejection accident occurs is assumed to be 0.15 μCi/gm of dose equivalent I-131.

Regulatory Guide 1.183 specifies that the iodine released from the fuel is 95% particulate (cesium iodide), 4.85% elemental, and 0.15% organic. These fractions are used for the containment leakage release pathway. However, for the steam generator steaming pathway the iodine in solution is considered to be all elemental and after it is released to the environment the iodine is modeled as 97% elemental and 3% organic.

Conservatively, all the iodine, alkali metals group and noble gas activity (from prior to the accident and resulting from the accident) is assumed to be in the primary coolant (and not in the containment) when determining doses due to the primary to secondary steam generator tube leakage.

The primary to secondary steam generator tube leak used in-the analysis is 150 gpd per steam generator (total of 600 gpd).

When determining the doses due to containment leakage, all of the iodine, alkali metal and noble gas activity is assumed to be in the containment. The design basis containment leak rate of 0.1% per day is used for the initial 24 hours. Thereafter, the containment leak rate is assumed to be one-half the design value, or 0.05% per day. Releases are continued for 30 days from the start of the event.

No credit for iodine removal is taken for any steam released to the condenser prior to reactor trip and concurrent loss of offsite power. All noble gas activity carried over to the secondary side through steam generator tube leakage is assumed to be immediately released to the outside atmosphere. Secondary side releases are terminated when the primary pressure drops below the secondary side pressure.

An iodine partition factor in the steam generators of 0.01 curies/gm steam per curies/gm water is used. A partition factor of 0.0025 is used for the alkali metal activity in the steam generators.

For the containment leakage pathway, no credit is taken for sedimentation removal of aerosols. No credit is taken for elemental iodine deposition onto containment surfaces or for containment spray operation which would remove both airborne particulates and elemental iodine.

The resultant site boundary dose is 3.1 rem TEDE. The low population zone dose is 4.2 rem TEDE. These doses are calculated using the meteorological dispersion factors discussed in Section 14.3.6.2.1.

The offsite doses resulting from the accident are less than 25-percent of the limit values of 10 CFR 50.67 (less than 6.25 rem TEDE) which is the dose acceptance limit identified in Regulatory Guide 1.183.

The accumulated dose to control room operators following the postulated accident was calculated using the same release, removal and leakage assumptions as the offsite doses, using the control room model discussed in Section 14.3.6.5 and Tables 14.3-50 and 14.3-51. The calculated control room dose is presented in Table 14.3-52 and is less than the 5.0 rem TEDE control room dose limit values of 10 CFR 50.67.

14.2.6.10 Pressure Surge

A detailed calculation of the pressure surge for an ejection worth of one dollar at beginning-of-life, hot full power, indicates that the peak pressure does not exceed that which would cause stress to exceed the faulted condition stress limits.[9] Since the severity of the present analysis does not exceed the worst case analysis, the accident for this plant will not result in an excessive pressure rise or further damage to the reactor coolant system.

14.2.6.11 Lattice Deformations

A large temperature gradient will exist in the region of the hot spot. Since the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods may produce a differential expansion tending to bow the midpoint of the rods toward the hotter side of the rod. Calculations have indicated that this bowing would result in a negative reactivity effect at the hot spot since Westinghouse cores are undermoderated, and bowing will tend to increase the undermoderation at the hot spot. Since the 15 x 15 fuel design is also undermoderated, the same effect would be observed. In practice, no significant bowing is expected since the structural rigidity of the core is more than sufficient to withstand the forces produced. Boiling in the hot spot region would produce a net flow away from the region. However, the heat from the fuel is released to the water relatively slowly, and it is considered inconceivable that cross flow will be sufficient to produce significant lattice forces. Even if massive and rapid boiling sufficient to distort the lattice is hypothetically postulated, the large void fraction in the hot spot region would produce a reduction in the total core moderator to fuel ratio and a large reduction in this ratio at the hot spot. The net effect would therefore be a negative feedback. It can be concluded that no conceivable mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analysis.

14.2.6.12 Conclusions

Analyses indicate that the described fuel and cladding limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is not danger of further consequential damage to the reactor coolant system. The analyses have demonstrated that the fission product release, as a result of a number of fuel rods entering departure from nucleate boiling, is limited to less than 10-percent of the fuel rods in the core. The radiological consequences of this event are within applicable limits.

REFERENCES FOR SECTION 14.2

1. Deleted

2. Deleted

3. Deleted

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TABLE 14.2-1
[Deleted]

TABLE 14.2-2 (Sheet 1 of 2)
Fuel Handling Accident – Design Basis Case

Fuel Parameters		
Reactor power (including 2% uncertainty), MWt		3280.3
Number of assemblies		193
Fuel Rods per assembly		204
Normalized power, highest rated discharged assembly		1.70
Time from Reactor Shutdown to Accident, Hrs		84
Fission Product Release		
Fraction of Fuel Rod Activity in gap[(1)]		
I-131		0.12
Kr-85		0.30
Other iodines and noble gases		0.10
Decontamination factor for retention by pool water	Iodines	200
	Noble gases	1.00
Decontamination factor for Filters		Not Credited
Dispersion and Potential Exposure at Site Boundary		
Atmospheric dispersion factor (χ/Q, sec/m^3)		
Site Boundary		7.5×10^{-4}
Low Population Zone		3.5×10^{-4}

Receptor breathing rate (m^3/sec) 3.5x10^{-4}

TABLE 14.2-2 (Sheet 2 of 2)
Fuel Handling Accident – Design Basis Case

Nuclide	Shutdown Core Inventory after 84 hours, Curies [(2)]	CEDE Dose Conversion Factor, rem/Ci	EDE Dose Conversion Factor, rem-m^3/Ci-sec
I-130	3.44E+4	2.64E+3	3.848E-1
I-131	6.94E+7	3.29E+4	6.734E-2
I-132	6.39E+7	3.81E+2	4.144E-1
I-133	1.17E+7	5.85E+3	1.088E-1
I-134	0	1.31E+2	4.810E-1
I-135	2.62E+4	1.23E+3	2.953E-1
Kr-85M	0	-	2.768E-2
Kr-85	1.10E+6	-	4.403E-4
Kr-87	0	-	1.524E-1
Kr-88	0	-	3.774E-1
Xe-131M	9.85E+5	-	1.439E-3
Xe-133M	2.91E+6	-	5.069E-3
Xe-133	1.36E+8	-	5.772E-3
Xe-135M	4.20E+3	-	7.548E-2
Xe-135	7.83E+5	-	4.403E-2
Xe-138	0	-	2.135E-1

Notes:

1. The gap fractions are consistent with Regulatory Guide 1.25 except for I-131 for which the gap fraction was increased above the Regulatory Guide 1.25 value of 0.10 following the recommendations of NUREG/CR-5009. These values were selected for the analysis in place of the lower gap fraction values provided in Regulatory Guide 1.183 due to the expectation that the fuel would not meet the criteria of a peak rod average power of ≤6.3 kw/ft for some of the high burnup fuel rods.

2. Inventory of 0 means less than one Curie per fuel assembly.

TABLE 14.2-2A
[Deleted]

TABLE 14.2-3
[Deleted]

TABLE 14.2-4
[Deleted]

TABLE 14.2-5
Volume Control Tank Activity[1]

Nuclide	Volume Control Tank Inventory, Curies [1]
I-130	1.741E-2
I-131	5.916E-1
I-132	9.220E-1
I-133	1.468E+0
I-134	2.143E-1
I-135	6.884E-1
Kr-85M	1.521E+2
Kr-85	2.357E+3
Kr-87	4.640E+1
Kr-88	2.254E+2
Xe-131M	3.766E+2
Xe-133M	4.104E+2
Xe-133	2.991E+4
Xe-135M	7.292E+1
Xe-135	9.081E+2
Xe-138	6.303E+0

Notes:
1. Inventory is based on operation with one percent fuel defects. The reported activity reflects the combined vapor space and liquid space inventories.

TABLE 14.2-6

Time Sequence of Events for the Rupture of a Main Steamline		
Event	Case with Offsite Power Time (sec)	Case without Offsite Power Time (sec)
Double-Ended Steamline Rupture in Loop 1 (1.4ft^2)	0.00	0.00
High Steamline Flow Setpoint Reached (2/4 loops)	0.29	0.27
Loss of Offsite Power (RCPs begin coasting down)	--	2.99
High Steamline Flow Signal Generated (2/4 loops)	9.29	9.27
Low-Low T_{avg} Setpoint Reached in Loop 1	9.92	10.66
Low-Low T_{avg} Setpoint Reached in Loop 2	12.99	14.65
Low-Low T_{avg} Signal Generated in Loop 1	16.92	17.66
Low-Low T_{avg} Signal Generated in Loop 2	19.98*	21.64*
Safety Injection SLI and FWI Actuation due to Coincidence of Low-Low T_{avg} (2/4 loops) / High Steam Flow (2/4 loops) ESF	19.99	21.66
MSIV Closure Initiated in Loops 1, 2, 3, and 4	24.89(1)	26.56(1)*
MSIV Closure Completed in Loops 1, 2, 3, and 4	25.00	26.67
MFIV Closure Initiated in Loops 1, 2, 3, and 4	32.89(1)*	34.56(1)*
MFIV Closure Completed in Loops 1, 2, 3, and 4	33.00	34.67
Maximum Heat Flux Reached	126.49	71.99

Note:
*additional modeling delay (round off) not included
1. An additional 0.1 second allowance for valve closure time.

TABLE 14.2-7
Parameters Used in the Analysis of the Rod Cluster Control Assembly Ejection Accident

	BOL-HFP	BOL-HZP	EOL-HFP	EOL-HZP
Power level, percent	102	0	102	0
Ejected rod worth, percent Δk	0.17	0.65	0.20	0.80
Delayed neutron fraction, percent	0.50	0.50	0.40	0.40
Feedback reactivity weighting	1.46	2.16	1.50	2.96
Trip reactivity, percent Δk	4.0	2.0	4.0	2.0
F_Q after rod ejection	6.8	12.0	7.1	20.0
Number of operational pumps	4	2	4	2

Key:
- BOL Beginning of Life
- EOL End-of-Life
- HFP Hot full Power
- HZP Hot zero Power

TABLE 14.2-8
Results of the Analysis of the Rod Cluster Control Assembly Election Accident

	BOL-HFP	BOL-HZP	EOL-HFP	EOL-HZP
Maximum fuel pellet average temperature, °F	3971	2472	3860	3300
Maximum fuel center temperature, °F	4958	2812	4861	3633
Maximum clad average temperature, °F	2199	1881	2132	2549
Maximum fuel stored energy, Btu/lb	311.0	178.0	300.7	249.6
Percent fuel melt	3.46	0	3.53	0

Key: BOL Beginning-of-Life
EOL End-of-Life
HFP Hot full Power
HZP Hot zero Power

TABLE 14.2-9
Time Sequence of Events for Rod Cluster Control Assembly Ejection

RCCA Ejection	Time of Event, sec			
Event	BOL-HFP	BOL-HZP	EOL-HFP	EOL-HZP
Initiation of rod ejection	0.0	0.0	0.0	0.0
Power range neutron flux set point reached (HFP, High / HZP, Low)	0.06	0.34	0.04	0.17
Peak nuclear power occurs	0.14	0.40	0.13	0.20
Rods begin to fall into core	0.56	0.84	0.54	0.67
Peak fuel average temperature occurs	2.17	2.45	2.24	1.67
Peak clad temperature occurs	2.29	2.36	2.35	1.51
Peak heat flux occurs	2.34	2.46	2.41	1.55

14.2 FIGURES

Figure No.	Title
Figure 14.2-0	Steam Generator Tube Rupture, Break Flow and Safety Injection Flow vs. Reactor Coolant System Pressure
Figure 14.2-1	Steam Line Valve Arrangement Schematic
Figure 14.2-2 Sh. 1	Steam Line Rupture Offsite Power Available, EOL, Core Heat Flux and Core Reactivity vs. Time
Figure 14.2-2 Sh. 2	Steam Line Rupture Offsite Power Available, EOL, Reactor Coolant Pressure and RV Inlet Temperature vs. Time
Figure 14.2-2 Sh. 3	Steam Line Rupture Offsite Power Available, EOL, Steam Flow and Steam Generator Pressure vs. Time
Figure 14.2-2 Sh. 4	Steam Line Rupture Offsite Power Available, EOL, Core Boron Concentration vs. Time
Figure 14.2-3 Sh. 1	Deleted
Figure 14.2-3 Sh. 2	Deleted
Figure 14.2-3 Sh. 3	Deleted
Figure 14.2-4 Sh. 1	Deleted
Figure 14.2-4 Sh. 2	Deleted
Figure 14.2-4 Sh. 3	Deleted
Figure 14.2-5 Sh. 1	Deleted
Figure 14.2-5 Sh. 2	Deleted
Figure 14.2-5 Sh. 3	Deleted
Figure 14.2-6 Sh. 1	Deleted
Figure 14.2-6 Sh. 2	Deleted
Figure 14.2-7	Containment Pressure Time History (Double - Ended Main Steam Line Break Main FCV Failure Maximum Containment Safeguards)
Figure 14.2-8 Through 14.2-10	Deleted
Figure 14.2-11	Rod Ejection Accident, BOL-HFP, Nuclear Power vs. Time
Figure 14.2-12	Rod Ejection Accident, BOL-HFP, Fuel Temperatures vs. Time
Figure 14.2-13	Rod Ejection Accident, BOL-HZP, Nuclear Power vs. Time
Figure 14.2-14	Rod Ejection Accident, BOL-HZP, Fuel Temperatures vs. Time
Figure 14.2-15	Rod Ejection Accident, EOL-HZP, Nuclear Power vs. Time
Figure 14.2-16	Rod Ejection Accident, EOL-HZP, Fuel Temperatures vs. Time
Figure 14.2-17	Rod Ejection Accident, EOL-HFP, Nuclear Power vs. Time
Figure 14.2-18	Rod Ejection Accident, EOL-HFP, Fuel Temperatures vs. Time
Figure 14.2-19 Thru Figure 14.2-22	Deleted

14.3 LOSS-OF-COOLANT ACCIDENTS

14.3.1 Identification of Causes And Frequency Classification

A loss-of-coolant accident (LOCA) is the result of a pipe rupture of the reactor coolant system pressure boundary. A major pipe break (large break) is defined as a rupture with a total cross-sectional area equal to or greater than 1.0-ft^2. This event is considered a limiting fault, an ANS Condition IV event, in that it is not expected to occur during the lifetime of the plant, but is postulated as a conservative design basis.

A minor pipe break (small break) is defined as a rupture of the reactor coolant pressure boundary with a total cross-sectional area less than 1.0-ft^2 in which the normally operating charging system flow is not sufficient to sustain pressurizer level and pressure. This is considered an ANS Condition III event in that it is an infrequent fault that may occur during the life of the plant.

The acceptance criteria for the loss-of-coolant accident are described in 10 CFR 50 Paragraph 46 (Reference 1), as follows:

1. The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. After any 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.

These criteria were established to provide significant margin in emergency core cooling system performance following a LOCA. Reference 2 presents a study in regard to the probability of occurrence of RCS system pipe ruptures.

14.3.2 Sequence Of Events And Systems Operations

Should a major break occur, the depressurization of the reactor coolant system results in a pressure decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low-pressure trip setpoint is reached. A safety injection actuation signal is generated when the appropriate setpoint is reached. These countermeasures limit the consequences of the accident in the following two ways:

1. Reactor trip and borated water injection complement void formation in causing a rapid reduction of power to a residual level corresponding to fission product decay heat.
2. The injection of borated water provides for heat transfer from the core, prevents excessive clad temperatures, and maintains subcriticality.

14.3.2.1 Description of Large-Break LOCA Transient

The RCS is assumed to be operating normally at full power. A break is assumed to open nearly instantaneously in one of the main coolant pipes. Calculations where the location and size of the break have been varied indicate that a break in the cold leg between the reactor coolant pump and the reactor vessel leads to the most severe transient. For this break location, a rapid depressurization occurs, along with a core flow reversal as subcooled liquid flows out of the vessel into the broken cold leg. Boiling begins in the core, and the reactor core begins to shut down. With in approximately 2 seconds, the core is highly voided, and core fission is terminated. The cladding temperature rises rapidly as heat transfer to the fuel rods is reduced.

Within approximately 6 seconds, the pressure in the pressurizer has fallen to the point where the protection systems initiate safety injection. Along with the safety injection, containment isolation is also initiated.

In the first few seconds, the coolant in all regions of the vessels begins to flash. In addition, the break flow becomes saturated and is substantially reduced. This reduces the depressurization rate, and may also lead to a period of positive core flow as the RCS pumps in the intact loops continue to supply water to the vessel, and as flashing continues in the vessel lower plenum and downcomer. Cladding temperatures may be reduced, and some portions of the core may rewet during this period.

This positive core flow period ends as two-phase conditions occur in the pumps, reducing their effectiveness. Once again, the core flow reverses as most of the vessel mass flows out through the broken cold leg. Core cooling occurs as a result of the reverse flow.

At approximately 10 seconds after the break, the pressure falls to the point where the accumulators begin injecting cold water into the cold legs. Because the break flow is still high, much of the injected ECCS water, which flows from the cold legs into the downcomer of the vessel, is assumed to be carried out to the break.

Approximately 28 seconds after the break, most of the original RCS inventory has been ejected or boiled off. The system pressure and break flow are reduced and the ECCS water from the accumulator, which has been filling the downcomer, begins to fill the lower plenum of the vessel.

During this time, core heat transfer is relatively poor and cladding temperatures increase.

Approximately 40 seconds after the break, the lower plenum has re-filled. ECCS water from the refueling water storage tank (RWST) begins to flow into the vessel and enters the core. The flow into the core is oscillatory, as cold water rewets hot fuel cladding, generating steam. This steam and entrained water must pass through the vessel upper plenum, the hot legs, the steam generator, and the pump before it can be vented out the break. The resistance of this flow path to the steam flow is balanced by the driving force of water filling the downcomer. Shortly after reflood begins, the accumulators exhaust their inventory of water, and begin to inject the nitrogen gas, which was used to pressurize the accumulators. This results in a short period of improved heat transfer as the nitrogen forces water from the downcomer into the core. When the accumulators have exhausted their supply of nitrogen the reflood rate may be reduced and peak cladding temperatures may again rise. This heatup may continue until the core has reflooded to several feet. Approximately 3 minutes after the break, all locations in the core begin to cool. The core is completely quenched within 5 minutes, and long term cooling and decay heat removal begin. Long term cooling for the next several minutes is characterized by continued boiling in the vessel as decay power and heat stored in the reactor structures is removed.

Continued operation of the emergency core cooling system pumps supplies water during long-term cooling. Core temperatures would be reduced to long-term steady-state levels associated with the dissipation of residual heat generation. After the water level of the refueling water storage tank reaches a minimum allowable value, coolant for long-term cooling of the core is obtained by switching to the cold-leg recirculation mode of operation in which spilled borated water is drawn from the recirculation sump [Deleted] by the recirculation pumps and returned to the reactor coolant system cold legs. The containment spray pumps continue to operate drawing water from the refueling water storage tank for further reduction of containment pressure. Approximately 6.5 hours after initiation of the LOCA, the emergency core cooling system is realigned to supply water to the reactor coolant system hot legs in order to control the boric acid concentration in the reactor vessel.

The sequence of events for the large break LOCA is summarized in Table 14.3-1.

14.3.2.2 <u>Description of Small-Break LOCA Transient</u>

As contrasted with the large break, the blowdown phase of the small break occurs over a longer time period. Thus, for the small break LOCA there are only three characteristic stages, i.e., a gradual blowdown in which the water level decreases, core recovery, and long-term recirculation.

For small break LOCAs, the most limiting single active failure is the one that results in the minimum ECCS flow delivered to the RCS. This has been determined to be the loss of an emergency power train, which results in the loss of one complete train of ECCS components. This means that credit can be taken for two out of three high head safety injection pumps, and one RHR (low head) pump. During the small break transient, two high head pumps are assumed to start and deliver flow into all four loops. The flow to the broken loop was conservatively assumed to spill to RCS in accordance with Reference 93 for a four-loop plant.

For the limiting break location analyzed (cold leg), the depressurization of the RCS causes fluid to flow into the loops from the pressurizer resulting in a pressure and level decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low-pressure trip setpoint is reached. Loss-Of-Offsite-Power (LOOP) is assumed to occur coincident with reactor trip. A safety injection signal is generated when the appropriate setpoint (pressurizer low pressure SI) is reached. After the safety injection signal is generated, an additional delay ensues. This delay accounts for the instrumentation delay, the diesel generator start time, plus the time necessary to align the appropriate valves and bring the pumps up to full speed. The safety features described will limit the consequences of the accident in two ways:

1) Reactor trip and borated water injection supplement void formation in causing rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay. No credit is taken in the small break LOCA

analysis for the boron content of the injection water. In addition, in the small break LOCA analysis, credit is taken for the insertion of Rod Cluster Control Assemblies (RCCAs) subsequent to the reactor trip signal, while assuming the RCCA at the most reactive location is stuck in the full out position, and

2) Injection of (borated) water ensures sufficient flooding of the core to prevent excessive clad temperatures.

Before the break occurs, the plant is assumed to be in normal plant operation at 102% of hot full power, i.e., the heat generated in the core is being removed via the secondary system. During the earlier phase of the small break transient, the effect of the break flow is not strong enough to overcome the flow maintained by the reactor coolant pumps through the core as the pumps coast down following LOOP. Upward flow through the core is maintained. However, depending on the break size, the core flow is not sufficient to prevent a partial core uncovery. Subsequently, the ECCS provides sufficient core flow to cover the core, adequately removing decay heat.

During blowdown, heat from fission product decay, hot internals, and the vessel continues to be transferred to the RCS. The heat transfer between the RCS and the secondary system may be in either direction depending on the relative temperatures. In the case of heat transfer from the RCS to the secondary, heat addition to the secondary results in increased secondary system pressure which leads to steam relief via the safety valves. Makeup to the secondary is automatically provided by the auxiliary feedwater pumps. The safety injection signal isolates normal feedwater flow by closing the main feedwater control and bypass valves. Auxiliary feedwater flow is initiated by the reactor trip signal with coincident LOOP. In the Small Break LOCA analysis, flow from a single motor driven auxiliary feedwater pump is assumed to begin 60 seconds after the generation of a reactor trip signal coincident with LOOP. The secondary flow aids in the reduction of RCS pressure. Also, due to the loss of offsite power assumption, the reactor coolant pumps are assumed to be tripped at the time of reactor trip during the accident and the effects of pump coastdown are included in the blowdown analysis.

The cold leg accumulators will inject borated water into the reactor coolant loops if the RCS depressurizes to the nitrogen cover gas pressure.

14.3.3 Core And System Performance

14.3.3.1 Mathematical Model

The requirements of an acceptable ECCS evaluation model are presented in 10 CFR 50.46 (Reference 1).

14.3.3.1.1 Large Break LOCA Evaluation Model

The evaluation model used to comply with the requirements of 10 CFR50.46 (Reference 1), Revisions to the Acceptance Criteria (Reference 3), and USNRC Regulatory Guide 1.157 (Reference 74), is described in this section. The analytical techniques used for the large break LOCA analysis are in compliance with 10 CFR 50.46 (Reference 1) as amended in Reference 3, and are described in References 69 and 75.

In 1988, the NRC staff amended the requirements of 10 CFR 50.46 and Appendix K, "ECCS Evaluation Models" to permit the use of a realistic evaluation model to analyze the performance of the ECCS during a hypothetical LOCA. This decision was based on an improved understanding of LOCA thermal-hydraulic phenomena gained by extensive research programs. Under the amended rules, best estimate thermal-hydraulic models may be used in place of models with Appendix K features. The rule change also requires, as part of the LOCA analysis, an assessment of the uncertainty of the best estimate calculations. It further requires that this analysis uncertainty be included when comparing the results of the calculations to the prescribed acceptance criteria of 10 CFR 50.46. Further guidance for the use of best estimate codes is provided in Regulatory Guide 1.157 (Reference 74).

To demonstrate use of the revised ECCS rule, the NRC and its consultants developed a method called the Code Scaling, Applicability, and Uncertainty (CSAU) evaluation methodology (Reference 77). This method outlined an approach for defining and qualifying a best estimate thermal-hydraulic code and quantifying the uncertainties in a LOCA analysis.

A Westinghouse LOCA evaluation methodology for three- and four-loop Pressurized Water Reactor (PWR) plants based on the revised 10 CFR 50.46 rules was developed with the support of EPRI and Consolidated Edison. The methodology is documented in WCAP-12945-P-A, “Code Qualification Document (CQD) for Best-Estimate LOCA Analysis” (Reference 75). [Deleted]

More recently, Westinghouse developed an alternate methodology called ASTRUM (Reference 69). This method is still based on the CQD methodology and follows the steps in the CSAU methodology. However, the uncertainly analysis (Element 3 in the CSAU) is replaced by a technique based on order statistics. The ASTRUM methodology replaces the responses surface technique with a statistical sampling method where the uncertainty parameters are simultaneously sampled for each case.

The three 10 CFR 50.46 criteria (peak clad temperature, maximum local oxidation and core-wide oxidation) are satisfied by running a sufficient number of WCOBRA/TRAC calculations (sample size). In particular, the statistical theory predicts that 124 calculations are required to simultaneously bound the 95 percentile of three parameters with a 95-percent confidence level.

The thermal-hydraulic computer code, which was reviewed and approved for the calculation of fluid and thermal conditions in the PWR during a large break LOCA is WCOBRA/TRAC Version MOD7A, Revision 6 (Reference 69).

WCOBRA/TRAC combines two-fluid, three-field, multi-dimensional fluid equations used in the vessel with one-dimensional drift-flux equations used in the loops to allow a complete and detailed simulation of a PWR.

The two-fluid formulation uses a separate set of conservation equations and constitutive relations for each phase. The effects of one phase on another are accounted for by interfacial friction and heat and mass transfer interaction terms in the equations. The conservation equations have the same form for each phase; only the constitutive relations and physical properties differ. Dividing the liquid phase into two fields is a convenient and physically accurate way of handling flows where the liquid can appear in both film and droplet form. The droplet field permits more accurate modeling of thermal-hydraulic phenomena such as entrainment, de-entrainment, fallback, liquid pooling, and flooding.

WCOBRA/TRAC also features a two-phase, one-dimensional hydrodynamics formulation. In this model, the effect of phase slip is modeled indirectly via a constitutive relationship, which provides the phase relative velocity as a function of fluid conditions. Separate mass and energy conservation equations exist for the two-phase mixture and for the vapor.

The reactor vessel is modeled with the three-dimensional, three-field model, while the loop, major loop components, and safety injection points are modeled with the one-dimensional model.

All geometries modeled using the three-dimensional model are represented as a matrix of cells. The number of mesh cells used depends on the degree of detail required to resolve the flow field, the phenomena being modeled, and practical restrictions such as computing costs and core storage limitations.

The basic building block for the mesh is the channel, a vertical stack of single mesh cells. Several channels can be connected together by gaps to model a region of the reactor vessel. Regions that occupy the same level form a section of the vessel. Vessel sections are connected axially to complete the vessel mesh by specifying channel connections between sections. Heat transfer surfaces and solid structures that interact significantly with the fluid can be modeled with rods and unheated conductors.

The noding diagram for Indian Point Unit 2 is shown in Figures 14.3-1 and 14.3-2. The vessel channel layout is shown in Figure 14.3-1. Figure 14.3-2 shows the one-dimensional component layout for the loops. Within the channels and components, additional subdivisions into cells are present, as described in Reference 75.

A typical calculation using WCOBRA/TRAC begins with the establishment of a steady-state, initial condition with all loops intact. The input parameters and initial conditions for this steady-state calculation are discussed in the next section.

Following the establishment of an acceptable steady-state condition, the transient calculation is initiated by introducing a break into one of the loops. The evolution of the transient through blowdown refill, and reflood follows continuously, using the same computer code.

WCAP-16009-P-A (Reference 69) provides ASTRUM methodology and also includes a description of the code models and their implementation. Volumes II and III of the CQD (Reference 75) presented a detailed assessment of the computer code WCOBRA/TRAC through comparisons to experimental data. From this assessment, a quantitative estimate was obtained of the code's ability to predict peak clad temperatures (PCTs) in a PWR large-break loss-of-coolant accident (LOCA). Modeling of a PWR introduced additional uncertainties, which were identified and discussed in Section 21 of the CQD Volume IV (Reference 75). A list of key LOCA parameters was compiled as a result of these studies. Models of several PWRs were used to perform sensitivity studies and establish the relative important uncertainties of the LOCA oxidation (CWO) at 95-percent probability, is described in the following sections. The methodology is summarized below:

Plant Model Development

In this step, a WCOBRA/TRAC model of the plant is developed. A high level of noding detail is used to insure an accurate simulation of the transient. Specific guidelines are followed to assure that the model is consistent with models used in the code validation. This results in a high level of consistency among plant models, with some plant-specific modeling dictated by hardware differences such as in the upper plenum of the reactor vessel or the Emergency Core cooling System (ECCS) injection configuration.

Determination of Plant Operating Conditions

In this step, the expected or desired operating range of the plant to which the analysis is to be applied is established using information supplied by the utility. The parameters considered are based on a "key LOCA parameters" list that was developed as part of the methodology. A set of these parameters, at mostly nominal values, is chosen as initial conditions to the plant model. A transient is run utilizing these parameters and is known as the “initial transient." Next, several confirmatory runs are made, which vary a subset of the key LOCA parameters over their expected operating range. Because certain parameters are not included in the uncertainty analysis, these parameters are set at their bounding condition. This analysis is commonly referred to as the confirmatory analysis. Section 1.2.11 of Reference 79 describes the parameters of interest for the confirmatory analysis. The most limiting input conditions, based on these confirmatory runs, are then combined into the model that will represent the limiting state for the plant, which is the starting point for the assessment of uncertainty.

Assessment of Uncertainty

The ASTRUM methodology is based on order statistics. The technical basis of the order statistics is described in Section 11 of WCAP-16009-P-A (Reference 69). The determination of the PCT uncertainty, LMO uncertainty, and CWO uncertainty relies on a statistical sampling technique. According to the statistical theory, 124 WCOBRA/TRAC calculations are necessary to assess against the three 10 CFR 50.46 criteria (PCT, LMP, and CWO).

The uncertainty contributors are sampled randomly from their respective distribution for each of the WCOBRA/TRAC calculations. The list of uncertainty parameters, which are randomly sampled for each WCOBRA/TRAC calculation, include initial conditions, power distributions, and model uncertainties. The time in the cycle, break type (split or double-ended guillotine), and break size for the split break are also sampled as uncertainty conditions within the ASTRM methodology.

Results from the 124 calculations are tallied by ranking the PCT from highest to lowest. A similar procedure is repeated for LMO and CWO. The highest rank of PCT, LMO, and CWO will bound 95 percent of their respective populations with 95-percent confidence level.

Plant Operating Range

The plant operating range over which the uncertainty evaluation applies is shown in Table 14.3-5A. If operation in maintained within these ranges, the large break LOCA analysis developed in Reference 79 using the WCOBRA/TRAC is valid.

14.3.3.1.2 Small Break LOCA Evaluation Model

For loss-of-coolant accidents due to small breaks less than 1 ft^2, the NOTRUMP (References 15, 16 and 93) computer code is used to calculate the transient depressurization of the RCS as well as to describe the mass and enthalpy of flow through the break.

Clad thermal analyses are performed with the LOCTA-IV code (Reference 7), which uses the RCS pressure, fuel rod power history, steam flow past the uncovered part of the core, and mixture height history from NOTRUMP hydraulic calculations as input. The LOCTA-IV code version used for the clad thermal analysis of the small break LOCA includes the clad swelling and rupture model of NUREG-0630.

For these analyses, the safety injection delivery considers pumped injection flow, which is depicted in Figure 14.3-3 as a function of RCS pressure. This figure represents injection flow from the high head safety injection pumps based on performance curves degraded 7 percent from the design head. A 25 second delay was assumed from the time that the SI signal is generated to the time that the pumps are at full speed and capable of injecting water into the system. The effect of the low head safety injection pumps (Residual Heat Removal pump) flow is not considered since their shutoff head is lower than the Reactor Coolant System pressure during the time period of the transient. Also, minimum Emergency Core Cooling System capability has been assumed in these analyses. The small break LOCA analysis also assumes that the rod drop time is 2.7 seconds.

Figure 14.3-53 presents the hot rod power shape utilized as input to perform the small break analysis presented here. This power shape was chosen because it represents a distribution with power concentrated in the upper regions of the reactor core. Such a distribution is limiting for SBLOCA since it minimizes coolant swell while maximizing vapor superheating and fuel rod heat generation at the uncovered elevations.

The small break analysis was performed with the Westinghouse ECCS small break Evaluation Model using the NOTRUMP code, approved for this use by the Nuclear Regulatory Commission in May 1985 (Reference 16) and in August 1996 (Reference 93).

14.3.3.2 Input Parameters and Initial Conditions

14.3.3.2.1 Large-Break Input Parameters and Initial Conditions

Table 14.3-3 and the following summarize key plant and model parameters whose range and uncertainty are considered in the large break LOCA analysis. The assumed initial condition for the initial and reference case calculations in Reference 79 is also given.

1.0 Plant Physical Description

1.0a **Dimensions:** Nominal geometry is assumed. Nominal geometry input is accounted for in the code uncertainty, since experiments were also subject to thermal expansion and dimensional uncertainty effects.

1.0b **Flow Resistance:** Best estimate values of loop flow resistance are assumed. Variations in this parameter are accounted for in the uncertainty analysis.

1.0c **Pressurizer Location:** On an intact loop, which was confirmed to be the limiting location or to have a small effect on the results.

1.0d **Hot Assembly Location:** The location assumed for the hot assembly is that which reduces the direct flow of water from the upper head or upper plenum. This location is described in Section 3.2.1 of Reference 79.

1.0e **Hot Assembly Type:** The hot assembly is a fresh 15 x 15 upgraded fuel reload assembly with ZIRLO^{TM} cladding. Variations in cycle burnup are accounted for in the uncertainty analysis.

1.0f **Steam Generator Tube Plugging Level:** The maximum value of SGTP level is used for the initial transient. The limiting value over the expected range is discussed in Section 4.3.1 of Reference 79.

2.0 Plant Initial Operating Conditions

2.1 Reactor Power

2.1a **Initial Core Average Linear Heat Rate:** Maximum power without measurement uncertainties is assumed. Uncertainties are accounted for as part of the uncertainty analysis.

2.1b **Hot Rod Peak Linear Heat Rate:** The hot rod peak linear heat rate is assumed to be the maximum expected value, without uncertainties, between the desired Tech Spec limit and the maximum value for steady-state depletion. The value of F_Q assumed in the initial transient is therefore substantially higher than the value likely to be measured during normal scheduled surveillance. Variations in this parameter are accounted for as part of the uncertainty analysis.

2.1c **Hot Rod Average Linear Heat Rate:** The hot rod average linear heat rate is derived from Tech Spec value. The value of $F_{\overline{\Delta H}}$ assumed in the reference transient is therefore substantially higher than the value likely to be measured during most of the fuel cycle. Variations in this parameter are accounted for as part of the uncertainty analysis.

2.1d **Hot Assembly Average Linear Heat Rate:** The power generated in the hot assembly rod is 4 percent lower than that generated in the hot rod. Variations in this parameter are accounted for as part of the uncertainty analysis.

2.1e **Hot Assembly Peak Linear Heat Rate:** Consistent with the average linear heat rates, the peaking factor used to calculate the peak nuclear energy generated in the hot assembly average rod is 4 percent lower than the value assumed in the hot rod. Variations in this parameter are accounted for as part of the uncertainty analysis.

2.1f **Axial Power Distribution:** A shape with a top skewed power distribution (Figure 14.3-20) within the expected range is assumed. Variations in axial power distribution due to transient operation are accounted for as part of the uncertainty analysis.

2.1g **Low Power Region (PLOW):** A relative power of 30 percent of the core average is assumed for the low power region. The limiting value over the expected operating range for this parameter is discussed in Section 4.3.3 of Reference 79.

2.1h **Hot Assembly Burnup:** Beginning of Life (BOL) conditions in the hot assembly are assumed in the initial transient. The time in cycle is a sampled attribute in the ASTRUM methodology.

2.1i **Prior Operating History:** The reactor is assumed to have been operating at full power. When a given axial power distribution is considered, it is assumed to have existed since this startup time. This means that the distribution of fission products coincides with the steady-state fission rate distribution. This assumption conservatively places both the initial fission rate and stored energy, and the subsequent decay heat production, at the same axial location.

2.1j **Moderator Temperature Coefficient:** The value greater than or equal to the maximum specified in Technical Specifications is assumed, to conservatively estimate core reactivity and fission power.

2.1k **Hot Full Power (HFP) Boron Concentration:** A low value typical of those used in current cores at BOL conditions is assumed.

2.2 Fluid Conditions

2.2a **Average Fluid Temperature (T_{avg}):** T_{avg} is assumed at the maximum expected value during normal full power operation. Minimum T_{avg} is analyzed as part of the confirmatory calculations in Section 4.3.2 of Reference 79. Variations in the uncertainty of this parameter are included in the uncertainty analysis.

2.2b **Pressurizer Pressure:** The nominal operating value of pressurizer pressure is assumed. Uncertainties associated to this parameter are accounted for in the uncertainty analysis.

2.2c **Loop Flowrate:** The thermal design loop flowrate is assumed.

2.2d **Upper Head Temperature (T_{UH}):** The appropriate best estimate value of T_{UH} is assumed. Since variation in this parameter is small, uncertainties are not included.

2.2e **Pressurizer Level:** The nominal value of pressurizer level is assumed. Because the pressurizer level is automatically controlled and the effect on PCT is small, uncertainties are not included.

2.2f **Accumulator Water Temperature:** A nominal value is assumed, with variations treated as part of the initial condition uncertainty.

2.2g **Accumulator Pressure:** A nominal value is assumed with variations treated as part of the uncertainty analysis.

2.2h **Accumulator Water Volume:** A nominal value is assumed with variations treated as part of the uncertainty analysis.

2.2i **Accumulator Line Resistance:** A best estimate value of accumulator line resistance is assumed. Uncertainties in line resistance are included in the initial condition uncertainty.

2.2j **Accumulator Boron Concentration:** The minimum value is assumed.

3.0 Accident Boundary Conditions

3.0a **Break Location:** A break near the mid-point in the cold leg is assumed. Scoping studies reported in the CQD (Reference 75) show that the cold leg remains the limiting location for large LOCA.

3.0b **Break Type:** A Double Ended Guillotine Cold Leg (DEGGL) break is assumed in the initial and reference transient. The effect of variations in break type is accounted for in the uncertainty analysis.

3.0c **Break Size:** A nominal cold leg area is assumed. The effect of variations in the break area is accounted for in the uncertainty analysis.

3.0d **Offsite Power:** No loss of offsite power is assumed. A calculation assuming loss of offsite power is performed as part of the confirmatory analysis in Section 4.3.4 of Reference 79 to confirm the limiting condition.

3.0e **Safety Injection (SI) Flow:** Minimum SI flow is assumed (see Section 3.2.3 of Reference 79, Emergency Core Cooling and Safety Injection Model). Scoping studies reported in the CQD (Reference 75) indicate that increased SI flow reduces PCT. This parameter is therefore bounded. The primary reason for this choice is that using best estimate values for this important parameter, while producing more realistic results, may also require additional testing and surveillance to verify the assumed flow uncertainty.

3.0f **Safety Injection (SI) Temperature:** Nominal values are assumed. Variations are accounted for in the uncertainty analysis.

3.0g **Safety Injection (SI) Delay:** Maximum values consistent with the offsite power assumption are used for the initial transient (offsite power available) and the confirmatory runs (loss of offsite power).

3.0h **Containment Pressure:** The containment pressure curve shown in Figure 14.3-22 is calculated using the approved containment model (References 6 and 8), the raw data in Table 14.3-2 and the Mass and Energy releases in Table 14.3-2A. Note that a conservative (lower) containment pressure curve than the containment pressure curve shown in Figure 13.2-22 is used for the WCOBRA/TRAC initial and confirmatory calculations in Section 4 and the ASTRUM calculations in Section 5 of Reference 79.

3.0i **Single Failure Assumption:** The worst single failure is assumed to be the loss of a full train of SI, consistent with the recommended scenario outlined in the CQD (Reference 75) and the RMR (Reference 76).

3.0j **Rod Drop Time:** Consistent with the current design basis for this plant control rods are assumed not to insert during the LBLOCA.

4.0 Model parameters

All model parameters are used at their best estimate or as coded values in the initial transient.

Table 14.3-3 summarizes the initial transient assumptions described above. For those parameters where a best estimate or nominal value was used, the corresponding uncertainty treatment is also given.

14.3.3.2.2 Small-Break Input Parameters and Initial Conditions

Table 14.3-11 lists important input parameters and initial conditions used in the Indian Point Unit 2 small break LOCA analysis.

The small break LOCA analysis was performed with the upper head fluid temperature equal to the Reactor Coolant System hot leg fluid temperature. In addition, this analysis has included the effects of a 10% uniform steam generator tube plugging.

The bases used to select the numerical values that are input parameters to the analysis have been conservatively determined from extensive sensitivity studies (References 17-18). In addition, the requirements of 10 CFR 50 Appendix K regarding specific model features were met by selecting models which provide a significant overall conservatism in the analysis. The assumptions made pertain to the conditions of the reactor and associated safety system equipment at the time the LOCA occurs and include such items as the core peaking factors and the performance of the ECCS. Decay heat generated throughout the transient is also conservatively calculated.

14.3.3.3 <u>Large Break Results</u>

14.3.3.3.1 Large Break LOCA Reference Transient Description

The LOCA transient can be conveniently divided into a number of time periods in which specific phenomena are occurring. For a typical large break, the blowdown period can be divided into the critical heat flux (CHF) phase, the upward core flow phase, and the downward core flow phase. These are followed by the refill, reflooding and long term cooling phases. The important phenomena occurring during each of these phases are discussed for the reference transient. The results are shown in Figures 14.3-6 and 14.3-19.

I. Critical Heat Flux (CHF) Phase (0 to ~ 2 seconds)

Immediately following the cold leg rupture, the break discharge rate is subcooled and high, the core flow reverses, the fuel rods go through departure from nucleate boiling (DNB) and the cladding rapidly heats up while core power shuts down. Figure 14.3-6 shows the maximum cladding temperature in the core, as a function of time. The hot water in the core and the upper plenum begins to flash to steam during this period. The phase is terminated when the water in the lower plenum and downcomer begins to flash. The mixture swells and the intact loop pumps, still rotating in single-phase liquid, push this two-phase mixture into the core.

II. Upward Core Flow Phase (~2 to 12 seconds)

Heat transfer is improved as the two-phase mixture is pushed into the core. This phase may be enhanced if the pumps are not degraded, and the break discharge rate is reduced because the fluid is saturated at the break. Figures 14.3-7 and 14.3-8 show the break flowrate for the vessel side and pump side, respectively, for the reference transient. This phase ends as lower plenum mass is depleted, the loops become two-phase, and the pump head degrades. If pumps are highly degraded or the break flow is large, the cooling effect due to upward flow may not be significant. Figures 14.3-9 shows the void fraction for one intact loop pump and the broken loop pump. The intact loop pump remains in single-phase liquid flow for several seconds, while the broken loop pump is in two-phase and steam flow soon after the break.

III. Downward Core Flow Phase (~12 to 28 seconds)

The loop flow is pushed into the vessel by the intact loop pumps and decreases as the pumps become two-phase. The break flow begins to dominate and pulls flow down through the core. Figures 14.3-10 and 14.3-11 show the vapor flow at the mid-core of channels 17 and 19, respectively. While liquid and entrained liquid flows also provide core cooling, the vapor flow entering the core best illustrates this phase of core cooling. This period is enhanced by flow from the upper head. As the system pressure continues to fall, the break flow and consequently the core flow, are reduced. The core begins to heat up as the system reaches containment pressure and the vessel begins to fill with Emergency Core Cooling System (ECCS) water.

IV. Refill Phase (~28 to 36 seconds)

The core continues experiences a nearly adiabatic heatup as the lower plenum fills with ECCS water. Figure 14.3-12 shows the lower plenum liquid level. This phase ends when the ECCS water enters the core and entrainment begins, with a resulting improvement in heat transfer. Figures 14.3-13 and 14.3-14 show the liquid flows from the accumulator and the safety injection, respectively, from an intact loop (Loop2).

V. Early Reflood Phase (~36 to end)

The accumulators begin to empty and nitrogen enters the system (Figure 14.3-13). This forces water into the core which then boils as the lower core region begins to quench, causing repressurization. The repressurization is best illustrated by the increase in downcomer liquid level (Figure 14.3-16). During this time, core cooling may be increased.

The system then settles into a gravity driven reflood. Figures 14.3-15 and 14.3-16 show the core and downcomer liquid levels, respectively. Figure 14.3-17 shows the vessel fluid mass. As the quench front progresses further into the core, the peak cladding temperature (PCT) location moves higher in the top core region. Figure

14.3-18 shows the movement of the PCT location. As the vessel continues to fill, the PCT location is cooled and the PCT heatup is terminated on all fuel rods (Figures 14.3-18 and 14.3-19).

VI. Long Term Core Cooling

At the end of the WCOBRA/TRAC calculation, the core and the downcomer levels are increasing as the pumped safety injection flow exceeds the break flow. The core and downcomer levels would be expected to continue to rise, until the downcomer mixture level approaches the loop elevation. At that point, the break flow would increase, until it roughly matches the injection flowrate. The core would continue to be cooled until the entire core is eventually quenched as shown in Figure 14.3-19.

The reference transient resulted in a blowdown PCT of 1506^{o}F and a limiting reflood PCT of 1747^{o}F.

14.3.3.3.2 Confirmatory Sensitivity Studies

A number of sensitivity calculations were carried out to investigate the effect of the key LOCA parameters, and to determine the reference transient. In the sensitivity studies performed, LOCA parameters were varied one at a time. For each sensitivity study, a comparison between the base case and the sensitivity case transient results was made.

The results of the sensitivity studies are summarized in Table 4.3-1 of Reference 79. A full report of the results for all confirmatory sensitivity study results is included in Section 4.3 of Reference 79. The results of these analyses lead to the following conclusions:

1. Modeling maximum steam generator tube plugging (10%) results in a higher PCT than minimum steam generator tube plugging (0%).

2. Modeling loss-of-offsite-power (LOOP) results in a higher PCT than no loss-of-offsite-power (no-LOOP).

3. Modeling the maximum value of vessel average temperature (T_{avg} = 572^{o}F) results in a higher PCT than minimum value of vessel average temperature (T_{avg} = 549^{o}F).

4. Modeling the maximum power fraction (P_{LOW} = 0.8) in the low power / periphery channel of the core results in a higher PCT than minimum power fraction (P_{LOW} = 0.3).

14.3.3.3.3 Uncertainty Evaluation and Results

The ASTRUM methodology requires the execution of 124 transients to determine a bounding estimate of the 95th percentile of the Peak Clad Temperature (PCT), Local Maximum Oxidation (LMO), and Core Wide Oxidation (CWO) with 95% confidence level. The results for the Indian Point 2 Nuclear Power Plant are given in Table 14.3-4, which shows the limiting peak clad temperature of 1962^{o}F, the limiting local maximum oxidation of 2.39% and the limiting corewide oxidation of 0.35%. The sequence of events for the large break LOCA limiting PCT transient is summarized in Table 14.3-1.

14.3.3.3.4 Evaluation

The base analysis discussed in Sections 14.3.3.3.1 to 14.3.3.3.3 was performed assuming a full core of upgraded fuel. For Indian Point 2 Nuclear Power Plant large break LOCA analysis, additional calculations were performed to assess the effect of [Deleted] missing fuel assembly alignment pins [Deleted].

[Deleted]

Missing Fuel Assembly Alignment Pins Evaluation

Operation of the Indian Point Unit 2 with missing fuel assembly alignment pins at peripheral core location A8 has been evaluated. Detailed assessment results in a conservative 5 ^{o}F PCT penalty.

[Deleted]

14.3.3.3.5 Plant Operation Range

The expected PCT and its uncertainty developed above is valid for a range of plant operation conditions. [Deleted] The range of variation of the operating parameters has been accounted for in the uncertainty evaluation. Table 14.3-5-A summarizes the operating ranges for Indian Point Unit 2. If operation is maintained within these ranges, the LOCA analyses developed in this section using WCOBRA/TRAC are valid.

14.3.3.3.6 Large Break LOCA Conclusions

It must be demonstrated that there is a high level of probability that the limits set forth in 10 CFR 50.46 are met. The demonstration that these limits are met for the Indian Point 2 Nuclear Power Plant is as follows:

1. There is a high level of probability that the peak cladding temperature (PCT) shall not exceed 2200 ^{o}F. The results presented in Table 14.3-4 indicate that this regulatory limit has been met with a calculated limiting PCT of 1962^{o}F, which is a bounding estimate of the 95th percentile PCT at the 95-percent confidence level. The PCT including Assessments is reported annually to the NRC as per the requirements of 10 CFR 50.46.

2. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount (or 1 percent) that would be generated if all of the metal in the cladding cylinders surrounding the fuel were to react. The results presented in Table 14.3-4 indicate that this regulatory limit has been met with a calculated maximum core-wide oxidation of 0.35 percent.

3. The calculated maximum local oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation. The results presented in Table 14.3-4 indicate that this regulatory limit has been met with a calculated maximum local oxidation of 2.39 percent.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling. This requirement is met by demonstrating that the PCT does not exceed 2200 °F, the maximum local oxidation does not exceed 17%, and the seismic and LOCA forces are not sufficient to distort the fuel assemblies to the extent that the core cannot be cooled. The approved methodology (Reference 75) specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless grid crushing extends beyond the assemblies in the lower power channel as defined in the WCOBRA/TRAC model. This situation has not been previously calculated to occur for the Indian Point Unit 2 Nuclear Power Plant. Therefore, this regulatory limit is met.

5. 10 CFR 50.46 acceptance criterion (b)(5) requires that long-term core cooling be provided following the successful initial operation of the ECCS. The approved position on this criterion is that this requirement is satisfied if a coolable core geometry is maintained, and the core remains subcritical following the LOCA (Reference 78). This position is unaffected by the use of the best-estimate LOCA methodology.

14.3.3.4 Small-Break Results

This section presents the results of the small break LOCA analysis for a range of break sizes and fuel with ZIRLO™ cladding. NUREG-0737 (Reference 80), Section II.K.3.31, requires a plant specific small break LOCA analysis using an Evaluation Model revised per Section II.K.3.30. In accordance with NRC Generic Letter 83-35 (Reference 81), generic analyses using NOTRUMP (References 15, 16, and 93) were performed and are presented in WCAP-11145 (Reference 59). Those results demonstrate that in a comparison of cold leg, hot leg and pump suction leg break locations, the cold leg break location is limiting. The limiting break for Indian Point Unit 2 was found to be a 3-inch cold leg break. Also, in compliance with 10 CFR50.46 Section (a)(1)(i), additional cases were analyzed to ensure that the 3-inch diameter break was limiting. Calculations were run assuming breaks of 2 inches and 4 inches for ZIRLO™ clad fuel.

A list of input assumptions used in the small break analysis is provided in Table 14.3-11. The results of a spectrum analysis (three break sizes) performed for the upgraded ZIRLO™ clad fuel are summarized in Table 14.3-13, while the key transient event times are listed in Table 14.3-12.

For the limiting 3-inch break transient, Figures 14.3-54 through 14.3-61 depict the following parameters:

- RCS Pressure
- Core mixture level
- Hot rod cladding temperature
- Core steam flow rate
- Hot assembly rod surface heat transfer coefficient
- Hot spot fluid temperature
- Cold leg break mass flow rate
- Safety injection mass flow rate

In addition, the following transient parameters are presented for the non-limiting 2-inch and 4 inch breaks:

- RCS Pressure

- Core mixture level
- Hot rod cladding temperature

Figures 14.3-62 through 14.3-64 are for the 2-inch break transient, while Figures 14.3-65 through 14.3-67 show the above parameters for the 4-inch break.

During the initial period of the small break transient, the effect of the break flow rate is not strong enough to overcome the flow rate maintained by the reactor coolant pumps as they coast down following Loss-Of-Offsite-Power (LOOP). At the low heat generation rates following reactor trip, the fuel rods continue to be well cooled as long as the core is covered by a two-phase mixture. From the cladding temperature transients for the limiting break calculation shown in Figure 14.3-56, it can be seen that the peak cladding temperature occurs near the time of minimum core mixture level (1308 seconds) when the top of the core is steam cooled. This time is accompanied by the highest vapor superheating above the mixture level. The peak cladding temperature during the transient was 1028°F. At the time the transient was terminated, the safety injection flow rate that was delivered to the RCS exceeded the mass flow rate out the break. The decreasing RCS pressure results in greater safety injection flow as well as reduced break flow. As the RCS inventory continues to gradually increase, the reactor mixture level will continue to increase and the fuel cladding temperatures will continue to decline.

The maximum calculated peak cladding temperature for all small breaks analyzed is 1028°F, which is less than the 10 CFR 50.46 ECCS Acceptance Criteria limit of 2200°F. The maximum local metal water reaction is below the embrittlement limit of 17-percent as required by 10 CFR 50.46. The total metal-water reaction is less than 1 percent, as compared with the 1 percent, criterion of 10 CFR 50.46, and the cladding temperature transient is terminated at a time when the core geometry is still coolable. As a result, the core temperature will continue to drop and the ability to remove decay heat for an extended period of time will be provided. The PCT results provided in Table 14.3-13 relate to the small break LOCA Analysis of Record and do not reflect any individual PCT assessments made relative to the Analysis-of-Record and the accepted SBLOCA Evaluation Model which are reported separately, pursuant to 10CFR 50.46 and Reference 82.

An additional feature of the 15 X 15 upgraded fuel, the Integral Fuel Burnable Absorber (IFBA), has been generically evaluated for its impact on small break LOCA Analyses. This feature was previously discussed in the Reload Safety Evaluation for Cycle 11, (Reference 85) for 15 x 15 VANTAGE+ fuel. The evaluation has determined that the magnitude of SBLOCA PCT differences between IFBA and non IFBA Fuel is negligible and remains valid for 15 x 15 upgraded fuel. Therefore the small break LOCA transient was analyzed assuming upgraded fuel without IFBA.

14.3.3.4.1 Conclusions

Analyses presented in this section show that the high head safety injection of the Emergency Core Cooling System (the low head safety injection pumps were not modeled in the Indian Point Unit 2 small break LOCA analysis), provides sufficient core flooding to keep the calculated peak cladding temperature below the required limit of 10 CFR 50.46.

The results of this analysis demonstrate that, for a small break LOCA, the Emergency Core Cooling System will meet the acceptance criteria as presented in 10 CFR 50.46 (Reference 1). These criteria are as follows:

1) The calculated peak fuel element cladding temperature is below the requirement of 2200°F.

2) The amount of fuel element cladding that reacts chemically with water or steam does not exceed one percent by weight of the total amount of zircaloy in the reactor.

3) The cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. The localized cladding oxidation limits of 17-percent by weight are not exceeded during or after quenching.

4) The core remains amenable to cooling during and after the break.

5) The core temperature is reduced and decay heat is removed for an extended period of time as required by the long-lived radioactivity remaining in the core.

14.3.4 Core And Internals Integrity Analysis

14.3.4.1 Design Criteria

The basic requirement of any LOCA (Loss-Of-Coolant-Accident), including the double- ended severance of a reactor coolant pipe, is that sufficient integrity be maintained to permit the safe and orderly shutdown of the reactor. This implies that the core must remain essentially intact and the deformations of the internals must be sufficiently small so that primary loop flow, and particularly, adequate safety injection flow, is not impeded. The ability to insert control rods, to the extent necessary, to provide shutdown following the accident must be maintained. Maximum allowable deflection limitations are established for those regions of the internals that are critical for plant shutdown. The allowable and no loss of function deflection limits under dead weight loads plus the maximum potential earthquake and/or blowdown excitation loads are presented in Table 14.3-14.

With the acceptance of Leak-Before-Break by USNRC, Reference 20, (see Section 14.3.5.4.3.2) the dynamic effects of main coolant loop piping no longer have to be considered in the design basis analysis. Only the dynamic effects of the next most limiting breaks of auxiliary lines need to be considered; and consequently the components will experience considerably less loads and deformations than those from the main loop line breaks.

14.3.4.2 Internals Evaluation

The horizontal and vertical forces exerted on reactor internals and the core, following a LOCA are computed by employing MULTIFLEX (3.0), Reference 21, NRC accepted for similar applications, Reference 19, computer code developed for the space-time dependent analysis of nuclear power plants.

14.3.4.2.1 LOCA Forces Analysis

MULTIFLEX (3.0), Reference 21, is a digital computer program for calculation of pressure, velocity, and force transients in reactor primary coolant systems during the subcooled, transition, and early saturation portion of blowdown caused by a LOCA. During this phase of the accident, large amplitude rarefaction waves are propagated through the system with the velocity of sound causing large differences in local pressures. As local pressures drop below saturation, causing formation of steam, the amplitudes and velocities of these waves drastically decrease. Therefore, the largest forces across the reactor internals due to wave propagation occur during the subcooled portions of the blowdown transient. MULTIFLEX includes mechanical structure models and their interaction with the thermal-hydraulic system.

14.3.4.2.2 MULTIFLEX

The thermal-hydraulic portion of MULTIFLEX (3.0), Reference 21, is based on the 1-dimensional homogeneous flow model which is expressed as a set of mass, momentum, and energy conservation equations. These equations are quasi-linear first order partial differential equations, which are solved by the method of characteristics. The numerical method employed is the explicit scheme, consequently time steps for stable numerical integration are restricted by sonic propagation.

In MULTIFLEX, the structural walls surrounding a hydraulic path may deviate from their neutral positions depending on the force differential on the wall. The wall displacements are represented by those of 1-dimensional mass points, which are described by the mechanical equations of vibration.

MULTIFLEX is a generalized program for analyzing and evaluating thermal-hydraulic-structure system dynamics. The thermal-hydraulic system is modeled with an equivalent pipe network consisting of 1-dimensional hydraulic legs, which define the actual system geometry. The actual system parameters of length, area, and volume are represented with the pipe network.

MULTIFLEX computes the pressure response of a system during a decompression transient. The asymmetric pressure field in the downcomer annulus region of a PWR can be calculated. This pressure field is integrated over the core support barrel area to obtain total dynamic load on the core support barrel. The pressure distributions computed by MULTIFLEX can also be used to evaluate the reactor core assembly and other primary coolant loop component support integrity.

MULTIFLEX evaluates the pressure and velocity transients for locations throughout the system. The pressure and velocity transients are made available to the programs LATFORC and FORCE-2 (described in Reference 24, Appendix A and B), which used detailed geometric descriptions to evaluate hydraulic loadings on reactor internals.

14.3.4.2.3 Horizontal / Lateral Forces - LATFORC

LATFORC, described in Reference 24 Appendix A, calculates the lateral hydraulic loads on the reactor vessel wall, core barrel, and thermal shield, resulting from a postulated loss-of-coolant accident in the primary reactor coolant system. A variation of the fluid pressure distribution in the downcomer annulus region during the blowdown transient produces significant asymmetrical loading on the reactor vessel internals. The LATFORC computer code is used in conjunction with MULTIFLEX, which provides the transient pressures, mass velocities, and other thermodynamic properties as a function of time.

14.3.4.2.4 Vertical Forces - FORCE2

FORCE-2, described in Reference 24 Appendix B, determines the vertical hydraulic loads on the reactor vessel internals. Each reactor component for which force calculations are required is designated as an element and assigned an element number. Forces acting upon each of the elements are calculated summing the effects of:

1. The pressure differential across the element.
2. Flow stagnation on, and unrecovered orifice losses across, the element.
3. Friction losses along the element.

Input to the code, in addition to the MULTIFLEX pressure and velocity transients, includes the effective area of each element on which acts the force due to the pressure differential across the element, a coefficient to account for flow stagnation and unrecovered orifice losses, and the total area of the element along which the shear forces act.

14.3.4.3 Structural Response of Reactor Vessel Internals During LOCA and Seismic Conditions

14.3.4.3.1 Structural Model and Method of Analysis

The response of reactor vessel internals components due to an excitation produced by a complete severance of auxiliary loop piping is analyzed. With the acceptance of Leak-Before-Break by USNRC, Reference 20, the dynamic effects of main coolant loop piping no longer have to be considered in the design basis analysis. Only the dynamic effects of the next most limiting breaks of auxiliary lines need to be considered; and consequently the components will experience considerably less loads than those from the main loop line breaks.

The required break locations are defined in Reference 25. Aside from 8 locations on the primary coolant loop piping, the 3 largest auxiliary line breaks are also postulated. These are the accumulator line, the pressurizer surge line, and the RHR line. In accordance with Reference 25, the auxiliary line break is postulated to occur at the safe-end junction between the branch connection and the branch piping. In practice, this has been conservatively represented in these applicable MULTIFLEX analyses as a break location 1 foot from the main coolant loop piping, with a branch line nozzle flow area equivalent to the main coolant loop piping, although a longer branch line connection (nozzle) with a smaller flow area is justified by the approved methodology described in Reference 24 and 25. Branch line nozzles with thermal shields are conservatively assumed to have no thermal shield, since the thermal shield could be postulated to be lost with the ruptured branch line piping.

Assuming that such a pipe break on the cold leg occurs in a very short period of time (1 ms), the rapid drop of pressure at the break produces a disturbance that propagates through the reactor vessel nozzle into the downcomer (vessel and barrel annulus) and excites the reactor vessel and the reactor internals. The characteristics of the hydraulic excitation combined with those of the structures affected present a unique dynamic problem. Because of the inherent gaps that exist at various interfaces of the reactor vessel/reactor internals/fuel, the problem becomes that of nonlinear dynamic analysis of the RPV system. Therefore, nonlinear dynamic analyses (LOCA and Seismic) of the RPV system includes the development of LOCA and seismic forcing functions which are also discussed here.

14.3.4.3.2 Structural Model

Figure 14.3-101 is schematic representation of the reactor pressure vessel system. In this figure, the major components of the system are identified. The RPV system finite element model for the nonlinear time history dynamic analysis consists of three concentric structural sub-models connected by nonlinear impact elements and linear stiffness matrices. The first sub-model, shown in Figure 14.3-102 represents the reactor vessel shell and its associated components. The reactor vessel is restrained by four reactor vessel supports (situated beneath alternate nozzles) and by the attached primary coolant piping. Also shown in Figure 14.3-102 is a typical RPV support mechanism.

The second sub-model, shown in Figure 14.3-103a represents the reactor core barrel, thermal shield, lower support plate, tie plates, and the secondary support components. These sub-models are physically located inside the first, and are connected to them by stiffness matrices at the vessel/internals interfaces. Core barrel to reactor vessel shell impact is represented by nonlinear elements at the core barrel flange, upper support plate flange, core barrel outlet nozzles, and the lower radial restraints.

The third and innermost sub-model, shown in Figure 14.3.103b represents the upper support plate assembly consisting of guide tubes, upper support columns, upper and lower core plates, and the fuel. The fuel assembly simplified structural model incorporated in to the RPV system model preserves the dynamic characteristics of the entire core. For each type of fuel design the corresponding simplified fuel assembly model is incorporated in to the system model. The third sub-model is connected to the first and second by stiffness matrices and nonlinear elements. Finally, Figure 14.3-104 shows the RPV system model representation.

14.3.4.3.3 Analysis Technique

The WECAN Computer Code (Westinghouse Electric Computer Analysis), Reference 22, which is used to determine the response of the reactor vessel and its internals, is a general purpose finite element code. In the finite element approach, the structure is divided into a finite number of discrete members or elements. The inertia and stiffness matrices, as well as the force array, are first calculated for each element in the local coordinates. Employing appropriate transformations, the element global matrices and arrays are assembled into global structural matrices and arrays, and used for dynamic solution of the differential equation of motion for the structure.

The WECAN Code solves equation of motions using the nonlinear modal superposition theory. Initial computer runs such as dead weight analysis and the vibration (modal) analyses are made to set the initial vertical interface gaps and to calculate eigenvalues and eigenvectors. The modal analysis information is stored on magnetic tapes, and is used in a subsequent computer runs which solves equations of motions. The first time step performs the static solution of equations to determine steady state solution under normal operating hydraulic forces. After the initial time step, WECAN calculates the dynamic solution of equations of motions and nodal displacements and impact forces are stored on tape for post-processing

The fluid-solid interactions in the LOCA analysis are accounted through the hydraulic forcing functions generated by MULTIFLEX Code, Reference 21. Following a postulated LOCA pipe rupture, forces are imposed on the reactor vessel and its internals. These forces result from the release of the pressurized primary system coolant. The release of pressurized coolant results in traveling depressurization waves in the primary system. These depressurization waves are characterized by a wave front with low pressure on one side and high pressure on the other.

Depressurization waves propagate from the postulated break location into the reactor vessel through either a hot leg or a cold leg nozzle. After a postulated break in the accumulator branch line on the cold leg, the depressurization path for waves entering the reactor vessel is through the nozzle which contains the broken pipe and into the region between the core barrel and the reactor vessel (i.e., downcomer region). The initial wave propagates up, around, and down the downcomer annulus, then up through the region circumferentially enclosed by the core barrel, that is, the fuel region. In the case of a break in a branch line on the cold leg, the region of the downcomer annulus close to the break depressurizes rapidly but, because of the restricted flow areas and finite wave speed (approximately 3000 feet per second), the opposite side of the core barrel remains at a high pressure. This results in a net horizontal force on the core barrel and the reactor vessel. As the depressurization wave propagates around the downcomer annulus and up through the core, the core barrel differential pressure reduces and, similarly, the resulting hydraulic forces drop.

In the case of a postulated auxiliary branch line break on the hot leg piping (such as the RHR line or Pressurizer surge line), the wave follows a similar depressurization path, passing through the outlet nozzle and directly into the upper internals region depressurizing the core and entering the downcomer annulus from the bottom exit of the core barrel. Thus, after a branch line break, on the hot leg, the downcomer annulus would be depressurized with very little difference in pressure forces across the outside the diameter of the core barrel. A branch line break on the hot leg produces less horizontal force because the depressurization wave travels directly to the inside of the core barrel (so that the downcomer annulus is not directly involved) and internal differential pressures are not as large as for a cold leg break of the same size. Since the differential pressure is less for a branch line break, the horizontal force applied to the core barrel is less for a hot leg break than for a branch line break on the cold leg. For breaks in branch line piping on both the hot leg and cold leg, the depressurization waves continue to propagate by reflection and translation through the reactor vessel and loops.

The MULTIFLEX computer code, Reference 21, calculates the hydraulic transients within the entire primary coolant system. It considers subcooled, transition, and early two-phase (saturated) blowdown regimes. The MULTIFLEX code employs the method of characteristics to solve the conservation laws, and assumes one-dimensionality of flow and homogeneity of the liquid-vapor mixture. As mentioned earlier, the MULTIFLEX code considers a coupled fluid-structure interaction by accounting for the deflection of constraining boundaries, which are represented by separate spring-mass oscillator system. A beam model of the core support barrel has been developed from the structural properties of the core barrel; in this model, the cylindrical barrel is vertically divided into equally spaced segments and the pressure as well as the wall motions are projected onto the plane parallel to the broken loop inlet nozzle. Horizontally, the barrel is divided into 10 segments; each segment consists of four separate walls. The spatial pressure variation at each time step is transformed into 10 horizontal forces which act on the 10 mass points of the beam model. Each flexible wall is bounded on either side by a hydraulic flow path. The motion of the flexible wall is determined by solving the global equations of motions for the masses representing the forced vibration of an undamped beam.

In order to obtain the response of reactor pressure vessel system (vessel/internals/fuel), the LOCA horizontal and vertical forces obtained from the LATFORC and FORCE2 Codes, which were described earlier, are applied to the finite element system model. The transient response of the reactor internals consists of time history nodal displacements and time history impact forces.

14.3.4.3.4 Seismic Analysis

The basic mathematical model for seismic analysis is essentially similar to the LOCA model except for some minor differences. In LOCA model, as mentioned earlier, the fluid-structure interactions are accounted though the MULTIFLEX Code; whereas in the seismic model the fluid-structure interactions are included through the hydrodynamic mass matrices in the downcomer region. Another difference between the LOCA and seismic models is the difference between in loop stiffness matrices. The seismic model uses the unbroken loop stiffness matrix, whereas the LOCA model uses the broken loop stiffness matrix. Except for these two differences, the RPV system seismic model is identical to that of LOCA model.

The horizontal fluid-structure or hydroelastic interaction is significant in the cylindrical fluid flow region between the core barrel and the reactor vessel annulus. Mass matrices with off-diagonal terms (horizontal degrees-of-freedom only) attach between nodes on the core barrel, thermal shield and the reactor vessel. The mass matrices for the hydroelastic interactions of two concentric cylinders are developed using the work of reference 23. The diagonal terms of the mass matrix are similar to the lumping of water mass to the vessel shell, thermal shield, and core barrel. The off-diagonal terms reflect the fact that all the water mass does not participate when there is no relative motion of the vessel and core barrel. It should be pointed out that the hydrodynamic mass matrix has no artificial virtual mass effect and is derived in a straight-forward, quantitative manner.

The matrices are a function of the properties of two cylinders with the fluid in the cylindrical annulus, specifically, inside and outside radius of the annulus, density of the fluid and length of the cylinders. Vertical segmentation of the reactor vessel and the core barrel allows inclusion of radii variations along their heights and approximates the effects beam mode deformation. These mass matrices were inserted between the selected nodes on the core barrel, thermal shield, and the reactor vessel as shown in Figure 14.3-104. The seismic evaluations are performed by including the effects of simultaneous application of time history accelerations in three orthogonal directions. The WECAN computer code, which is described earlier, is also used to obtain the response for the RPV system under seismic excitations.

14.3.4.3.5 Results and Acceptance Criteria

The reactor internals behave as a highly nonlinear system during horizontal and vertical oscillations of the LOCA forces. The nonlinearities are due to the coulomb friction at the sliding surfaces and due to gaps between components causing discontinuities in force transmission. The frequency response is consequently a function not only of the exciting frequencies in the system but also of the amplitude. Different break conditions excite different frequencies in the system. This situation can be seen clearly when the response under LOCA forces is compared with the seismic response. Under seismic excitations, the system response is not as nonlinear as LOCA response because various gaps do not close during the seismic excitations.

The results of the nonlinear LOCA and seismic dynamic analyses include the transient displacements and impact loads for various elements of the mathematical model. These displacements and impact loads, and the linear component loads (forces and moments) are then used for detailed component evaluations to assess the structural adequacy of the reactor vessel, reactor internals, and the fuel.

14.3.4.3.6 Structural Adequacy of Reactor Internals Components

The reactor internal components of Indian Point Unit 2 are not ASME Code components, because Sub-section NG of the ASME Boiler and Pressure Code edition applicable to this unit did not include design criteria for the reactor internals since its design preceded Subsection NG of the ASME Code. However, these components were originally designed to meet the intent of the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with addenda through the Winter 1971. As mentioned earlier, that with the acceptance of Leak-Before-Break (LBB) by USNRC, Reference 20, the dynamic effects of the main reactor coolant loop piping no longer have to be considered in the design basis analysis. Only the dynamic effects of the next most limiting breaks of the auxiliary lines (Accumulator line and Pressurizer Surge or RHR line) are considered. Consequently, the components experience considerably less loads and deformations than those from the main loop breaks which were considered in the original design of the reactor internals.

14.3.4.3.7 Allowable Deflection and Stability Criteria

The criteria for acceptability in regard to mechanical integrity analyses is that adequate core cooling and core shutdown must be ensured. This implies that the deformation of reactor internals must be sufficiently small so that the geometry remains substantially intact. Consequently, the limitations established on the reactor internals are concerned principally with the maximum allowable deflections and stability of the components.

For faulted conditions, deflections of critical internals structures are limited to values given in Table 14.3-14. In a hypothesized vertical displacement of internals, energy-absorbing devices limit the displacement to 1.25 inches by contacting the vessel bottom head.

Core Barrel Response Under Transverse Excitations

In general, there are two possible modes of dynamic response of the core barrel during LOCA conditions: a) during a cold leg break the inside pressure of the core barrel is much higher than the outside pressure (downcomer), thus subjecting the core barrel to outward deflections, and b) during hot leg break the pressure outside the core barrel (downcomer) is greater than the inside pressure thereby subjecting the core barrel to compressive loadings. Therefore this condition requires the dynamic stability check of the core barrel during hot leg break.

(1) To ensure shutdown and cooldown of the core during cold leg blowdown, the basic requirement is a limitation on the outward deflection of the barrel at the locations of the inlet nozzles connected to unbroken lines. A large outward deflection of the upper barrel in front of the inlet nozzles, accompanied with permanent strains, could close the inlet area and restrict the cooling water coming from the accumulators. Consequently, a permanent barrel deflection in front of the unbroken inlet nozzles larger than a certain limit, called “no loss of function” limit, could impair the efficiency of the ECCS.

(2) During the hot leg break, the rarefaction wave enters through the outlet nozzle into the upper internals region and thus depressurizes the core and then enters the downcomer annulus from the bottom exit of the core barrel. This depressurization of the annulus region subjects the core barrel to external pressures and this condition requires a stability check of the core barrel during hot leg break. Therefore, to ensure rod insertion and to avoid disturbing the control rod cluster guide structure, the barrel should not interfere with the guide tubes.

Table 14.3-14 summarizes the allowable and no loss of function deflection limits of the core barrel for both the cold leg and hot leg breaks postulated in the main line loop piping. With the acceptance of LBB, the reactor internal components such as core barrel will experience much less loads and deformations than those obtained from main loop piping.

Control Rod Cluster Guide Tubes

The deflection limits of the guide tubes, which were established from the test data, and for fuel assembly thimbles, cross-section distortion (to avoid interference between the control rod and the guides) are given in Table 14.3-14.

Upper Package

The local vertical deformation of the upper core plate, where a guide tube is located, shall be below 0.100 inch. This deformation will cause the plate to contact the guide tube since the clearance between the plate and the guide tube is 0.100 inch. This limit will prevent the guide tubes from undergoing compression. For a plate local deformation of 0.150 inch, the guide tube will be compressed and deformed transversely to the upper limit previously established. Consequently, the value of 0.150 inch is adopted as the no loss function local deformation with an allowable limit of 0.100 inch. These limits are given in Table 14.3-14.

14.3.4.4 Evaluations of Effects of Loss-of-Coolant and Safety Injection on the Reactor Vessel

The effects of Safety Injection on the Reactor Vessel following a loss of coolant accident were generically evaluated after the Three Mile Island – 2 accident as part of NUREG-0737, Item II.K.2.13, and determined to be acceptable as documented in NRC's June 15, 1984 Safety Evaluation Report (SER) from Steven A. Varga (NRC) to John D. O'Toole (Consolidated Edison). The potential for thermal shock of reactor vessels was later broadened in scope to include all over cooling events, the evaluation of which is currently required by the Pressurized Thermal Shock (PTS) Rule, 10 CFR 50.61. As described in Section 4.2.5, NRC's February 27, 1987 Safety Evaluation Report (SER) from M. Slosson (NRC) to M. Selman (Consolidated Edison) concluded that the Indian Point Unit 2 evaluations were acceptable and meet the requirements of the PTS Rule.

14.3.5 Containment Integrity Analysis

14.3.5.1 Containment Structure

14.3.5.1.1 Design Bases

The design and analysis of the Indian Point 2 containment structure are described in Chapter 5. The design bases and design criteria are discussed in Section 5.1.1.1.6 and 5.1.2.2, respectively. The discussion contained in this Section pertains to containment response to Loss of Coolant Accidents. Containment response to secondary system pipe ruptures is discussed in Section 14.2.5.6.

Sources and amounts of energy that may be available for release to the containment are discussed in Section 14.3.5.3. To obtain a conservative pressure, energy is added to the containment in the manner most detrimental to peak pressure response for the containment response analysis.

Systems for removing energy from within the containment include the safety injection system (Section 6.2), the containment fan cooler system (Section 6.4), and the containment spray system (Section 6.3). The containment fan coolers remove energy from the containment atmosphere. Containment spray is used for rapid pressure reduction and for containment airborne activity removal. During the recirculation phase, the recirculation system removes heat from the reactor fuel via containment sump water. Heat removal by containment spray during the recirculation phase, which is part of the engineered safety features, is not assumed in the containment response analyses.

Engineered safety features systems are redundant and independent such that any single active failure in the engineered safety features system during the injection phase or any single active or passive failure during recirculation (See Section 6.2.3.3) will not affect the ability to mitigate containment pressure as discussed in Sections 14.3.5.3.7 and 14.3.5.5.

Reference 61 has provided the basis for the loss-of-coolant accident spectrum that is analyzed to provide limiting containment pressures and temperatures. These results are bounded by the transient used for design as discussed in Section 5.1.2.2. Results are provided for a Double-Ended Pump Suction (DEPS) break with minimum and maximum safeguards and a Double-Ended Hot Leg (DEHL) break. These analyses were performed at a reactor power level of 3216 MWt. Analyses, assumptions, and results are presented in sections 14.3.5.1.3 through 14.3.5.3.9 for the break spectrum analyzed.

To summarize the break cases, Tables 14.3-16 through 14.3-30 show mass and energy release information, Tables 14.3-15 and 14.3-37 show systems and containment assumptions, and the assumed containment safeguards equipment. Tables 14.3-35 and 14.3-36 show the containment passive heat sink information assumed, and Figure 14.3-115 shows the heat removal capability assumed for one RCFC. Results of the break cases are shown in Figures 14.3-109 through 14.3-114, and are summarized in Table 14.3-34. The break cases show that a reactor coolant system double-ended pump suction (DEPS) rupture, assuming operation of the minimum emergency cooling system equipment, three RCFC units, and one containment spray pump consistent with the assumption of a single failure of one diesel generator, results in the highest containment pressure after a LOCA. The chronology of events for the DEPS minimum safeguards case is shown in Table 14.3-31. (See Section 5.1.1.1.6 for a discussion of the structural containment evaluation based on the limiting case.) The selection of the limiting case, based on both the sensitivity cases and the generic conclusions of the mass and energy release topical report (Reference 61), remains valid for reanalysis of the Indian Point Unit 2 containment transients at stretch power uprate conditions.

The analysis of the limiting case, a DEPS rupture with minimum safeguards, has been performed at an NSSS power of 3230 MWt (core power of 3216 MWt). The analysis was performed using the models and assumptions presented in Reference 61 and Table 14.3-15. The mass and energy release models include the Model 44F replacement steam generator input (including the conservative assumption of 0% tube plugging) and the containment response model includes the release of the accumulator nitrogen gas to containment. Tables 14.3-16 through 14.3-18 show the mass and energy releases for the blowdown phase, the reflood phase, and the post-reflood phase respectively. Tables 14.3-19 and 14.3-20 show the mass and energy balance data, while Table 14.3-21 shows the principal parameters during the reflood phase. Table 14.3-37 shows the assumed containment safeguards equipment, and Tables 14.3-35 and 14.3-36 show the containment passive heat sink information assumed. Calculation of containment pressure and temperature transients is accomplished by use of the COCO (Reference 6) computer code.

Fan cooler (RCFC) heat removal performance assumed in the analysis is shown in Figure 14.3-115. The critical parameter as regards RCFC capability in the calculated containment pressure is the available total RCFC heat removal capacity. In the containment pressure response analysis, three RCFCs, each with the heat removal capability presented in Figure 14.3-115, are modeled. Any RCFC configuration that assures that heat removal greater than or equal to three times that of Figure 14.3-115 is available post-LOCA via the RCFC system is equally acceptable. Service water flow rate and temperature, fouling factor, and the number of RCFCs available under accident conditions may be modified as long as the required total RCFC heat removal capability exists.

The reanalysis of the limiting containment pressure case, a DEPS rupture with minimum safeguards, has been performed at an NSSS power level of 3230 MWt (core power level of 3216 MWt). The chronology of events is shown in Table 14.3-31. Quantities of heat removed by structures, fan coolers and containment spray are shown in Figures 14.3-105, 14.3-106, and 14.3-107 respectively. The structural heat transfer coefficient is shown in Figure 14.3-108. Results in Figures 14.3-109 and 14.3-110 show that the calculated maximum pressure and temperature are 45.71 psig and 266.81°F, respectively. This indicates margin to the containment design pressure of 47 psig.

Heat removal by recirculation spray is not credited in the analysis. Therefore, the increase in the duration of the recirculation spray flow has no impact on the containment integrity design basis LOCA analysis.

14.3.5.1.2 System Design

Structural design of the containment and containment internal structures is discussed in Chapter 5.

14.3.5.1.3 Design Evaluation

The results of the transient analysis of the containment for the loss-of-coolant accidents are shown in Figures 14.3-105 through 14.3-114. A series of cases were performed in this analysis illustrating the sensitivity to break location. Subsection 14.3.5.3 documented the mass and energy release (LOCA) for the minimum and maximum safeguards cases for a Double-Ended Pump Suction (DEPS) break and the releases from the blowdown of a Double-Ended Hot Leg (DEHL) break. All of these design basis cases show that the containment pressure will remain below design pressure with margin without taking credit for the recirculation spray. After the peak pressure is attained, the performance of the minimum safeguards system reduces that containment pressure. At the end of the first day following the accident, the containment pressure has been reduced to a low value. The peak pressures are shown in Table 14.3-34 for a variety of containment safeguards availability assumptions.

Calculation of containment pressure and temperature transients is accomplished by use of the digital computer code, COCO[6]. Transient phenomena within the reactor coolant system affect containment conditions by means of mass and energy transport through the pipe break.

For analytical rigor and convenience, the containment air-steam-water mixture is separated into systems. The first system consists of the air-steam phase; the second consists of the water phase. Sufficient relationships to describe the transient are provided by the equations of conservation of mass and energy as applied to each system, together with appropriate boundary conditions. Thermodynamic equations of state and conditions may vary during the transient. The equations have been derived for all possible cases of superheated or saturated steam and subcooled or saturated water. Switching between states is handled automatically within the COCO code. The following are the major assumptions made in the containment analysis:

1. Discharge mass and energy flow rates through the reactor coolant system break are established from the analysis in Section 14.3.5.3.

2. For the LOCA containment response analysis, the discharge flow from either end of the break separates into steam and water phases upon entry to the containment atmosphere. For each input set of tables of break effluent mass and energy, the COCO code assumes that the saturated water phase is at the total containment pressure, while the steam phase is at the partial pressure of the steam in the containment.

3. Homogeneous mixing is assumed. The steam-air mixture and the water phase each have uniform properties. More specifically, thermal equilibrium between the air and steam is assumed. This does not imply thermal equilibrium between the steam-air mixture and the water phase, which may be at different temperature.

4. Air is taken as an ideal gas, while compressed water and steam tables are employed for water and steam thermodynamic properties.

14.3.5.1.4 Initial Conditions

The pressure, temperature, and humidity of the containment atmosphere prior to the postulated reactor coolant system rupture are conservatively specified in the analysis. Also, conservative values for the temperature of the service water and refueling water storage tank water solution are assumed. All of these values are as shown in Table 14.3-37.

In each of the transients, the safeguards systems shown in Table 14.3-37 are assumed to operate with a 60 second delay in startup. The assumed spray flow rate is based on one of two trains of the containment spray system operating.

14.3.5.1.5 Heat Removal

The significant heat removal source during the early portion of the transient are structural heat sinks. Provision is made in the containment pressure transient analysis for heat transfer through, and heat storage in, both interior and exterior walls. Every wall is divided into many nodes; for each node, a conservation of energy equation expressed in finite- difference form accounts for transient conduction into and out of the node and temperature rise of the node. Tables 14.3-35 and 14.3-36 are summaries of the containment structural heat sinks used in the analysis.

The heat transfer coefficient to the containment structure is calculated by the code based primarily on the work of Tagami[31]. From this work, it was determined that the value of the heat transfer coefficient increases parabolically to peak value at the end of blowdown for LOCA. The value then decreases exponentially to a stagnant heat transfer coefficient, which is a function of steam-to-air-mass ratio.

Tagami presents a plot of the maximum value of h as a function of "coolant energy transfer speed," defined as follows:

$$\frac{\text{total coolant energy transferred into containment}}{\text{(containment volume) x (time interval to peak pressure)}}$$

From this, the maximum h of steel is calculated:

$$h_{max} = 75\left[\frac{E}{t_p V}\right]^{0.60} \qquad (14.3-1)$$

where:

75 = material coefficient for steel

h_{max} = maximum value of h (Btu/hr ft ^{2} °F).

t_p = time from start of accident to end of blowdown (sec)

V = containment volume (ft^3).

E = coolant energy discharge (Btu).

The parabolic increase to the peak value is given by:

$$h_s = h_{max}\left(\frac{t}{t_p}\right)^{0.5}, 0 \le t \le t_p \qquad (14.3-2)$$

where

h_s = heat transfer coefficient for steel (Btu/hr ft^2 °F).

t = time from start of accident (sec).

For concrete, the heat transfer coefficient is taken as 40-percent of the value calculated for steel.

The exponential decrease of the heat transfer coefficient is given by:

$$h_s = h_{stag} + \left(h_{max} - h_{stag}\right) e^{-0.05\left(t-t_p\right)}, t > t_p \qquad (14.3\text{-}3)$$

where

h_{stag} = 2 + 50X, 0 < X < 1.4.

h_{stag} = h for stagnant conditions (Btu/hr ft^2 ^oF).

X = steam-to-air mass ratio in containment.

For a large break, the engineered safety features are quickly brought into operation. Because of the brief period of time required to depressurize the reactor coolant system, the containment safeguards do not influence the blowdown peak pressure; however, they significantly reduce the containment pressure after the blowdown and maintain a low long-term pressure. Also, although the containment structure is not a very effective heat sink during the initial reactor coolant system blowdown, it still contributes significantly as a form of heat removal.

14.3.5.2 Engineered Safety Features

During the injection phase of post-accident operation, the emergency core cooling system pumps water from the refueling water storage tank (RWST) into the reactor vessel (the containment spray pumps also inject RWST water into the containment). Since this water enters the vessel at refueling water storage tank temperature, which is less than the temperature of the water in the vessel, it can absorb heat from the core until saturation temperature is reached. During the recirculation phase of operation, water is taken from the containment sump and cooled in the residual heat removal heat exchanger. The cooled water is then pumped back to the reactor vessel to absorb more decay heat. The heat is removed from the residual heat exchanger by component cooling water and from the component cooling heat exchanger by service water.

14.3.5.2.1 Containment Spray

Another containment heat removal system is the containment spray. During the injection phase of operation, the containment spray pumps draw water from the RWST and spray it into the containment through nozzles mounted high above the operating deck. As the spray droplets fall, they absorb heat from the containment atmosphere. Since the water comes from the RWST, the entire heat capacity of the spray from the RWST temperature to the temperature of the containment atmosphere is available for energy absorption. During the recirculation phase of post-accident operation, water can be drawn from the residual heat removal heat exchanger outlet and sprayed into the containment atmosphere via the recirculation spray system. However, no-credit was taken for recirculation spray in the analysis in calculating the peak containment pressure.

When a spray drop enters the hot, saturated, steam-air containment environment following a loss-of-coolant accident, the vapor pressure of the water at its surface is much less than the partial pressure of the steam in the atmosphere. Hence, there will be diffusion of steam to the drop surface and condensation on the drop. This mass flow will carry energy to the drop. Simultaneously, the temperature difference between the atmosphere and the drop will cause the drop temperature and vapor pressure to rise. The vapor pressure of the drop will eventually become equal to the partial pressure of the steam, and the condensation will cease. The temperature of the drop will equal the temperature of the steam-air mixture.

The equations describing the temperature rise of a falling drop are as follows:

$$\frac{d}{dt}(Mu) = mh_g + q \qquad (14.3-4)$$

$$\frac{d}{dt}(M) = m \qquad (14.3-5)$$

where

$q = h_c A (T_s - T).$

$m = k_g A (P_s - P_v).$

The coefficients of heat transfer (h_c) and mass transfer (k_g) are calculated from the Nusselt number for heat transfer, Nu, and the Nusselt number for mass transfer, Nu'.

Both Nu and Nu' may be calculated from the equations of Ranz and Marshall.[38]

$$Nu = 2 + 0.6 (Re)^{1/2} (Pr)^{1/3} \qquad (14.3\text{-}6)$$

$$Nu' = 2 + 0.6 (Re)^{1/2} (Sc)^{1/3} \qquad (14.3\text{-}7)$$

Thus, Equations 14.3-4 and 14.3-5 can be integrated numerically to find the internal energy and mass of the drop as a function of time as it falls through the atmosphere. Analysis shows that the temperature of the (mass) mean drop produced by the SPRACO 1713A spray nozzles rises to a value within 99-percent of the bulk containment temperature in less than 2 seconds. Drops of approximately 1000 micron average size (as discussed in Chapter 6) will reach temperature equilibrium with the steam-air containment atmosphere after falling through less than half the available spray fall height. Detailed calculations of the heatup of spray drops in post-accident containment atmospheres by Parsly[43] show that drops of all sizes encountered in the containment spray reach equilibrium in a fraction of their residence time in a typical pressurized water reactor containment. These results confirm the assumption that the containment spray will be 100-percent effective in removing heat from the atmosphere. Nomenclature in this section is as follows:

A	=	area
h_c	=	coefficient of heat transfer
h_g	=	steam enthalpy
k_g	=	coefficient of mass transfer
M	=	droplet mass
m	=	diffusion rate
Nu	=	Nusselt number for heat transfer
Nu'	=	Nusselt number for mass transfer
P_s	=	steam partial pressure
P_v	=	droplet vapor pressure
Pr	=	Prandtl number
q	=	heat flow rate
Re	=	Reynolds number

Sc = Schmidt number

T_s = droplet temperature

T = steam temperature

t = time

u = internal energy

14.3.5.2.2 Reactor Containment Fan Coolers (RCFCs)

The reactor containment fan coolers are a principal means of post-accident containment heat removal. The fans draw the dense atmosphere through banks of finned cooling coils and mix the cooled steam/air mixture with the rest of the containment atmosphere. The coils are kept at a low temperature by maintaining the required flow of cooling water from the service water system. Since the RCFCs do not use water from the RWST, the mode of operation remains the same before and after the containment spray and emergency core cooling systems are changed to the recirculation mode.

The ability of the containment air recirculation coolers to function properly in the accident environment is demonstrated by the coil vendor's analysis. This analysis determines the plate-fin cooling coil heat removal rate when operating in a saturated steam-air mixture.

In the heat removal analysis of the RCFC coils, a mass flow rate of cooling water is first established. This determines the inside film coefficient of the tube. Next, the resistance to heat transfer between the cooling water and the outside of the fin collars is computed, including inside film coefficient, fouling factor, tube radial conduction, fin-collar interface resistance, and conduction across the fin collars. [***Note*** *- A fouling factor of 0.001 hr-ft^2-$^\circ$F/Btu, under both normal and design basis accident conditions, has been assumed for cooling coil design purposes. This value is conventionally used in sizing heat exchangers cooled by river water at 95°F or less and with tube water velocity greater than 3-ft/sec*[33] *and is considered sufficiently conservative for this application. Computer analysis of the coils selected shows that the required post-accident heat removal rate can be achieved even with a slight increase in fouling.*] The analysis now becomes iterative. One assumes an overall heat transfer rate Q_{tot} and the temperature at the outside of the fin collars is determined from Q_{tot} and the sum of the resistances cited above.

A second iterative procedure is now established. The variable whose value is assumed is the effective film coefficient between the fins and the gas stream, which involves the effect of convective heat transfer and mass transfer. With this value of $h_{effective}$, fin efficiency and the fin temperature distribution can be determined. It is assumed that a condensate film exists on the vertical fins. An analysis is performed, which relates this film thickness to the rate of removal due to gravity and shear and the rate of addition of condensate by mass transfer from the bulk gas. In the process, from an energy balance the temperature of the interface between the bulk gas and the condensate can be determined; this is necessary for determining the mass transfer rate from the gas. Now that the thickness of the condensate film is known, the value of the assumed $h_{effective}$ is checked from the relation $h_{eff} = K_{water}/\delta_{film}$. If the assumed and computed values are not the same, a new value is selected and calculations repeated until the assumed and computed values are equal.

When this occurs, the heat transfer rate from the fins and fin collar is computed, using the standard equations for fin and fin collar heat transfer and the values of $h_{effective}$ and film-bulk gas interface temperature. If this value is not the same as Q_{tot} initially assumed in order to determine fin collar temperature, the whole analysis is repeated with a new estimate of Q_{tot}. When, finally, the heat transfer rate to the cooling water from the fin collar equals the resulting computed rate to the fin collar and fins from the gas, the effect of this heat transfer rate on the cooling water is computed. The water exit temperature is established, and this value is used as the inlet temperature for the next heat exchanger pass. Also, the effect of convective heat transfer and condensate mass transfer is determined relative to the gas composition and thermodynamic state. The updated gas state is used as inlet conditions for the next pass. The process is repeated for the second, third, etc., passes until the gas exits the heat exchanger.

The mass transfer coefficients used in the computer code were derived from analyses and reports of experimental data.[33, 34, 35] From Reference 34, the mass flow rate of condensate is defined by [***Note*** *- Nomenclature used is given at the end of this discussion.*]

$$\dot{m} = \bar{h}_D \left(\rho_{sg} - \rho_{sw}\right) \qquad (14.3\text{-}8)$$

From Reference 34, pp. 471-473, experimental data for mass and heat transfer correlate well with the expression

$$\frac{\bar{h}_D}{u_s}(Sc)^{-2/3} = St(Pr)^{-2/3} \qquad (14.3\text{ - }9)$$

as shown in Figure 16-10 of Reference 34. Thus,

$$\bar{h}_D = u_s \text{ x } St\left(\frac{Sc}{Pr}\right)^{2/3} \qquad (14.3\text{ - }10a)$$

$$\text{Substituting : } St = \frac{h}{\rho C u_s} \text{ thus we get,}$$

$$\bar{h}_D = \frac{u_s \text{ x } h}{\rho C u_s} \text{ x } \left(\frac{Sc}{Pr}\right)^{2/3} \qquad (14.3\text{ - }10b)$$

As Reference 34 points out, for large partial pressures of the condensing components, Equation 14.3-10b must be corrected by a factor P_t/P_{am}. Thus,

$$\bar{h}_D = \frac{h}{\rho C} \text{x} \frac{P_t}{P_{am}} \text{x}\left(\frac{Sc}{Pr}\right)^{2/3} \qquad (14.3\text{-}11)$$

This is essentially the same result as reported by Reference 35, p. 343 and Reference 33.

Reference 34 states that experiments show Equation (14.3-8) to be valid when the Schmidt number does not differ greatly from 1.0. Equations (14.3-8) and (14.3-11) are combined to give the mass transfer rate, which is

$$\dot{m} = \frac{h}{\rho C} \times \frac{P_t}{P_{am}} \times \left(\frac{Sc}{Pr}\right)^{2/3} \times \left(\rho_{sg} - \rho_{sw}\right) \qquad (14.3 - 12)$$

An approximation was made in assuming that $(Sc/Pr)^{2/3} \cong 1.0$, thus the local mass transfer rate was computed from

$$\dot{m} = \frac{h}{\rho C} \times \frac{P_t}{P_{am}} \times \left(\rho_{sg} - \rho_{sw}\right) \qquad (14.3 - 13)$$

The heat transfer rate due to condensation is computed from

$$q_1 = \frac{\lambda h P_t}{\rho C P_{am}} \times \left(\rho_{sg} - \rho_{sw}\right) \qquad (14.3 - 14)$$

where

ρ_{sg}	is evaluated at the local bulk gas temperature
ρ_{sw}	is evaluated at the local gas-condensate interface temperature
λ	is evaluated at the local gas-condensate interface temperature
P_t	is evaluated at the local bulk gas temperature
C	is evaluated at the local bulk gas temperature

The heat transfer coefficient, h, was determined from experiments on the same geometry used in this application.

The heat transfer rate, locally, is computed from

$$q_2 = h \times (T_g - T_i) \qquad (14.3\text{-}15)$$

The basis for selecting these values is that the authorities cited as references have shown, through analyses and through cited experiments, that the methods used are accurate.

The air side pressure drop across the cooling coils at a conservative design-basis accident condition of 47 psig is estimated to be approximately 3.2-in. of water, or 0.115 psi. This will have a negligible effect on the heat removal capability of the cooling coils.

The pressure of noncondensible gases is taken into consideration because the theory behind the analysis assumed that the condensible vapor must diffuse through a noncondensible gas.

The nomenclature is as follows:

$\dot{m}$	mass flow rate of condensate, lbm/hr-ft^2
$\bar{h}_D$	mass transfer coefficient, ft/hr
ρ_{sg}	density of saturated steam at local bulk gas

temperature, lbm/ft^3

ρ_{sw} density of saturated steam at local condensate-gas interface temperature, lbm/ft^3

U_S free steam gas velocity, ft/min

Sc Schmidt number, $\mu/\rho D$, dimensionless

μ viscosity of bulk gas, lbm/ft-hr

ρ bulk gas density, lbm/ft^3

D gas-air diffusion coefficient, ft^2/hr

St Stanton number, $h/\rho C u_s$, dimensionless

h convective heat transfer coefficient, Btu/hr-ft^2-^{o}F

C specific heat of bulk gas, Btu/lbm-^{o}F

Pr Prandtl number, μ c/k, dimensionless

k thermal conductivity of bulk gas, Btu/hr-ft-^{o}F

P_t total gas pressure, lbf/ft^2

P_{am} air log-mean $\dfrac{P_{aw} - P_{ag}}{\ln \dfrac{P_{aw}}{P_{ag}}}$, lbf/ft^2

P_{aw} partial pressure of air at the local gas-condensate interface, lbf/ft^2

P_{ag} partial pressure of air at the local bulk gas temperature, lbf/ft^2

λ latent heat of vaporization (or condensation) at the local gas-condensate interface temperature, Btu/lbm

q_1 local heat transfer rate due to condensation, Btu/hr-ft^2

q_2 local heat transfer rate due to convection, Btu/hr-ft^2

T_g local bulk gas temperature, °F

T_i local gas-condensate interface temperature, °F

δ_{film} water film thickness, ft

A similar heat removal analysis of the currently installed RCFC coils results in the fan-cooler heat removal rate per fan as presented in Figure 14.3-115.

14.3.5.3 Mass and Energy Release Analyses for Postulated Loss-of-Coolant Accidents

This analysis presents the mass and energy releases to the containment subsequent to a hypothetical loss-of-coolant accident (LOCA) at 3216 MWt. The release rates are calculated for pipe failure at three distinct locations:

1. Hot leg (between vessel and steam generator)
2. Pump suction (between steam generator and pump)
3. Cold leg (between pump and vessel)

The LOCA transient is typically divided into four phases:

1. Blowdown - which includes the period from accident occurrence (when the reactor is at steady state operation) to the time when the total break flow stops.

2. Refill - the period of time when the lower plenum is being filled by accumulator and safety injection water. (This phase is conservatively neglected in computing mass and energy releases for containment evaluations.)

3. Reflood - begins when the water from the lower plenum enters the core and ends when the core is completely quenched.

4. Post-Reflood - describes the period following the reflood transient. For the pump suction and cold leg breaks, a two-phase mixture exits the core, passes through the hot legs, and is superheated in the steam generators. After the broken loop steam generator cools, the flow out of the break becomes two phase.

During the reflood phase, these breaks have the following different characteristics. For a cold leg pipe break, all of the fluid, which leaves the core must vent through a steam generator and becomes locally superheated. However, relative to breaks at the other locations, the core flooding rate (and therefore the rate of fluid leaving the core) is low, because all the core vent paths include the resistance of the reactor coolant pump. For a hot leg pipe break, the vent path resistance is relatively low, which results in a high core flooding rate, but the majority of the fluid, which exits the core bypasses the steam generators in venting to the containment. The pump suction break combines the effects of the relatively high core flooding rate, as in the hot leg break, and steam generator heat addition, as in the cold leg break. As a result, the pump suction break yields the highest energy flow rates during the post-blowdown period, thereby bounding the hot leg breaks.

The spectrum of breaks analyzed includes the largest pump suction and hot leg breaks. Because of the phenomena of reflood as discussed above, the pump suction break location is the worst case for long term containment depressurization. Smaller hot leg breaks have been shown on similar plants to be less severe than the double-ended hot leg. Cold leg breaks, however, are lower both in the blowdown peak and in the reflood pressure rise and therefore have not been analyzed.

14.3.5.3.1 Mass and Energy Release Data

Blowdown Mass and Energy Release Data

Tables 14.3-16, 14.3-22 and 14.3-28 present the calculated mass and energy releases for the blowdown phase of the various breaks analyzed.

The mass and energy releases for the double-ended pump suction break, given in Table 14.3-16, terminate 26.4 seconds after the postulated accident for the minimum ECCS case. The DEPS maximum ECCS case has a blowdown time of 26.0 seconds and the mass and energy release are given in Table 14.3-22.

Reflood Mass and Energy Release Data

Tables 14.3-17 and 14.3-23 present the calculated mass and energy releases for the reflood phase of the various breaks analyzed along with the corresponding safety injection assumption (minimum and maximum).

Two Phase Post-Reflood Mass and Energy Release Data

Tables 14.3-18 and 14.3-24 present the two phase (froth) mass and energy release data for a double-ended pump suction break using minimum and maximum safety injection assumptions, respectively.

Equilibrium and Depressurization Energy Release Data

The equilibrium and depressurization energy release has been incorporated in the post-reflood mass and energy release data. This eliminates the need to determine additional releases due to the cooling of steam generator secondary and primary metal.

14.3.5.3.2 Mass and Energy Sources

The sources of mass considered in the LOCA mass and energy release analysis are given in the mass balance Tables 14.3-19, 14.3-25, and 14.3-29. These sources are the reactor coolant system, accumulators and pumped injection.

The energy inventories considered in the LOCA mass and energy release analysis are given in Tables 14.3-20, 14.3-26, and 14.3-30. The energy sources include:

1. Reactor coolant system
2. Accumulators
3. Pumped injection
4. Decay heat
5. Core stored energy
6. Primary metal energy
7. Secondary metal energy
8. Steam generator secondary energy
9. Secondary transfer of energy (feedwater into and steam out of the steam generator secondary), main feedwater coastdown following reactor trip and SI signal generation.

The inventories are presented at the following times, as appropriate:

1. Time zero (initial conditions)
2. End of blowdown time
3. End of refill time
4. End of reflood time
5. Time that broken loop secondary energy is removed.
6. Time that intact loops secondary energy is removed.
7. Time that the secondary side is assumed to equilibrate to 14.7 psia and 212°F.

The methods and assumptions used to release the various energy sources are given in NRC-approved WCAP-10325[61].

The following items ensure that the core energy release is conservatively analyzed for maximum containment pressure:

1. Maximum expected operating temperature of the reactor coolant system
2. Allowance in operating temperature for instrument error and deadband (+7.5°F)
3. Margin in volume (1.4-percent)
4. Allowance in volume for thermal expansion (1.6-percent)
5. A core power level of 3216 MWt was assumed
6. Allowance for calorimetric error (2-percent of 3216 MWt)
7. Appropriately modified coefficients of heat transfer
8. Allowance in core stored energy for effect of fuel densification
9. Margin in core stored energy (+15-percent)

14.3.5.3.3 Blowdown Model Description

The computer code used to calculate the mass and energy release in the blowdown phase is SATAN-VI. The model is described in WCAP-9220[12] and WCAP-8302[4]. WCAP–10325[61] provides the method by which the model is used.

14.3.5.3.4 Refill Model Description

At the end of blowdown, a large amount of water remains in the cold legs, downcomer, and lower plenum. To conservatively model the refill period for the purpose of containment mass and energy releases, this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. Thus, the time required for refill is conservatively neglected.

14.3.5.3.5 Reflood Model Description

The computer code used for the reflood phase is WREFLOOD. The model is described in WCAP-9220[12] and WCAP-8170[5]. WCAP-10325[61] describes the method by which this model is used and the modifications. A complete thermal equilibrium mixing condition for the steam and ECCS injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the use and application of the M&E release evaluation model (Reference 61) in recent analyses, for example, D. C. Cook Docket (Reference 60). Even though the WCAP-10325-P-A (Reference 61) model credits steam/water mixing only in the intact loop and not in the broken loop, the justification, applicability, and NRC approval for using the mixing model in the broken loop has been documented (Reference 60). Transients of the principle parameters during reflood are given in Tables 14.3-21 and 14.3-27 for the double-ended pump suction break with minimum and maximum safety injection.

14.3.5.3.6 Post-Reflood Model Description

Two-Phase (FROTH)

The transient model (FROTH), along with its method of use, is described in WCAP-8312-A[62]. The mass and energy rates calculated by FROTH are utilized in the containment analysis to the time of containment depressurization.

Long Term (Dry Steam)

After depressurization, the mass and energy release from decay heat for 3216 MWt is based on ANSI/ANS-5.1- 1979 and the following input:

1. Decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239. The highest decay heat release rates come from the fission of the U-238 nuclei. Thus, to maximize the decay heat rate a maximum value (8%) has been assumed for the U-238 fission fraction.

2. The second highest decay heat release rate comes from the fission of the U-235 nuclei. Therefore, the remaining fission fraction (92%) has been assumed for U-235.

3. Fission rate is constant over the operating history of maximum power level.

4. The factor accounting for neutron capture in fission products has been taken from Table 10 of ANS (1979).

5. The fuel has been assumed to be at full power for 10^8 seconds.

6. The total recoverable energy associated with one fission has been assumed to be 200 MeV/fission.

7. Two sigma uncertainty has been applied to the fission product decay.

14.3.5.3.7 Single Failure Analysis

The effect of single failures of various ECCS components on the mass and energy releases is included in these data. Two analyses bound this effect for the pump suction double-ended rupture.

No failure of any ECCS component is assumed in determining the mass and energy releases for the maximum safeguards case. For the maximum safeguards case, the single failure assumed is the loss of one containment spray pump. For the minimum safeguards case, the single failure assumed is the loss of one emergency diesel generator, which results in the loss of the pumped safety injection (i.e., one residual heat removal pump and one safety injection pump) and the loss of the containment safeguards on that diesel. For further conservatism, an additional containment fan cooler unit is assumed to be unavailable, thus limiting the assumed available containment safeguards to three fan cooler and one spray pump. The analysis of both maximum and minimum safeguards cases ensure that the effect of all credible single failures on mass and energy releases is bounded.

A single failure analysis is not performed for the hot leg ruptures since the ECCS has no effect on the maximum containment pressure, which occurs at the end of blowdown.

14.3.5.3.8 Metal-Water Reaction

In the mass and energy release data presented, no zirconium-water reaction heat was considered because the clad temperature did not rise high enough for the rate of reaction to be of any significance.

14.3.5.3.9 Additional Information

System parameters needed to perform confirmatory analyses are provided in Tables 14.3-37, 14.3-38, 14.3-39, and 14.3-40. The chronology of events for the DEPS breaks are presented in Tables 14.3-31 and 14.3-32.

14.3.5.4 Evaluation of Containment Internal Structures

14.3.5.4.1 Previous Design Basis

The containment internal structures such as the reactor coolant loop compartments and the reactor shield wall are designed for the pressure build-up that could occur following a loss of coolant. If a LOCA were to occur in these relatively small volumes, the pressure would build up at a rate faster than the overall compartments.

A digital computer code, COMCO, was developed to analyze the pressure build-up in the reactor coolant loop compartments. The COMCO code is largely an extension of the COCO code in that a separation of the two-phase blowdown into steam and water is calculated and the pressure build-up of the steam-air mixture in the compartment is determined. Each compartment has a vent opening to the free volume of the containment.

The main calculation performed is a mass energy balance within the control volume of a compartment. The pressure builds up in the compartment until a mass and energy relief through the vent exceeds the mass and energy entering the compartment from the break. The reactor coolant loop compartments are designed for the maximum calculated differential pressure resulting from an instantaneous double-ended rupture of the reactor coolant pipe.

There are two reactor coolant loop compartments (i.e., crane wall areas) with two loops in each compartment. The total free volume of each compartment is 113,500-ft^3 with a vent area of 1000-ft^2. The calculated differential pressure across the wall of the compartment is 6.4 psi.

The primary shield around the reactor vessel is designed for a pressure of 1000 psi to provide missile protection against the highly unlikely failure of the reactor vessel by longitudinal splitting or by various modes of circumferential cracking.

14.3.5.4.2 Current Design Basis

Additional analyses for initial conditions, including prior operation parameters and 3216 MWt power operation parameters, were evaluated relative to short term subcompartment pressurization effects. The mass and energy releases from postulated full double-ended Reactor Coolant System (RCS) breaks were determined with the SATAN-V computer program, reference 62. The TMD computer program, reference 64, was used to evaluate the subcompartment containment response to the hypothetical pipe ruptures. The results of the evaluation indicate that for the full double-ended breaks the peak calculated differential pressure across the wall of the loop compartment was conservatively calculated to be greater that the current design basis of 6.4 psi, as discussed in Section 14.3.5.4.1.

References 65 and 66 demonstrate that RCS primary loop pipe breaks need not be considered in the structural design basis of the Indian Point 2 Plant. Therefore, implementation of Leak-Before-Break (LBB) Technology has eliminated the large RCS breaks from dynamic consideration. For the LOCA event, the break locations and the break sizes are significantly less severe than the previously mentioned RCS double-ended breaks. The previously calculated subcompartment pressure of 6.4 psi is discussed in 14.3.5.4.1. The subcompartment pressure loadings have been evaluated and it has been determined that the loadings, including LBB and operation at 3216 MWt, are less than 6.4 psi. The peak differential pressure across the primary shield wall is bounded by the design pressure of 1000 psi, as discussed in Section 14.3.5.4.1. The effects of the differential operating parameters at 3216 MWt do not result in a challenge to the subcompartment designs.

14.3.5.5 Evaluation of Long Term Fan Cooler Capability

The ability of the fan coolers to limit containment pressure following loss of the component cooling system has been examined. If the component cooling loop were lost for any reason during long-term recirculation, core subcooling could be lost and boiling in the core would begin. Since the cooling units of the fans are cooled by service water, the energy from the core would be removed from the containment via the fans.

The model employed in this analysis does not consider recirculation spray to operate and conservatively considers decay heat from the core to enter the containment as steam during the entire LOCA long-term transient. Therefore, the pressures calculated are not affected with a postulated component cooling system failure, because core energy is already postulated to enter the containment as boil off. Containment pressure at various times for the DEPS case with minimum safeguards is shown below:

Time After Accident Occurs	3 Fans (psig)	2 Fans (psig)
Deleted	Deleted	Deleted
At 1 day	17	25.6
At 1 week	12.6	17.9

14.3.5.6 Radiolytic Hydrogen Formation

Radiolytic hydrogen formation is discussed in Section 6.8.3.

14.3.6 Environmental Consequences Of A Loss-Of-Coolant Accident

Chapters 5 and 6 describe the protection systems and features that are specifically designed to limit the consequences of a major LOCA. The capability of the safety injection system for preventing melting of the fuel clad and the ability of the containment and containment cooling systems to absorb the blowdown resulting from a major loss of coolant are discussed in Section 14.3.4. The capability of the safeguards in meeting dose limits set forth in 10 CFR 50.67 was demonstrated as documented in this section.

For the Large Break Loss-of-Coolant Accident radiological consequences, an abrupt failure of the main reactor coolant pipe is assumed to occur. It is assumed that the emergency core cooling features fail to prevent the core from experiencing significant degradation (i.e. melting). A portion of the activity that is released to the containment is assumed to be released to the environment due to the containment leaking at its design rate.

In the following sections, the expected activity is described and the containment and isolation features are discussed. Sodium tetraborate is used to control pH in the recirculation solutions, as described in Sections 6.3.2.1.2 and 6.3.2.2.12.

14.3.6.1 Effectiveness of Containment and Isolation Features in Terminating Activity Release

The reactor containment serves as a boundary limiting activity leakage. The containment is steel lined and designed to withstand internal pressure in excess of that resulting from the design-basis LOCA (Chapter 5). All weld seams and penetrations are designed with a double barrier to inhibit leakage. In addition, the weld channel and penetration pressurization system supplies a pressurized nitrogen seal, at a pressure above the containment design pressure, between the double barriers so that if leakage occurred it would be into the containment (Section 6.5). The containment isolation system, Section 5.2, provides a minimum of two barriers in piping penetrating the containment. The isolation valve seal-water system, Section 6.6, provides a water seal at a pressure above containment design pressure in the piping lines that could be a source of leakage and is actuated on the containment isolation signal within 1 min to terminate containment leakage. The containment is designed to leak at a rate of less than 0.1-percent per day at design pressure without including the benefit of either the isolation valve seal-water system or the weld channel and penetration pressurization system. The weld seams and penetrations are pressurized continuously during reactor operation causing zero outleakage through these paths.

14.3.6.1.1 Effectiveness of Spray System for Removal of Airborne Activity

One train of the containment spray system is assumed to operate following the LOCA. The containment sprays are an effective means for removing airborne activity existing as aerosols or as elemental iodine. As discussed in Appendix 6A, the following spray removal coefficients have been determined for Indian Point Unit 2:

Aerosol Removal

Injection spray mode of operation	4.4 hr^{-1}
Recirculation spray mode of operation	2.25 hr^{-1}

Once a DF of 50 is attained (i.e., when the airborne activity is reduced to 2% of the total activity released to the containment atmosphere), the spray removal coefficient is reduced by a factor of 10. For the Indian Point 2 analysis it is assumed that the sprays are terminated after the DF of 50 is reached for aerosols and that aerosol removal continues after that time due to sedimentation only. Consistent with this assumption, sprays are credited for 3.4 hours following the event.

Elemental Iodine Removal

Injection spray mode of operation	20 hr^{-1}
Recirculation spray mode of operation	5.0 hr^{-1}

Once a DF of 200 is attained (i.e., when the airborne activity is reduced to 0.5% of the total activity released to the containment atmosphere), no additional removal of elemental iodine is assumed.

14.3.6.1.2 [Deleted]

14.3.6.1.3 [Deleted]

14.3.6.1.4 Sedimentation Removal of Particulates

During spray operation credit is taken for sedimentation removal only in the unsprayed portion of the containment. It is assumed that containment spray operation is terminated at 3.4 hours as discussed in Section 14.3.6.1.1. After spray operation is terminated sedimentation is credited throughout the containment.

Based on the Containment Systems Experiments (CSE) which examined the air cleanup experienced through natural transport processes, it was found that a large fraction of the aerosols were deposited on the floor rather than on the walls indicating that sedimentation was the dominant removal process for the test (Reference 86). The CSE tests determined that there was a significant sedimentation removal rate even with a relatively low aerosol concentration. From Reference 86, even at an air concentration of 10 $\mu g/m^3$, the sedimentation removal coefficient was above 0.3 hr^{-1}. With 2.0-percent of particulates remaining airborne at the end of crediting spray removal, there would be in excess of 10,000 $\mu g/m^3$ and an even higher sedimentation rate would be expected. The sedimentation removal coefficient is conservatively assumed to be only 0.1 hr^{-1}. It is also conservatively assumed that sedimentation removal does not continue beyond a DF of 1000.

14.3.6.2 Source Term

The reactor coolant activity is assumed to be released over the first 30 seconds of the accident. However, the activity in the coolant is insignificant compared with the release from the core and is not included in the analysis.

The use of NUREG-1465 (Reference 87) and Regulatory Guide 1.183 (Reference 92) source term modeling results in several major departures from the assumptions used in previous LOCA dose analyses from TID-14844 (Reference 88). Instead of assuming instantaneous melting of the core and release of activity to the containment, the release of activity from the core occurs over a 1.8 hour interval. Also, instead of considering only the release of iodines and noble gases, a wide spectrum of nuclides is taken into consideration. Table 14.3-43 lists the nuclides being considered for the LOCA with core melt (eight groups of nuclides). Table

14.3-43a provides the fission product release fractions and the timing/duration of releases to the containment as assumed in the analysis based on Regulatory Guide 1.183.

Instead of the iodine being primarily in the elemental form, the iodine is mainly in the particulate form (cesium iodide) and the fraction that is in the organic form is much smaller than in the earlier model. The iodine characterization from NUREG-1465 and Regulatory Guide 1.183 is 4.85% elemental, 0.15% organic and 95% particulate. The other groups of nuclides (other than the noble gases) all occur as particulates only.

14.3.6.2.1 Atmosphere Dispersion

The offsite dispersion factors were calculated with the following meteorology and the model described in Reg. Guide 1.4 (Reference 67).

a. Pasqual Type F, 1 m/sec wind speed, nonvarying wind direction, and volumetric building wake correction factor with C = 0.5 and the cross-sectional area of the containment structure for the first 8 hr.

b. From 8 to 24 hr, Pasqual Type F, 1 m/sec wind speed with plume meander in a 22.5-degree sector.

c. From 1 to 4 days, Pasqual Type F and 2 m/sec wind speed with a frequency of 60-percent Pasqual Type D and 3 m/sec wind speed with a frequency of 40-percent, with a meander in the same 22.5-degree sector.

d. From 4 to 30 days, Pasqual Types C, D, and F each occurring 33-1/3-percent of the time with wind speeds of 3 m/sec, 3 m/sec, and 2 m/sec, respectively, with a meander in the same 22.5-degree sector 33-1/3-percent of the time.

The radiological consequences analysis employs the dispersion factors listed in Table 14.3-46 for the site boundary and low population zone.

14.3.6.3 Method of Analysis

The activity leaking from the containment following the accident is calculated for each isotope as a function of time taking into account the core activity, release fractions, removal in containment via sprays and sedimentation (as described previously) and the containment leak rate. The major assumptions and parameters used to determine the doses due to containment leakage are given in Table 14.3-49. To evaluate the ability to meet the 10 CFR 50.67 limits, the total effective dose equivalent (TEDE) dose was calculated at the site boundary and at the low population zone. Onsite exposure is evaluated in the control room. The TEDE dose is equivalent to the committed effective dose equivalent (CEDE) dose from inhalation of activity plus the effective dose equivalent (EDE) dose from submersion in the activity cloud for the duration of the exposure to the cloud.

14.3.6.3.1 Offsite CEDE Dose

The CEDE dose resulting from activity leaking from the reactor containment following an accident is computed from:

$$D(I,T) = Q(I,T) \cdot DCF(I) \cdot B(T) \cdot \frac{\chi}{Q(x,T)}$$

Where:

D(I,T) = CEDE dose from isotope I during period T (rem)
Q(I,T) = activity of isotope I released in time period T (curies)
DCF(I) = CEDE dose conversion factor for isotope I (rem/curie) (See Table 14.3-45)
B(T) = breathing rate (m^3/sec)
χ/Q(x,T)= atmospheric dispersion factor at distance x and during period T (sec/m^3)

14.3.6.3.2 Offsite EDE Dose

For the computation of the offsite EDE doses from cloud immersion, the following equation was used:

$$D(I,T) = Q(I,T) \cdot DCF(I) \cdot \frac{\chi}{Q(x,T)}$$

Where:

D(I,T) = EDE dose from isotope I during period T (rem)
Q(I,T) = activity of isotope I released in time period T (curies)
DCF(I) = EDE dose conversion factor for isotope I (rem-m^3/curie-sec) (See Table 14.3-45)
χ/Q(x,T) = atmospheric dispersion factor (sec/m^3) at distance x and during period T

14.3.6.4 Containment Leakage NUREG-1465 Core Release Doses

The resultant site boundary dose is 17.8 rem TEDE. The low population zone dose is 12.1 rem TEDE.

The total large break LOCA offsite dose is the combination of the dose for the containment leakage pathway discussed above and the dose for the ECCS recirculation leakage pathway discussed in Section 14.3.6.6.

14.3.6.5 Control Room Dose Evaluations

The control room is modeled as a discrete volume. The filtered and unfiltered inflow to the control room are used to calculate the activity in the control room. The control room parameters modeled in the analysis are presented in Table 14.3-50.

The control room CEDE dose from each isotope for each time period is:

$$D(I,T) = CONC(I,T) \cdot DCF(I) \cdot B(T)$$

Where:

D(I,T) = CEDE dose from isotope I during period T (rem)
CONC(I,T) = concentration of isotope I in the control room (Ci-sec/m^3)
DCF(I) = CEDE dose conversion factor for isotope I (rem/curie)
B(T) = breathing rate (m^3/sec)

The control room EDE dose from each nuclide for each time period is:

$$D(I,T) = \frac{1}{GF} CONC(I,T) \cdot DCF(I)$$

Where:

D(I,T) = inhalation dose from isotope I during period T (rem)
DCF(I) = inhalation dose conversion factor for isotope I (rem-m^3/curie-sec)
CONC(I,T) = concentration of isotope I in the control room (Ci-sec/m^3)
GF = geometry factor, calculated based on Reference 89 using the following equation, where V is the control room volume

$$GF = \frac{1173}{V^{0.338}}$$

The ARCON96 computer code was utilized to analyze the X/Q (atmospheric dispersion factor) values at the control room intake for releases at Indian Point 2. This code was developed by Pacific Northwest National Laboratory for the United States Nuclear Regulatory Commission.

The ARCON96 analysis for Indian Point 2 required calculation of X/Q values for four locations: a containment surface leak, the side of the auxiliary boiler feedwater building, vent stacks on the roof of the auxiliary boiler feedwater building, and the containment vent. These correspond to potential release points for various accident scenarios. Additional conservatisms were added to the calculations:

1. The initial plume standard deviations used were equal to one-sixth of the width and available height of the containment.
2. The initial horizontal plume dimension for vent releases is the equivalent vent diameter divided by six
3. All vertical velocities were set to zero

The X/Q values calculated for release of activity from the event-specific release point to the control room intake are used to determine the activity available at the control room intake, and are presented in Table 14.3-51.

The accumulated dose to control room operators following the postulated accidents were calculated using the same release, removal and leakage assumptions as the offsite doses. The control room personnel dose calculations includes the direct dose from the radiation cloud outside the control room as well as the inhalation and acute doses from the activity introduced inside the control room. That direct dose takes into account the shielding afforded by the control room walls.

In addition to the dose from activity released from containment, the large break LOCA control room dose includes a conservative calculation of the direct whole-body gamma dose in the control room from the activity inside the containment. The activity is assumed to be homogeneously distributed within the free volume of the reactor containment. The source intensity as a function of time after the accident is determined considering decay and removal by processes described in Section 14.3.6.1. The direct dose rate in the control room due to the activity dispersed within the containment is calculated based on a point kernel attenuation model. The source region is divided into a number of incremental source volumes and the associated attenuation, gamma ray buildup, and distance through regions between each source point and the control room are computed. The summation of all point source contributions gives the total direct dose rate at the control room.

The control room doses calculated for each of the events are presented in table 14.3-52 and in all cases are less than the 5.0 rem TEDE control room dose limit values of 10 CFR 50.67.

14.3.6.6 External Recirculation

The Indian Point Unit 2 design includes internal recirculation which is to be maintained for the first 6.5 hours following a LOCA. An analysis has been performed to calculate the dose resulting from leakage from the ECCS outside containment after external recirculation is established at 6.5 hours. The analysis models the same core iodine release model as the containment leakage releases discussed in Section 14.3.6.2, the same dose calculation method as discussed in Section 14.3.6.3 and the control room model discussed in Section 14.3.6.5. The offsite dose is calculated using the meteorological dispersion factors discussed in Section 14.3.6.2.1. The analysis considered a leak rate of 4.0 gph. This is double the Technical Specification limit as required by Regulatory Guide 1.183 (Reference 92). This is more than 15 times greater than the estimated SI and RHR system design leakage of 999 cm^3/hr discussed is Section 6.2.3.8 and Table 6.2-9. The leakage is assumed to start at 6.5 hours and continues until 30 days from accident initiation. A conservatively low sump water volume is modeled to maximize the iodine concentration in the leakage.

The calculations were performed using the approach in Regulatory Guide 1.183 (Reference 92) guidance that if the calculated flash fraction is less than 10% or if the water is less than 212^{o}F, then an amount of iodine smaller than 10% of the iodine in the leakage may be used if justified based upon actual sump pH history and ventilation rates. Iodine release fractions have been specifically calculated for external leakage sources (ECCS leakage post LOCA) beginning at 6.5 hours post accident when ECCS flow is directed by procedure to go to portions of the external safety injection system. These calculations are based upon calculated post accident fluid temperatures and pH in sump water, flows and volumes in the primary auxiliary building (PAB), and ventilation flow rates in various areas of the PAB. Leakage is assumed to be at 4 gph. The calculation was performed both with and without the boundary layer effect. The boundary layer effect credits the iodine concentration gradient across the boundary layer at the liquid-gas interface, thus lowering the equilibrium iodine concentration in the gas phase. The calculated values are:

	Fraction of Incoming Iodine Released	
Time Period	With Boundary Layer Effect	Without Boundary Layer Effect
6.5 to 8 hours	0.012	0.12
8 to 24 hours	0.00855	0.0855
1 to 4 days	0.00523	0.0523
4 to 30 days	0.003	0.03

The releases would be subject to filtration by the filtered ventilation system provided for the primary auxiliary building which houses the portions of the ECCS located outside containment. However, filtration of the releases is not credited in the analysis.

Since the leakage is initiated at 6.5 hours after the LOCA, it does not contribute to the 2 hour site boundary dose. When boundary layers effects are considered the 30 day low population zone dose is 0.15 rem TEDE and the 30 day control room dose is 0.14 rem TEDE. When the boundary layer effects are neglected the doses increase to 1.5 rem at the low population zone and 1.36 rem in the control room.

The total large break LOCA offsite and control room doses are the combination of the doses for the containment leakage pathway discussed in Sections 14.3.6.4 and 14.3.6.5 and the doses for the ECCS recirculation leakage pathway discussed above.

The remainder of this section discusses the analysis performed prior to implementation of the Regulatory Guide 1.183 dose methodology and is retained for historical purposes.

Indian Point Unit 2 has an internal spilled coolant and injection water recirculation system incorporating two pumps for return of water to the reactor core for decay heat removal after a LOCA. The residual heat removal pumps serve as a backup to these pumps. The residual heat removal compartment and piping is surrounded by 2-ft-thick concrete shield walls. In addition, each residual heat removal compartment is shielded from its adjacent residual heat removal compartment and piping by 2-ft of concrete. Figure 14.3-129 shows the results of an evaluation of direct radiation levels surrounding a 14-in. residual heat removal pipe. The evaluation was based on gap activity, except noble gases, being diluted in the reactor coolant and refueling water volume, which is being recirculated through the pipes. With the 24-in. of concrete provided, the dose levels would be an order of magnitude less than shown for 12-in. of concrete.

As discussed in Section 6.2, design leakage for the external recirculation system was less that 1000 cm^3/hr. Westinghouse performed experiments in which solutions of iodine in sodium hydroxide of pH that would exist in the containment after a loss of coolant were evaporated to dryness. The result was that less that 10^{-3} of the iodine was released. For purpose of conservatism, it was assumed that for a period of 1 hr, 10-percent of the iodine in the leakage was released to atmosphere. Assuming gap iodine activity immediately after the loss of coolant was present in the sump water being recirculated, the offsite thyroid dose for the period was less than 2 mrem. Protection from inhalation dose in the auxiliary building following an accident can be attained by the use of self-contained breathing apparatus during those periods when access is required.

14.3.6.7 <u>Small Break LOCA Radiological Consequences</u>

The radiological consequences resulting from a small break LOCA which is large enough to result in actuation of the containment spray system would be bounded by the Large Break LOCA analysis. This is true because a small break releases less activity to the containment than that assumed in the large break, but the spray system would function in an identical manner.

An analysis was performed to determine the radiological consequences for a small break LOCA that does not actuate the containment sprays. As a result of the accident, fuel clad damage is assumed to occur. Due to the potential for leakage between the primary and secondary systems, radioactive reactor coolant is assumed to leak from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere through either the atmospheric relief valves or the main steam safety valves. Radioactive reactor coolant is also discharged to the containment via the break. A portion of this radioactivity is released through containment leakage to the environment.

In determining the offsite doses following the accident, it is conservatively assumed that all of the fuel rods in the core suffer sufficient damage that all of their gap activity is released. Five percent of the core activity of iodines, noble gases, and alkali metals is assumed to be contained in the pellet-clad gap. The iodine released from the fuel is assumed to be 95% particulate (cesium iodide), 4.85% elemental, and 0.15% organic. These fractions are used for the containment leakage release pathway. However, for the steam generator steaming pathway the iodine in solution is considered to be all elemental and after it is released to the environment the iodine is modeled as 97% elemental and 3% organic.

Conservatively, all the iodine, alkali metals group and noble gas activity (from prior to the accident and resulting from the accident) is assumed to be in the primary coolant (and not in the containment) when determining doses due to the primary to secondary steam generator tube leakage.

The primary to secondary steam generator tube leak used in the analysis is 150 gpd per steam generator (total of 600 gpd).

When determining the doses due to containment leakage, all of the iodine, alkali metal and noble gas activity is assumed to be in the containment. The design basis containment leak rate of 0.1% per day is used for the initial 24 hours. Thereafter, the containment leak rate is assumed to be one-half the design value, or 0.05% per day. Releases are continued for 30 days from the start of the event.

No credit for activity partitioning is taken for any steam released to the condenser prior to reactor trip and concurrent loss of offsite power. All noble gas activity carried over to the secondary side through steam generator tube leakage is assumed to be immediately released to the outside atmosphere. Secondary side releases are terminated when the primary pressure drops below the secondary side pressure.

An iodine partition factor in the steam generators of 0.01 curies/gm steam per curies/gm water is used. This partition factor is also used for the alkali metal activity in the steam generators. This conservatively overstates the release of alkali metal activity via this pathway since their release would be limited by the moisture carryover fraction of 0.0025.

For the containment leakage pathway, no credit is taken for containment spray operation which would remove airborne particulates and elemental iodine. Credit is taken for sedimentation of particulates and deposition of elemental iodine onto containment surfaces. The sedimentation coefficient is assumed to be 0.1 hr^{-1}, the same as credited in the large break LOCA analysis (see Section 14.3.6.1.4). Deposition removal of elemental iodine is determined using the model described in SRP Section 6.5.2 (Reference 68). The first order deposition removal rate constant for elemental iodine is written as follows:

$$\lambda_e = kA / V$$

where λ_e = Elemental removal rate constant due to deposition, hr^{-1}
k = Mass transfer coefficient = 4.9 m/hr
A = Area available for deposition, ft^2
V = Containment volume, ft^3

Parameters for Indian Point Unit 2 are:

A = 250,000 ft^2
V = 2.61×10^6 ft^3

The resulting deposition removal coefficient is 1.5 hr^{-1}. Consistent with SRP Section 6.5.2, removal of elemental iodine is terminated when a DF of 200 is reached.

The resultant 2 hour site boundary dose is 7.8 rem TEDE. The 30 day low population zone dose is 10.8 rem TEDE. These doses are calculated using the meteorological dispersion factors discussed in Section 14.3.6.2.1. The offsite doses resulting from the accident are less than the 25 rem TEDE limit value of 10 CFR 50.67.

The accumulated dose to the control room operators following the postulated accident was calculated using the same release, removal and leakage assumptions as the offsite dose, and using the control room model discussed in Section 14.3.6.5 and Tables 14.3-50 and 14.3-51. The calculated central control room doses are presented in Table 14.3-52 and are less than the 5.0 rem TEDE control room dose limit values of 10CFR 50.67.

14.3.6.8 Summary and Conclusions

The total large break LOCA offsite and control room doses are the combination of the doses for the containment leakage pathway discussed in Sections 14.3.6.4 and 14.3.6.5 and the doses for the ECCS recirculation leakage pathway discussed in Section 14.3.6.6. With boundary layer effects considered in the ECCS recirculation leakage analysis the total LOCA doses are 17.8 rem TEDE for the limiting 2 hour site boundary dose, 12.25 rem TEDE for the 30 day low population zone dose and 3.68 rem TEDE for the 30 day control room dose. Neglecting boundary layer effects in the ECCS leakage analysis has no impact on the limiting 2 hour site boundary dose, but increases the 30 day low population zone and control room doses to 13.6 rem TEDE and 4.9 rem TEDE, respectively.

The small break LOCA doses are 7.8 rem TEDE for the limiting 2 hour site boundary dose, 10.8 rem TEDE for the 30 day low population zone dose and 3.5 rem TEDE for the 30 day control room dose.

Table 14.3-52 lists the calculated control room doses for all the analyzed accidents and demonstrates that the large break LOCA results in the highest control room doses.

Thus, the doses resulting from large break and small break LOCA the accidents are less than the 25 rem TEDE offsite dose limit and 5.0 rem TEDE control room dose limit values of 10 CFR 50.67. It is concluded that even with very pessimistic assumptions that do not take full credit for the safeguards systems provided, doses after a loss of coolant accident would be within the 10 CFR 50.67 limits.

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TABLE 14.3-1
Large Break LOCA Sequence of Events for Limiting PCT Transient

Event	Time (sec)
Start of Transient	0.0
Safety Injection Signal (Pressurizer Pressure)	6.0
Accumulator Injection Begins	10.0
Containment Spray Heat Removal System Starts (Offsite Power Available)	20.0
End of Blowdown	28.0
Containment Fan Cooler Heat Removal System Starts (Offsite Power Available)	30.0
Accumulator Empty	39.0
Bottom of core Recovery	40.0
Safety Injection Begins	51.0
PCT Occurs	123.0
PCT Elevation Quench	330.0
End of Transient	500.0

TABLE 14.3-2
Large-Break Containment Data

Net free volume	2.61×10^6-ft^3
Initial conditions	
Pressure	14.7 psia
Temperature	80^{o}F
Refueling water storage tank temperature	35^{o}F
Service water temperature	28^{o}F
Outside temperature	-20^{o}F
Spray system	
Number of pumps operating	2
Total flow rate	6712 gpm
Actuation time	20 sec
Safeguards fan coolers	
Number of fan coolers operating	5
Fastest postaccident initiation of fan coolers	30 sec

.

TABLE 14.3-2 (Cont.)
Large-Break Containment Data

Structural heat sinks		
	Thickness (in.)	Area (ft^2)
1.	0.007 paint, 0.375 steel, 54.0 concrete	38,584
2.	0.007 paint, 0.5 steel, 42.0 concrete	28,613
3.	12.0 concrete	15,000
4.	0.375 stainless steel, 12.0 concrete	10,000
5.	12.0 concrete	61,000
6.	0.5 steel	68,792
7.	0.007 paint, 0.375 steel	81,704
8.	0.25 steel	27,948
9.	0.007 paint, 0.1875 steel	69,800
10.	0.125 steel	3,000
11.	0.138 steel	22,000
12.	0.0625 steel	10,000
13.	0.019 stainless steel, 1.25 insulation, 0.75 steel, 54.0 concrete	785
14.	0.019 stainless steel, 1.25 insulation 0.5 steel, 54.0 concrete	6,849
15.	0.025 stainless steel, 1.5 insulation 0.5 steel, 54.0 concrete	3,792
16.	0.025 stainless steel, 1.5 insulation 0.375 steel, 54.0 concrete	4362
17.	0.007 paint, 0.375 steel, 54.0 concrete	7,100
18.	0.025 stainless steel, 1.5 insulation, 0.5 steel, 54.0 concrete	24
19.	0.0334 stainless steel	53457

TABLE 14.3-2A
Best-Estimate Large Break LOCA Mass and Energy Releases from BCL Used for COCO Calculation at Selected Time Points for Indian Point Unit 2

	M&E from Vessel Side BCL		M&E from Loop Side BCL	
Time (seconds)	**Mass Flow (lbm/sec.)**	**Energy Flow (BTU/sec)**	**Mass Flow (lbm/sec)**	**Energy Flow (BTU/sec)**
0.0	8623	4591667	-8	0
0.5	26190	13828421	54917	29053714
1.0	25923	13848634	51797	27373685
1.5	24961	13659035	47428	25064545
2.0	22548	12660066	42978	22737052
4.0	11656	7400663	27704	14808982
6.0	7208	5577153	21746	11977783
8.0	5777	4809423	17896	10226020
10.0	4630	4000111	13209	8027556
12.0	3700	3204590	9758	6010368
14.0	2714	2398163	10389	4983225
16.0	1517	1519547	8428	3404399
18.0	854	909753	6549	2103497
20.0	458	513981	6494	1569218
25.0	104	127461	1487	244532
50.0	108	137218	842	349322
75.0	51	64361	156	132775
100.0	40	51027	94	74727
125.0	48	60750	164	119909
150.0	46	58576	175	130207
175.0	43	54090	146	114152
200.0	48	60379	174	141615
225.0	46	58331	160	128531
250.0	43	53809	173	112595
275.0	48	58978	165	137987
300.0	51	62270	250	141408
325.0	53	63195	227	152226
350.0	74	81605	248	145791
375.0	49	59722	221	134873
400.0	53	61745	170	119837
425.0	46	55114	154	126105
450.0	42	50763	138	114950
475.0	79	82319	171	136287
500.0	69	73949	125	96929

TABLE 14.3-3
Key LOCA Parameters and Initial Transient Assumptions for
Indian Point Unit 2

Parameter	Initial Transient	Range / Uncertainty
1.0 Plant Physical Description		
a. Dimensions	Nominal	Sample (3)
b. Flow resistance	Nominal	Sample (3)
c. Pressurizer location	Opposite broken loop	Bounded
d. Hot assembly location	Under limiting location	Bounded
e. Hot assembly type	15 x 15 upgraded, ZIRLO™ clad and Non-IFBA	Bounded
f. SG tube plugging level	High (10%)	Bounded(1)
2.0 Plant Initial Operating Conditions		
2.1 Reactor Power		
a. Core average linear heat rate (AFLUX)	Nominal – Based on 100% of uprated power (3216 MWt)	Sample (3)
b. Hot Rod Peak Linear heat rate (PLHR)	Derived from desired Tech Spec (TS) limit F_Q = 2.5 and maximum baseload F_Q = 2.0	Sample (3)
c. Hot rod average linear heat rate (HRFLUX)	Derived from TS $F_{\Delta H}$ = 1.7	Sample (3)
d. Hot assembly average heat rate (HAFLUX)	HRFLUX/1.04	Sample (3)
e. Hot assembly peak heat rate (HAPHR)	PLHR/1.04	Sample (3)
f. Axial power distribution (PBOT, PMID)	Figure 14.3-20	Sample (3)
g. Low power region relative power (PLOW)	0.3	Bounded (2)
h. Cycle burnup	~100 MWD/MTD	Sample (3)
i. Prior operating history	Equilibrium decay heat	Bounded
j. Moderator Temperature Coefficient (MTC)	Tech Spec Maximum (0)	Bounded
k. HFP boron	800 ppm	Generic

TABLE 14.3-3 (Cont.)
Key LOCA Parameters and Initial Transient Assumptions for
Indian Point Unit 2

Parameter	Initial Transient	Range / Uncertainty
2.2 Fluid Conditions		
a. T_{avg}	High Nominal T_{avg} =572°F	Bounded (1), Sample (3)
b. Pressurizer pressure	Nominal (2250.0 psia)	Sample (3)
c. Loop flow	80,700 gpm	Bounded (4)
d. T_{UH}	T_{Hot}	0
e. Pressurizer level	Nominal at high Tavg	0
f. Accumulator temperature	Nominal (105 °F)	Sample (3)
g. Accumulator pressure	Nominal (656.2 psia)	Sample (3)
h. Accumulator liquid volume	Nominal (795 ft^3)	Sample (3)
i. Accumulator line resistance	Nominal	Sample (3)
j. Accumulator boron	Minimum (2000 ppm)	Bounded
3.0 Accident Boundary Conditions		
a. Break location	Cold leg	Bounded
b. Break type	Guillotine (DEGCL)	Sample (3)
c. Break size	Nominal (cold leg area)	Sample (3)
d. Offsite power	Available (RCS pumps running)	Bounded(2)
e. Safety injection flow	Minimum (Table 14.3-5B)	Bounded
f. Safety injection temperature	Nominal (725 °F)	Sample (3)
g. Safety injection delay	Max delay (38.0 sec)	Bounded
h. Containment pressure	Bounded – Lower (conservative) than pressure curve shown in figure 14.3-22	Bounded
i. Single failure	ECCS: Loss of 1 SI train; Containment pressure: all trains operational	Bounded
j. Control rod drop time	No control rods	Bounded

TABLE 14.3-3 (Cont.)
Key LOCA Parameters and Initial Transient Assumptions for
Indian Point Unit 2

Parameter	Initial Transient	Range / Uncertainty
4.0 Model Parameters		
a. Critical Flow	Nominal (C_D = 1.0)	Sample (3)
b. Resistance uncertainties in broken loop	Nominal (as coded)	Sample (3)
c. Initial stored energy/fuel rod behavior	Nominal (as coded)	Sample (3)
d. Core heat transfer	Nominal (as coded)	Sample (3)
e. Delivery and bypassing of ECC	Nominal (as coded)	Conservative
f. Steam binding/entrainment	Nominal (as coded)	Conservative
g. Noncondensable gases/accumulator nitrogen	Nominal (as coded)	Conservative
h. Condensation	Nominal (as coded)	Sample (3)

Notes:
1. Confirmed to be limiting
2. High PLOW of 0.8 confirmed to be limiting; Loss-Of-Offsite-Power confirmed to be limiting
3. Sampling distribution defines in Table 5.2-1 of Reference 79
4. Assumed to be result of loop resistance uncertainty

TABLE 14.3-4
Limiting Large Break PCT and Oxidation Results for Indian Point Unit 2

Parameter	Result
95/95 Peak Clad Temperature (PCT)	1,962°F*
95/95 Maximum Cladding Oxidation (LMO)	<2152°F_1
95/95 Maximum Core-wide Oxidation (CWO)	<13%

* The PCT result provided do not reflect any individual PCT assessments discussed in Section 14.3.3.3.4

TABLE 14.3-5A
Plant Operating Range Allowed by the Best-Estimate Large Break LOCA Analysis for Indian Point Unit 2

Parameter		Operating Range
1.0	Plant Physical Description	
	a) Dimensions	No in-board assembly grid deformation during LOCA + SSE
	b) Flow resistance	N/A
	c) Pressurizer location	N/A
	d) Hot assembly location	Anywhere in core interior (149 locations)[1]
	e) Hot assembly type	15 X 15 Upgraded fuel design
	f) SG tube plugging level	≤ 10%
	g) Fuel assembly type	15 X 15 upgraded fuel with ZIRLO™ cladding, non-IFBA or IFBA [2]
2.0	Plant Initial Operating Conditions	
	2.1 Reactor Power	
	a) Core average linear heat rate	Core power $\leq$ 102% of 3216 MWt
	b) Peak linear heat rate	$F_Q \leq 2.5$
	c) Hot rod average linear heat rate	$F_{\Delta H} \leq 1.70$
	d) Hot assembly average linear heat rate	$P_{HA} \leq 1.7 / 1.04$
	e) Hot assembly peak linear heat rate	$F_{Q(HA)} \leq 2.5 / 1.04$
	f) Axial power distribution (PBOT, PMID)	Figure 14.3-21
	g) Low power region relative power (PLOW)	$0.3 \leq$ PLOW ≤ 0.8
	h) Hot assembly burnup	$\leq$ 75,000 MWD/MTU, lead rod
	i) Prior operating history	All normal operating histories
	j) MTC	$\leq$ 0 at hot full power (HFP)
	k) HFP boron (minimum)	800 ppm (at BOL)

TABLE 14.3-5A (Cont.)
Plant Operating Range Allowed by the Best-Estimate Large Break LOCA Analysis
for Indian Point Unit 2

Parameter		Operating Range
	2.2 Fluid Conditions	
	a) T_{avg}	$549 - 3.3°F \leq T_{avg} \leq 572 + 3.3°F$ (2)
	b) Pressurizer pressure	2250 -25 psia $\leq P_{RCS} \leq$ 2250 + 25 psia (3)
	c) Loop flow	≥ 80,700 gpm/loop
	d) T_{UH}	Current upper internals, T_{Hot} UH
	e) Pressurizer level	Normal level, automatic control
	f) Accumulator temperature	$80°F \leq T_{ACC} \leq 130°F$
	g) Accumulator pressure	612.7 psia $\leq P_{ACC} \leq$ 699.7 psia
	h) Accumulator liquid volume	723 $ft^3 \leq V_{acc} \leq$ 875-ft^3
	i) Accumulator fL/D	Current line configuration
	j) Minimum ECC boron	≥ 2000 ppm
3.0	Accident Boundary Conditions	
	a) Break location	N/A
	b) Break type	N/A
	c) Break size	N/A
	d) Offsite power	Available or Loss-Of-Offsite-Power (LOOP)
	e) Safety injection flow	Table 14.3-5B
	f) Safety injection temperature	35°F ≤ SI Temp ≤110°F
	g) Safety injection delay	≤ 38 seconds (with offsite power) ≤ 45 seconds (with LOOP)
	h) Containment pressure	Figure 14.3-22, raw data in Table 14.3-2 and M&E releases in Table 14.3-2A
	i) Single failure	Loss of one ECCS train
	j) Control rod drop time	N/A

NOTE:
(1) 44 peripheral locations (Figure 3.2-8 from Reference 79) will not physically be lead power assembly.
(2) Include -3 (bias); Bias sign correction: "+" means indicated value is higher than actual and "-" means indicated value is lower than actual.

(3) Include -3, + 12 (bias); Bias sign correction: "+" means indicated value is higher than actual and "-" means indicated value is lower than actual.

TABLE 14.3-5B
Total Minimum Injected Safety Injection Flow Used in Best-Estimate Large Break LOCA Analysis for Indian Point Unit 2

RCS Pressure (psig)	**Flow Rate (gpm)**
0	2330.03
10	1962.54
20	1636.46
30	1333.48
40	1041.40
50	770.92
60	691.73
100	678.21
200	641.35
300	603.25
400	564.49
500	525.07
600	469.87
700	396.91
800	335.54
900	304.38
1000	235.22
1100	134.33
1200	23.56
1300	0.0

TABLE 14.3-6
Broken Loop Accumulator and Safety Injection Spill to Containment During Blowdown
Deleted

TABLES 14.3-7 through 14.3-10
Deleted

TABLE 14.3-11
Initial Parameters For Small Break LOCA Analysis

Licensed Core Power (MWt) (includes 2% calorimetric uncertainty)	3281
Total Peaking Factor, Fq	2.5
Axial Offset, %	13
Hot Channel Enthalpy Rise Factor, $F_{\Delta H}$	1.70
Maximum Assembly Average Power, PHA	1.51
Fuel Assembly Array	15 x 15 upgraded with IFMs
Nominal Accumulator Water Volume, ft^3	795
Accumulator Tank Volume, ft^3	1100
Minimum Accumulator Gas Pressure, psia	613
Loop Flow (gpm)	80700
Vessel Inlet Temperature, °F	537.451
Vessel Outlet Temperature, °F	606.549
RCS Pressure with Uncertainty, psia	2310
Steam Pressure, psia	735.645
Steam Generator Tube Plugging, %	10
Maximum Refueling Water Storage Tank Temperature, ºF	110
Maximum Condensate Storage Tank Temperature, ºF	120
Non-IFBA Fuel Backfill Pressure, psig	275
Reactor Trip Setpoint, psia	1860
Safety Injection Signal Setpoint, psia	1715
Safety Injection Delay Time, sec.	25
Signal Processing Delay and Rod Drop Time, sec.	4.7 (2.0 + 2.7)
Feedwater Trip Processing Delay Time, sec.	2
Time for Main Feedwater Flow Coastdown, sec.	8
Auxiliary Feedwater Flow – gpm (1)	380
Auxiliary Feedwater Pump Start Delay Time, sec.	60
Maximum Loop Specific Purge Volume, ft^3	268.8

NOTE:
(1) The flow from one motor-driven Auxiliary Feedwater Pump is modeled.

TABLE 14.3-12
Small - Break LOCA Time Sequence of Events

EVENT	Break Size		
	2.0 Inch	3.0 Inch	4.0 Inch
Break Initiation, sec.	0.0	0.0	0.0
Reactor Trip Signal, sec.	43.3	18.2	10.4
Safety Injection Signal, sec.	61.0	26.4	14.9
Top of Core Uncovered, sec.	1711	629	692
Accumulator Injection Begins, sec.	NA	1689	850
Peak Clad Temperature Occurs, sec.	1967	1308	955
Top of Core Recovered, sec.	3854	1924	1170

TABLE 14.3-13
Small Break LOCA Analysis Results

RESULT	Break Size		
	2.0 Inch	3.0 Inch	4.0 Inch
Peak Clad Temperature, °F	938	1028	878
Peak Clad Temperature Location, ft.	10.75	11.00	11.00
Local Zr/H_2O Reaction (max), %	<17	<17	<17
Local Zr/H_2O Reaction Location, ft.	11.25	11.00	11.25
Total Zr/H_2O Reaction, %	<1.0	<1.0	<1.0
Hot Rod Burst Time, seconds	NA	NA	NA
Hot Rod Burst Location, ft.	NA	NA	NA

TABLE 14.3-14
Internals Deflections Under Abnormal Operation

	Allowable Limit[1] (inches)	No Loss-of-Function Limit[1] (inches)
Upper barrel, expansion/compression (to ensure sufficient inlet flow area/and to prevent the barrel from touching any guide tube to avoid disturbing the rod cluster control guide structure)	Inward - 4.1 Outward - 1.0	8.2 1.0
Upper package, axial deflection (to maintain the control rod guide structure geometry)[2,3]	0.100	0.150
Rod cluster control guide tube, deflection as a beam (to be consistent with conditions under which ability to trip has been tested)[3]	1.0	1.60/1.75
Fuel assembly thimbles, cross-section distortion (to avoid interference between the control rods and the guides)[3]	0.036	0.072

Notes:

1. The deflection limit values given above correspond to stress levels for the internals structure well below the limiting criteria given by the collapse curves in WCAP-5890 (Reference 30). Consequently, for the internals the geometric limitations established to ensure safe shutdown capability are more restrictive than those given by the failure stress criteria.
2. See Reference 26.
3. See Reference 27.

TABLE 14.3-15
SYSTEM PARAMETERS FOR 3216 MWt

Parameters	**Value**
RCS Pressure (psia) (with 60 psi uncertainty)	2310
Core Thermal Power (MWt) (without uncertainties)	3216
Reactor Coolant System Total Flowrate (lbm/sec)	34,250
Vessel Outlet Temperature (°F) (with uncertainty)	613.3
Core Inlet Temperature (°F) (with uncertainty)	545.7
Vessel Average Temperature (°F)	579.5
Initial Steam Generator Steam Pressure (psia)	788
Steam Generator Tube Plugging (%)	0
Initial Steam Generator Secondary Side Mass (lbm)	104,300.1
Assumed Maximum Containment Backpressure (psia)	61.7
Accumulator	
Water Volume (ft^3) per accumulator (including line volume)	770
N_2 Cover Gas Pressure (psia)	700
Temperature (°F)	130
Safety Injection Delay, total (sec) (from beginning of event) (Minimum ECCS case)	49.1
(Maximum ECCS case)	45

TABLE 14.3-16 (Sheet 1 of 4)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATH NO.1*		BREAK PATH NO.2**	
SECONDS	FLOW LBM/SEC	ENERGY THOUSANDS BTU/SEC	FLOW LBM/SEC	ENERGY THOUSANDS BTU/SEC
.00000	.0	.0	.0	.0
.00102	84849.3	45618.7	38460.5	20632.5
.00204	40171.1	21550.8	39870.6	21387.9
.00312	40159.2	21545.3	39615.5	21250.0
.101	39922.0	21501.5	19727.2	10572.6
.201	40974.9	22258.1	22318.8	11974.5
.302	44538.4	24465.2	23349.8	12534.5
.402	44682.9	24869.9	23496.8	12619.0
.502	43717.2	24675.3	23121.9	12423.6
.601	44127.3	25230.0	22645.7	12173.7
.701	43629.7	25226.5	22265.5	11975.3
.801	42265.6	24676.5	22065.9	11873.3
.902	40921.3	24115.0	21964.7	11823.2
1.00	39778.0	23661.6	21916.4	11800.6
1.10	38622.2	23215.4	21868.9	11777.7
1.20	37319.2	22690.8	21834.5	11761.1
1.30	35944.7	22103.1	21808.2	11748.2
1.40	34695.2	21548.2	21802.4	11746.0
1.50	33741.2	21128.7	21829.4	11761.1
1.60	32976.7	20806.2	21824.2	11758.5
1.70	32268.2	20512.2	21705.1	11693.9
1.80	31535.6	20200.6	21555.6	11612.9
1.90	30716.4	19828.7	21402.4	11530.0
2.00	29976.9	19501.2	21256.3	11451.0
2.10	29196.0	19140.5	21112.8	11373.8
2.20	28344.1	18723.1	20957.2	11290.1
2.30	27335.3	18191.3	20784.2	11197.1
2.40	26135.3	17523.8	20600.6	11098.5
2.50	24599.3	16613.7	20405.2	10993.7
2.60	22535.4	15316.1	20199.6	10883.6
2.70	21036.9	14396.0	19989.1	10771.0
2.80	20639.2	14205.3	19798.0	10668.9
2.90	19987.2	13800.9	19602.5	10564.7
3.00	19522.8	13516.0	19407.4	10460.8
3.10	19376.6	13446.0	19204.5	10352.8
3.20	19201.3	13342.5	18988.4	10237.7
3.30	18810.9	13089.4	18759.2	10115.5
3.40	18480.2	12877.9	18531.2	9994.0
3.50	18122.3	12639.8	18312.4	9877.7
3.60	17692.9	12347.4	18094.2	9761.8
3.70	17211.2	12017.4	17873.1	9644.3
3.80	16724.6	11684.5	17658.8	9530.6
3.90	16264.9	11369.3	17458.8	9424.7

TABLE 14.3-16 (Sheet 2 of 4)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
SECONDS	FLOW LBM/SEC	ENERGY THOUSANDS BTU/SEC	FLOW LBM/SEC	ENERGY THOUSANDS BTU/SEC
4.00	15820.9	11062.9	17267.5	9323.6
4.20	14978.6	10480.2	16898.7	9128.8
4.40	14290.6	10002.9	16558.4	8949.6
4.60	13707.5	9594.2	16243.5	8784.0
4.80	13236.1	9259.0	15953.9	8632.0
5.00	12820.2	8956.5	15678.5	8487.5
5.20	12481.3	8705.1	15423.5	8353.9
5.40	12234.8	8509.6	15184.4	8228.7
5.60	12013.2	8329.5	14948.5	8105.1
5.80	11845.2	8184.2	14736.2	7994.2
6.00	11685.0	8040.9	14523.9	7883.0
6.20	11581.6	7932.9	14331.5	7782.7
6.40	11553.1	7869.2	14292.3	7767.5
6.60	12293.5	8327.7	14710.1	8000.1
6.80	11952.9	8084.8	14733.3	8016.3
7.00	10706.7	7749.8	14578.9	7935.9
7.20	9189.8	7146.8	14522.0	7909.0
7.40	8892.9	6975.6	14368.8	7828.6
7.60	8891.4	6931.8	14262.7	7774.8
7.75	8873.2	6896.3	14156.0	7719.6
7.80	8859.4	6880.4	14108.8	7694.8
8.00	8797.6	6810.4	13887.9	7577.7
8.20	8769.7	6749.4	13661.1	7457.0
8.40	8796.7	6713.6	13513.7	7379.2
8.60	8840.2	6682.9	13477.8	7360.1
8.80	8856.5	6634.0	13353.8	7289.4
9.00	8859.7	6593.2	13187.4	7194.4
9.20	8823.9	6536.6	13058.2	7120.2
9.40	8768.8	6472.5	12930.8	7047.5
9.60	8705.1	6398.9	12780.7	6962.8
9.80	8632.0	6315.4	12629.7	6878.0
10.0	8548.7	6227.9	12492.6	6801.4
10.2	8442.2	6132.4	12355.1	6724.5
10.401	8328.6	6042.5	12216.2	6646.9
10.402	8328.1	6042.1	12215.6	6646.6
10.403	8327.4	6041.6	12214.9	6646.2
10.6	8200.0	5951.8	12080.4	6571.1
10.8	8065.0	5865.6	11944.4	6495.3
11.0	7923.0	5780.9	11806.4	6418.6
11.2	7779.9	5700.5	11668.3	6342.2
11.4	7631.7	5620.8	11530.0	6265.9
11.6	7480.7	5541.8	11389.2	6188.4
11.8	7327.0	5463.6	11250.5	6112.2

TABLE 14.3-16 (Sheet 3 of 4)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
SECONDS	FLOW LBM/SEC	ENERGY THOUSANDS BTU/SEC	FLOW LBM/SEC	ENERGY THOUSANDS BTU/SEC
12.0	7176.5	5390.8	11111.5	6036.0
12.2	7026.3	5316.4	10968.4	5957.5
12.4	6883.8	5243.8	10826.9	5880.1
12.6	6747.1	5172.2	10685.1	5802.7
12.8	6615.8	5101.2	10544.3	5726.0
13.0	6488.9	5030.5	10403.6	5649.5
13.2	6366.6	4960.4	10263.5	5573.5
13.4	6249.0	4891.3	10125.0	5498.4
13.6	6135.2	4822.6	9987.3	5423.8
13.8	6026.2	4755.4	9853.5	5351.4
14.0	5919.5	4688.6	9716.7	5277.2
14.2	5816.8	4623.7	9595.4	5206.8
14.4	5713.0	4557.7	9502.1	5137.0
14.6	5602.6	4486.4	9411.0	5054.8
14.8	5476.2	4402.2	9352.2	4978.2
15.0	5328.9	4296.1	9293.2	4893.3
15.2	5176.5	4174.4	9247.0	4809.1
15.4	5038.0	4049.0	9247.1	4747.4
15.6	4932.8	3939.5	9212.9	4671.6
15.8	4851.8	3846.7	9144.7	4586.4
16.0	4778.1	3768.8	9017.4	4479.5
16.2	4704.7	3700.7	8935.1	4400.9
16.4	4630.2	3639.4	8875.9	4338.7
16.6	4554.4	3583.5	8757.9	4251.9
16.8	4479.1	3533.9	8641.2	4168.4
17.0	4403.7	3489.6	8576.6	4112.2
17.2	4326.9	3449.9	8497.4	4051.1
17.4	4248.8	3415.1	8359.4	3964.2
17.6	4169.2	3386.2	8225.0	3880.8
17.8	4088.8	3361.4	8059.9	3783.8
18.0	4003.3	3338.9	8074.0	3771.4
18.2	3911.2	3320.1	7968.5	3702.9
18.4	3816.0	3306.6	7735.9	3574.5
18.6	3711.0	3295.4	7557.1	3468.0
18.8	3599.3	3288.9	7489.2	3409.1
19.0	3476.9	3281.6	7426.3	3351.2
19.2	3339.5	3274.3	7291.6	3261.6
19.4	3112.8	3201.9	7025.2	3115.2
19.6	2872.0	3112.9	6504.2	2859.2
19.8	2656.5	3017.4	5888.0	2563.0
20.0	2468.0	2906.1	5468.7	2349.1
20.2	2308.0	2789.5	5535.0	2328.4

TABLE 14.3-16 (Sheet 4 of 4)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
SECONDS	FLOW LBM/SEC	ENERGY THOUSANDS BTU/SEC	FLOW LBM/SEC	ENERGY THOUSANDS BTU/SEC
20.4	2123.5	2598.3	6023.0	2465.5
20.6	1956.7	2408.2	6647.5	2649.6
20.8	1812.0	2238.1	6252.1	2446.3
21.0	1685.8	2087.7	5729.5	2214.5
21.2	1569.8	1948.2	5441.1	2075.4
21.4	1456.6	1811.1	5220.4	1957.8
21.6	1354.4	1686.8	5013.5	1843.9
21.8	1255.2	1565.8	4785.1	1723.3
22.0	1167.3	1458.1	4545.6	1601.6
22.2	1080.0	1351.1	4308.3	1484.2
22.4	1007.1	1261.7	4080.5	1374.5
22.6	925.4	1160.7	3859.9	1271.9
22.8	867.4	1089.4	3646.6	1176.7
23.0	825.3	1037.2	3444.0	1089.3
23.2	789.4	992.7	3240.0	1005.3
23.4	746.7	939.5	3027.4	922.4
23.6	698.4	879.3	2818.3	844.1
23.8	652.2	821.7	2632.9	775.9
24.0	605.7	763.5	2411.8	700.2
24.2	558.3	704.1	2167.0	620.5
24.4	510.1	643.7	1892.7	535.3
24.6	461.8	583.1	1579.6	442.0
24.8	413.7	522.6	1221.0	338.7
25.0	364.5	460.6	822.5	226.8
25.2	313.9	396.9	427.8	117.6
25.4	261.3	330.6	101.7	28.0
25.6	207.1	262.2	.0	.0
25.8	156.1	197.8	.0	.0
26.0	102.9	130.6	.0	.0
26.2	40.0	50.9	.0	.0
26.4	.0	.0	.0	.0

Notes:
- * mass and energy exiting the SG side of the break
- ** mass and energy exiting the pump side of the break

TABLE 14.3-16a (Sheets 1, 2, 3, & 4 of 4)
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TABLE 14.3-16b (Sheets 1, 2, 3, 4 & 5 of 5)
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TABLE 14.3-16c (Sheets 1 & 2 of 2)
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TABLE 14.3-16d
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TABLE 14.3-16e
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TABLE 14.3-16f (Sheets 1 & 2 of 2)
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TABLE 14.3-16g
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TABLE 14.3-16h
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TABLE 14.3-16i
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TABLE 14.3-17 (Sheet 1 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
REFLOOD MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATH NO.1*		BREAK PATH NO.2**	
	FLOW	ENERGY	FLOW	ENERGY
SECONDS	LBM/SEC	THOUSAND SBTU/SEC	LBM/SEC	THOUSAND S BTU/SEC
26.4	.0	.0	.0	.0
26.9	.0	.0	.0	.0
27.1	.0	.0	.0	.0
27.2	.0	.0	.0	.0
27.3	.0	.0	.0	.0
27.4	.0	.0	.0	.0
27.4	.0	.0	.0	.0
27.5	31.9	37.5	.0	.0
27.6	13.9	16.4	.0	.0
27.7	12.9	15.2	.0	.0
27.8	18.5	21.8	.0	.0
27.9	23.4	27.6	.0	.0
28.0	29.8	35.1	.0	.0
28.1	35.0	41.2	.0	.0
28.2	39.7	46.7	.0	.0
28.3	44.2	52.1	.0	.0
28.4	47.1	55.5	.0	.0
28.5	51.2	60.3	.0	.0
28.7	54.5	64.2	.0	.0
28.8	58.2	68.6	.0	.0
28.84	60.4	71.1	.0	.0
28.9	61.2	72.1	.0	.0
29.0	64.6	76.1	.0	.0
29.1	67.4	79.4	.0	.0
29.2	70.6	83.1	.0	.0
29.3	73.2	86.2	.0	.0
29.4	75.6	89.1	.0	.0
30.4	97.2	114.5	.0	.0
31.4	115.0	135.6	.0	.0
32.4	130.5	153.9	.0	.0
33.4	144.3	170.2	.0	.0
33.7	148.5	175.2	.0	.0
34.4	279.2	329.8	2803.8	441.0
35.5	382.8	453.1	4084.0	671.4
36.5	380.7	450.7	4057.5	673.4
37.5	374.3	443.1	3986.8	665.2
38.5	367.8	435.4	3914.7	656.5

TABLE 14.3-17 (Sheet 2 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
REFLOOD MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
SECONDS	FLOW LBM/SEC	ENERGY THOUSAND SBTU/SEC	FLOW LBM/SEC	ENERGY THOUSAND S BTU/SEC
38.7	366.6	433.8	3900.4	654.8
39.5	361.5	427.8	3843.7	647.9
40.5	355.4	420.5	3774.2	639.4
41.5	349.5	413.5	3706.6	631.0
42.5	343.8	406.7	3640.9	622.9
43.5	338.3	400.2	3577.1	614.9
44.5	333.0	393.9	3515.2	607.2
44.7	332.0	392.6	3503.0	605.7
45.5	327.9	387.8	3455.1	599.8
46.5	412.6	487.9	233.8	276.9
47.5	566.9	673.5	318.8	379.0
48.5	551.8	655.3	310.6	369.1
49.5	470.2	557.7	326.3	288.5
50.3	446.6	529.3	314.3	272.8
50.5	444.3	526.6	313.1	271.3
51.5	434.2	514.5	307.9	264.6
52.5	424.5	502.9	302.9	258.3
53.5	415.1	491.7	298.1	252.1
54.5	405.9	480.7	293.3	246.1
55.5	397.0	470.1	288.7	240.3
56.5	388.2	459.7	284.2	234.6
56.6	387.4	458.6	283.8	234.0
57.5	379.7	449.5	279.8	229.0
58.5	371.4	439.5	275.6	223.6
59.5	363.2	429.8	271.4	218.4
60.5	355.2	420.3	267.3	213.2
61.5	347.4	411.0	263.3	208.2
62.5	339.8	401.9	259.4	203.3
63.5	332.3	393.0	255.5	198.5
64.5	324.9	384.3	251.8	193.8
65.5	317.8	375.7	248.2	189.2
66.5	310.8	367.4	244.6	184.8
67.5	303.9	359.3	241.1	180.4
68.5	297.2	351.3	237.7	176.2
69.5	290.7	343.5	234.4	172.0
70.5	284.3	336.0	231.1	168.0
71.5	278.1	328.6	228.0	164.1
72.4	272.6	322.1	225.2	160.7

TABLE 14.3-17 (Sheet 3 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
REFLOOD MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
SECONDS	FLOW LBM/SEC	ENERGY THOUSAND SBTU/SEC	FLOW LBM/SEC	ENERGY THOUSAND S BTU/SEC
72.5	272.0	321.4	224.9	160.3
73.5	266.1	314.3	221.9	156.6
74.5	260.3	307.5	219.0	153.0
75.5	254.7	300.9	216.2	149.5
76.5	249.3	294.4	213.5	146.2
77.5	244.0	288.2	210.8	142.9
78.5	238.9	282.0	208.2	139.7
79.5	233.9	276.1	205.7	136.6
80.5	229.0	270.3	203.3	133.6
81.5	224.2	264.7	200.9	130.7
82.5	219.6	259.2	198.6	127.9
83.5	215.1	253.9	196.4	125.2
84.5	210.8	248.8	194.3	122.5
85.5	206.6	243.8	192.2	120.0
86.5	202.5	239.0	190.2	117.5
87.5	198.6	234.3	188.2	115.1
89.5	191.0	225.4	184.5	110.6
91.5	184.0	217.0	181.0	106.4
93.5	177.4	209.3	177.8	102.4
94.6	174.0	205.2	176.2	100.4
95.5	171.3	202.0	174.9	98.8
97.5	165.6	195.3	172.1	95.5
99.5	160.3	189.1	169.6	92.4
101.5	155.5	183.3	167.2	89.5
103.5	151.0	178.0	165.1	86.9
105.5	146.8	173.1	163.1	84.5
107.5	143.0	168.6	161.3	82.3
109.5	139.5	164.5	159.7	80.3
111.5	136.4	160.8	158.2	78.5
113.5	133.5	157.4	156.8	76.9
115.5	130.8	154.3	155.6	75.4
117.5	128.5	151.4	154.5	74.0
119.5	126.3	148.9	153.5	72.8
121.5	124.4	146.6	152.6	71.7
123.5	122.6	144.6	151.8	70.8
125.0	121.5	143.2	151.2	70.1
125.5	121.1	142.8	151.1	69.9
127.5	119.7	141.1	150.4	69.1

TABLE 14.3-17 (Sheet 4 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
REFLOOD MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
SECONDS	FLOW LBM/SEC	ENERGY THOUSAND SBTU/SEC	FLOW LBM/SEC	ENERGY THOUSAND S BTU/SEC
129.5	118.5	139.7	149.8	68.4
131.5	117.4	138.4	149.3	67.8
133.5	116.4	137.2	148.9	67.3
135.5	115.6	136.3	148.5	66.8
137.5	114.9	135.4	148.2	66.4
139.5	114.2	134.6	147.9	66.0
141.5	113.7	134.0	147.6	65.7
143.5	113.2	133.4	147.4	65.4
145.5	112.8	133.0	147.2	65.2
147.5	112.5	132.6	147.0	65.0
149.5	112.3	132.4	146.9	64.9
151.5	112.1	132.2	146.8	64.8
153.5	112.0	132.0	146.8	64.7
155.5	111.9	131.9	146.7	64.6
157.5	111.8	131.8	146.7	64.6
159.5	111.8	131.8	146.6	64.5
161.1	111.8	131.7	146.6	64.5
161.5	111.8	131.8	146.6	64.5
163.5	111.8	131.8	146.6	64.5
165.5	111.8	131.8	146.6	64.5
167.5	111.9	131.9	146.7	64.6
169.5	112.0	132.0	146.7	64.6
171.5	112.1	132.2	146.7	64.6
173.5	112.2	132.3	146.8	64.7
175.5	112.4	132.5	146.8	64.8
177.5	112.5	132.6	146.9	64.8
179.5	112.7	132.8	146.9	64.9
181.5	112.9	133.0	147.0	65.0
183.5	113.0	133.3	147.1	65.1
185.5	113.2	133.5	147.1	65.1
187.5	113.4	133.7	147.2	65.2
189.5	113.6	133.9	147.3	65.3
191.5	113.8	134.2	147.4	65.4
193.5	114.0	134.4	147.4	65.5
195.5	114.3	134.7	147.5	65.6
197.5	114.5	134.9	147.6	65.7
199.5	114.7	135.2	147.7	65.8
201.5	114.9	135.4	147.8	65.9

TABLE 14.3-17 (Sheet 5 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
REFLOOD MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
SECONDS	FLOW LBM/SEC	ENERGY THOUSAND SBTU/SEC	SECONDS	FLOW LBM/SEC
203.5	115.1	135.7	147.9	66.0
205.5	115.3	135.9	147.9	66.1
207.5	115.5	136.1	148.0	66.2
209.5	115.7	136.4	148.1	66.3
211.5	115.9	136.6	148.2	66.4
213.5	116.1	136.9	148.3	66.5
215.5	116.3	137.1	148.4	66.6
217.5	116.5	137.4	148.4	66.7
219.5	116.8	137.6	148.5	66.8
221.5	117.0	137.9	148.6	66.9
223.5	117.2	138.1	148.7	67.0
225.5	117.4	138.4	148.8	67.1
227.5	117.6	138.7	148.9	67.2
229.5	117.9	138.9	149.0	67.4
231.5	118.1	139.2	149.1	67.5
233.5	118.3	139.5	149.1	67.6
235.5	118.5	139.7	149.2	67.7
237.5	118.8	140.0	149.3	67.8
239.5	119.0	140.3	149.4	67.9
239.7	119.0	140.3	149.4	67.9

Notes:

* mass and energy exiting the SG side of the break

** mass and energy exiting the pump side of the break

TABLE 14.3-18
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
POST-REFLOOD MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
	FLOW	ENERGY	FLOW	ENERGY
SECONDS	LBM/SEC	THOUSANDS BTU/SEC	LBM/SEC	THOUSANDS BTU/SEC
239.8	218.7	272.7	208.8	137.2
244.8	218.2	272.0	208.5	136.8
249.8	217.7	271.4	208.2	136.4
254.8	217.1	270.7	207.9	136.0
259.8	216.5	269.9	207.5	135.6
264.8	216.6	270.0	207.2	135.2
269.8	215.9	269.2	206.9	134.8
274.8	215.2	268.3	206.5	134.4
279.8	215.2	268.3	206.2	134.0
284.8	214.4	267.3	205.9	133.6
289.8	214.3	267.1	205.5	133.2
294.8	213.4	266.1	205.2	132.9
299.8	213.2	265.8	204.9	132.5
304.8	212.9	265.4	204.5	132.1
309.8	211.9	264.2	204.2	131.7
314.8	211.5	263.7	203.8	131.3
319.8	211.0	263.1	203.5	130.9
324.8	210.5	262.4	203.2	130.4
329.8	210.5	262.4	202.8	130.0
334.8	209.8	261.5	202.5	129.6
339.8	209.6	261.3	202.1	129.2
344.8	208.7	260.2	201.8	128.8
349.8	208.3	259.7	201.4	128.4
354.8	207.8	259.1	201.1	128.0
359.8	207.2	258.3	200.7	127.6
364.8	207.0	258.0	200.4	127.2
369.8	206.6	257.6	200.0	126.8
374.8	206.0	256.9	199.7	126.3
379.8	205.3	255.9	199.3	125.9
384.8	204.8	255.3	199.0	125.5
389.8	204.6	255.0	198.6	125.1
394.8	204.0	254.3	198.3	124.7
399.8	203.5	253.8	197.9	124.2
404.8	202.8	252.8	197.5	123.8
409.8	202.4	252.4	197.2	123.4
414.8	202.3	252.2	196.8	123.0
419.8	201.6	251.4	196.5	122.6
424.8	201.1	250.7	196.1	122.2
429.8	205.4	256.1	199.9	126.6

TABLE 14.3-18 (Cont.)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
POST-REFLOOD MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
SECONDS	FLOW LBM/SEC	ENERGY THOUSANDS BTU/SEC	SECONDS	FLOW LBM/SEC
434.8	205.1	255.7	199.5	126.1
439.8	204.6	255.1	199.1	125.7
444.8	204.0	254.3	198.8	125.3
449.8	203.4	253.6	198.4	124.8
454.8	85.7	106.9	310.3	154.0
627.6	85.7	106.9	310.3	154.0
627.7	87.5	108.4	308.4	147.8
629.8	87.5	108.3	308.5	147.6
1262.4	87.5	108.3	308.5	147.6
1262.5	74.8	86.1	321.1	31.0
1500.5	71.4	82.2	324.5	31.6
1500.6	71.4	82.2	167.3	63.8
2334.0	64.4	74.1	174.3	65.0
2334.1	64.4	74.1	174.3	65.0
3600.0	57.2	65.8	181.5	66.3
3600.1	54.3	62.5	184.3	48.7
10000.0	39.5	45.5	199.2	52.6
23400.0	31.9	36.7	206.8	54.6
23400.1	31.9	36.7	73.3	19.4
100000.0	21.1	24.3	84.1	22.2
1000000.0	9.1	10.4	96.1	25.4
10000000.0	2.8	3.3	102.4	27.0

* mass and energy exiting the SG side of the break
** mass and energy exiting the pump side of the break

TABLE 14.3-19
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
MASS BALANCE FOR 3216 MWt

		Mass Balance						
Time (Seconds)		.00	26.40	26.4+δ	239.71	627.68	1262.40	3600.00
		Mass (Thousand lbm)						
Initial	In RCS and ACC	714.25	714.25	714.25	714.25	714.25	714.25	714.25
Added Mass	Pumped Injection	.00	.00	.00	74.24	227.83	479.16	1074.54
	Total Added	.00	.00	.00	74.24	227.83	479.16	1074.54
*** TOTAL AVAILABLE ***		714.25	714.25	714.25	788.50	942.08	1193.41	1788.79
Distribution	Reactor Coolant	524.25	58.26	84.53	144.26	144.26	144.26	144.26
	Accumulator	190.00	126.74	100.47	.00	.00	.00	.00
	Total Contents	714.25	185.00	185.00	144.26	144.26	144.26	144.26
Effluent	Break Flow	.00	529.24	529.24	644.22	801.15	1052.40	1647.79
	ECCS Spill	.00	.00	.00	.00	.00	.00	.00
	Total Effluent	.00	529.24	529.24	644.22	801.15	1052.40	1647.79
*** TOTAL ACCOUNTABLE ***		714.25	714.24	714.24	788.48	945.41	1196.65	1792.04

TABLE 14.3-20
DOUBLE-ENDED PUMP SUCTION BREAK GUILLOTINE MIN SI
ENERGY BALANCE FOR 3216 MWt

		Energy Balance						
Time (Seconds)		.00	26.40	26.4+δ	239.71	627.68	1262.40	3600.00
		Energy (Million Btu)						
Initial Energy	In RCS, ACC, Steam Gen	781.41	781.41	781.41	781.41	781.41	781.41	781.41
Added Energy	Pumped Injection	.00	.00	.00	5.79	17.78	37.38	177.08
	Decay Heat	.00	7.52	7.52	30.60	63.24	107.96	235.94
	Heat From Secondary	.00	8.54	8.54	8.54	8.54	8.54	8.54
	Total Added	.00	16.07	16.07	44.94	89.56	153.89	421.56
*** TOTAL AVAILABLE ***		781.41	797.48	797.48	826.35	870.98	935.30	
Distribution	Reactor Coolant	305.58	13.36	15.98	38.17	38.17	38.17	38.17
	Accumulator	18.95	12.64	10.02	.00	.00	.00	.00
	Core Stored	27.00	13.89	13.89	3.95	3.78	3.55	2.71
	Primary Metal	166.68	158.73	158.73	131.10	92.65	69.95	53.20
	Secondary Metal	40.99	41.26	41.26	38.20	29.44	20.05	15.21
	Steam Generator	222.23	237.68	237.68	217.15	162.06	107.20	80.60
	Total Contents	781.41	477.56	477.56	428.56	326.09	238.91	189.88
Effluent	Break Flow	.00	319.44	319.44	389.59	537.57	680.69	998.74
	ECCS Spill	.00	.00	.00	.00	.00	.00	.00
	Total Effluent	.00	319.44	319.44	389.59	537.57	680.69	998.74
*** TOTAL ACCOUNTABLE ***		781.41	797.01	797.01	818.15	863.66	919.61	1188.62

TABLE 14.3-21

DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI

PRINCIPLE PARAMETERS DURING REFLOOD FOR 3216 MWt

Time	Flooding		Carry-over	Core	Downcomer	Flow	Injection			
	Temp	Rate	Fraction	Height	Height	Fraction	Total	Accum	Spill	Enthalpy
Seconds	(°F)	(in/sec)	(-----)	(Feet)	(Feet)	(-----)	(Pounds Mass Per Second)			Btu/Lbm
26.4	190.0	.000	.000	.00	.00	.250	.0	.0	.0	.00
27.1	188.6	20.878	.000	.50	1.17	.000	6713.2	6713.2	.0	99.50
27.4	187.2	24.643	.000	1.09	1.23	.000	6647.4	6647.4	.0	99.50
27.8	186.9	2.520	.126	1.34	2.09	.225	6528.7	6528.7	.0	99.50
28.1	187.0	2.568	.184	1.39	2.78	.288	6457.6	6457.6	.0	99.50
28.8	187.3	2.426	.300	1.50	4.37	.322	6325.9	6325.9	.0	99.50
29.4	187.5	2.365	.373	1.58	5.66	.333	6214.4	6214.4	.0	99.50
33.7	189.4	2.656	.616	2.00	14.86	.353	5534.7	5534.7	.0	99.50
35.5	190.2	4.041	.665	2.18	16.12	.552	4887.5	4887.5	.0	99.50
37.5	191.2	3.817	.693	2.39	16.12	.548	4666.9	4666.9	.0	99.50
38.7	191.8	3.708	.703	2.51	16.12	.545	4554.1	4554.1	.0	99.50
44.7	195.4	3.354	.726	3.00	16.12	.529	4072.9	4072.9	.0	99.50
45.5	195.9	3.319	.727	3.06	16.12	.527	4017.0	4017.0	.0	99.50
46.5	196.5	3.905	.732	3.14	16.05	.638	.0	.0	.0	.00
47.5	197.3	4.688	.732	3.24	15.59	.640	.0	.0	.0	.00
50.3	199.4	3.866	.735	3.51	14.51	.608	358.5	.0	.0	78.02
56.6	204.5	3.371	.738	4.00	13.08	.603	367.3	.0	.0	78.02
64.5	211.7	2.865	.737	4.54	11.70	.596	375.5	.0	.0	78.02
72.4	219.2	2.447	.735	5.00	10.70	.587	381.4	.0	.0	78.02
83.5	229.1	1.994	.731	5.54	9.81	.571	386.6	.0	.0	78.02
94.6	236.8	1.674	.727	6.00	9.37	.554	389.8	.0	.0	78.02
109.5	244.9	1.407	.723	6.52	9.23	.532	392.0	.0	.0	78.02
125.0	251.7	1.265	.721	7.00	9.42	.516	393.0	.0	.0	78.02

TABLE 14.3-21 (Cont.)

DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
PRINCIPLE PARAMETERS DURING REFLOOD FOR 3216 MWt

Time	Flooding		Carry-over Fraction	Core Height	Downcomer Height	Flow Fraction	Injection			
	Temp	Rate					Total	Accum	Spill	Enthalpy
Seconds	(°F)	(in/sec)	(-----)	(Feet)	(Feet)	(-----)	(Pounds Mass Per Second)			Btu/Lbm
143.5	258.3	1.196	.724	7.52	9.83	.508	393.4	.0	.0	78.02
161.1	263.8	1.177	.728	8.00	10.30	.506	393.5	.0	.0	78.02
173.5	267.2	1.174	.732	8.33	10.64	.507	393.4	.0	.0	78.02
181.5	269.2	1.175	.734	8.54	10.86	.508	393.4	.0	.0	78.02
199.5	273.4	1.179	.740	9.00	11.35	.510	393.3	.0	.0	78.02
219.5	277.5	1.183	.747	9.50	11.89	.513	393.3	.0	.0	78.02
239.7	281.2	1.188	.755	10.00	12.42	.515	393.2	.0	.0	78.02

TABLE 14.3-22 (Sheet 1 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MAXIMUM ECCS FLOWS
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATH NO.1*		BREAK PATH NO.2**	
	FLOW	ENERGY	FLOW	ENERGY
SECONDS	LBM/SEC	THOUSANDS BTU/SEC	LBM/SEC	THOUSANDS BTU/SEC
.00000	.0	.0	.0	.0
.00102	84849.3	45618.7	38460.5	20632.5
.00204	40171.1	21550.8	39870.6	21387.9
.00312	40159.2	21545.3	39615.5	21250.0
.101	39922.8	21502.1	19730.1	10574.2
.201	40979.6	22261.5	22314.8	11972.4
.301	44573.7	24485.7	23347.7	12533.3
.401	44733.5	24903.4	23497.2	12619.1
.502	43754.1	24707.6	23117.1	12420.9
.602	44173.0	25273.0	22640.6	12170.9
.701	43682.7	25278.5	22266.0	11975.5
.802	42297.2	24725.0	22065.4	11873.0
.901	40947.3	24164.9	21967.8	11824.8
1.00	39767.1	23698.6	21919.4	11802.2
1.10	38584.1	23240.8	21873.8	11780.4
1.20	37249.5	22702.1	21840.4	11764.4
1.30	35816.5	22086.0	21815.1	11752.1
1.40	34574.8	21534.6	21810.6	11750.5
1.50	33613.4	21111.2	21839.1	11766.5
1.60	32853.5	20790.6	21835.5	11764.7
1.70	32154.3	20501.2	21717.1	11700.6
1.80	31432.8	20195.4	21569.0	11620.3
1.90	30640.2	19839.4	21417.8	11538.5
2.00	29904.6	19514.1	21273.0	11460.3
2.10	29142.5	19163.4	21131.5	11384.2
2.20	28311.2	18759.2	20976.6	11300.9
2.30	27339.3	18251.3	20805.2	11208.8
2.40	26109.9	17561.4	20624.4	11111.9
2.50	24628.0	16684.9	20436.4	11011.2
2.60	22707.6	15483.7	20235.9	10904.1
2.70	21119.5	14495.7	20024.8	10791.3
2.80	20677.2	14277.7	19830.0	10687.6
2.90	20092.1	13921.6	19641.2	10587.2
3.00	19618.0	13629.3	19452.2	10486.9
3.10	19439.5	13538.0	19253.4	10381.6

TABLE 14.3-22 (Sheet 2 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MAXIMUM ECCS FLOWS
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATH NO.1*		BREAK PATH NO.2**	
	FLOW	ENERGY		FLOW
SECONDS	LBM/SEC	THOUSANDS BTU/SEC	SECONDS	LBM/SEC
3.20	19277.2	13446.3	19038.5	10267.5
3.30	18887.7	13195.0	18811.0	10146.7
3.40	18582.5	13000.8	18590.3	10029.7
3.50	18234.9	12768.3	18376.3	9916.6
3.60	17794.6	12467.4	18158.9	9801.7
3.70	17321.2	12144.4	17944.9	9688.6
3.80	16848.6	11822.4	17737.4	9579.2
3.90	16396.6	11512.6	17538.0	9474.3
4.00	15955.2	11206.7	17348.5	9374.9
4.20	15135.8	10639.0	16986.7	9185.4
4.40	14450.3	10162.8	16655.3	9012.6
4.60	13877.1	9759.9	16344.2	8850.7
4.80	13404.7	9422.8	16060.8	8703.8
5.00	13011.8	9135.4	15789.2	8563.0
5.20	12732.5	8922.1	15540.3	8434.4
5.40	12478.1	8723.0	15299.7	8310.1
5.60	12276.0	8558.7	15078.5	8196.2
5.80	12100.2	8407.6	14860.7	8083.8
6.00	11970.8	8286.4	14662.3	7982.1
6.20	11897.3	8198.2	14466.7	7881.5
6.40	11941.5	8184.6	14308.5	7801.8
6.60	12573.4	8577.2	14836.8	8099.2
6.80	12267.5	8335.5	14923.1	8152.2
7.00	11115.9	8022.4	14778.1	8077.9
7.20	9516.4	7395.4	14698.4	8039.6
7.40	9167.6	7210.5	14540.2	7957.4
7.60	9127.7	7152.4	14376.2	7872.8
7.80	9064.7	7090.9	14232.0	7799.4
8.00	8976.5	7009.1	13995.3	7674.5
8.20	8938.7	6944.0	13762.8	7551.6
8.40	8944.4	6890.1	13558.1	7442.5
8.60	8964.5	6847.8	13401.7	7357.6
8.80	8988.7	6815.2	13346.4	7326.0
9.00	8943.5	6738.5	13265.6	7276.9

TABLE 14.3-22 (Sheet 3 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MAXIMUM ECCS FLOWS
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATH NO.1*		BREAK PATH NO.2**	
	FLOW	ENERGY		FLOW
SECONDS	LBM/SEC	THOUSANDS BTU/SEC	SECONDS	LBM/SEC
9.20	8873.3	6665.8	13116.3	7188.5
9.40	8771.5	6589.3	12977.4	7107.1
9.60	8643.0	6499.3	12853.6	7035.2
9.80	8522.7	6406.2	12713.2	6954.8
10.0	8413.6	6305.9	12565.4	6870.7
10.2	8325.3	6213.6	12425.6	6791.3
10.4	8236.9	6121.7	12287.2	6712.8
10.6	8147.1	6034.8	12149.6	6634.7
10.8	8049.5	5950.5	12013.2	6557.5
11.0	7943.5	5868.5	11876.1	6480.1
11.2	7827.4	5787.9	11739.4	6403.4
11.4	7703.1	5708.8	11602.8	6327.0
11.6	7571.4	5630.8	11466.2	6251.0
11.8	7432.6	5552.9	11327.9	6174.2
12.0	7287.4	5475.4	11190.3	6098.1
12.2	7143.9	5404.4	11053.9	6022.8
12.4	6998.6	5332.3	10913.4	5945.4
12.6	6857.7	5261.2	10773.8	5868.7
12.8	6722.4	5191.7	10634.2	5792.3
13.0	6590.5	5122.9	10494.3	5715.9
13.2	6461.5	5054.6	10355.0	5640.1
13.4	6336.3	4987.1	10215.8	5564.4
13.6	6213.6	4920.1	10076.1	5488.5
13.8	6095.2	4854.0	9939.9	5414.5
14.0	5981.4	4789.2	9804.5	5341.0
14.2	5870.0	4725.2	9667.8	5266.6
14.4	5762.4	4663.0	9548.5	5195.8
14.6	5651.0	4597.9	9450.6	5121.3
14.8	5528.1	4523.8	9346.8	5029.6
15.0	5387.0	4432.0	9292.2	4951.8
15.2	5233.8	4321.4	9221.7	4856.4
15.4	5084.6	4200.2	9195.7	4779.9
15.6	4953.8	4082.5	9185.0	4710.7
15.8	4851.5	3981.3	9150.7	4634.3
16.0	4763.9	3896.2	9065.1	4540.5

TABLE 14.3-22 (Sheet 4 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MAXIMUM ECCS FLOWS
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATH NO.1***		**BREAK PATH NO.2****	
	FLOW	**ENERGY**		**FLOW**
SECONDS	**LBM/SEC**	**THOUSANDS BTU/SEC**	**SECONDS**	**LBM/SEC**
16.2	4679.7	3824.4	8924.7	4427.4
16.4	4594.8	3761.2	8849.9	4352.3
16.6	4509.0	3704.4	8774.1	4281.8
16.8	4423.0	3654.2	8624.3	4179.2
17.0	4338.2	3611.9	8508.6	4095.2
17.2	4249.9	3574.2	8449.4	4040.2
17.4	4161.1	3542.1	8334.7	3961.4
17.6	4070.4	3517.3	8134.0	3843.5
17.8	3977.6	3498.7	7692.7	3611.5
18.0	3879.6	3483.8	7925.8	3695.0
18.2	3766.4	3467.4	8408.4	3898.6
18.4	3647.5	3459.9	7772.1	3588.3
18.6	3523.9	3459.4	6787.4	3115.0
18.8	3316.3	3392.0	6792.5	3085.4
19.0	3075.5	3296.5	6861.7	3076.2
19.2	2851.5	3194.6	6591.0	2917.6
19.4	2653.8	3085.2	6186.4	2705.8
19.6	2481.6	2968.9	5760.6	2488.9
19.8	2319.3	2822.8	5425.6	2309.7
20.0	2157.3	2647.7	5521.7	2301.1
20.2	1997.9	2463.6	5978.1	2425.4
20.4	1849.6	2288.4	6479.4	2560.5
20.6	1720.9	2134.5	6024.8	2338.2
20.8	1601.7	1991.3	5615.7	2151.8
21.0	1491.6	1857.6	5333.2	2015.1
21.2	1391.2	1735.8	5105.3	1895.5
21.4	1296.0	1619.3	4883.9	1777.2
21.6	1207.7	1511.3	4646.3	1654.6
21.8	1116.9	1399.1	4398.9	1531.3
22.0	1047.8	1314.8	4158.4	1414.7
22.2	968.7	1216.9	3926.8	1305.8
22.4	922.7	1160.5	3713.1	1207.8
22.6	883.2	1111.8	3507.5	1116.8
22.8	840.3	1058.5	3309.9	1032.7
23.0	800.0	1008.2	3105.1	950.2

TABLE 14.3-22 (Sheet 5 of 5)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MAXIMUM ECCS FLOWS
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATH NO.1*		BREAK PATH NO.2**	
	FLOW	ENERGY		FLOW
SECONDS	LBM/SEC	THOUSANDS BTU/SEC	SECONDS	LBM/SEC
23.2	755.0	952.2	2893.1	869.5
23.4	706.2	891.1	2726.2	805.7
23.6	656.7	829.2	2523.1	734.2
23.8	606.2	765.9	2294.3	658.1
24.0	555.7	702.5	2035.7	576.5
24.2	504.9	638.5	1740.4	487.3
24.4	454.2	574.8	1396.2	387.3
24.6	403.2	510.5	1003.6	276.4
24.8	350.6	444.2	589.7	161.7
25.0	296.1	375.3	226.7	62.1
25.2	239.7	303.9	.0	.0
25.4	183.3	232.7	.0	.0
25.6	130.6	165.9	.0	.0
25.8	75.7	96.4	.0	.0
26.0	.0	.0	.0	.0

* mass and energy exiting the SG side of the break
** mass and energy exiting the pump side of the break

TABLE 14.3-23
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TABLE 14.3-24
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TABLE 14.3-25
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TABLE 14.3-26
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TABLE 14.3-27 (Sheet 1 of 2)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MAXSI
PRINCIPLE PARAMETERS DURING REFLOOD FOR 3216 MWt

Time Seconds	Flooding		Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Frac	Total	Injection Accum	Spill	Enthalpy Btu/lbm
	Temp °F	Rate in/sec					(Pounds Mass per Second)			
26.0	189.3	.000	.000	.00	.00	.250	.0	.0	.0	.00
26.7	187.9	20.997	.000	.50	1.18	.000	6759.0	6759.0	.0	99.50
27.0	186.5	24.771	.000	1.10	1.24	.000	6692.1	6692.1	.0	99.50
27.4	186.3	2.530	.127	1.34	2.12	.228	6571.3	6571.3	.0	99.50
27.7	186.4	2.571	.171	1.38	2.64	.279	6514.3	6514.3	.0	99.50
28.4	186.6	2.434	.294	1.50	4.35	.321	6369.9	6369.9	.0	99.50
29.1	186.9	2.368	.379	1.59	5.82	.333	6242.7	6242.7	.0	99.50
33.3	188.8	2.663	.616	2.00	14.96	.353	5562.9	5562.9	.0	99.50
35.2	189.6	4.048	.667	2.19	16.12	.553	4902.2	4902.2	.0	99.50
37.2	190.6	3.818	.694	2.40	16.12	.549	4684.2	4684.2	.0	99.50
38.3	191.2	3.718	.703	2.50	16.12	.546	4579.7	4579.7	.0	99.50
44.3	194.8	3.360	.726	3.00	16.12	.530	4093.2	4093.2	.0	99.50
45.2	195.4	3.530	.727	3.08	16.12	.553	4511.9	3864.4	.0	96.42
46.2	196.1	2.828	.729	3.15	16.12	.410	1858.2	1183.4	.0	91.70
47.2	196.8	3.885	.733	3.23	16.00	.581	629.7	.0	.0	78.02
50.4	199.3	3.715	.737	3.50	15.54	.579	635.3	.0	.0	78.02
56.9	205.1	3.407	.741	4.00	14.78	.573	647.7	.0	.0	78.02
64.2	212.5	3.145	.743	4.52	14.17	.566	658.0	.0	.0	78.02
71.7	220.5	2.923	.745	5.00	13.75	.560	666.2	.0	.0	78.02
80.2	229.4	2.716	.747	5.51	13.47	.552	674.5	.0	.0	78.02
89.1	237.4	2.544	.749	6.00	13.38	.544	682.4	.0	.0	78.02

TABLE 14.3-27 (Sheet 2 of 2)
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MAXSI
PRINCIPLE PARAMETERS DURING REFLOOD FOR 3216 MWt

Time Seconds	Flooding		Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Frac	Total	Injection Accum	Spill	Enthalpy Btu/lbm
	Temp °F	Rate in/sec					(Pounds Mass per Second)			
99.2	245.0	2.401	.751	6.52	13.46	.537	688.5	.0	.0	78.02
109.1	251.4	2.305	.754	7.00	13.67	.531	692.3	.0	.0	78.02
121.2	258.0	2.230	.757	7.56	14.04	.527	695.0	.0	.0	78.02
131.2	262.8	2.194	.761	8.00	14.41	.525	696.1	.0	.0	78.02
143.2	267.8	2.170	.765	8.52	14.90	.524	696.7	.0	.0	78.02
147.2	269.3	2.165	.767	8.69	15.06	.524	696.7	.0	.0	78.02
154.7	272.0	2.179	.770	9.00	15.37	.528	695.5	.0	.0	78.02
165.2	275.4	2.200	.773	9.44	15.70	.536	693.0	.0	.0	78.02
167.2	276.0	2.200	.774	9.52	15.74	.538	692.6	.0	.0	78.02
178.9	279.3	2.168	.778	10.00	15.95	.544	692.1	.0	.0	78.02

TABLE 14.3-28 (Sheet 1 of 5)
DOUBLE-ENDED HOT LEG GUILLOTINE
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATHNO.1*		BREAK PATH NO.2**	
	FLOW	ENERGY	FLOW	ENERGY
SECONDS	LBM/SEC	THOUSANDS BTU/SEC	LBM/SE	THOUSANDS BTU/SEC
.00000	.0	.0	.0	.0
.00107	45431.7	28592.9	45428.6	28589.4
.00213	44959.4	28295.7	44682.5	28114.2
.102	45793.5	29109.1	25686.4	16129.1
.201	33239.6	21496.0	22659.2	14136.4
.301	32619.6	21083.9	20264.4	12470.7
.401	31885.0	20590.9	19026.0	11515.6
.502	31493.9	20329.6	18206.6	10840.9
.601	31480.4	20318.8	17625.0	10345.0
.701	31467.6	20326.8	17235.4	9988.6
.801	31177.0	20177.2	16891.0	9682.4
.902	30811.3	19992.6	16655.5	9455.9
1.00	30442.3	19816.4	16457.2	9266.0
1.10	30178.5	19718.7	16334.0	9128.3
1.20	29985.2	19679.7	16264.2	9030.1
1.30	29765.5	19624.5	16277.2	8984.8
1.40	29462.3	19513.9	16329.9	8966.8
1.50	29085.4	19347.4	16416.8	8972.9
1.60	28711.1	19176.2	16524.2	8994.9
1.70	28394.9	19041.5	16647.5	9030.0
1.80	28092.0	18914.9	16773.3	9071.1
1.90	27710.5	18731.3	16894.8	9114.1
2.00	27250.2	18485.7	17006.0	9155.3
2.10	26796.9	18239.2	17106.1	9193.9
2.20	26405.9	18037.0	17195.7	9229.7
2.30	26026.9	17844.1	17274.6	9262.1
2.40	25597.1	17606.7	17340.4	9289.5
2.50	25129.9	17331.2	17393.6	9311.9
2.60	24686.1	17068.7	17437.0	9330.3
2.70	24290.3	16839.1	17470.2	9344.3
2.80	23893.3	16603.8	17493.4	9353.7
2.90	23492.6	16354.8	17505.6	9358.0
3.00	23104.3	16107.1	17508.7	9357.8
3.10	22737.0	15867.2	17504.4	9354.2
3.20	22389.3	15634.4	17493.1	9347.1
3.30	22077.7	15422.8	17476.1	9337.2
3.40	21783.4	15217.4	17454.0	9324.9
3.50	21490.5	15003.4	17426.7	9310.0
3.60	21223.8	14801.9	17394.4	9292.6
3.70	20991.8	14622.4	17358.7	9273.7

TABLE 14.3-28 (Sheet 2 of 5)
DOUBLE-ENDED HOT LEG GUILLOTINE
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATHNO.1*		BREAK PATH NO.2**	
	FLOW	ENERGY		FLOW
SECONDS	LBM/SEC	THOUSANDS BTU/SEC	SECONDS	LBM/SEC
3.80	20770.1	14444.9	17319.3	9253.0
3.90	20560.5	14270.0	17275.4	9230.1
4.00	20383.2	14116.6	17227.8	9205.6
4.20	20059.6	13822.3	17120.7	9150.8
4.40	19813.2	13575.6	16995.4	9087.4
4.60	19604.3	13349.2	16852.0	9015.4
4.80	19455.3	13162.8	16689.9	8934.5
5.00	19357.0	13009.0	16509.6	8845.2
5.20	19365.9	12932.0	16313.3	8748.6
5.40	19406.3	12882.9	16099.0	8643.5
5.60	19468.9	12860.5	15867.0	8530.1
5.80	19556.2	12870.9	15615.7	8407.4
6.00	19707.4	12910.1	15356.3	8281.5
6.20	11028.8	8300.7	15067.3	8140.3
6.40	14455.2	10617.0	14672.0	7941.4
6.60	14508.9	10566.7	14237.6	7722.0
6.80	14629.0	10544.4	13845.1	7525.9
7.00	14807.5	10579.1	13465.1	7335.8
7.20	14990.4	10601.2	13051.2	7125.5
7.40	15147.5	10624.3	12651.4	6922.1
7.60	15324.6	10652.1	12283.8	6735.6
7.80	15406.3	10588.1	11920.3	6549.8
8.00	15644.1	10638.4	11545.0	6356.1
8.20	15556.0	10536.5	11181.0	6167.9
8.40	15808.7	10588.4	10841.7	5992.4
8.60	16038.3	10635.9	10516.7	5824.0
8.80	16243.1	10677.0	10199.7	5659.1
9.00	16434.6	10716.8	9899.8	5502.5
9.20	16619.4	10756.8	9613.9	5352.9
9.40	16808.2	10802.1	9342.8	5210.8
9.60	17018.1	10862.2	9081.5	5073.5
9.80	17302.6	10968.3	8833.8	4943.2
10.0	17347.4	10951.5	8587.4	4813.4
10.2	17122.8	10772.8	8345.5	4686.2
10.4	15365.1	9795.4	8104.7	4559.7
10.602	14402.9	9265.0	7870.3	4437.2
10.604	14399.0	9262.5	7866.6	4435.2
10.607	14396.3	9260.9	7864.2	4433.9
10.609	14394.2	9259.5	7862.2	4432.9

TABLE 14.3-28 (Sheet 3 of 5)
DOUBLE-ENDED HOT LEG GUILLOTINE
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	**BREAK PATHNO.1***		**BREAK PATH NO.2****	
SECONDS	**FLOW LBM/SEC**	**ENERGY THOUSANDS BTU/SEC**	**SECONDS**	**FLOW LBM/SEC**
10.8	14314.8	9194.1	7642.1	4318.4
11.0	14303.2	9168.8	7427.1	4207.3
11.2	14286.7	9144.1	7231.0	4106.7
11.4	14268.5	9117.2	7039.7	4008.3
11.6	14235.3	9078.9	6850.8	3911.2
11.8	14133.9	9001.0	6665.1	3816.0
12.0	13860.2	8831.1	6483.7	3723.3
12.2	13361.0	8543.6	6304.3	3632.2
12.4	12862.1	8261.1	6126.6	3542.6
12.6	12547.5	8079.7	5955.6	3457.0
12.8	12329.5	7951.6	5788.3	3373.8
13.0	12138.1	7840.4	5628.4	3294.8
13.2	11932.6	7723.9	5474.2	3219.1
13.4	11697.7	7593.9	5327.5	3147.3
13.6	11418.6	7442.6	5182.9	3076.7
13.8	11117.0	7281.9	5044.5	3009.5
14.0	10808.3	7119.7	4908.8	2944.0
14.2	10513.3	6967.5	4777.7	2881.1
14.4	10232.1	6825.1	4650.0	2820.0
14.6	9944.6	6681.6	4522.3	2759.0
14.8	9642.7	6534.6	4391.9	2696.5
15.0	9312.3	6377.9	4248.5	2627.8
15.2	8962.9	6217.0	4092.0	2554.0
15.4	8607.5	6059.7	3918.8	2473.7
15.6	8230.6	5898.9	3734.6	2389.4
15.8	7823.9	5728.2	3547.8	2303.4
16.0	7408.1	5558.9	3361.8	2216.0
16.2	7003.5	5399.7	3189.1	2131.5
16.4	6605.4	5247.9	3034.3	2052.1
16.6	6205.0	5096.2	2898.8	1978.6
16.8	5809.6	4945.4	2784.2	1913.1
17.0	5418.6	4794.4	2687.3	1855.1
17.2	5037.9	4645.9	2604.3	1803.6
17.4	4654.9	4468.2	2532.0	1757.9
17.6	4317.7	4214.3	2465.5	1715.5
17.8	4092.9	4020.9	2404.2	1676.5
18.0	3912.3	3859.9	2346.2	1640.3
18.2	3471.5	3595.3	2289.7	1606.7
18.4	3010.9	3305.0	2234.0	1575.2

TABLE 14.3-28 (Sheet 4 of 5)
DOUBLE-ENDED HOT LEG GUILLOTINE
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATHNO.1*		BREAK PATH NO.2**	
	FLOW	ENERGY		FLOW
SECONDS	LBM/SEC	THOUSANDS BTU/SEC	SECONDS	LBM/SEC
18.6	2713.6	3107.4	2178.1	1544.9
18.8	2476.1	2875.7	2123.0	1515.5
19.0	2277.1	2699.9	2073.9	1487.3
19.2	2102.0	2522.1	2025.1	1455.8
19.4	1987.8	2406.6	1972.2	1422.9
19.6	1858.1	2262.5	1904.6	1390.6
19.8	1732.1	2117.2	1821.2	1366.2
20.0	1620.5	1990.4	1718.2	1345.1
20.2	1508.6	1860.9	1595.9	1316.2
20.4	1405.8	1743.3	1474.1	1276.4
20.6	1309.4	1633.1	1369.7	1240.5
20.8	1222.1	1531.5	1267.3	1214.7
21.0	1146.3	1445.3	1143.8	1196.4
21.2	1074.3	1361.7	1014.4	1163.9
21.4	1011.3	1284.7	856.4	1034.6
21.6	959.8	1221.2	744.5	912.0
21.8	916.3	1166.8	642.3	790.3
22.0	877.2	1117.9	575.6	710.2
22.2	825.8	1053.1	520.8	643.3
22.4	774.8	989.3	442.9	548.5
22.6	726.6	929.0	403.6	500.8
22.8	654.6	838.1	374.4	464.9
23.0	611.8	785.3	360.8	448.2
23.2	580.1	746.3	343.4	427.4
23.4	545.2	702.3	325.1	404.9
23.6	504.4	650.4	317.1	395.2
23.8	509.9	654.9	295.6	368.6
24.0	522.0	673.2	269.9	337.2
24.2	514.7	663.5	275.4	344.2
24.4	509.9	657.6	278.5	348.3
24.6	504.6	650.7	274.1	342.8
24.8	493.8	636.8	256.7	321.2
25.0	484.3	624.5	254.1	318.3
25.2	474.5	611.6	241.9	303.2
25.4	470.6	606.4	238.5	299.0
25.6	462.9	596.3	227.1	285.0
25.8	450.9	580.8	189.6	238.2
26.0	423.4	545.3	167.1	210.4

TABLE 14.3-28 (Sheet 5 of 5)
DOUBLE-ENDED HOT LEG GUILLOTINE
BLOWDOWN MASS AND ENERGY RELEASES FOR 3216 MWt

TIME	BREAK PATHNO.1*		BREAK PATH NO.2**	
	FLOW	ENERGY		FLOW
SECONDS	LBM/SEC	THOUSANDS BTU/SEC	SECONDS	LBM/SEC
26.2	388.3	500.6	178.8	225.3
26.4	381.0	487.6	153.7	193.7
26.6	407.2	521.4	136.6	172.6
26.8	395.8	499.9	156.5	197.7
27.0	430.6	530.6	174.5	220.1
27.2	408.0	513.6	186.8	235.5
27.4	450.7	557.4	175.5	221.5
27.6	432.8	543.9	200.1	252.3
27.8	436.3	542.5	181.9	229.3
28.0	513.0	630.5	183.0	230.9
28.2	537.6	661.0	216.2	272.5
28.4	552.1	677.6	224.9	283.2
28.6	492.9	615.3	203.0	256.0
28.8	316.7	407.5	201.8	254.4
29.0	89.2	116.7	60.2	76.2
29.2	.0	.0	.0	.0

* mass and energy exiting from the reactor vessel side of the break
** mass and energy exiting from the SG side of the break

TABLE 14.3-29
DOUBLE-ENDED HOT LEG GUILLOTINE
MASS BALANCE FOR 3216 MWt

Time (Seconds)		.00	29.20	29.20+δ
		Mass (Thousand lbm)		
Initial	In RCS and ACC	731.97	731.97	731.97
Added Mass	Pumped Injection	.00	.00	.00
	Total Added	.00	.00	.00
TOTAL AVAILABLE		731.97	731.97	731.97
Distribution	Reactor Coolant	524.25	96.33	123.07
	Accumulator	207.72	129.91	103.17
	Total Contents	731.97	226.24	226.24
Effluent	Break Flow	.00	505.71	505.71
	ECCS Spill	.00	.00	.00
	Total Effluent	.00	505.71	505.71
TOTAL ACCOUNTABLE		731.97	731.95	731.95

TABLE 14.3-30
DOUBLE-ENDED HOT LEG GUILLOTINE
ENERGY BALANCE FOR 3216 MWt

Time (Seconds)		.00	29.20	29.20+δ
			Energy (Million Btu)	
Initial Energy	In RCS, ACC, Steam Gen	784.57	784.57	784.57
Added Energy	Pumped Injection	.00	.00	.00
	Decay Heat	.00	8.37	8.37
	Heat From Secondary	.00	-.23	-.23
	Total Added	.00	8.14	8.14
TOTAL AVAILABLE		784.57	792.72	792.72
Distribution	Reactor Coolant	305.58	22.91	25.57
	Accumulator	20.67	12.93	10.27
	Core Stored	27.00	10.30	10.30
	Primary Metal	166.68	155.81	155.81
	Secondary Metal	40.99	40.76	40.76
	Steam Generator	223.66	222.24	222.24
	Total Contents	784.57	464.94	464.94
Effluent	Break Flow	.00	327.28	327.28
	ECCS Spill	.00	.00	.00
	Total Effluent	.00	327.28	327.28
TOTAL ACCOUNTABLE		784.57	792.23	792.23

TABLE 14.3-31
DOUBLE-ENDED PUMP SUCTION GUILLOTINE MIN SI
SEQUENCE OF EVENTS FOR 3216 MWt

Time (sec)	Event Description
0.0	Break occurs, reactor trip and LOOP power are assumed
0.604	Reactor trip on pressurizer low pressure of 1860 psia
1.75	Containment HI-1 pressure setpoint reached
4.1	Low pressurizer pressure SI setpoint @ 1695 psia reached (SI begins coincident with low pressurizer pressure SI setpoint)
7.75	Main Feedwater Flow Control Valve closed
11.43	Containment HI-3 pressure setpoint reached
13.9	Broken-loop accumulator begins injecting water
14.2	Intact-loop accumulator begins injecting water
26.40	End-of-blowdown phase
45.806	Broken-loop accumulator water injection ends
46.256	Intact-loop accumulator water injection ends
49.1	SI begins
61.75	Reactor containment air recirculation fan coolers actuate
71.48	Containment spray pump(s) (RWST) start
239.706	End-of-reflood for MIN SI Case
1264.1	Peak pressure and temperature occur
1500.46	RHR/HHSI alignment for recirculation
2354	Containment spray is terminated due to RWST LO-LO signal
23400	Hot leg recirculation
$1.0x10^7$	Transient modeling terminated

TABLE 14.3-32
DOUBLE-ENDED PUMP GUILLOTINE MAX SI
SEQUENCE OF EVENTS FOR 3216 MWt

Time (sec)	Event Description
0.0	Break Occurs, and Loss of Offsite Power are assumed
1.75	Containment HI-1 Pressure Setpoint Reached
4.1	Low Pressurizer Pressure SI Setpoint - 1695 psia reached in blowdown
11.32	Containment HI-3 Pressure Setpoint Reached
14.0	Broken Loop Accumulator Begins Injecting Water
14.3	Intact Loop Accumulator Begins Injecting Water
26.0	End of Blowdown Phase
45.0	Safety Injection Begins
45.6	Broken Loop Accumulator Water Injection Ends
46.15	Intact Loop Accumulator Water Injection Ends
61.75	Reactor Containment Air Recirculation Fan Coolers Actuate
71.32	Containment Spray Pump(s) (RWST) start
178.9	End of Reflood Phase
319.0	Peak Pressure and Temperature Occur
1085.	Cold Leg Recirculation Begins
1536.	Containment Spray is terminated due to RWST LO-LO Signal
23400.	Hot Leg Recirculation Begins
1.0E+07	Transient Modeling Terminated

TABLE 14.3-33
DOUBLE-ENDED HOT LEG GUILLOTINE
SEQUENCE OF EVENTS FOR 3216 MWt

Time (sec)	Event Description
0.0	Break Occurs, and Loss of Offsite Power are assumed
1.86	Containment HI-1 Pressure Setpoint Reached
3.8	Low Pressurizer Pressure SI Setpoint - 1695 psia reached in blowdown
9.87	Containment HI-3 Pressure Setpoint Reached
14.0	Broken Loop Accumulator Begins Injecting Water
14.2	Intact Loop Accumulator Begins Injecting Water
23.5	Peak Pressure and Temperature Occur
29.2	End of Blowdown Phase and Transient Modeling Terminated

TABLE 14.3-34
CONTAINMENT PEAK PRESSURE AND TEMPERATURE
FOR 3216 MWt

Case	Peak Press. (psig)	Peak Steam Temp. (°F)	Pressure (psig) @ 24 hours	Steam Temperature (°F) @ 24 hours
Double-Ended Pump Suction Min SI	45.71 @ 1264.1 sec	266.81 @ 1264.1 sec	17.05 @ 24 hrs	204.97 @ 24 hrs
Double-Ended Pump Suction Max SI	39.67 @ 319 sec	257.596 @ 319 sec	21.38 @ 24 hrs	216.192 @ 24 hrs
Double-Ended Hot Leg	40.62 @ 23.50 sec	259.98 @ 23.49 sec	NA	NA

TABLE 14.3-35

CONTAINMENT HEAT SINKS

NO.	MATERIAL	HEAT TRANSFER AREA (FT^2)	THICKNESS IN
1.	Carbon Steel Concrete	41530	0.375 54.0
2.	Carbon Steel Concrete	26012	0.5 42.0
3.	Concrete	13636	12.0
4.	Concrete	55454	12.0
5.	Stainless Steel Concrete	9091	0.375 12.0
6.	Carbon Steel	62538	0.5
7.	Carbon Steel	74276	0.375
8.	Carbon Steel	25407	0.25
9.	Carbon Steel	63454	0.1875
10.	Carbon Steel	2727	0.125
11.	Carbon Steel	20000	0.138
12.	Carbon Steel	9090	0.0625
13.	Stainless Steel PVC Insulation Carbon Steel Concrete	714	0.019 1.25 0.75 54.0

TABLE 14.3-35 (CONT.)

CONTAINMENT HEAT SINKS

NO.	MATERIAL	HEAT TRANSFER AREA (FT^2)	THICKNESS IN
14.	Stainless Steel	6226	0.019
	PVC Insulation		1.25
	Carbon Steel		0.5
	Concrete		54.0
15.	Stainless Steel	3469	0.025
	Foam Insulation		1.5
	Carbon Steel		0.5
	Concrete		54.0
16.	Stainless Steel	3965	0.025
	Foam Insulation		1.5
	Carbon Steel		0.375
	Concrete		54.0

Note:

1. All carbon steel exterior surfaces are modeled with 0.00033-ft layer of paint on top of a 0.000258-ft layer of carbozinc primer.
2. Approximately 25-ft^2 of the PVC insulation was replaced with fiberglass. As described in Section 14.3.5.1.1, modeling the PVC insulation, instead of the fiberglass insulation was determined to be conservative and bounding.
3. Approximately 7100-ft^2 of the liner top coat material (Phenoline 305) was replaced with Carboline 890. As described in Section 14.3.5.1.1, modeling the Phenoline 305 top coat material, instead of the Carboline 890 top coat material was determined to be conservative and bounding.
4. Installation of the Sump Strainer Modification and Vortex Suppression Modification resulted in an overall increase in metal mass in the Containment. For the containment pressure analyses it is conservative not to include this.

TABLE 14.3-36
THERMOPHYSICAL PROPERTIES OF CONTAINMENT HEAT SINKS

Material	**Thermal Conductivity (Btu/hr-ft - °F)**	**Volumetric Heat Capacity (Btu/ft^3 - °F)**
Paint layer 1, Phenoline	0.08	28.8
Paint layer 2, Carbozinc	0.9	28.8
Carbon Steel	26.0	56.35
Stainless Steel	8.6	56.35
Concrete	0.8	28.8
PVC Insulation	0.0208	1.20
Foam Insulation	0.0417	1.53

TABLE 14.3-37
LOCA CONTAINMENT RESPONSE ANALYSIS PARAMETERS

Service water temperature (°F)	95
RWST water temperature (°F)	110
Initial containment temperature (°F)	130
Initial containment pressure (psia)	16.7
Initial relative humidity (%)	20
Net free volume (ft^3)	2.61×10^6
Reactor Containment Air Recirculation Fan Coolers	
Total	5
Analysis maximum	4
Analysis minimum	3
Containment Hi-1 setpoint (psig)	10.0
Delay time (sec)	
With Offsite Power	NA
Without Offsite Power	60.0
Containment Spray Pumps	
Total	2
Analysis maximum	1
Analysis minimum	1
Flowrate (gpm)	
Injection phase (per pump)- see Table 14.3-40	2180
Recirculation phase (total)	0
Containment Hi-3 setpoint (psig)	30.
Delay time (sec)	
With Offsite Power (delay after High High setpoint)	NA
Without Offsite Power (total time from t=0)	60.0
ECCS Recirculation Switchover, sec	
Minimum Safeguards	1500.
Maximum Safeguards	1085.
Containment Spray Termination on LO-LO RWST Level, (sec)	
Minimum Safeguards	2345.
Maximum Safeguards	1536.

TABLE 14.3-37 (CONT.)
LOCA CONTAINMENT RESPONSE ANALYSIS PARAMETERS

Emergency Core Cooling System (ECCS) Flows (GPM)	
Minimum ECCS	
Injection alignment	2871.2
Recirculation alignment	1864.0
Maximum ECCS	
Injection alignment	5394.5
Recirculation alignment	6320.5
Residual Heat Removal System	
RHR Heat Exchangers	
Modeled in analysis *	1
Recirculation switchover time, sec	
Minimum Safeguard	1500.
Maximum Safeguard	1085.
UA, 10^6 *	
BTU/hr-°F	0.767
Flows - Tube Side and Shell Side - gpm	
Minimum Safeguard	4936.
Maximum Safeguard	9871.
Component Cooling Water Heat Exchangers	
Modeled in analysis	2
UA, 10^6 *	
BTU/hr-°F	2.40
Flows - Shell Side and Tube Side - gpm	
Shellside *	4936.
Tubeside *	
(service water)	5000.
Additional heat loads, (BTU/hr)	19.675×10^6

*Minimum safeguard data representing 1 EDG

TABLE 14.3-38
SAFETY INJECTION FLOW MINIMUM SAFEGUARDS

RCS Pressure (psia)	**Total Flow (gpm)**
INJECTION MODE (Reflood Phase)	
14.7	3250.0
34.7	3097.8
54.7	2932.7
61.7	2871.2
74.7	2753.6
94.7	2558.3
114.7	2330.3
214.7.	872.1
INJECTION MODE (Post-Reflood Phase)	
61.7	2871.2
COLD LEG RECIRCULATION MODE	
61.7	1864.0
HOT LEG RECIRCULATION MODE	
61.7	822.0

TABLE 14.3-39

SAFETY INJECTION FLOW MAXIMUM SAFEGUARDS

RCS Pressure (psia)	**Total Flow (gpm)**
INJECTION MODE (Reflood Phase)	
14.7	6320.50
34.7	5996.18
54.7	5652.86
74.7	5283.84
94.7	4862.22
114.7	4389.80
174.7	1865.02
214.7	1651.00
INJECTION MODE (Post-Reflood Phase)	
61.7	5523.7
COLD LEG RECIRCULATION MODE	
61.7	6320.5
HOT LEG RECIRCULATION MODE	
61.7	6320.5

TABLE 14.3-40

CONTAINMENT SPRAY PERFORMANCE

Containment Pressure (psig)	with 1 Pump(gpm)
0 - 47	2180
Containment Pressure (psig)	with 2 Pumps(gpm)
0 - 47	4200

TABLE 14.3-41
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TABLE 14.3-42
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TABLE 14.3-43
Core Fission Product Inventory

Nuclide	Inventory (Ci)
I-130	3.80E+06
I-131	9.16E+07
I-132	1.33E+08
I-133	1.88E+08
I-134	2.06E+08
I-135	1.75E+08
Kr-85M	2.43E+07
Kr-85	1.10E+06
Kr-87	4.66E+07
Kr-88	6.56E+07
Xe-131M	1.01E+06
Xe-133M	5.87E+06
Xe-133	1.80E+08
Xe-135M	3.68E+07
Xe-135	4.77E+07
Xe-138	1.55E+08
Cs-134	2.06E+07
Cs-136	6.01E+06
Cs-137	1.19E+07
Cs-138	1.71E+08
Rb-86	2.38E+05
Te-127	9.84E+06
Te-127M	1.29E+06
Te-129	2.92E+07
Te-129M	4.30E+06
Te-131M	1.33E+07
Te-132	1.31E+08
Sb-127	9.95E+06
Sb-129	2.97E+07
Sr-89	8.83E+07
Sr-90	8.75E+06
Sr-91	1.11E+08
Sr-92	1.20E+08
Ba-139	1.67E+08
Ba-140	1.61E+08
Ru-103	1.40E+08
Ru-105	9.62E+07

Nuclide	Inventory (Ci)
Ru-106	4.89E+07
Rh-105	8.86E+07
Mo-99	1.75E+08
Tc-99M	1.53E+08
Ce-141	1.52E+08
Ce-143	1.42E+08
Ce-144	1.20E+08
Pu-238	4.13E+05
Pu-239	3.50E+04
Pu-240	5.23E+04
Pu-241	1.18E+07
Np-239	1.88E+09
Y-90	9.11E+06
Y-91	1.14E+08
Y-92	1.20E+08
Y-93	1.39E+08
Nb-95	1.56E+08
Zr-95	1.54E+08
Zr-97	1.55E+08
La-140	1.73E+08
La-141	1.53E+08
La-142	1.48E+08
Nd-147	6.11E+07
Pr-143	1.37E+08
Am-241	1.41E+04
Cm-242	3.52E+06
Cm-244	3.82E+05

TABLE 14.3-43a
Core Fission Product Release Fractions

	Gap Release (1)	**Early In-Vessel** (2)
Noble gases	0.05	0.95
Halogens	0.05	0.35
Alkali Metals	0.05	0.25
Tellurium group	0	0.05
Barium, Strontium	0	0.02
Noble Metals (Ruthenium group)	0	0.0025
Cerium group	0	0.0005
Lanthanides	0	0.0002

Note:
(1) Release is initiated at 30 seconds and is terminated at 0.5 hours.
(2) Released over a 1.3 hour period starting at the end of the gap release phase.

TABLE 14.3-44
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TABLE 14.3-45
Data Used in Evaluating Offsite Doses
(Isotope Dependent Data)

COMMITTED EFFECTIVE DOSE EQUIVALENT DOSE CONVERSION FACTORS			
Isotope	DCF (rem/curie)	Isotope	DCF (rem/curie)
I-130	2.64E3	Cs-138	1.01E2
I-131	3.29E4	Cs-134	4.63E4
I-132	3.81E2	Cs-136	7.33E3
I-133	5.85E3	Cs-137	3.19E4
I-134	1.31E2	Rb-86	6.62E3
I-135	1.23E3		
		Ru-103	8.95E3
Kr-85m	N/A	Ru-105	4.55E2
Kr-85	N/A	Ru-106	4.77E5
Kr-87	N/A	Rh-105	9.55E2
Kr-88	N/A	Mo-99	3.96E3
Xe-131m	N/A	Tc-99m	3.26E1
Xe-133m	N/A		
Xe-133	N/A	Y-90	8.44E3
Xe-135m	N/A	Y-91	4.89E4
Xe-135	N/A	Y-92	7.81E2
Xe-138	N/A	Y-93	2.15E3
		Nb-95	5.81E3
Te-127	3.18E2	Zr-95	2.36E4
Te-127m	2.15E4	Zr-97	4.33E3
Te-129m	2.39E4	La-140	4.85E3
Te-129	8.95E1	La-141	5.81E2
Te-131m	6.4E3	La-142	2.53E2
Te-132	9.44E3	Nd-147	6.85E3
Sb-127	6.03E3	Pr-143	8.10E4
Sb-129	6.44E2	Am-241	4.44E8
		Cm-242	1.73E7
Ce-141	8.95E3	Cm-244	2.48E8
Ce-143	3.39E3		
Ce-144	3.74E5	Sr-89	4.14E4
Pu-238	3.92E8	Sr-90	1.3E6
Pu-239	4.29E8	Sr-91	1.66E3
Pu-240	4.29E8	Sr-92	8.07E2
Pu-241	8.25E6	Ba-139	1.7E2
Np-239	2.51E3	Ba-140	3.74E3

TABLE 14.3-45 (Cont.)
Data Used in Evaluating Offsite Doses
(Isotope Dependent Data)

EFFECTIVE DOSE EQUIVALENT DOSE CONVERSION FACTORS			
Nuclide	DCF (rem-m^3/Ci-sec)	Nuclide	DCF (rem-m^3/Ci-sec)
I-130	3.848E-01	Cs-134	2.801E-01
I-131	6.734E-02	Cs-136	3.922E-01
I-132	4.144E-01	Cs-137[(1)]	1.066E-01
I-133	1.088E-01	Cs-138	4.477E-01
I-134	4.810E-01	Rb-86	1.780E-02
I-135	2.953E-01		
		Ru-103	8.325E-02
Kr-85m	2.768E-02	Ru-105	1.410E-01
Kr-85	4.403E-04	Ru-106	0.00E+00
Kr-87	1.524E-01	Rh-105	1.376E-02
Kr-88	3.774E-01	Mo-99	2.694E-02
Xe-131m	1.439E-03	Tc-99m	2.179E-02
Xe-133m	5.069E-03		
Xe-133	5.772E-03	Y-90	7.030E-04
Xe-135m	7.548E-02	Y-91	9.620E-04
Xe-135	4.403E-02	Y-92	4.810E-02
Xe-138	2.135E-01	Y-93	1.776E-02
		Nb-95	1.384E-01
Te-127	8.954E-04	Zr-95	1.332E-01
Te-127m	5.439E-04	Zr-97	3.337E-02
Te-129m	5.735E-03	La-140	4.329E-01
Te-129	1.018E-02	La-141	8.843E-03
Te-131m	2.594E-01	La-142	5.328E-01
Te-132	3.811E-02	Nd-147	2.290E-02
Sb-127	1.232E-01	Pr-143	7.770E-05
Sb-129	2.642E-01	Am-241	3.027E-03
		Cm-242	2.105E-05
Ce-141	1.269E-02	Cm-244	1.817E-05
Ce-143	4.773E-02		
Ce-144	3.156E-03	Sr-89	2.860E-04
Pu-238	1.806E-05	Sr-90	2.786E-05
Pu-239	1.569E-05	Sr-91	1.277E-01
Pu-240	1.758E-05	Sr-92	2.512E-01
Pu-241	2.683E-07	Ba-139	8.029E-03
Np-239	2.845E-02	Ba-140	3.175E-02

Note:
1. Decay of Cs-137 does not result in gamma radiation. The EDE DCF listed for Cs-137 is actually the value associated with the decay of the short-lived daughter product Ba-137m.

TABLE 14.3-46
Input Values for Doses

Atmospheric Dilution

Time Period (hr)	χ/Q (520m) (sec/m^3)	χ/Q (1100m) (sec/m^3)
0-8	7.5×10^{-4}	3.5×10^{-4}
8-24	--	1.2×10^{-4}
24-96	--	4.2×10^{-5}
96-720	--	9.3×10^{-6}

Containment Leakage

Time Period (hr)	Leak Rate (percent/day)
0-24	0.1
24-720	0.05

Breathing Rate Offsite

Time Period (hr)	Breathing Rate (m^3/sec)
0-8	3.5×10^{-4}
8-24	1.8×10^{-4}
24-720	2.3×10^{-4}

TABLE 14.3-47
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TABLE 14.3-48
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TABLE 14.3-49
ASSUMPTIONS USED FOR LARGE LOCA DOSE ANALYSIS

Iodine Chemical Species	
Elemental	4.85%
Methyl	0.15%
Particulate	95%
Iodine Removal in Containment	
Containment Spray	
Spray Start Delay	60 sec
Injection spray flowrate	2135 gpm
Injection spray duration	37.8 min
Recirculation spray flowrate	1080 gpm
Recirculation spray duration	Note 1
Iodine removal coefficient	
Elemental, λ_s	
during spray injection	20.0/hr DF < 200
during spray recirculation	5.0/hr DF < 200
Particulate λ_p	
during spray injection	4.4/hr DF $\leq$ 50
during spray recirculation	2.25/hr DF $\leq$ 50
Sedimentation Particulate Removal	0.1/hr DF < 1000 (Note 2)
Fan Cooler Units Containment Filters	
Start Delay Time	60 sec
Number of Units	3
Flow Rate per Unit	64,500 cfm
Containment Free Volume	2.61×10^6-ft^3
Containment Leak Rate	
0-24 hr	0.10%/day
> 24 hr	0.05%/day

Notes:
1. Total spray duration assumed is 3.4 hours following the initiation of the event.
2. Credit for sedimentation removal is limited to the unsprayed portion of the containment until sprays are terminated (at 3.4 hours).

TABLE 14.3-49a
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TABLE 14.3-50
ASSUMPTIONS USED FOR ANALYSIS OF
CONTROL ROOM DOSES

Volume	102,400-ft^3
Unfiltered Inleakage	700 cfm
Filtered Makeup	1800 cfm
Filtered Recirculation	0 cfm
Filter Efficiency	
Elemental	95%
Organic	90%
Particulate	99%
Breathing Rate	3.5×10^{-4} m^3/sec
Atmospheric Dispersion Factors	See Table 14.3-51
Occupancy Factors	
0-1 day	1.0
1-4 days	0.6
4-30 days	0.4

TABLE 14.3-51
ATMOSPHERIC DISPERSION FACTORS USED
FOR ANALYSIS OF CONTROL ROOM DOSES

Release Point	Atmospheric Dispersion Factors (sec/m^3)
Containment Surface Leak (1)	
0-2 hr	3.82×10^{-4}
2-8 hr	2.81×10^{-4}
8-24 hr	1.05×10^{-4}
24-96 hr	8.31×10^{-5}
96-720 hr	7.04×10^{-5}
Side of the Auxiliary Boiler Feedwater Building (2)	
0-2 hr	1.09×10^{-3}
2-8 hr	1.02×10^{-3}
8-24 hr	4.99×10^{-4}
24-96 hr	3.86×10^{-4}
96-720 hr	2.99×10^{-4}
Vent Stacks on the Roof of the Auxiliary Boiler Feedwater Building (3)	
0-2 hr	9.49×10^{-4}
2-8 hr	8.65×10^{-4}
8-24 hr	4.17×10^{-4}
24-96 hr	3.30×10^{-4}
96-720 hr	2.54×10^{-4}
Containment Vent (4)	
0-2 hr	6.44×10^{-4}
2-8 hr	4.69×10^{-4}
8-24 hr	1.72×10^{-4}
24-96 hr	1.37×10^{-4}
96-720 hr	1.17×10^{-4}

Notes:

1. Used for Containment Leakage Releases in Rod Ejection (14.2.6.9), Large Break LOCA (14.3.6.5) and Small Break LOCA (14.3.6.7).
2. Used for Steamline Break (14.2.5.7).
3. Used for Locked Rotor (14.1.6.5.3) and Steam Generator Tube Rupture (14.2.4) and Secondary Side Releases for Rod Ejection (14.2.6.9) and Small Break LOCA (14.3.6.7).
4. Used for Fuel Handling Accident (14.2.1.1) and Large Break LOCA ECCS Recirculation Leakage (14.3.6.6).

TABLE 14.3-52
CALCULATED CONTROL ROOM DOSES

Event	TEDE Dose (rem)
Large Break LOCA	
Containment Leakage	3.5
Direct Dose from Activity in Containment	0.02
ECCS Recirculation Leakage With Boundary Layer Effects	0.14
ECCS Recirculation Leakage Without Boundary Layer Effects	1.36
Total With Boundary Layer Effects	3.68
Total Without Boundary Layer Effects	4.90
Small Break LOCA	3.5
Locked Rotor	0.65
Rod Ejection	1.4
Fuel Handling Accident	3.0
Steamline Break	
Pre-Existing Iodine Spike	0.18
Accident-Initiated Iodine Spike	0.52
Steam Generator Tube Rupture	
Pre-Existing Iodine Spike	1.4
Accident-Initiated Iodine Spike	0.48

14.3 FIGURES

14.4 ANTICIPATED TRANSIENTS WITHOUT SCRAM

An anticipated transient without scram (ATWS) is an anticipated operational occurrence (such as loss of feedwater, loss of load, or loss of offsite power) that is assumed to be accompanied by a failure of the reactor trip system to shut down the reactor. As presented in Reference 1, the reactor is adequately protected against anticipated plant transients by the reactor protection system in the Westinghouse design, which is both redundant and diverse. As a result, failure to trip was not considered a credible event and the effects of ATWS were not considered part of the design basis for transients analyzed for Westinghouse plants. Nevertheless, in response to an AEC request for further information at the time of Indian Point Unit 2 initial licensing, the hypothetical effects of anticipated transients with no credit taken for reactor trip were provided in Supplement 6 to the original Indian Point Unit 2 FSAR. Those assessments were historical and were superseded by a later series of generic studies on ATWS (References 2 & 3) that showed acceptable consequences would result for Westinghouse designed plants provided that the turbine trips and auxiliary feedwater flow is initiated in a timely manner. The final USNRC ATWS Rule (Reference 4) requires that all US Westinghouse-designed plants install ATWS Mitigation System Actuation Circuitry (AMSAC) to initiate a turbine trip and actuate auxiliary feedwater independent of the reactor trip system. The Indian Point Unit 2 AMSAC is described in Section 7.10.

REFERENCES FOR SECTION 14.4

1. T. W. T. Burnett, et al., Reactor Protection System Diversity in W PWRs, WCAP-7306, Westinghouse Electric Corporation, April 1969.

2. Burnett, T.W.T, et al., "Westinghouse Anticipated Transients Without Trip Analysis," WCAP-8330, August 1974.

3. Letter from T.M. Anderson (Westinghouse) to S.H. Hanauer (USNRC), "ATWS Submittal," NS-TMA-2182, December 1979.

4. ATWS Final Rule, Code of Federal Regulations 10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants.

TABLE 14.4-1
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TABLE 14.4-2
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TABLE 14.4-3
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TABLE 14.4-4
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TABLE 14.4-5
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TABLE 14.4-6
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TABLE 14.4-7
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TABLE 14.4-8
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14.4 FIGURES

APPENDIX 14A
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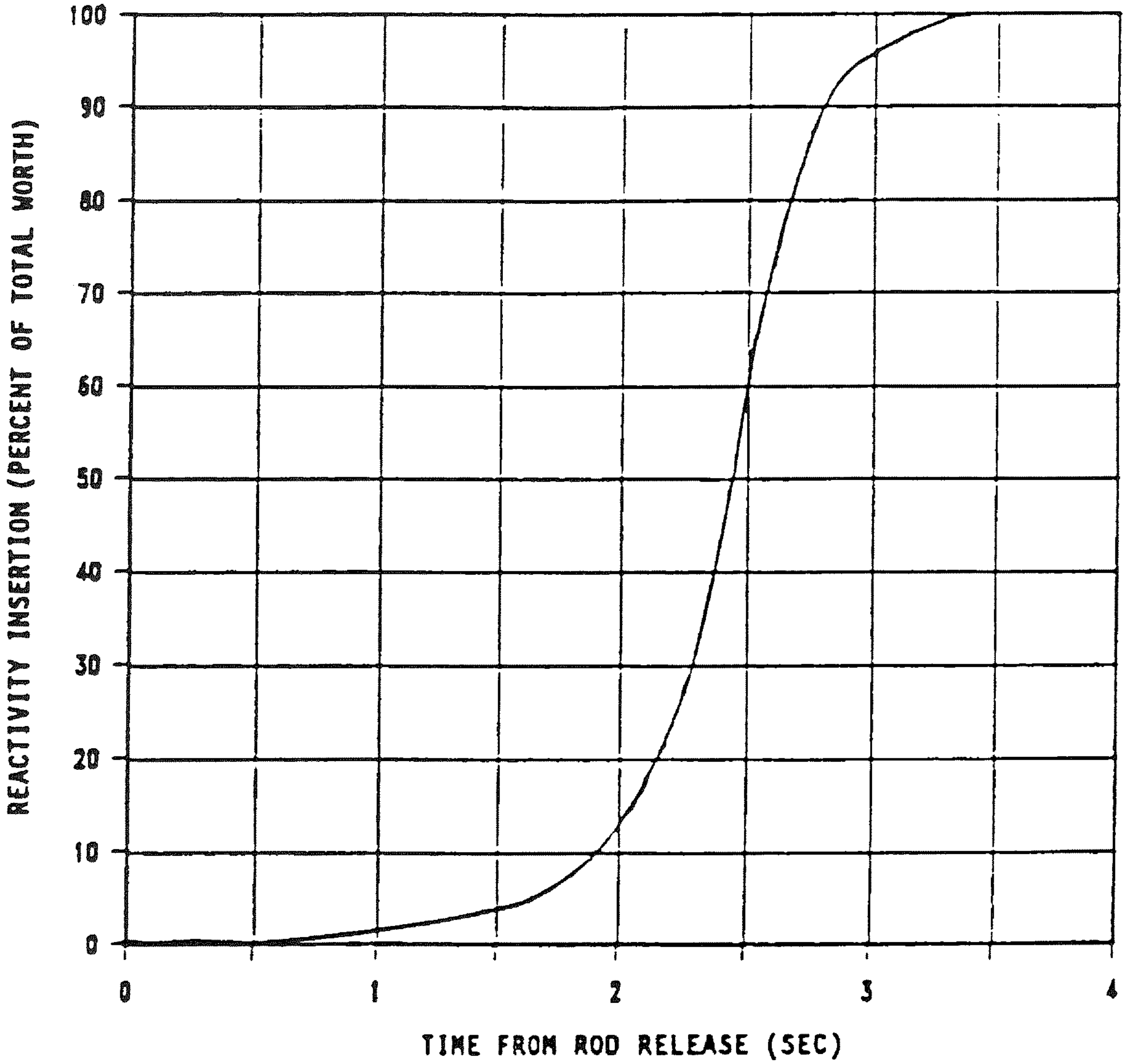
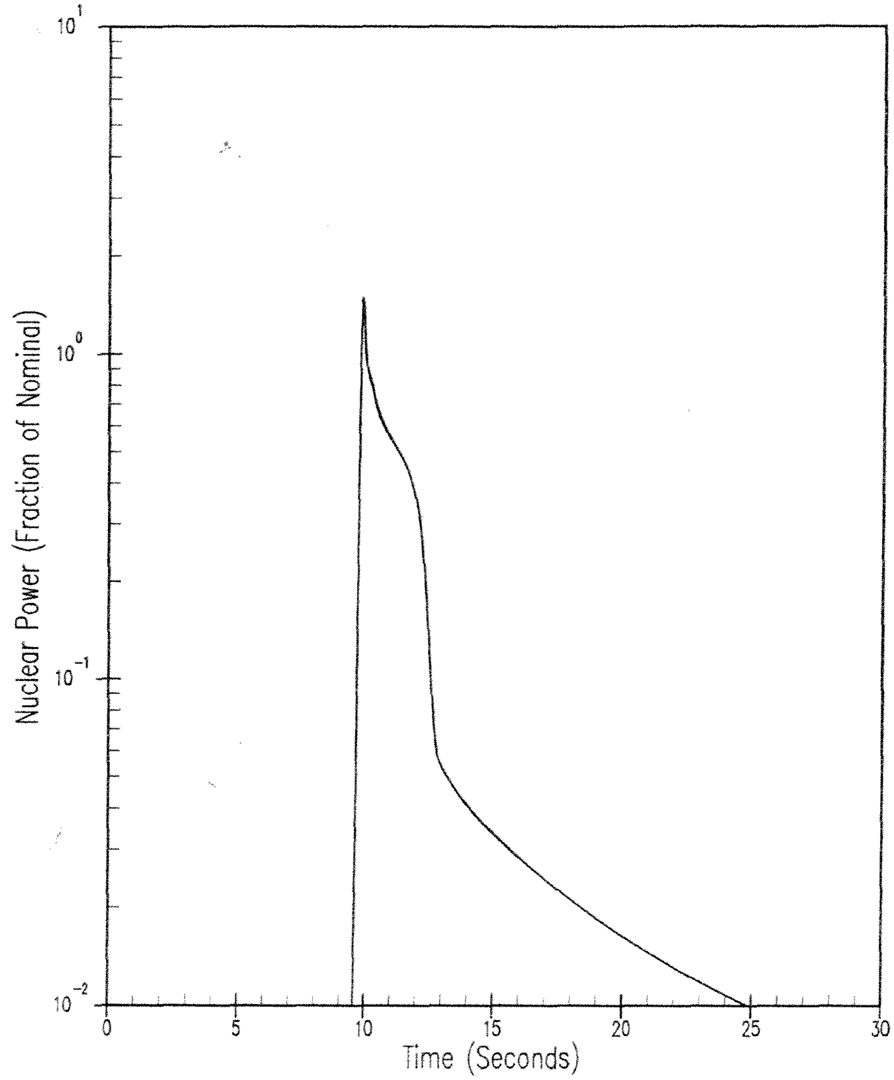


INDIAN POINT UNIT No. 2

UFSAR FIGURE 14.0-1

REACTIVITY INSERTION vs
TIME FOR REACTOR TRIP

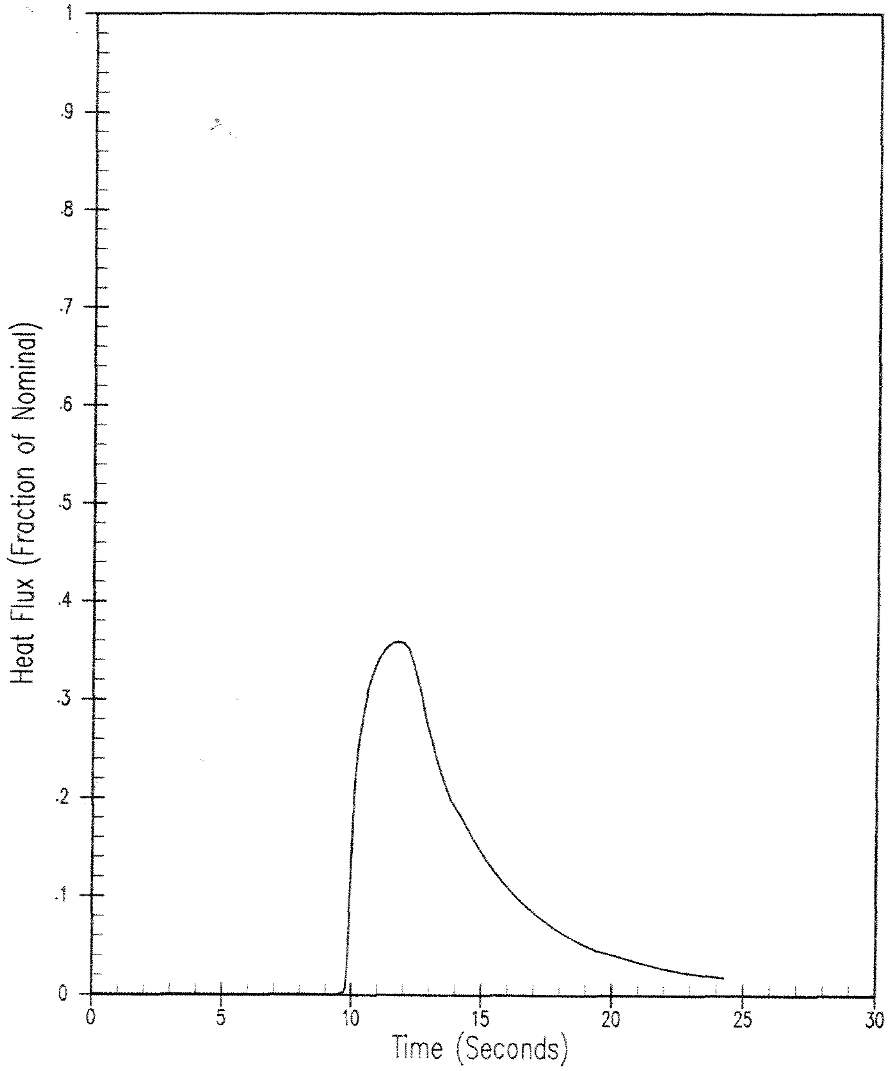
MIC. No. 1999MC3969	REV. No. 17A



INDIAN POINT UNIT No. 2

UNCONTROLLED RCCA WITHDRAWAL
FROM A SUBCRITICAL CONDITION
NUCLEAR POWER vs TIME

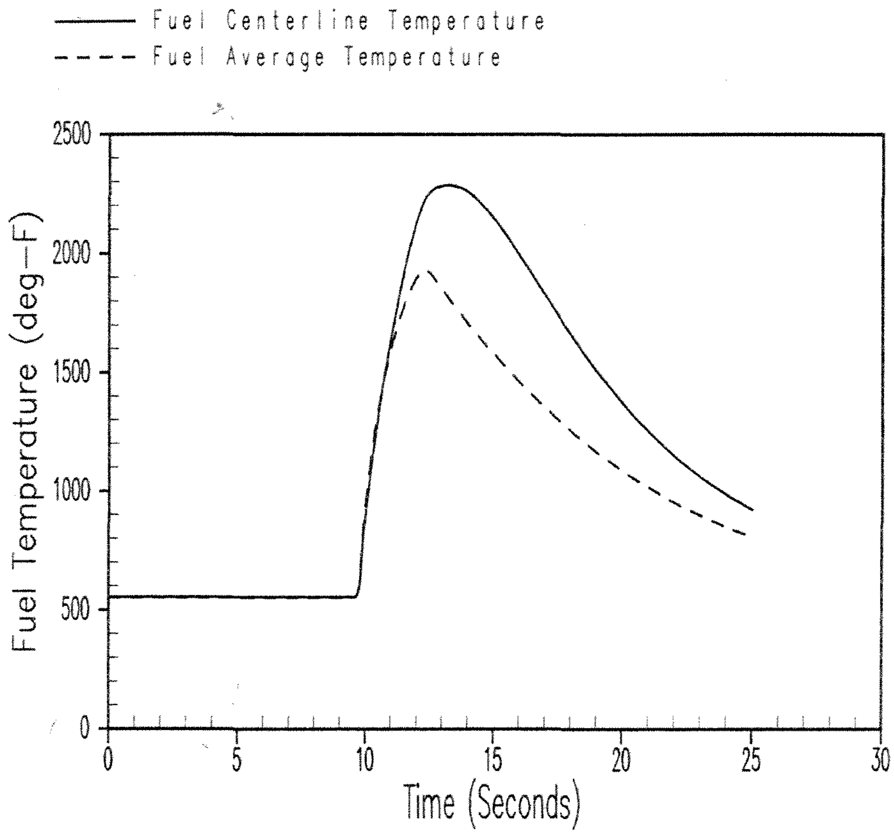
UFSAR FIGURE 14.1-1	REV. No. 19



INDIAN POINT UNIT No. 2

UNCONTROLLED RCCA WITHDRAWAL FROM A SUBCRITICAL CONDITION HEAT FLUX vs TIME, AVG. CHANNEL

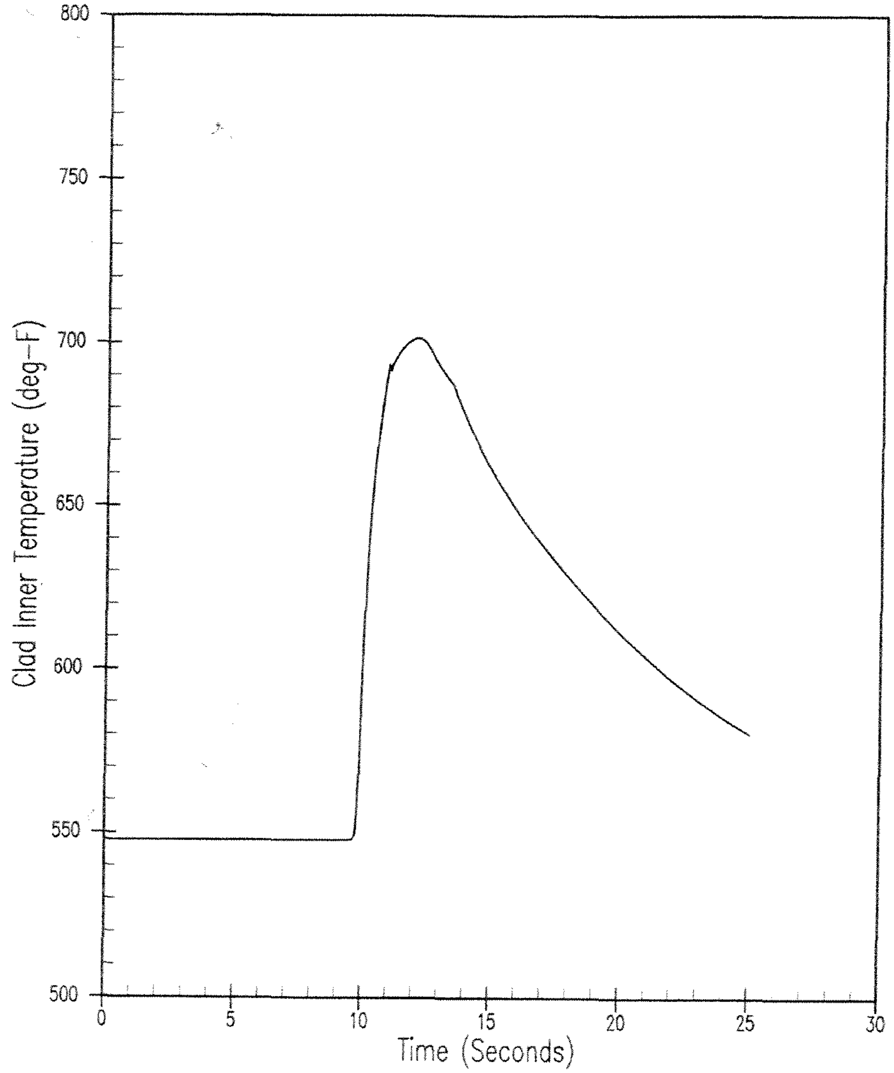
UFSAR FIGURE 14.1-2	REV. No. 19



INDIAN POINT UNIT No. 2

UNCONTROLLED RCCA WITHDRAWAL FROM A SUBCRITICAL CONDITION FUEL AVERAGE TEMPERATURE vs TIME AT HOT SPOT

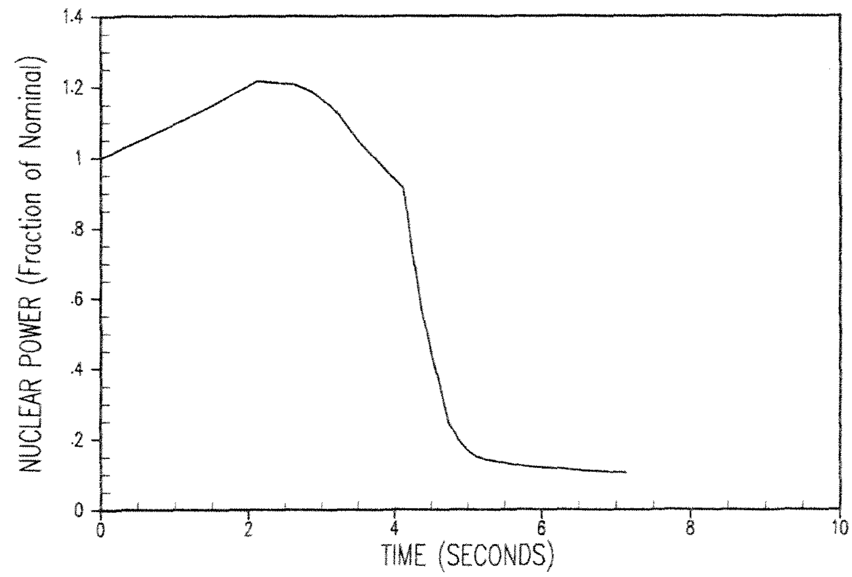
UFSAR FIGURE 14.1—3	REV. No. 19

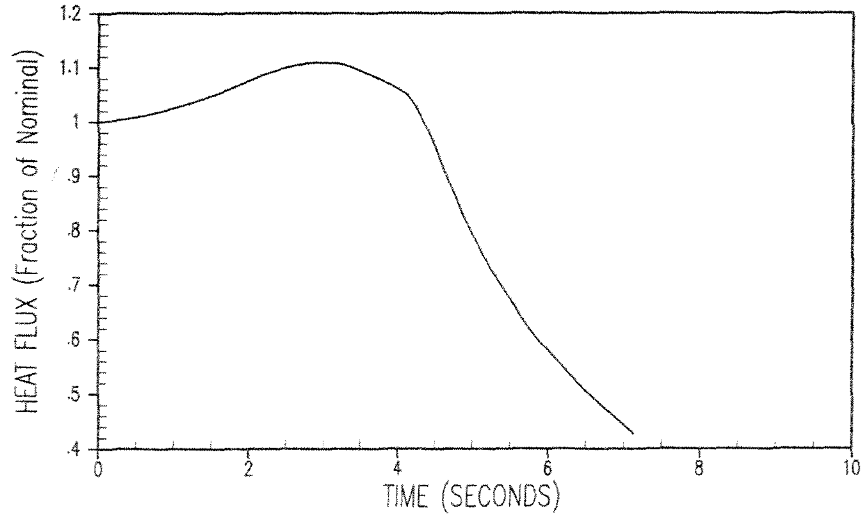


INDIAN POINT UNIT No. 2

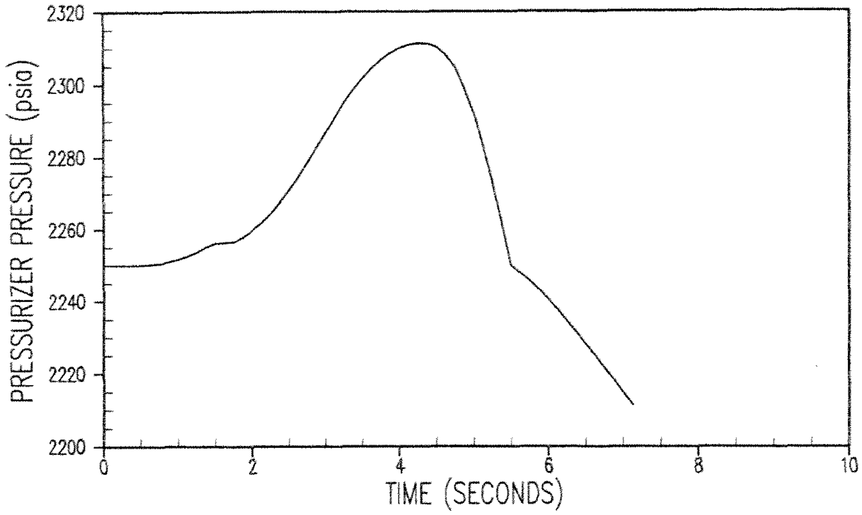
UNCONTROLLED RCCA WITHDRAWAL FROM A SUBCRITICAL CONDITION CLAD INNER TEMPERATURE vs TIME AT HOT SPOT

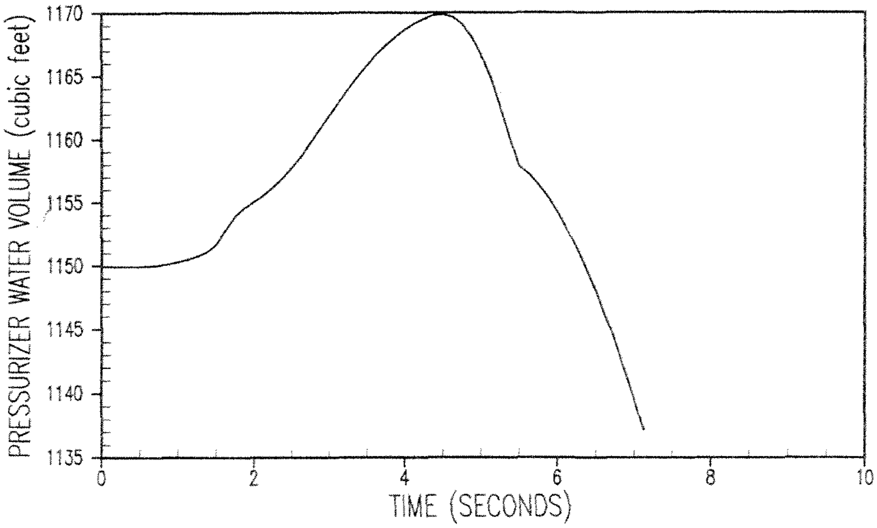
UFSAR FIGURE 14.1-4	REV. No. 19





INDIAN POINT UNIT No. 2	
UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (70 pcm/sec WITHDRAWAL RATE), NUCLEAR POWER AND CORE HEAT FLUX vs TIME	
UFSAR FIGURE 14.1-5	REV. No. 19

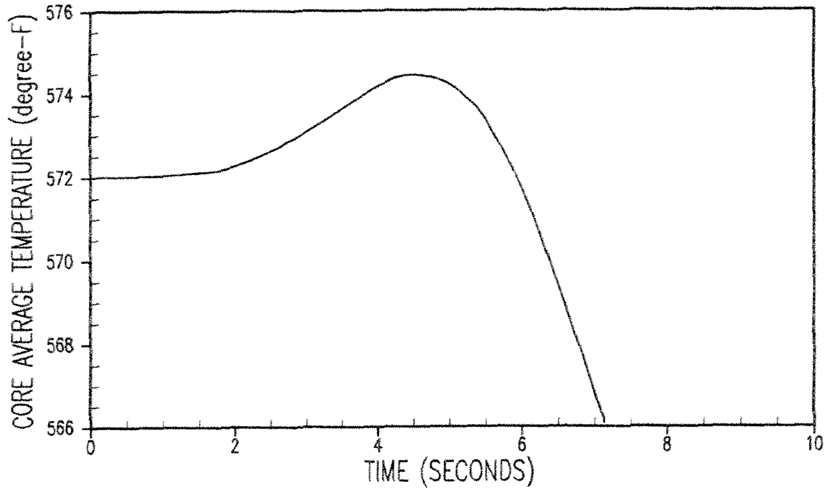


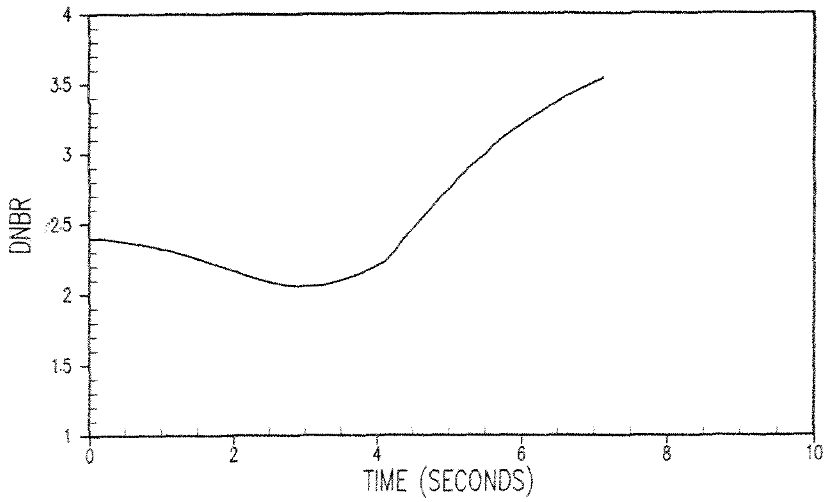


INDIAN POINT UNIT No. 2

UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (70 pcm/sec WITHDRAWAL RATE), PRESSURIZER PRESSURE AND WATER VOLUME vs TIME

UFSAR FIGURE 14.1-6	REV. No. 19

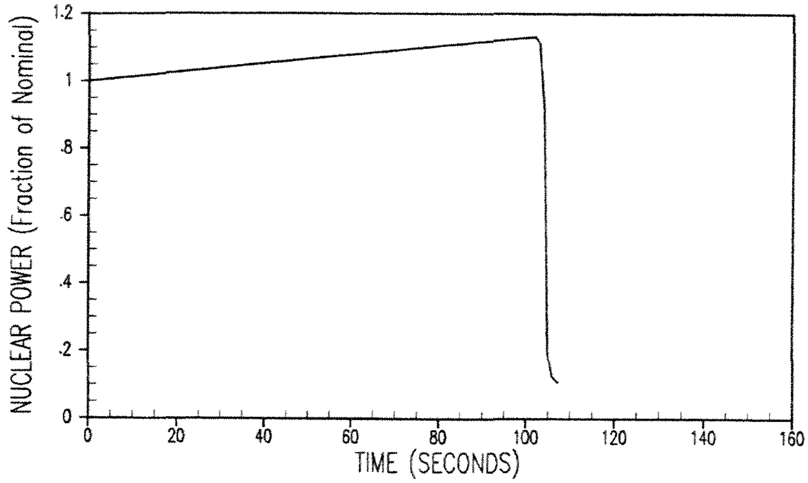


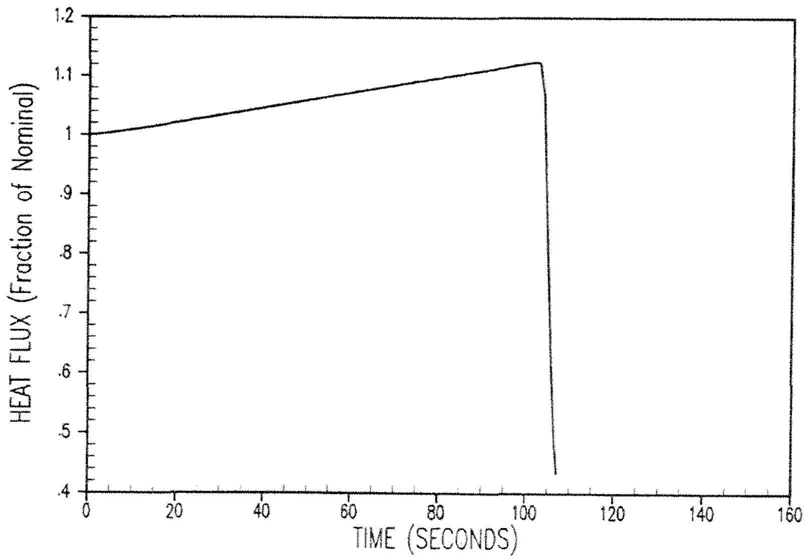


INDIAN POINT UNIT No. 2

UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (70 pcm/sec WITHDRAWAL RATE), CORE WATER AVERAGE TEMPERATURE AND DNBR vs TIME

UFSAR FIGURE 14.1-7	REV. No. 19

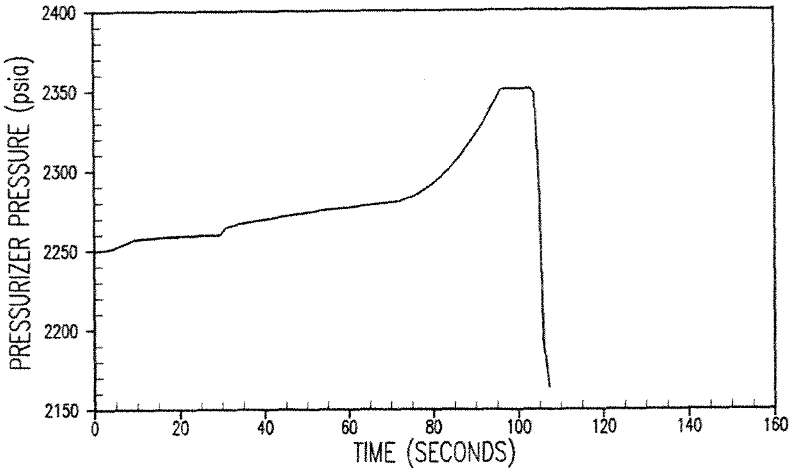


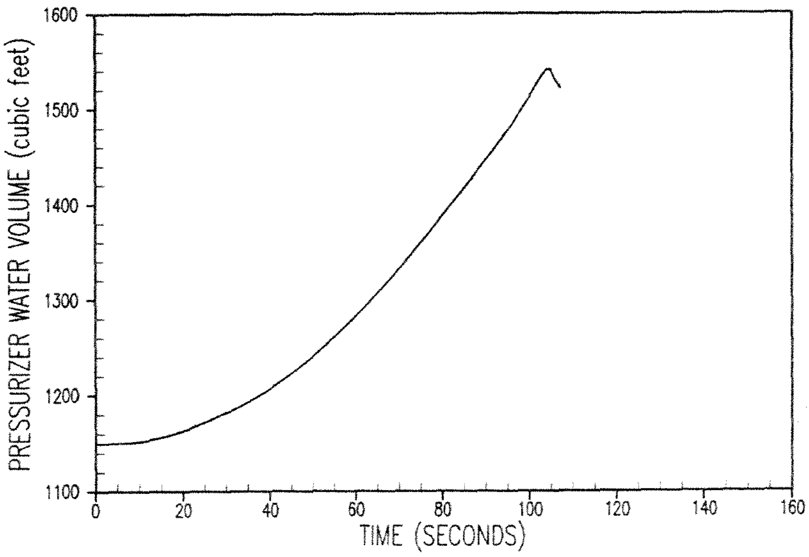


INDIAN POINT UNIT No. 2

UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (1 pcm/sec WITHDRAWAL RATE), NUCLEAR POWER AND CORE HEAT FLUX vs TIME

UFSAR FIGURE 14.1–8	REV. No. 19

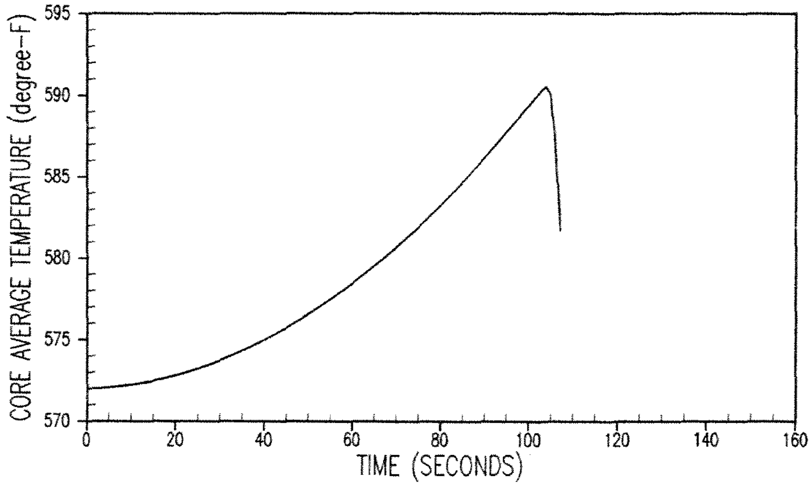


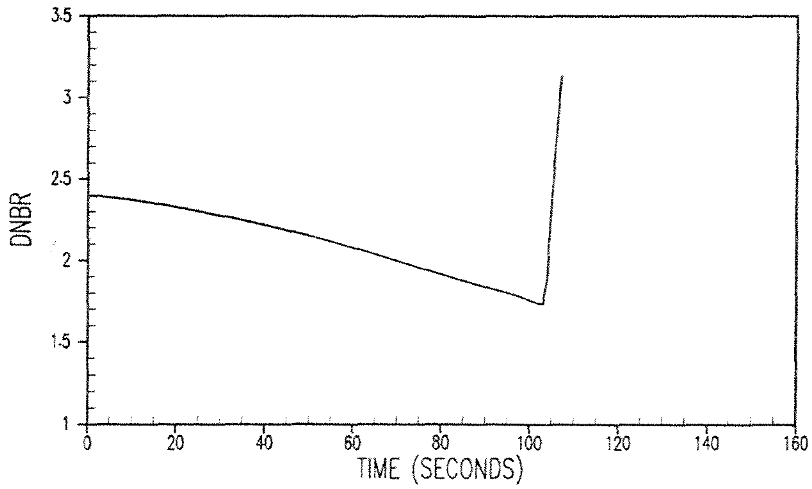


INDIAN POINT UNIT No. 2

UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (1 pcm/sec WITHDRAWAL RATE), PRESSURIZER PRESSURE AND WATER VOLUME vs TIME

UFSAR FIGURE 14.1-9	REV. No. 19

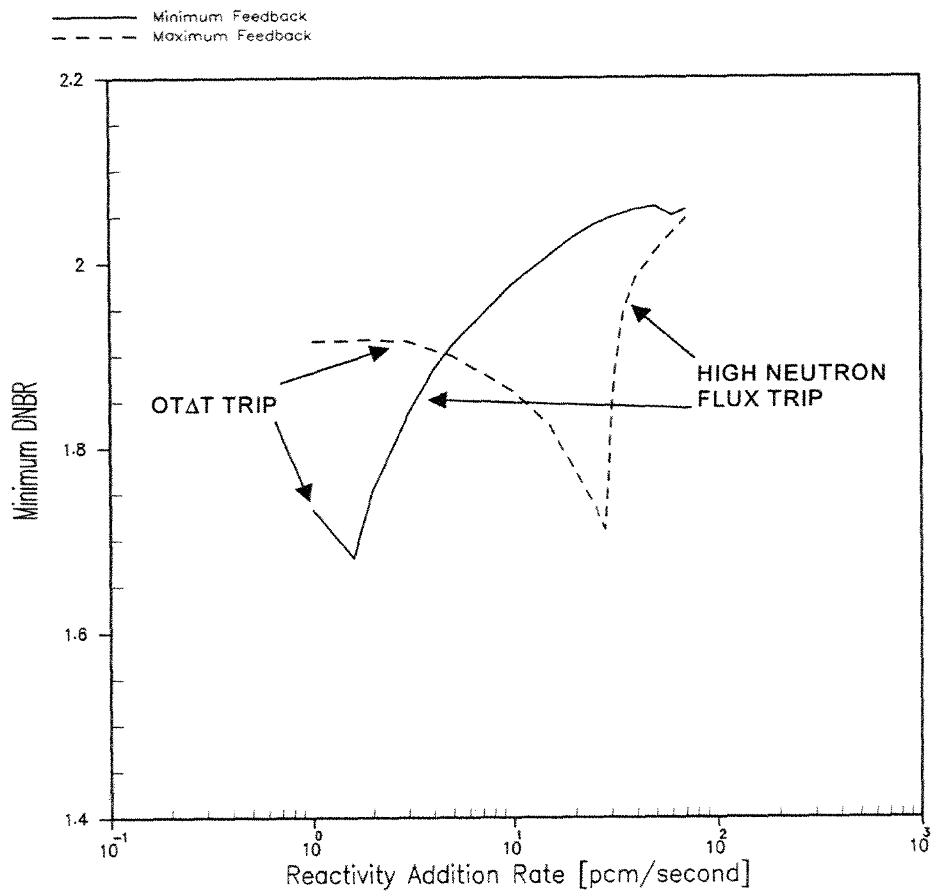




INDIAN POINT UNIT No. 2

UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (1 pcm/sec WITHDRAWAL RATE), CORE WATER AVERAGE TEMPERATURE AND DNBR vs TIME

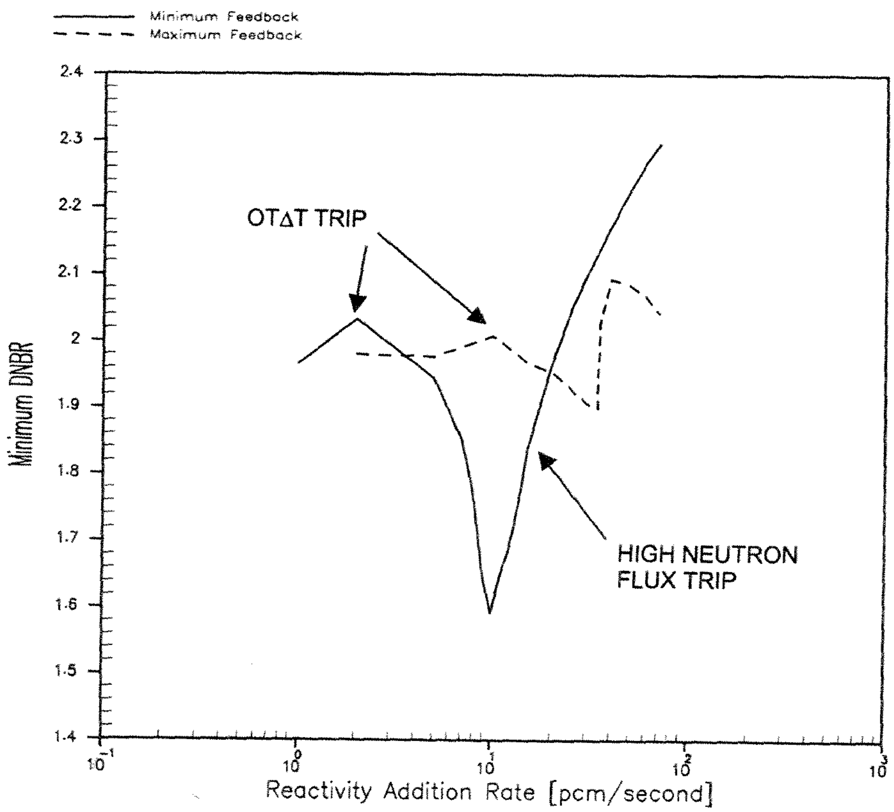
UFSAR FIGURE 14.1–10	REV. No. 19



INDIAN POINT UNIT No. 2

MINIMUM DNBR VERSUS REACTIVITY INSERTION RATE, ROD WITHDRAWAL FROM 100 PERCENT POWER

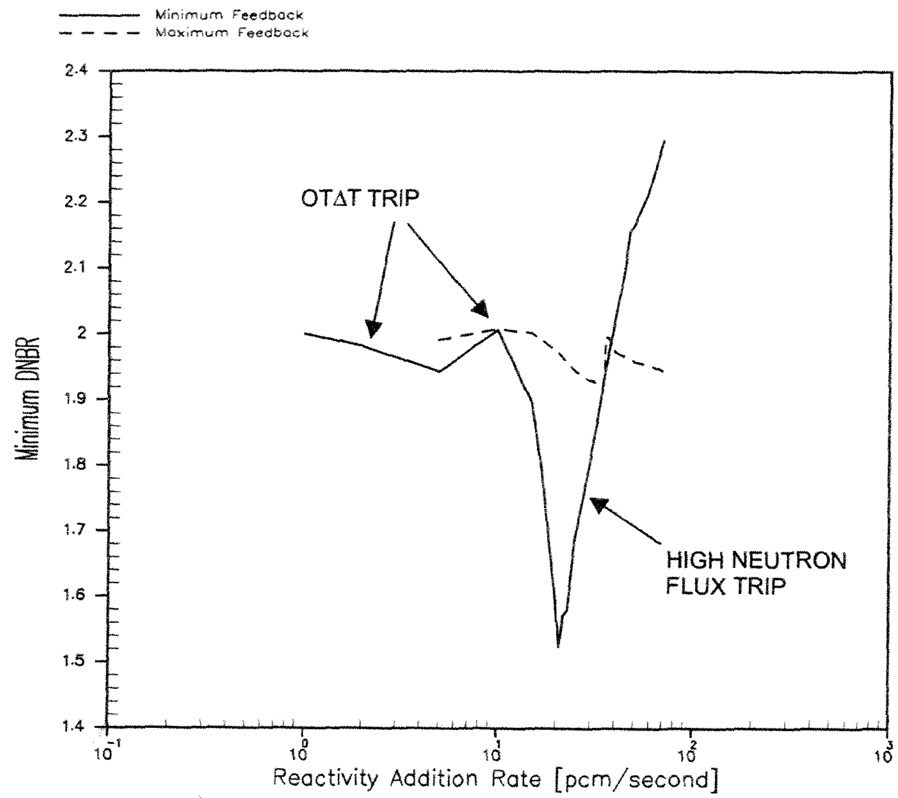
UFSAR FIGURE 14.1-11 | REV. No. 19



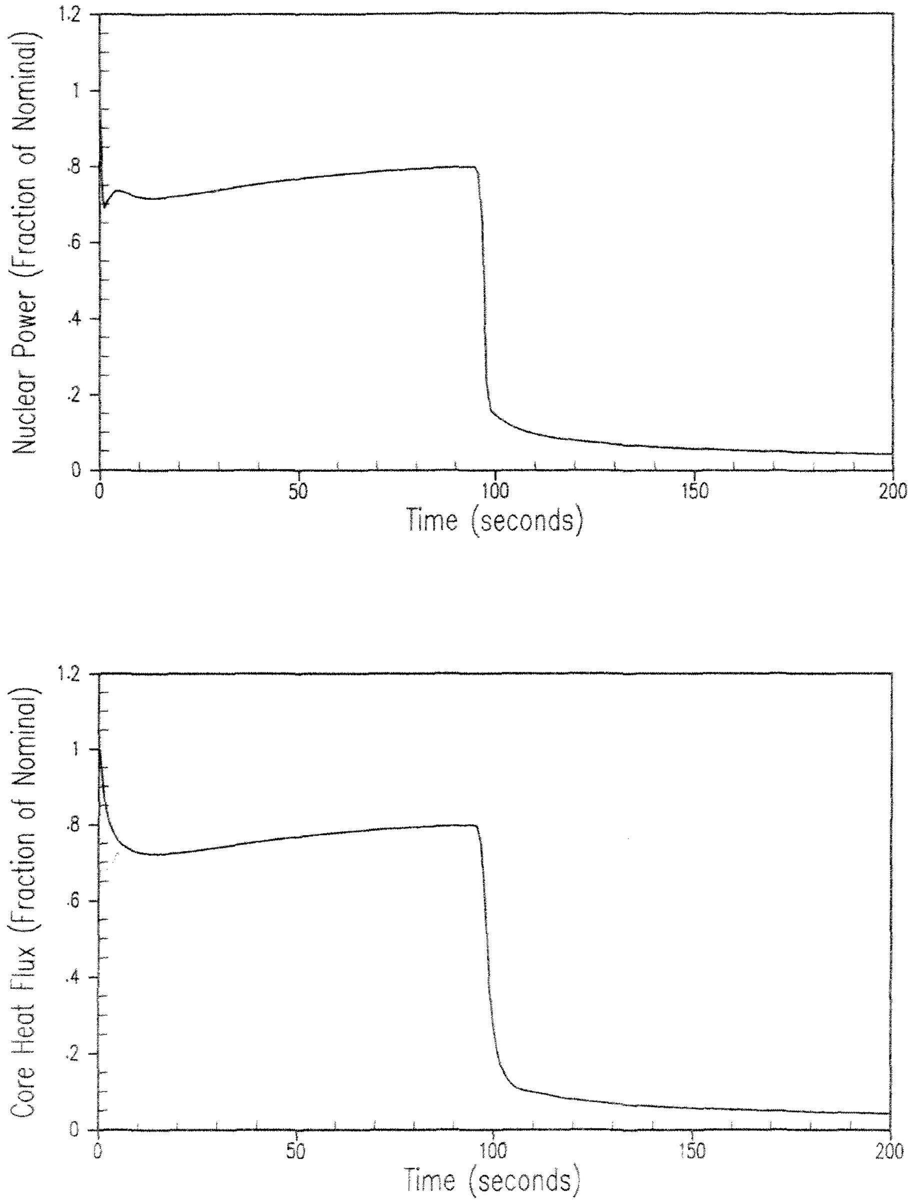
INDIAN POINT UNIT No. 2

MINIMUM DNBR VERSUS REACTIVITY INSERTION RATE, ROD WITHDRAWAL FROM 60 PERCENT POWER

UFSAR FIGURE 14.1-12	REV. No. 19



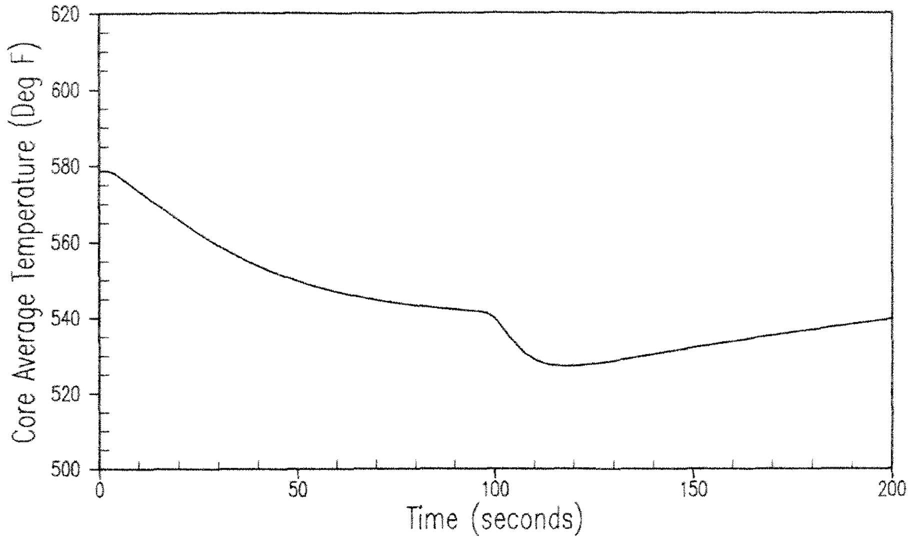
INDIAN POINT UNIT No. 2	
MINIMUM DNBR VERSUS REACTIVITY INSERTION RATE, ROD WITHDRAWAL FROM 10 PERCENT POWER	
UFSAR FIGURE 14.1−13	REV. No. 19

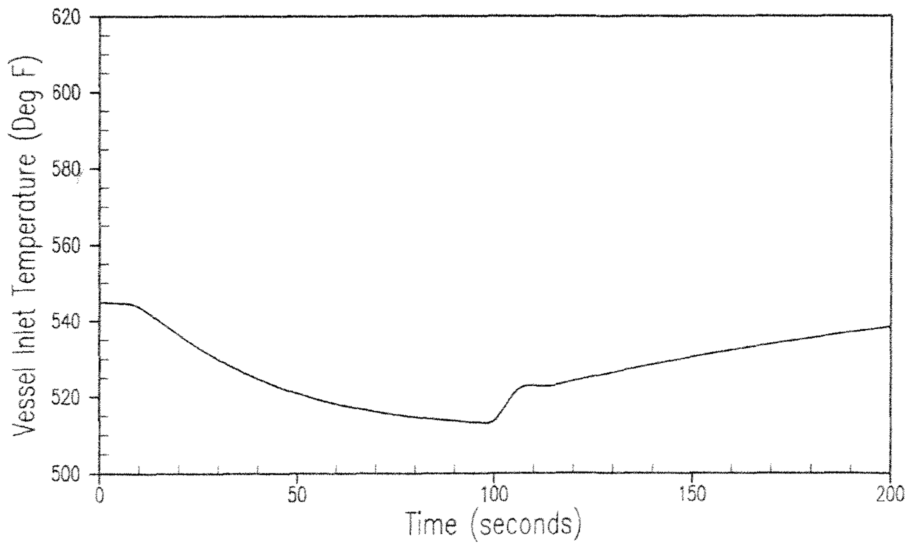


INDIAN POINT UNIT No. 2

DROPPED ROD INCIDENT MANUAL ROD CONTROL
NUCLEAR POWER AND CORE HEAT FLUX
AT BOL (SMALL NEGATIVE MTC) FOR
DROPPED RCCA OF WORTH – 400 PCM

UFSAR FIGURE 14.1–14	REV. No. 19

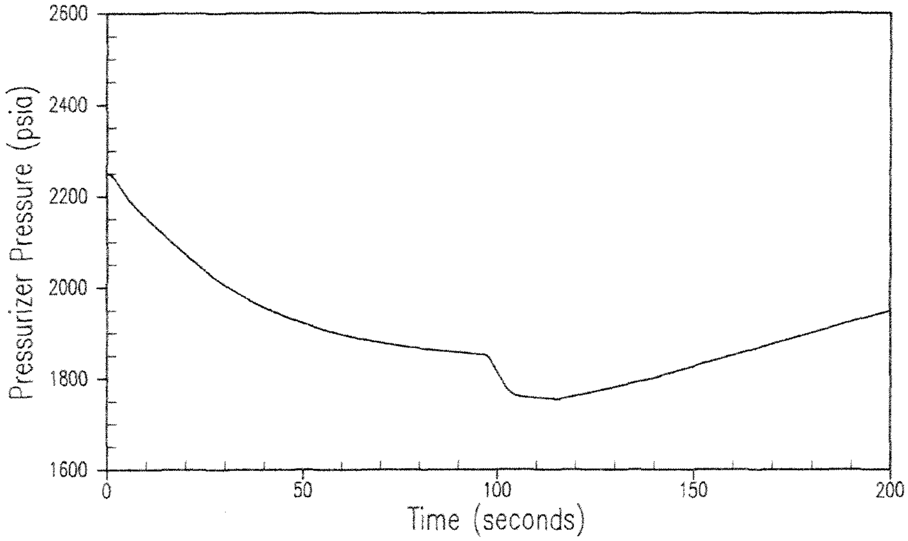




INDIAN POINT UNIT No. 2

DROPPED ROD INCIDENT MANUAL ROD CONTROL CORE AVERAGE AND VESSEL INLET TEMPERATURE AT BOL (SMALL NEGATIVE MTC) FOR DROPPED RCCA OF WORTH – 400 PCM

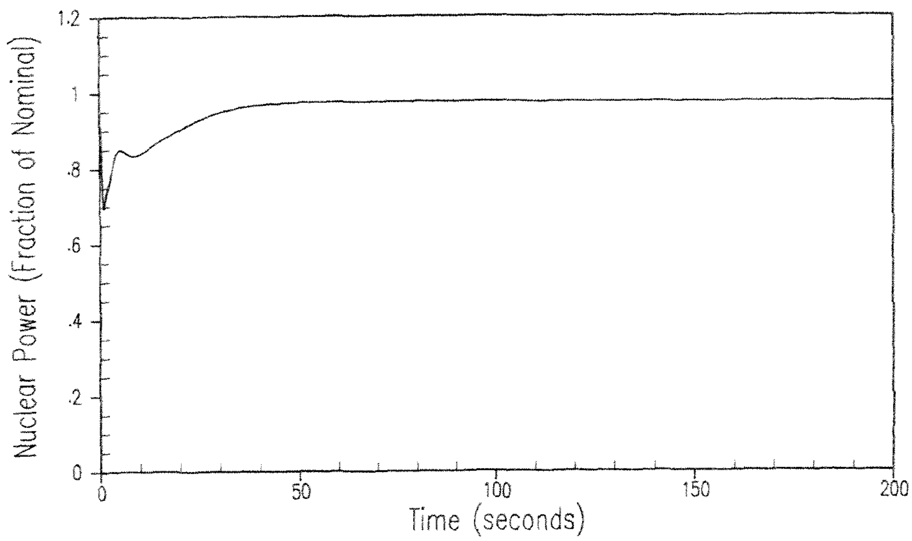
UFSAR FIGURE 14.1–15	REV. No. 19

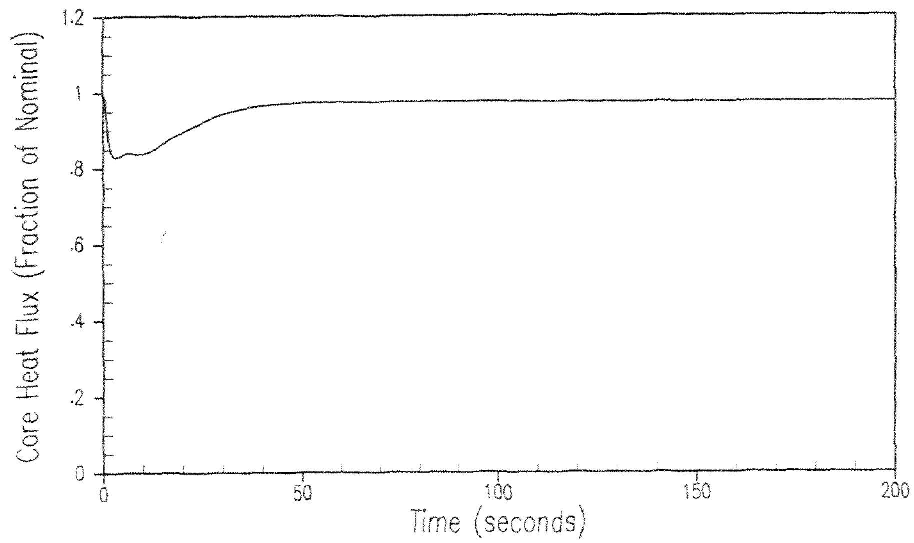


INDIAN POINT UNIT No. 2

DROPPED ROD INCIDENT MANUAL ROD CONTROL
PRESSURIZER PRESSURE
AT BOL (SMALL NEGATIVE MTC) FOR
DROPPED RCCA OF WORTH – 400 PCM

UFSAR FIGURE 14.1–16 | REV. No. 19

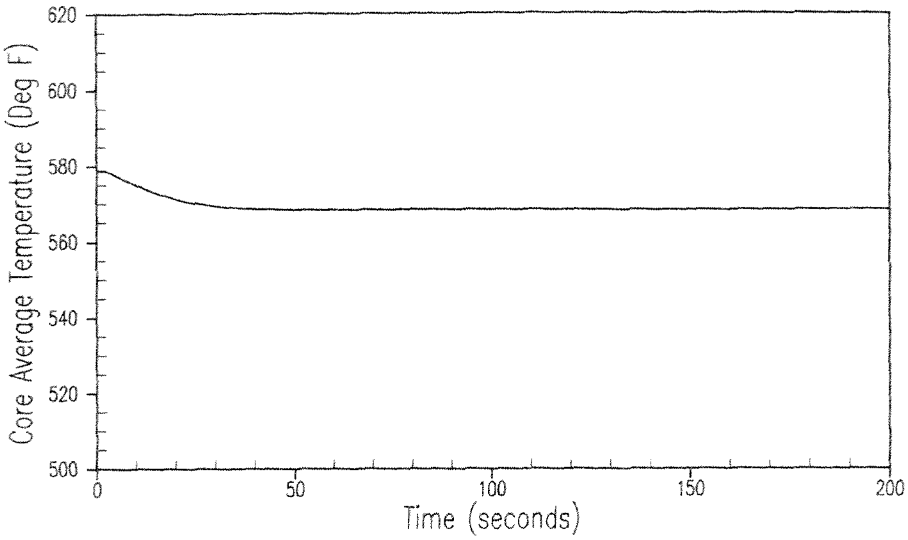


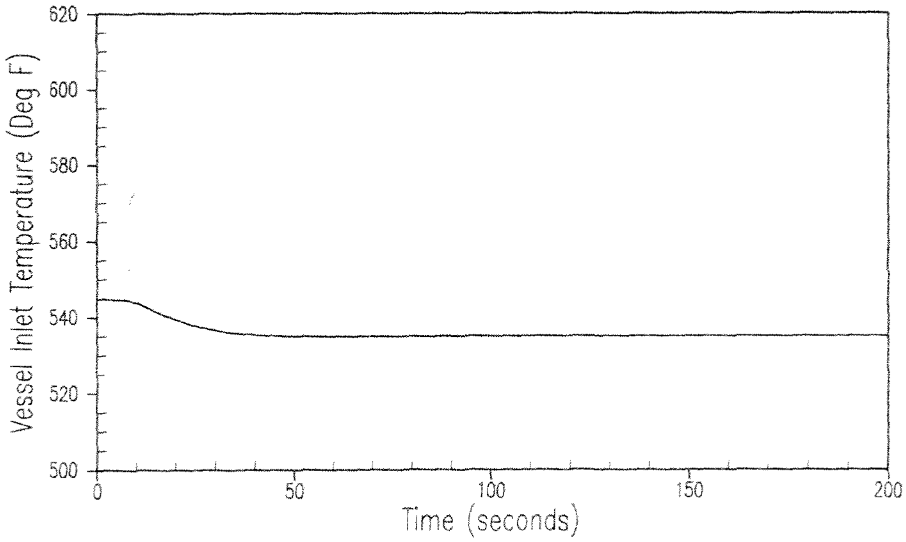


INDIAN POINT UNIT No. 2

DROPPED ROD INCIDENT MANUAL ROD CONTROL
NUCLEAR POWER AND CORE HEAT FLUX
AT EOL (LARGE NEGATIVE MTC) FOR
DROPPED RCCA OF WORTH – 400 PCM

UFSAR FIGURE 14.1-17 | REV. No. 19

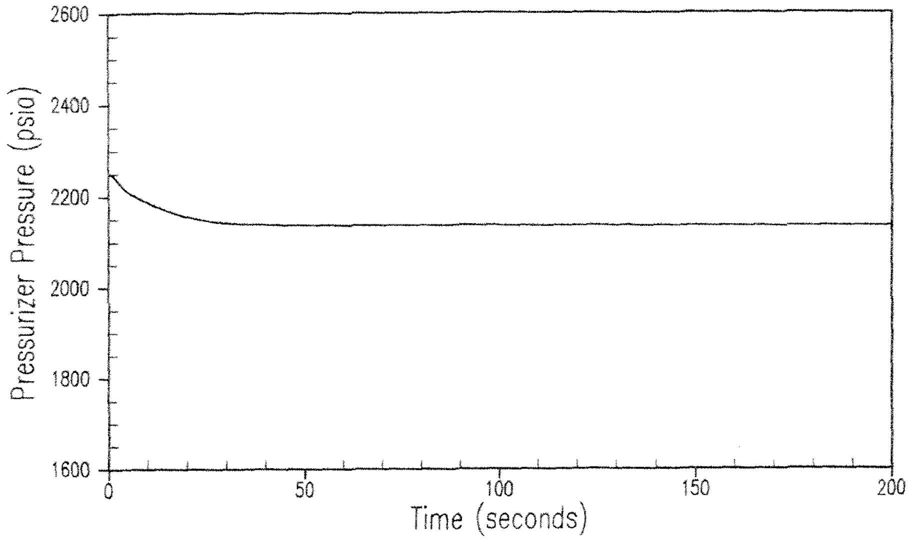




INDIAN POINT UNIT No. 2

DROPPED ROD INCIDENT MANUAL ROD CONTROL
CORE AVERAGE AND VESSEL INLET TEMPERATURE
AT EOL (LARGE NEGATIVE MTC) FOR
DROPPED RCCA OF WORTH – 400 PCM

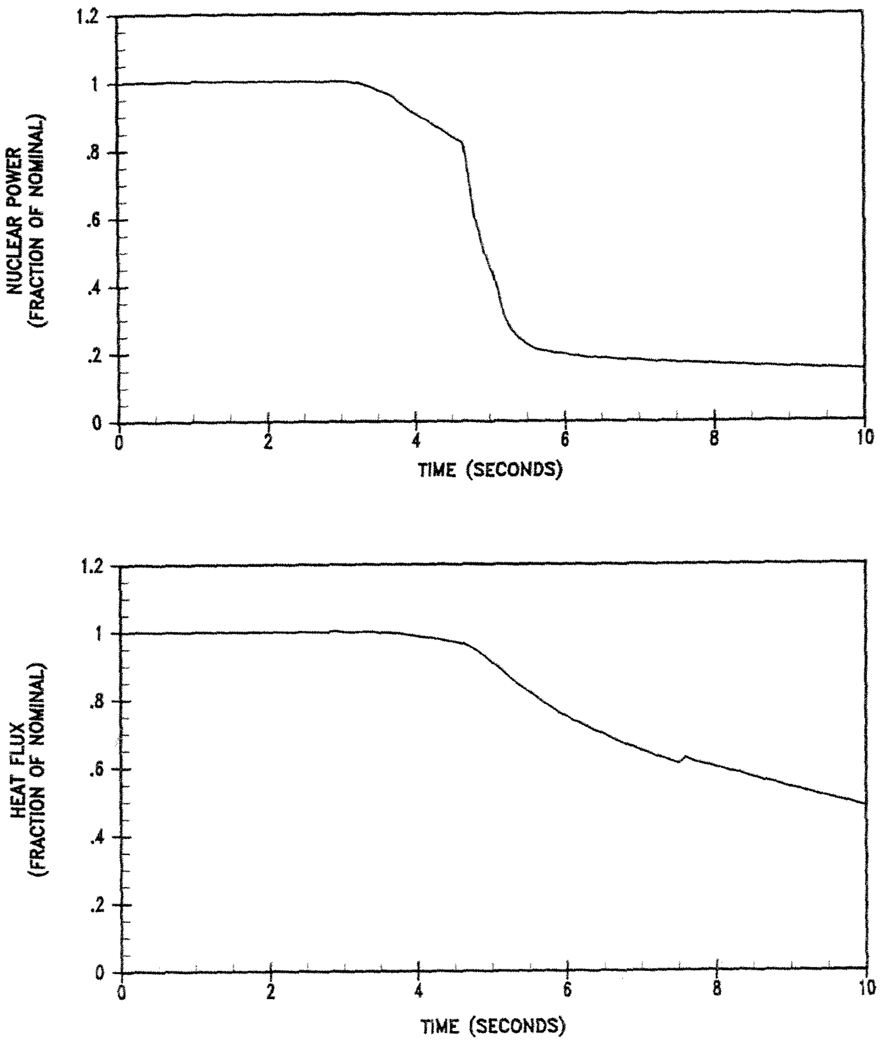
UFSAR FIGURE 14.1–18 | REV. No. 19



INDIAN POINT UNIT No. 2

DROPPED ROD INCIDENT MANUAL ROD CONTROL
PRESSURIZER PRESSURE
AT EOL (LARGE NEGATIVE MTC) FOR
DROPPED RCCA OF WORTH – 400 PCM

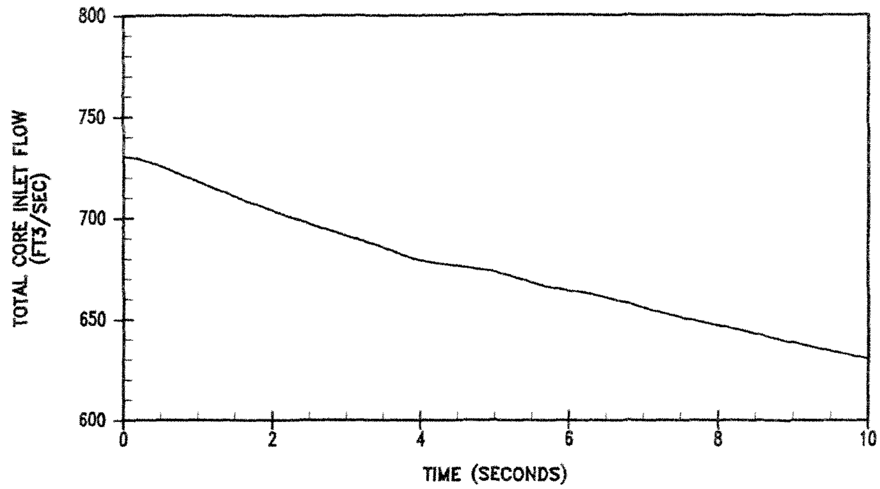
UFSAR FIGURE 14.1–19 | REV. No. 19

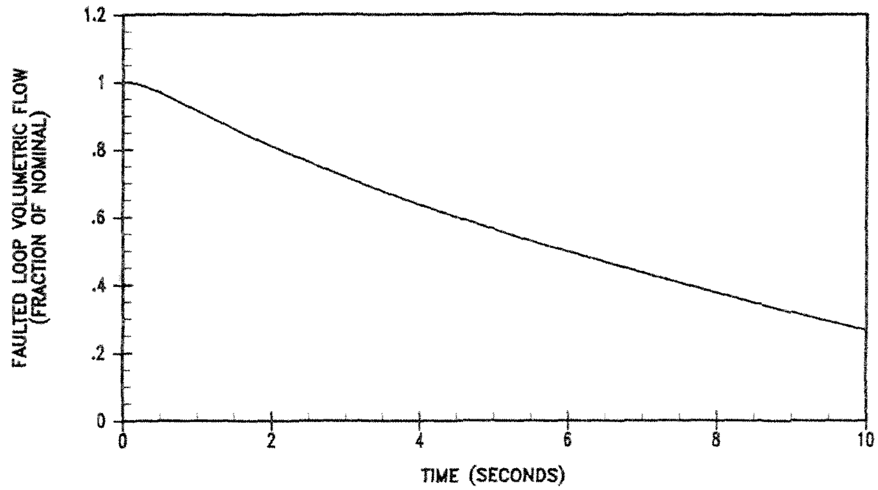


INDIAN POINT UNIT No. 2

LOSS OF ONE PUMP OUT OF FOUR
NUCLEAR POWER AND CORE HEAT
FLUX vs TIME

UFSAR FIGURE 14.1–20 | REV. No. 19

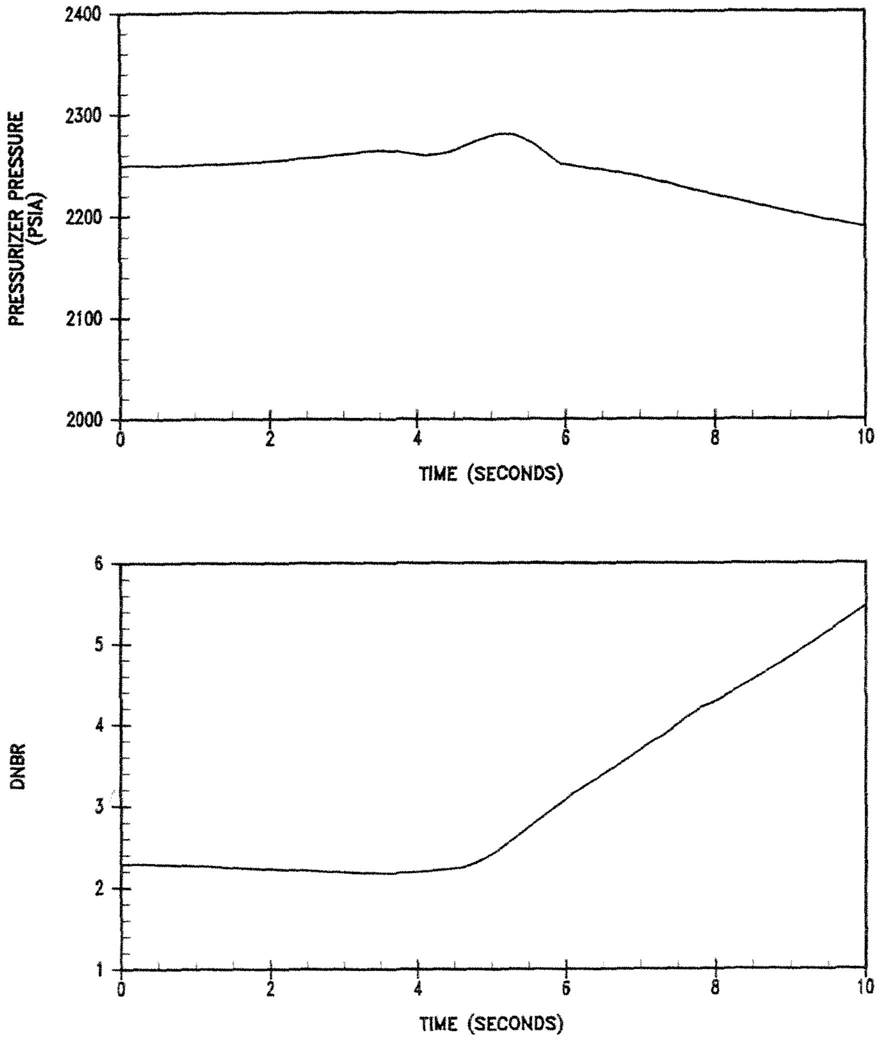




INDIAN POINT UNIT No. 2

LOSS OF ONE PUMP OUT OF FOUR
TOTAL CORE FLOW AND FAULTED
LOOP FLOW vs TIME

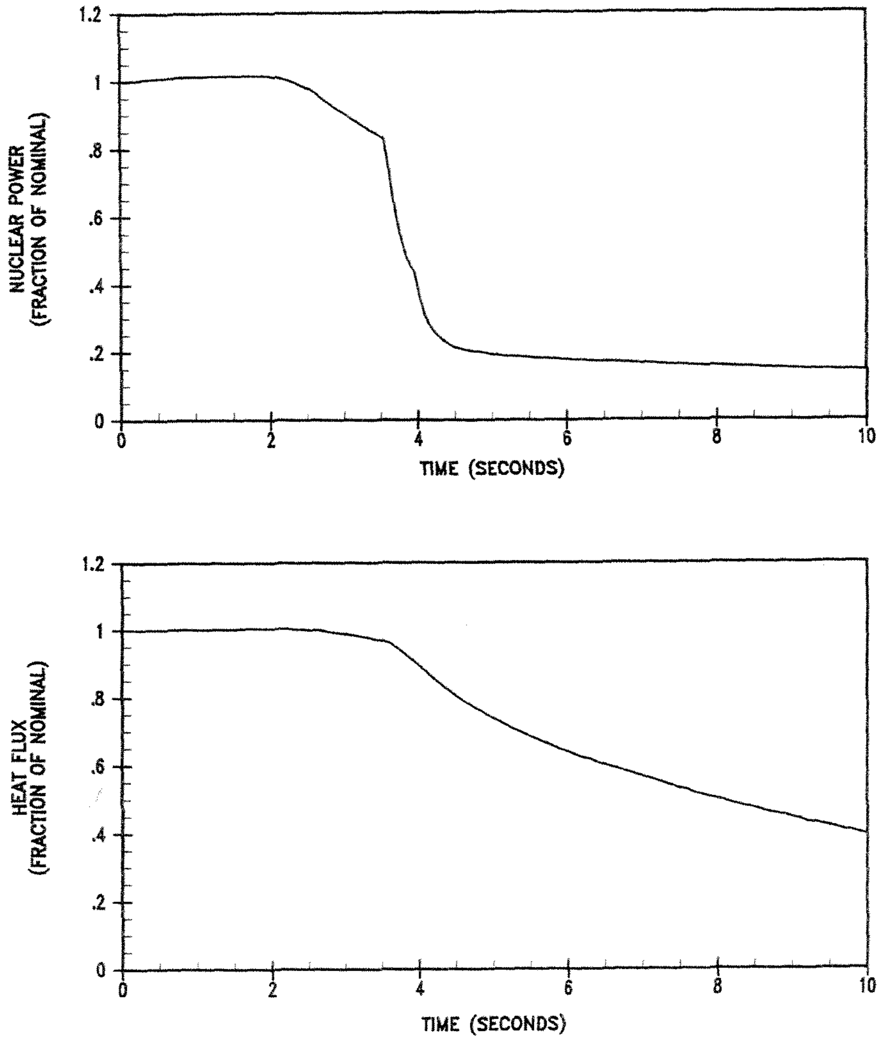
UFSAR FIGURE 14.1-21	REV. No. 19



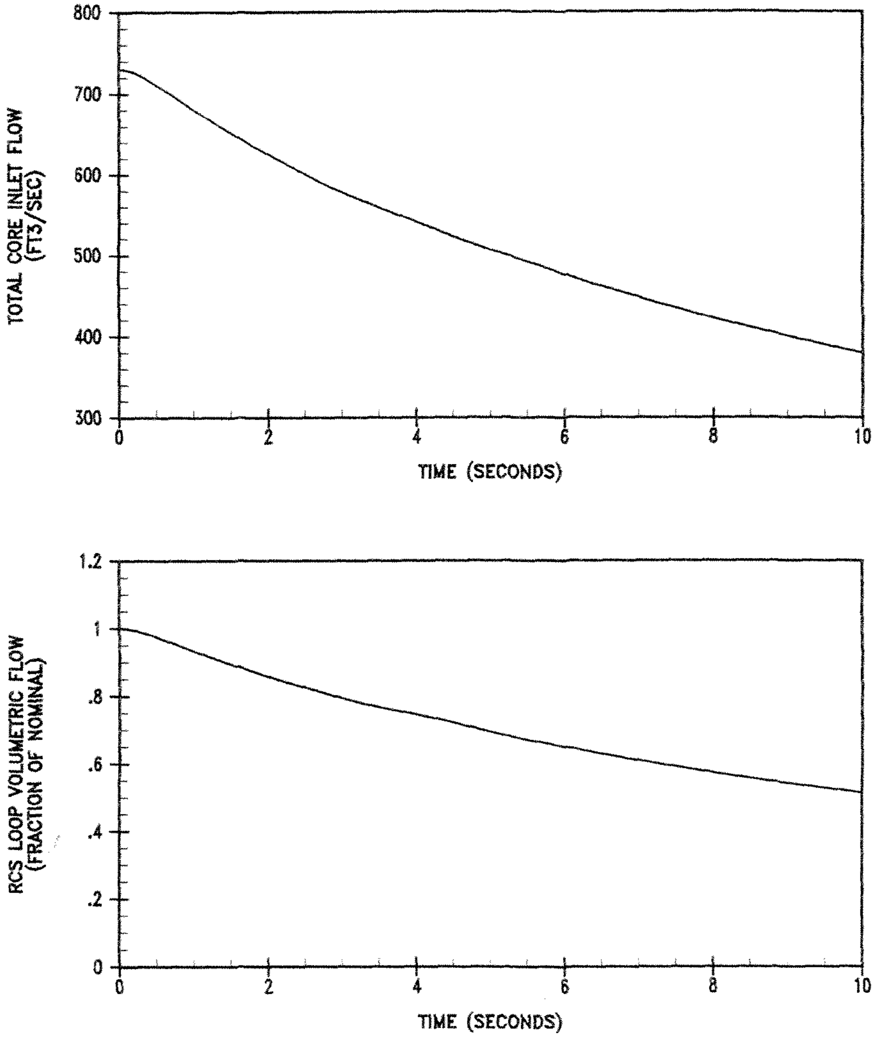
INDIAN POINT UNIT No. 2

LOSS OF ONE PUMP OUT OF FOUR PRESSURIZER PRESSURE AND DNBR vs TIME

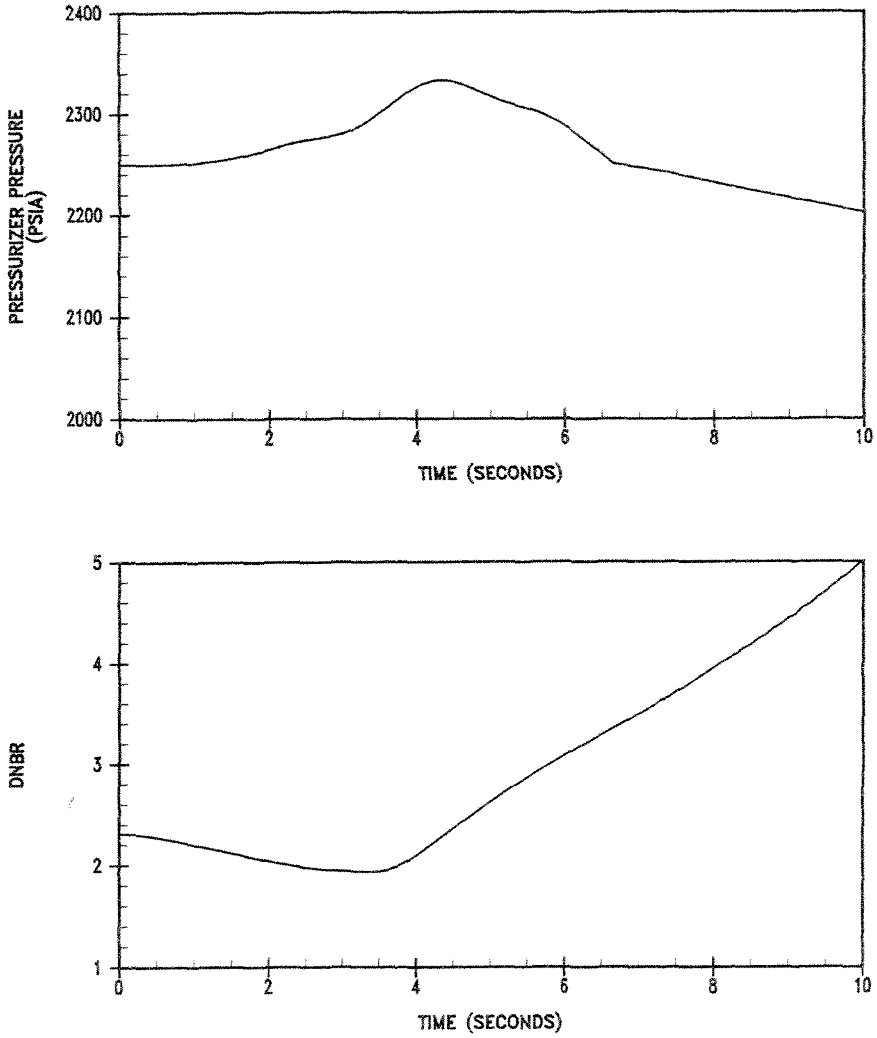
UFSAR FIGURE 14.1-22	REV. No. 19



INDIAN POINT UNIT No. 2	
FOUR PUMP LOSS OF FLOW – UNDERVOLTAGE NUCLEAR POWER AND CORE HEAT FLUX vs TIME	
UFSAR FIGURE 14.1–23	REV. No. 19



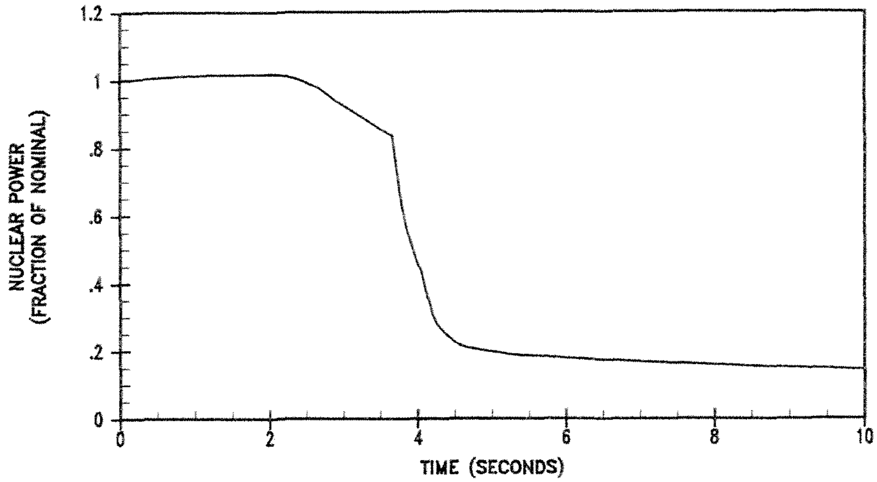
INDIAN POINT UNIT No. 2	
FOUR PUMP LOSS OF FLOW – UNDERVOLTAGE TOTAL CORE FLOW AND RCS LOOP FLOW vs TIME	
UFSAR FIGURE 14.1–24	REV. No. 19

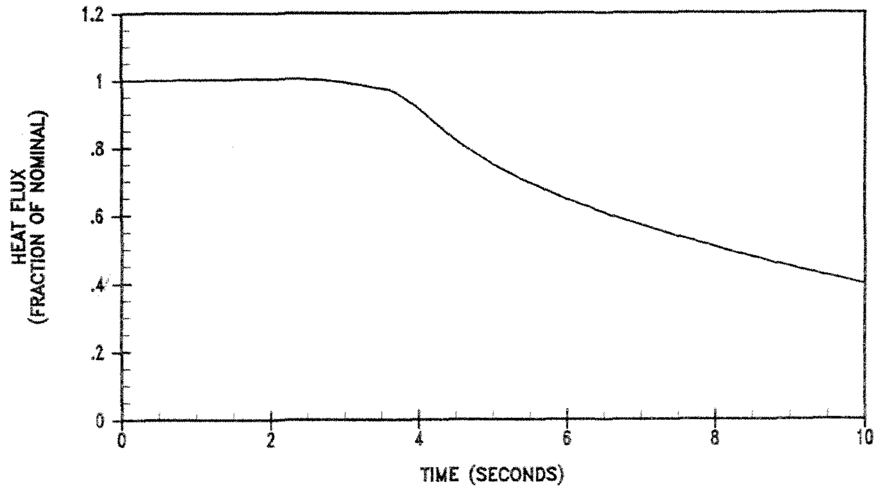


INDIAN POINT UNIT No. 2

FOUR PUMP LOSS OF FLOW – UNDERVOLTAGE PRESSURIZER PRESSURE AND DNBR vs TIME

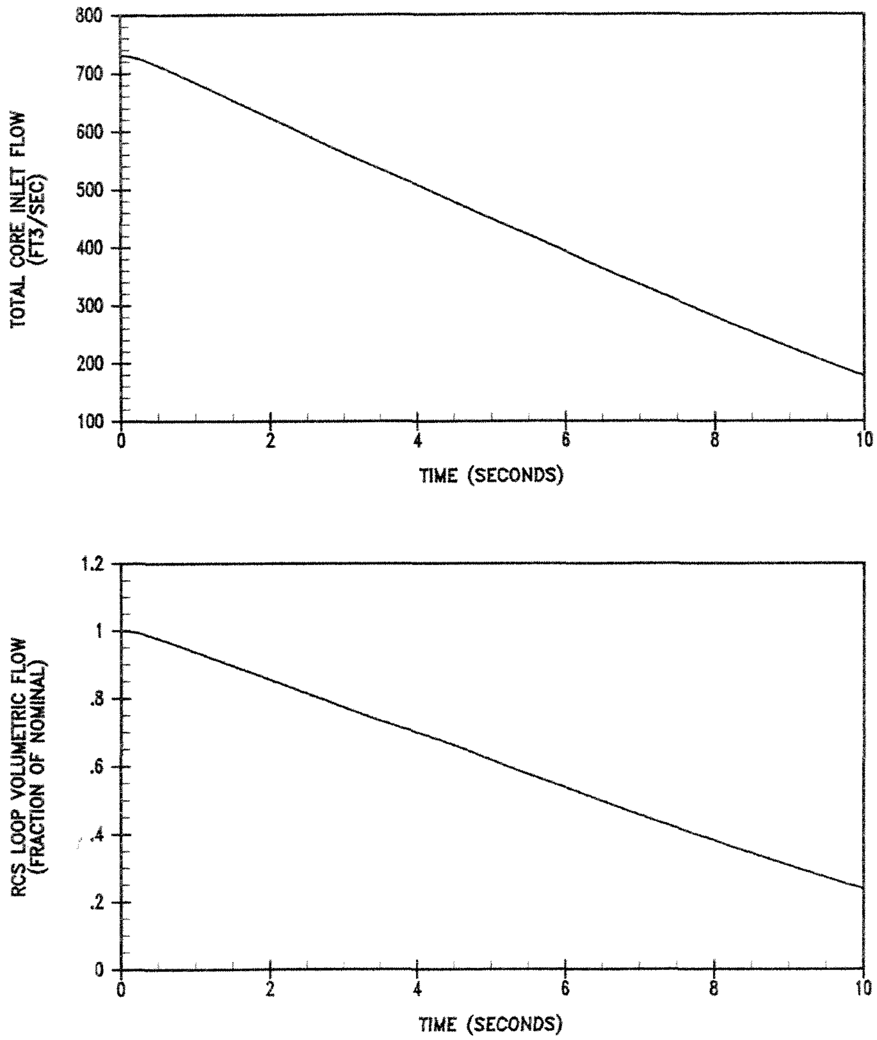
UFSAR FIGURE 14.1–25 | REV. No. 19





INDIAN POINT UNIT No. 2
FOUR PUMP LOSS OF FLOW – UNDERFREQUENCY NUCLEAR POWER AND HEAT FLUX vs TIME

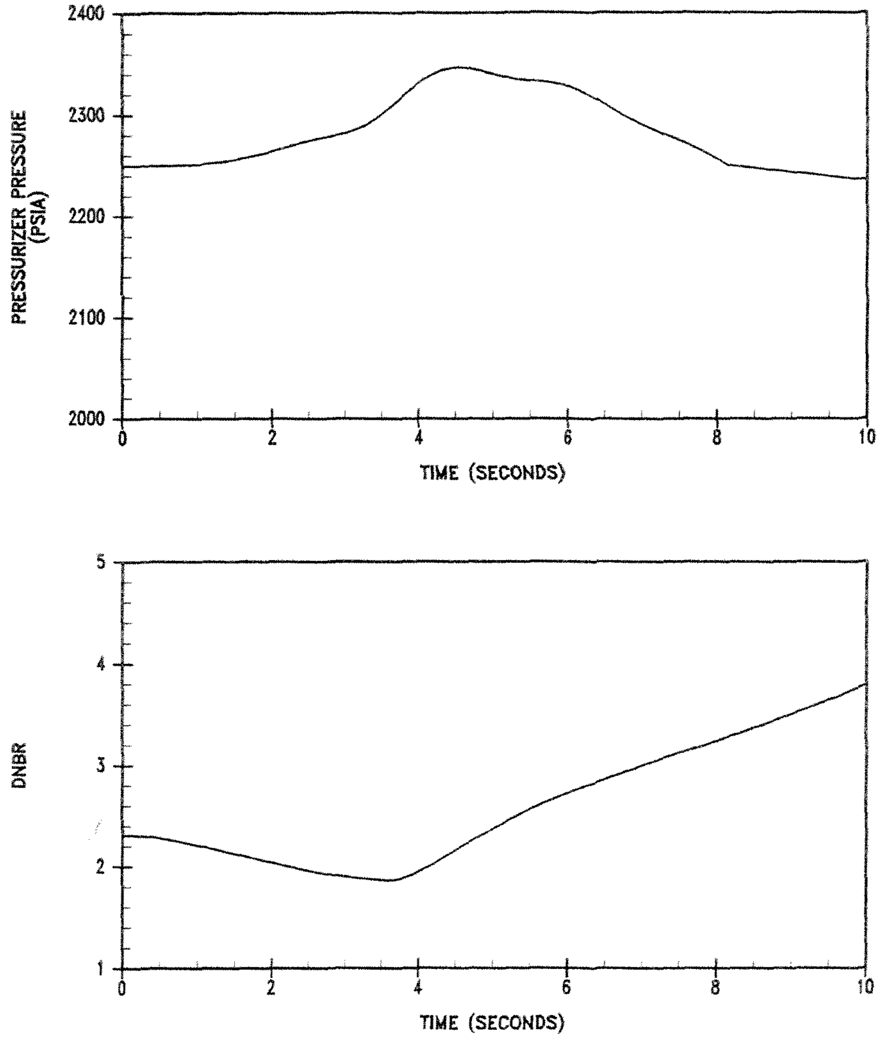
UFSAR FIGURE 14.1–26	REV. No. 19



INDIAN POINT UNIT No. 2

FOUR PUMP LOSS OF FLOW – UNDERFREQUENCY TOTAL CORE FLOW AND RCS LOOP FLOW vs TIME

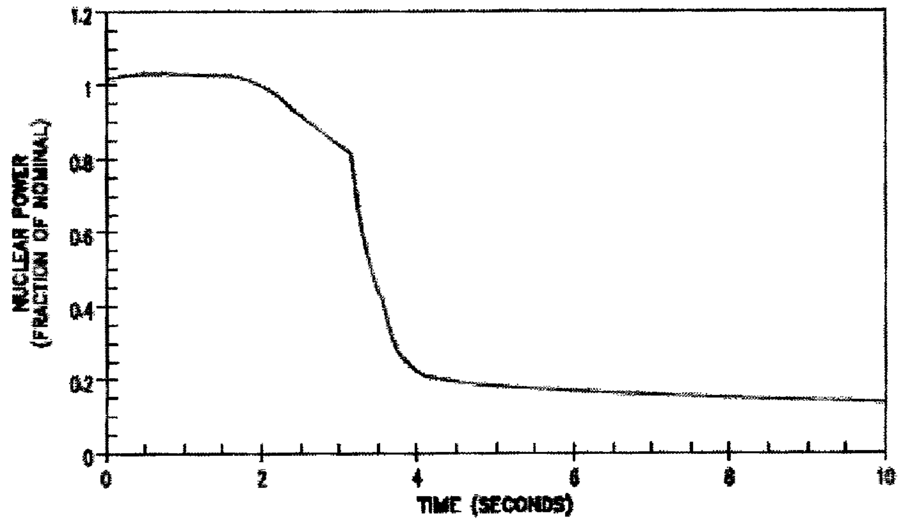
UFSAR FIGURE 14.1–27	REV. No. 19

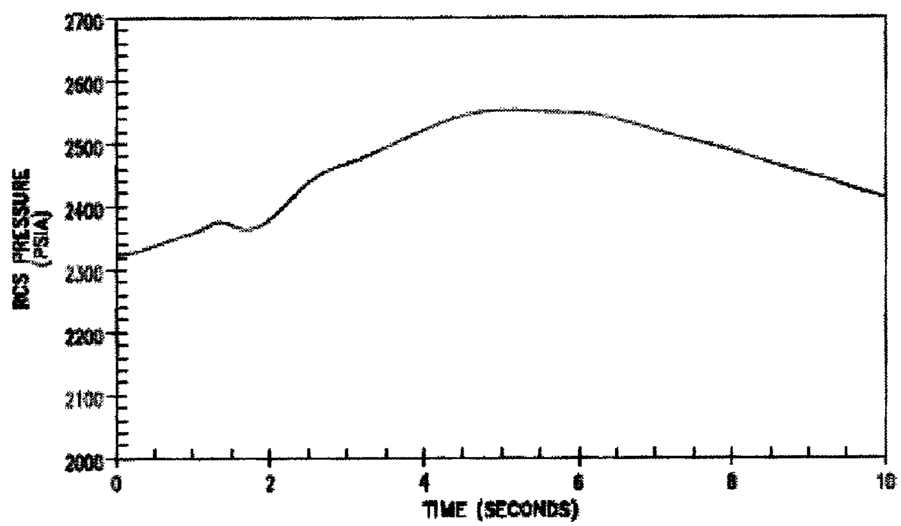


INDIAN POINT UNIT No. 2

FOUR PUMP LOSS OF FLOW – UNDERFREQUENCY PRESSURIZER PRESSURE AND DNBR vs TIME

UFSAR FIGURE 14.1–28	REV. No. 19

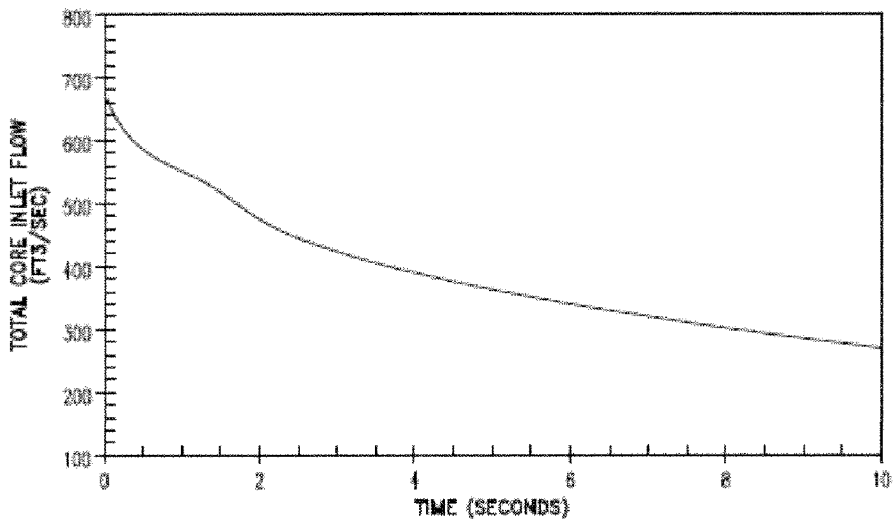


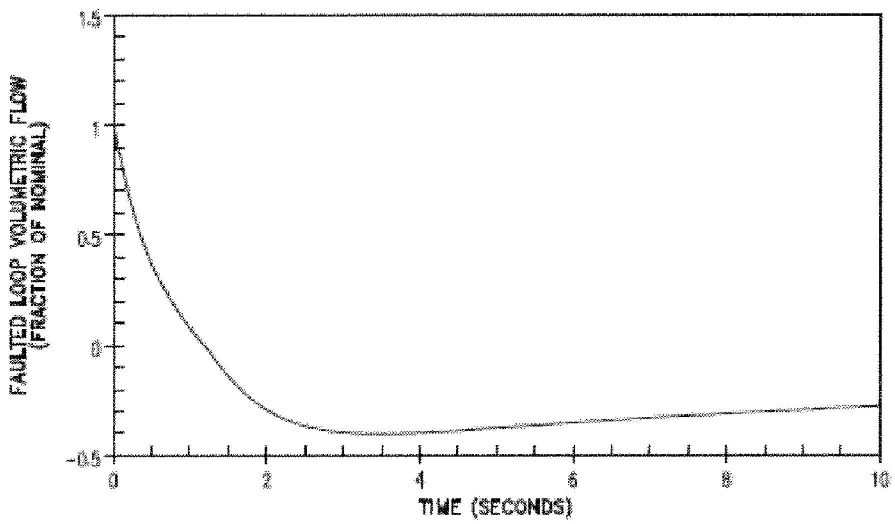


INDIAN POINT UNIT No. 2

LOCKED ROTOR NUCLEAR POWER AND RCS PRESSURE vs TIME

UFSAR FIGURE 14.1-29 | REV. No. 22

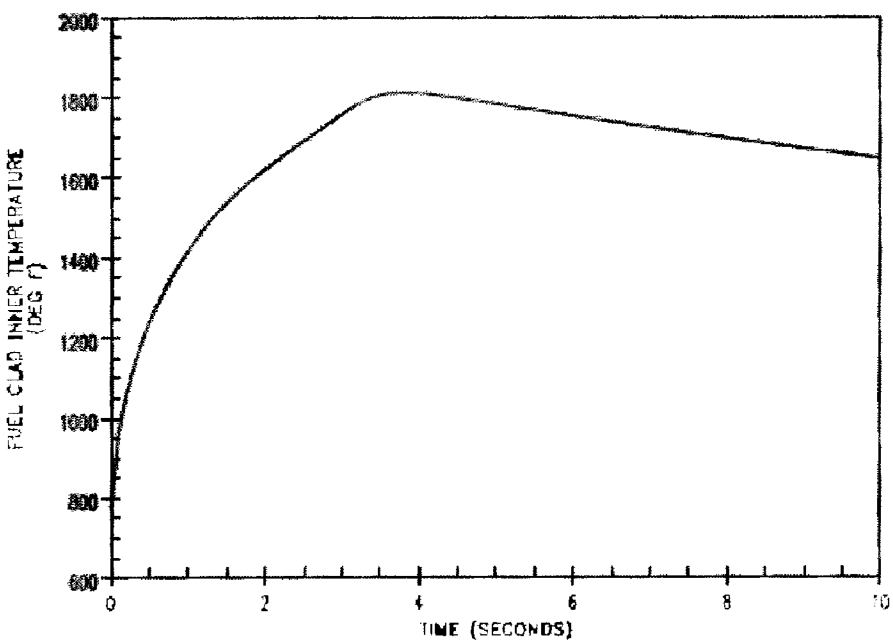




INDIAN POINT UNIT No. 2

LOCKED ROTOR TOTAL CORE FLOW AND FAULTED LOOP FLOW vs TIME

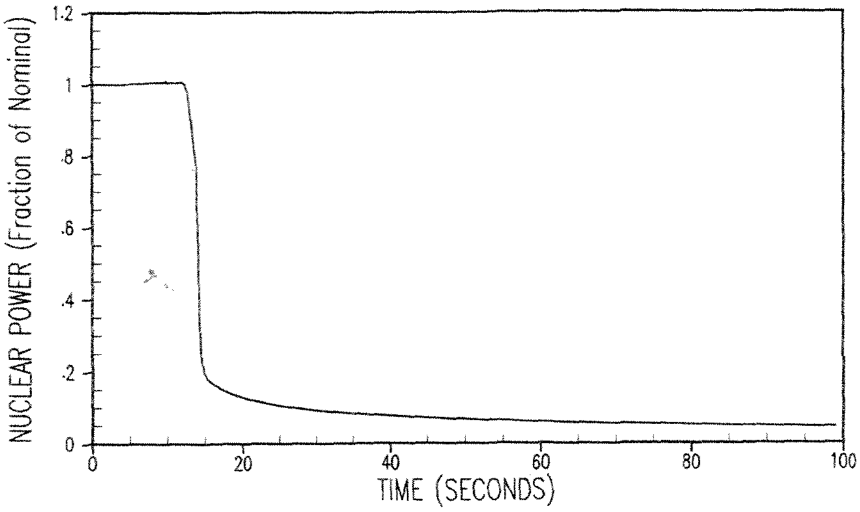
UFSAR FIGURE 14.1-30	REV. No. 22

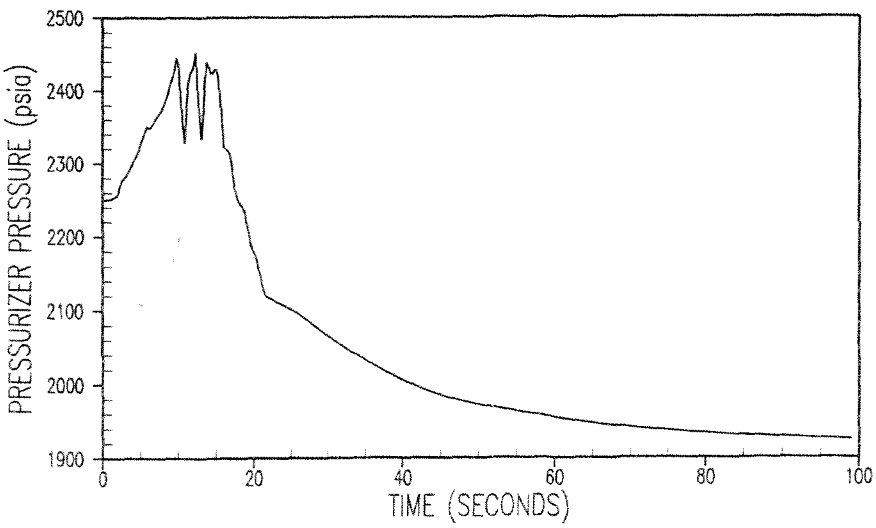


INDIAN POINT UNIT No. 2

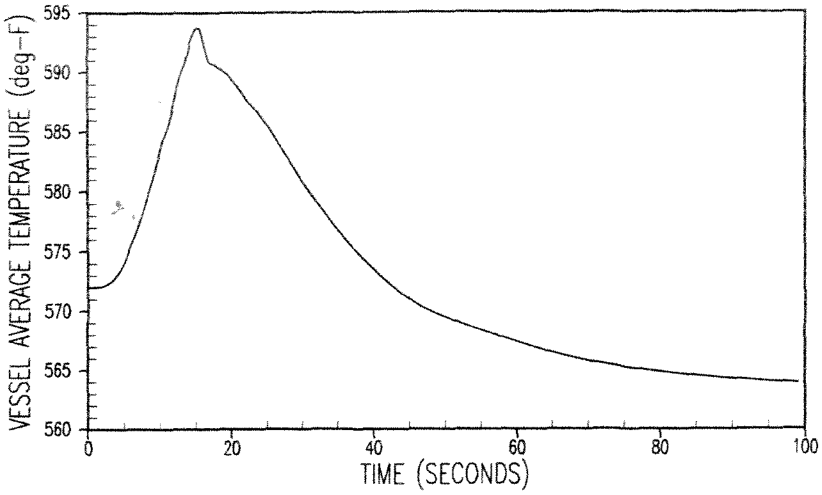
LOCKED ROTOR FUEL CLAD
INNER TEMPERATURE vs TIME

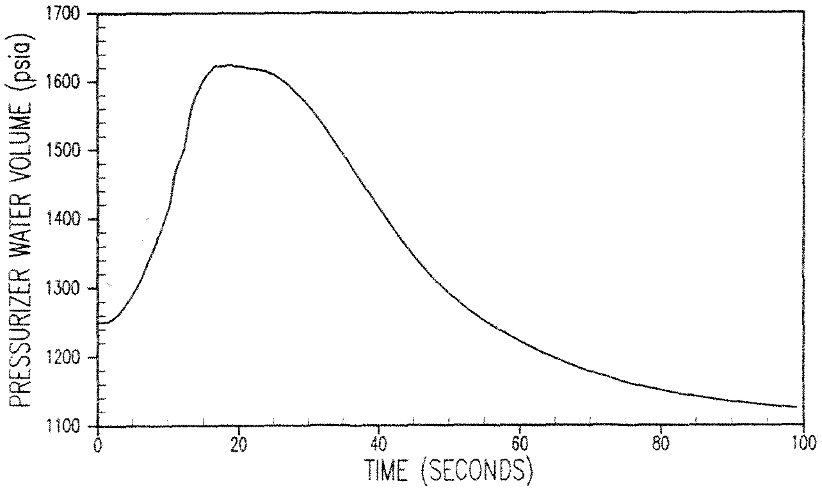
UFSAR FIGURE 14.1-30A	REV. No. 22



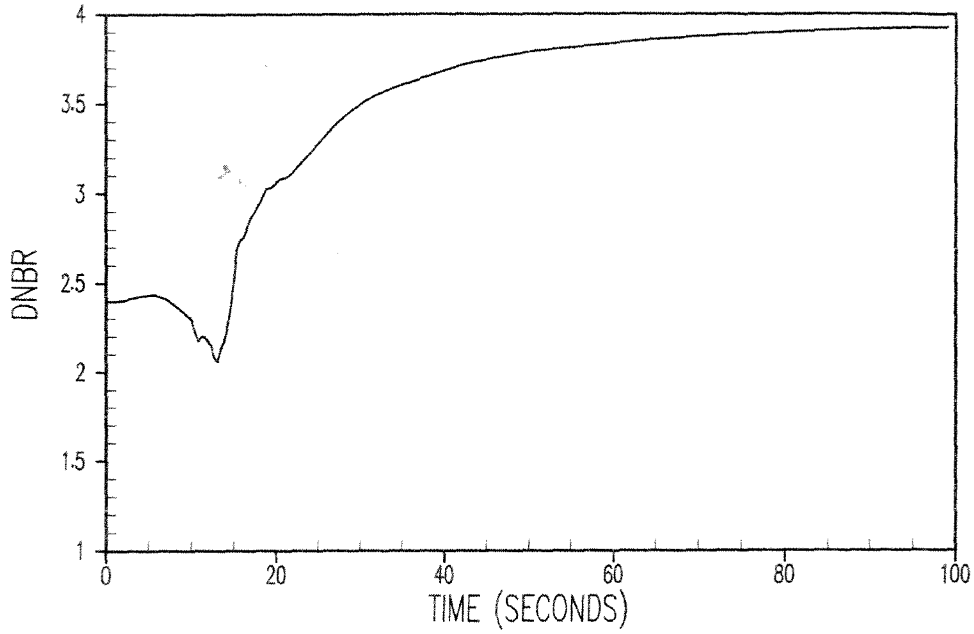


INDIAN POINT UNIT No. 2	
LOSS OF LOAD WITH PRESSURIZER SPRAY AND PORV, NUCLEAR POWER AND PRESSURIZER PRESSURE vs TIME	
UFSAR FIGURE 14.1–31	REV. No. 19





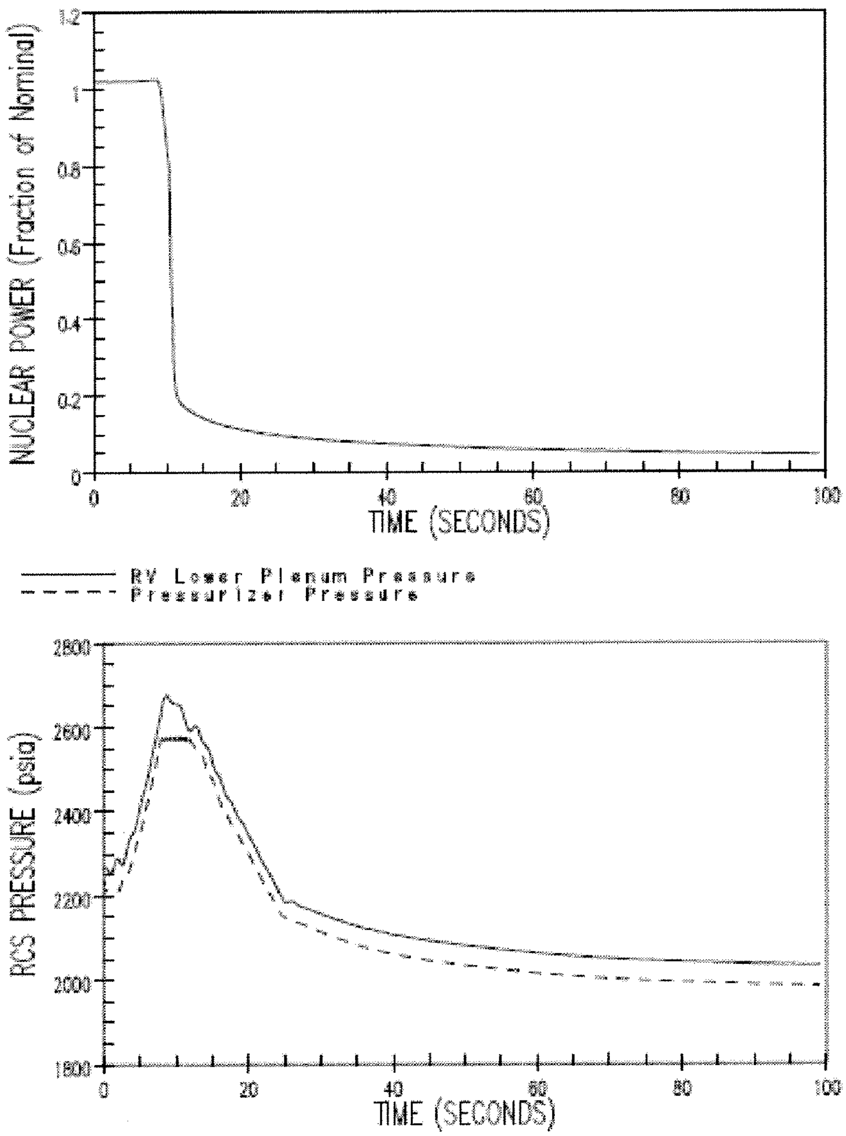
INDIAN POINT UNIT No. 2	
LOSS OF LOAD WITH PRESSURIZER SPRAY AND PORV, AVERAGE COOLANT TEMPERATURE AND PRESSURIZER WATER VOLUME vs TIME	
UFSAR FIGURE 14.1–32	REV. No. 19



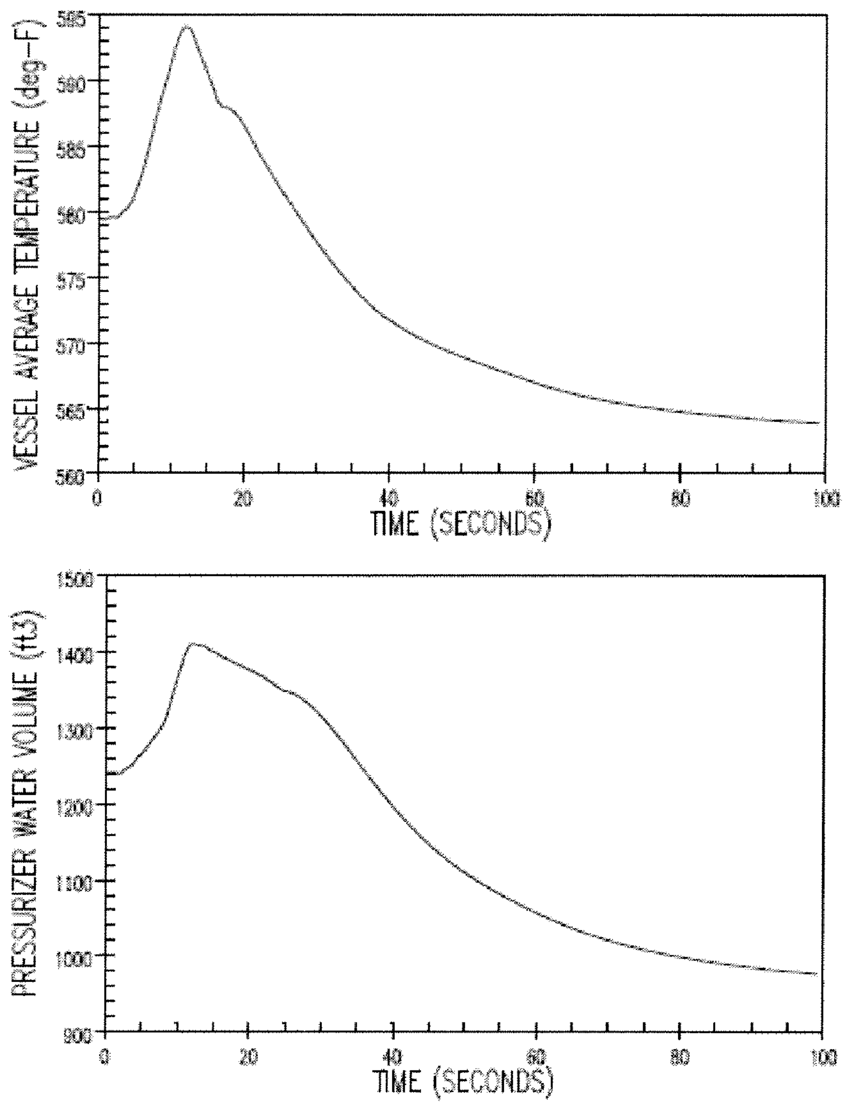
INDIAN POINT UNIT No. 2

LOSS OF LOAD WITH PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVES
DNBR vs TIME

UFSAR FIGURE 14.1-33 | REV. No. 19



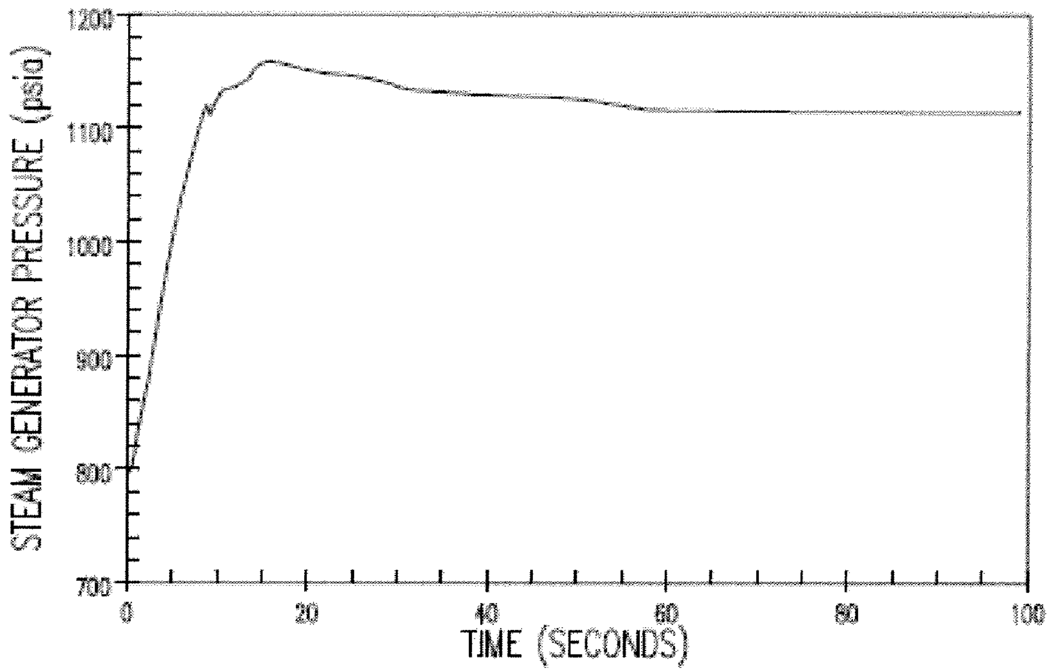
INDIAN POINT UNIT No. 2	
LOSS OF LOAD WITHOUT PRESSURIZER SPRAY AND PORV, NUCLEAR POWER AND PRESSURIZER PRESSURE vs TIME	
UFSAR FIGURE 14.1-37	REV. No. 22



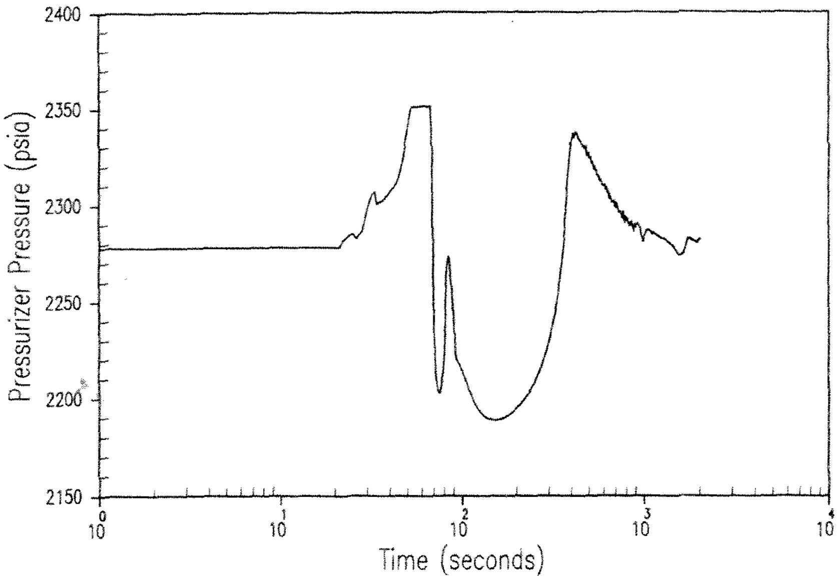
INDIAN POINT UNIT No. 2

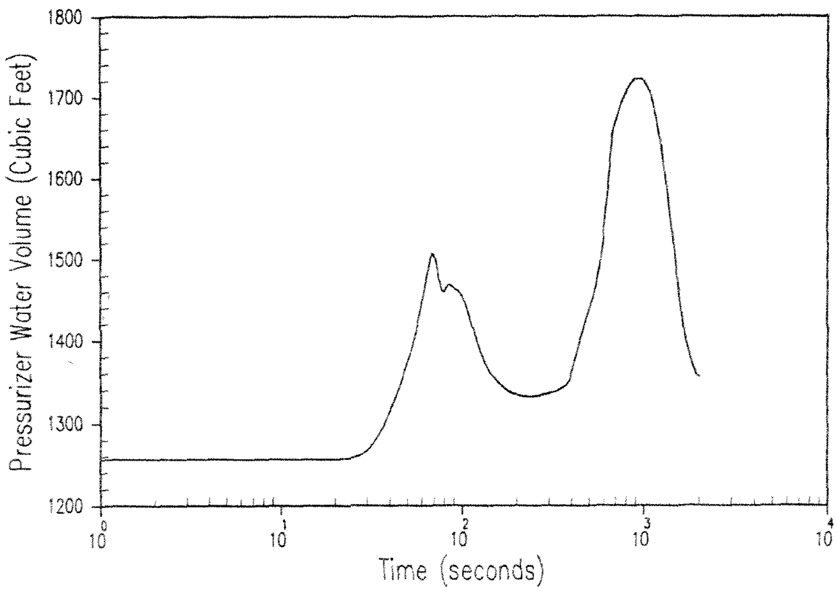
LOSS OF LOAD WITHOUT PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVES, AVERAGE COOLANT TEMPERATURE AND PRESSURIZER WATER VOLUME vs TIME

UFSAR FIGURE 14.1-38	REV. No. 22

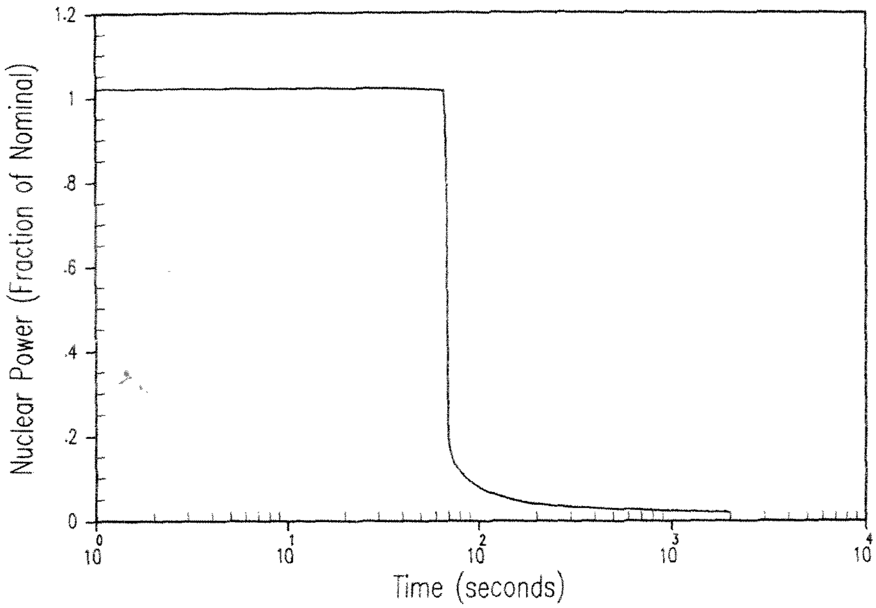


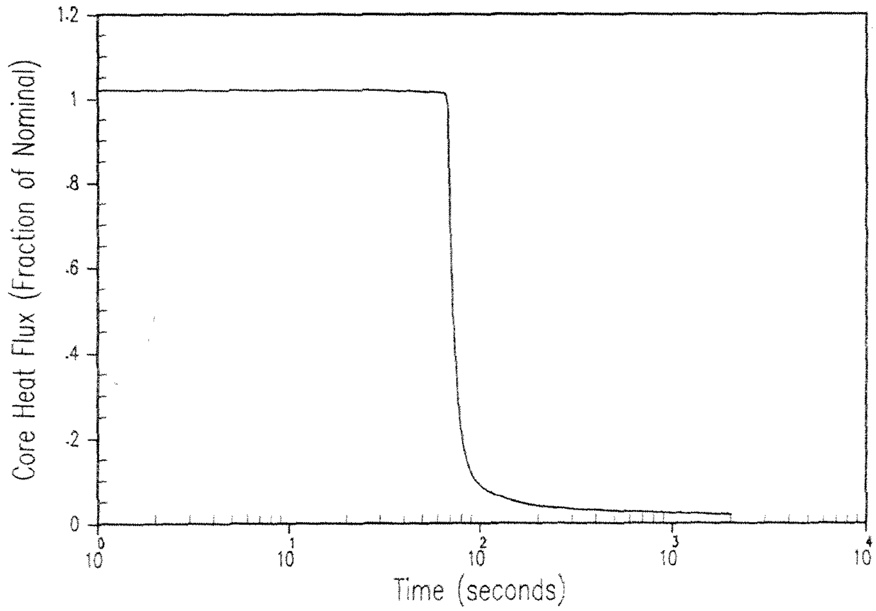
INDIAN POINT UNIT No. 2	
LOSS OF LOAD WITHOUT PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVES, STEAM PRESSURE, vs TIME	
UFSAR FIGURE 14.1-39	REV. No. 22





INDIAN POINT UNIT No. 2	
LOSS OF NORMAL FEEDWATER, OFFSITE POWER AVAILABLE, HIGH Tavg PROGRAM, PRESSURIZER PRESSURE AND PRESSURIZER WATER VOLUME vs TIME	
UFSAR FIGURE 14.1–43, sht.1	REV. No. 19

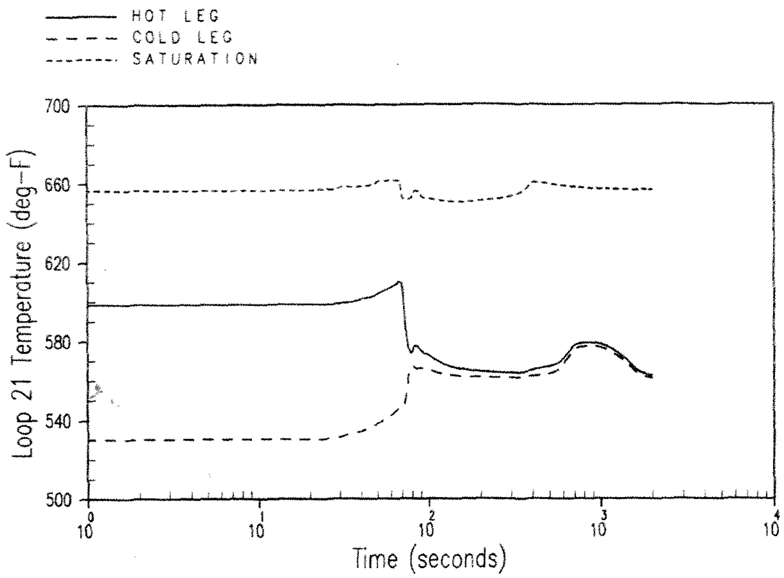


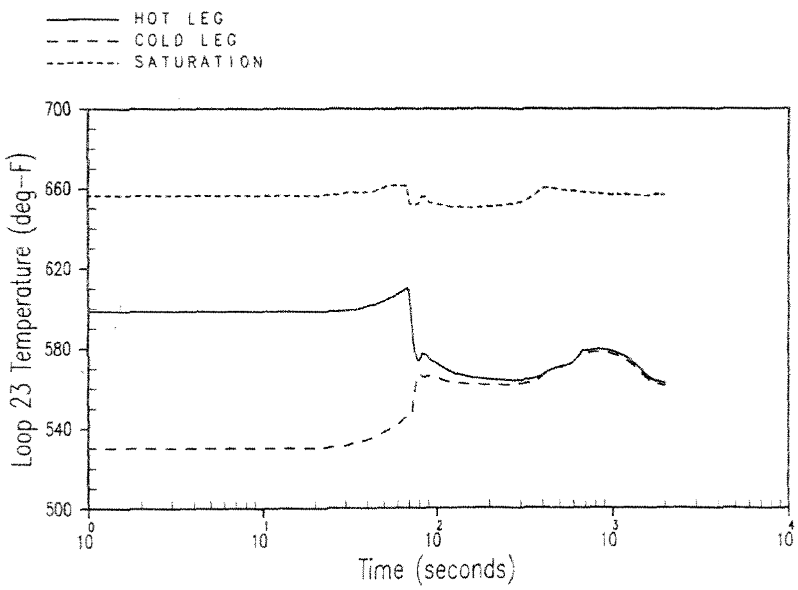


INDIAN POINT UNIT No. 2

LOSS OF NORMAL FEEDWATER, OFFSITE POWER AVAILABLE, HIGH Tavg PROGRAM, NUCLEAR POWER AND CORE HEAT FLUX vs TIME

UFSAR FIGURE 14.1-43, sht.2	REV. No. 19

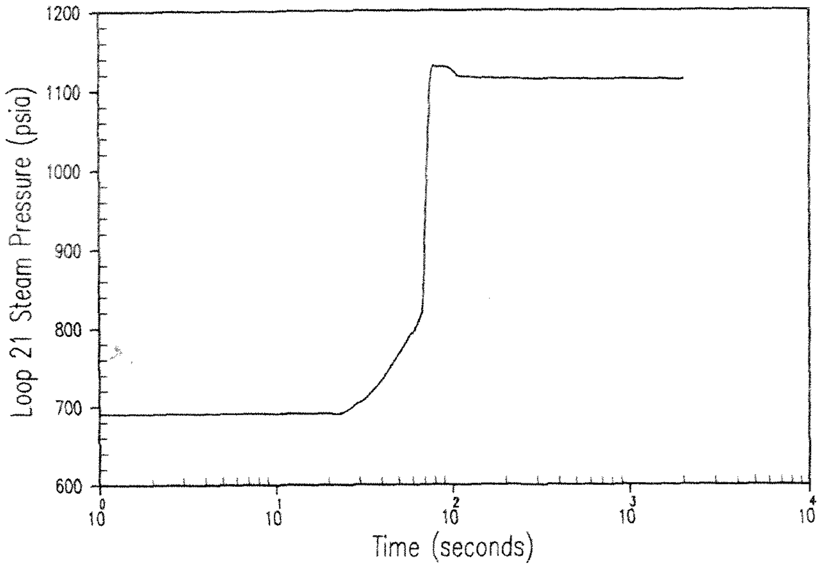


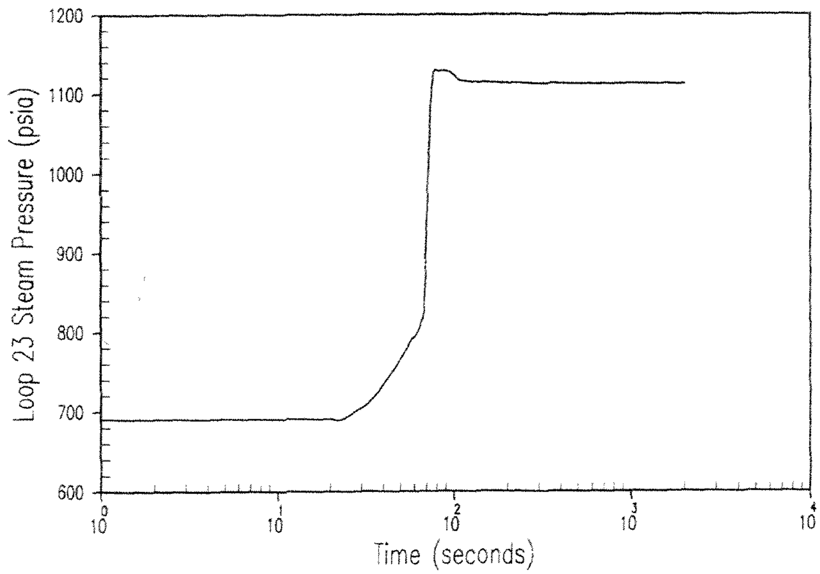


INDIAN POINT UNIT No. 2

LOSS OF NORMAL FEEDWATER, OFFSITE POWER AVAILABLE, HIGH Tavg PROGRAM, LOOP 21 AND LOOP 23 TEMPERATURE vs TIME

UFSAR FIGURE 14.1-43, sht.3	REV. No. 19

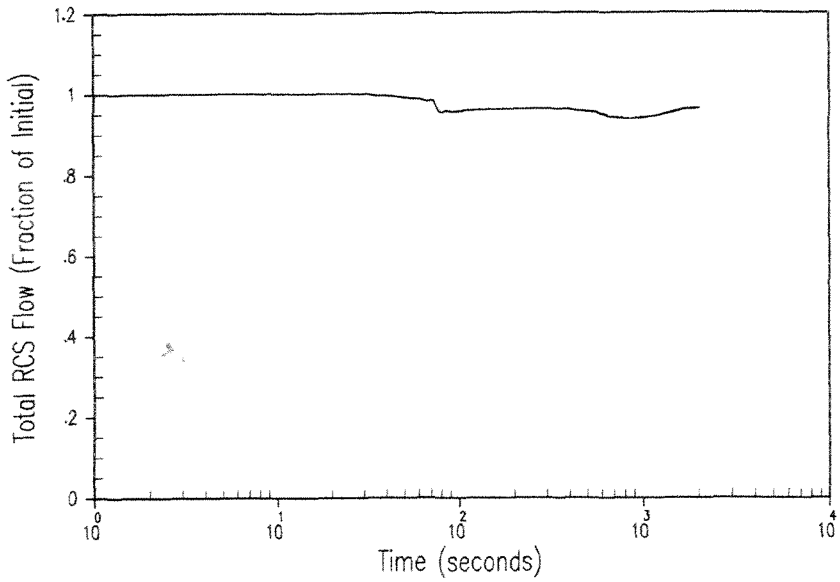


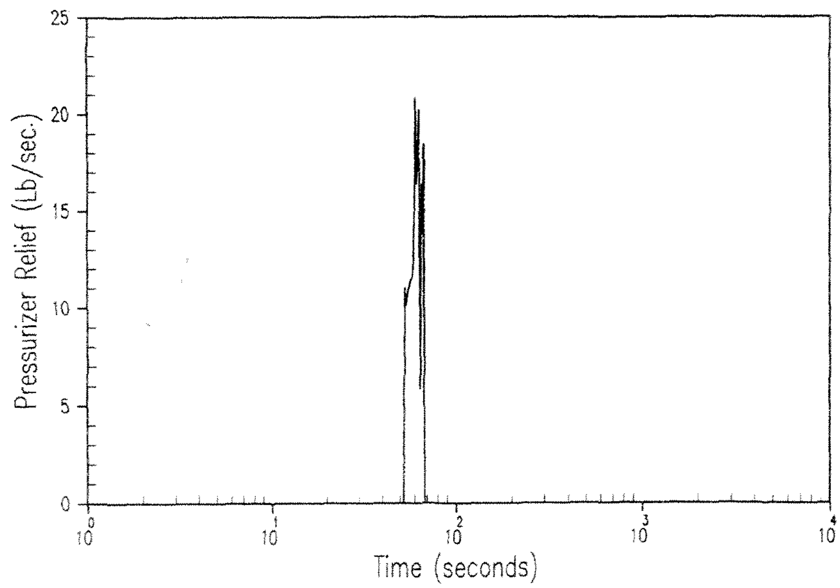


INDIAN POINT UNIT No. 2

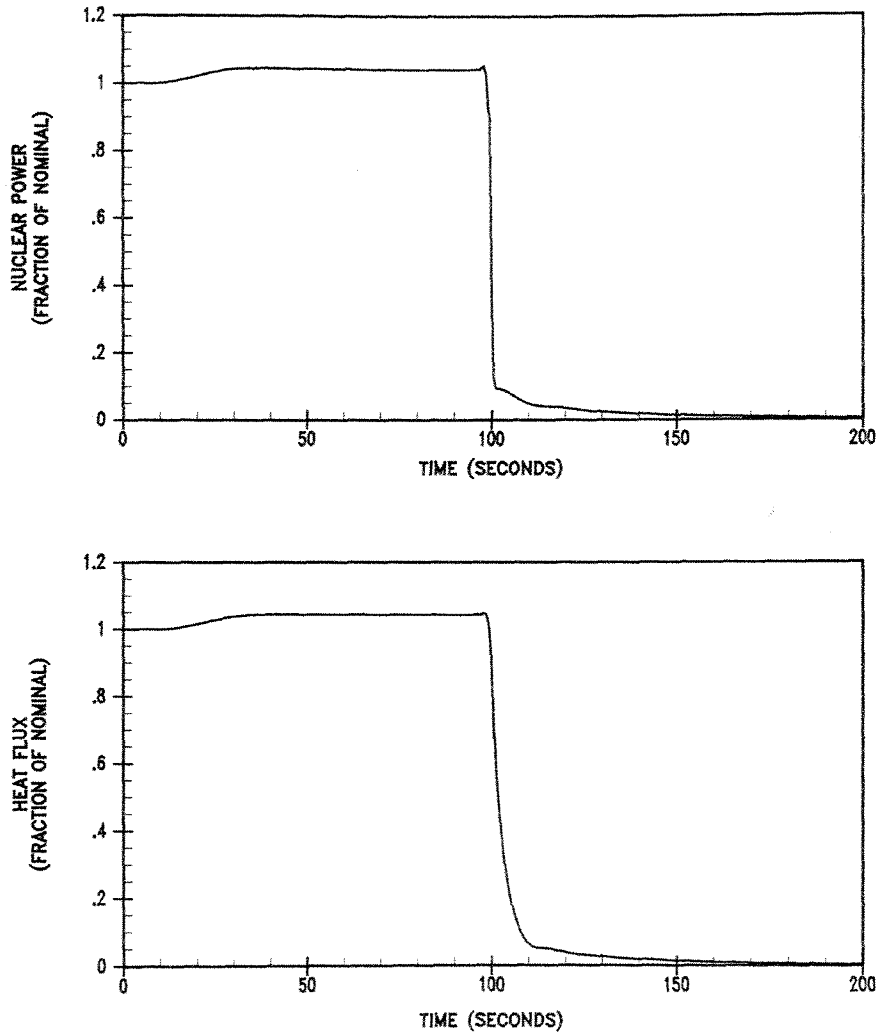
LOSS OF NORMAL FEEDWATER, OFFSITE POWER AVAILABLE, HIGH Tavg PROGRAM, STEAM GENERATOR 21 AND STEAM GENERATOR 23 PRESSURE vs TIME

UFSAR FIGURE 14.1-43, sht.4 | REV. No. 19

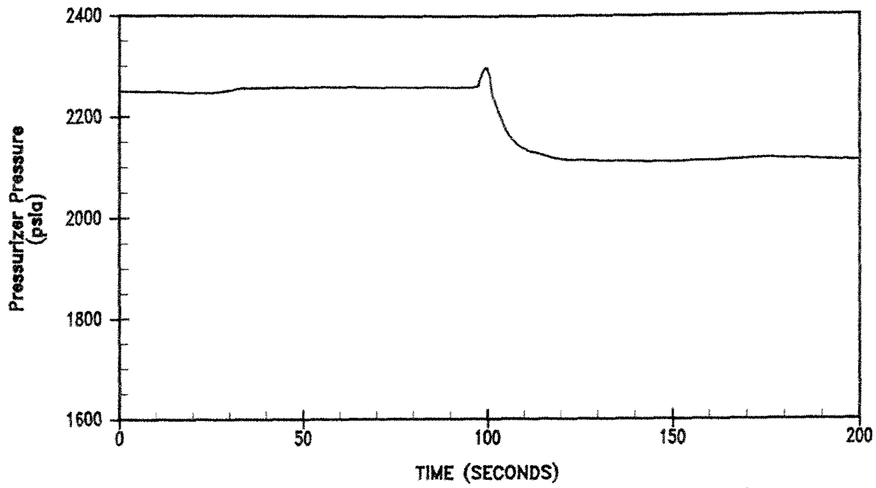


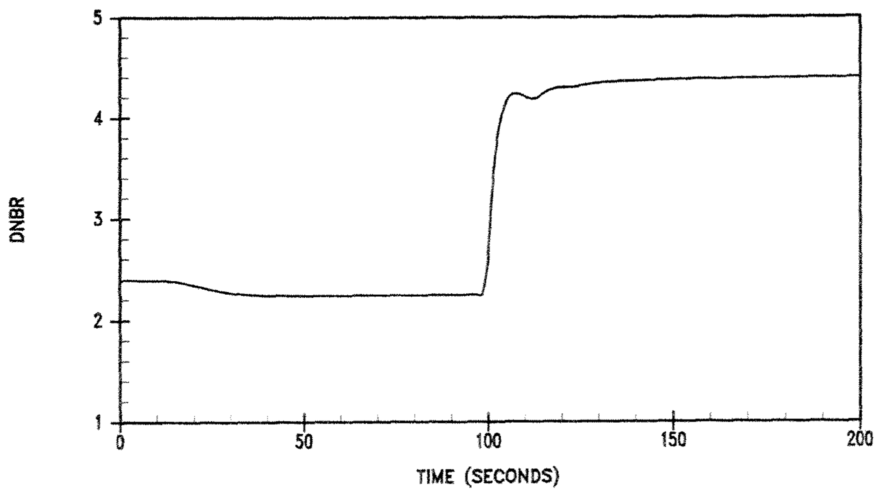


INDIAN POINT UNIT No. 2	
LOSS OF NORMAL FEEDWATER, OFFSITE POWER AVAILABLE, HIGH Tavg PROGRAM ,TOTAL RCS FLOW AND PRESSURIZER RELIEF vs TIME	
UFSAR FIGURE 14.1−43, sht.5	REV. No. 19



INDIAN POINT UNIT No. 2	
FEEDWATER SYSTEM MALFUNCTION EXCESSIVE FEEDWATER FLOW – HFP CONDITIONS MANUAL ROD CONTROL NUCLEAR POWER AND CORE HEAT FLUX vs TIME	
UFSAR FIGURE 14.1-45, sht.1	REV. No. 19

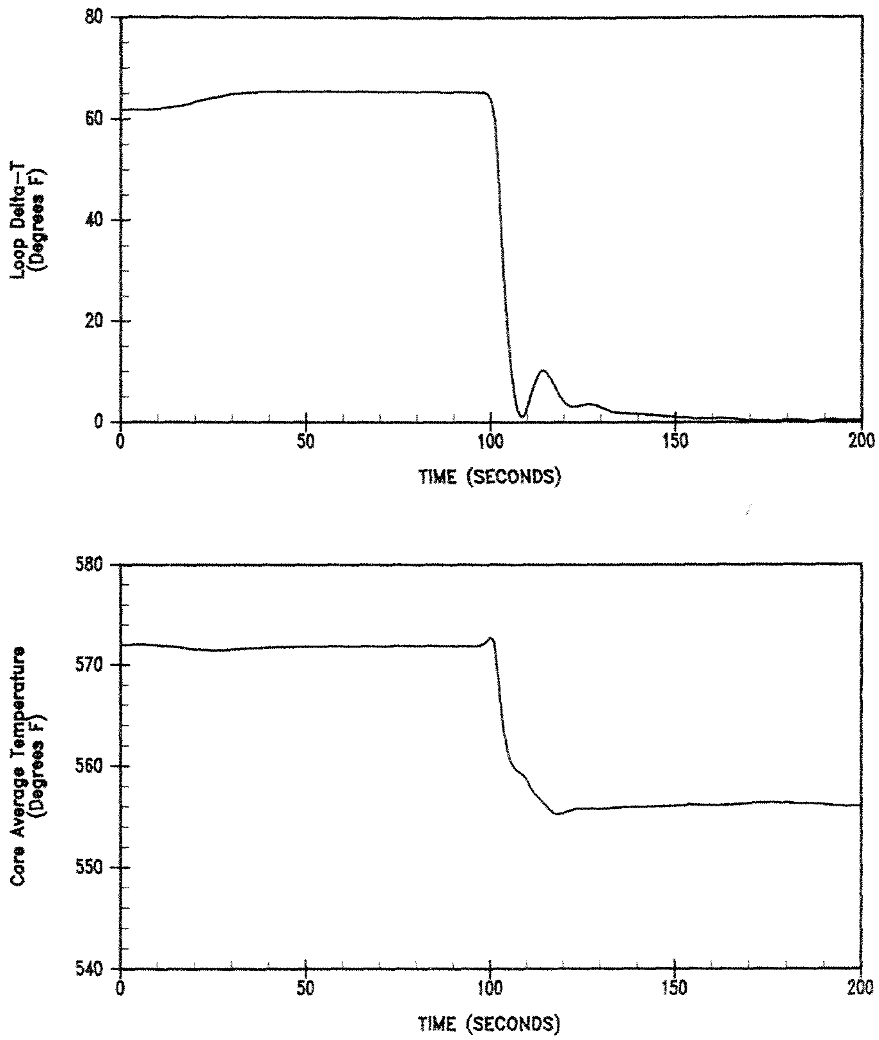




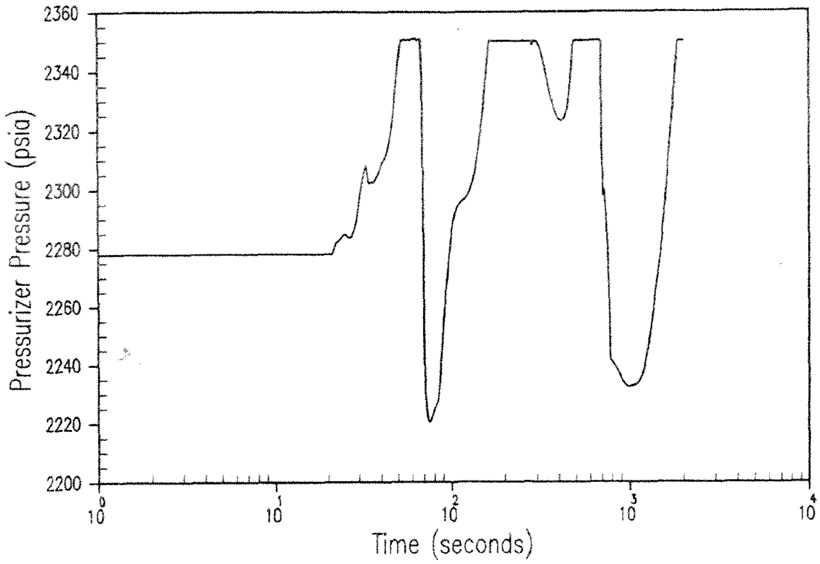
INDIAN POINT UNIT No. 2

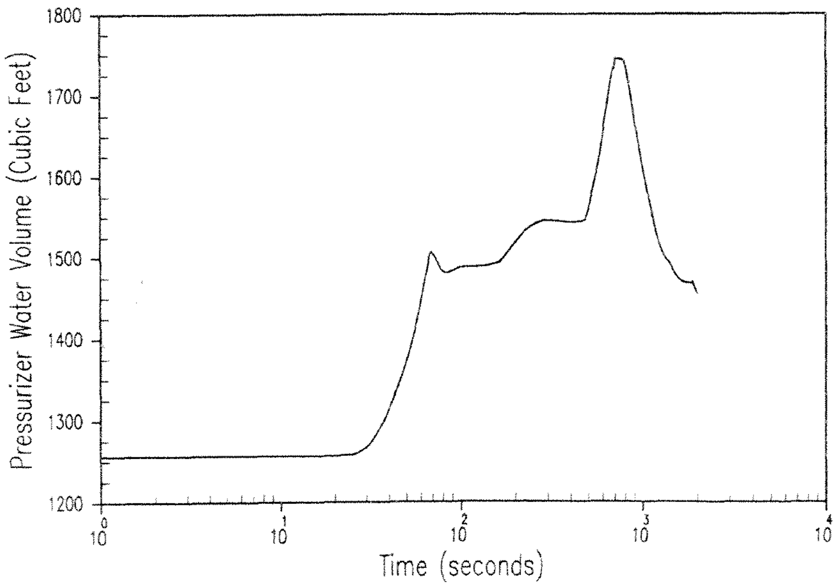
FEEDWATER SYSTEM MALFUNCTION EXCESSIVE FEEDWATER FLOW – HFP CONDITIONS MANUAL ROD CONTROL PRESSURIZER PRESSURE AND DNBR vs TIME

UFSAR FIGURE 14.1–45, sht.2	REV. No. 19

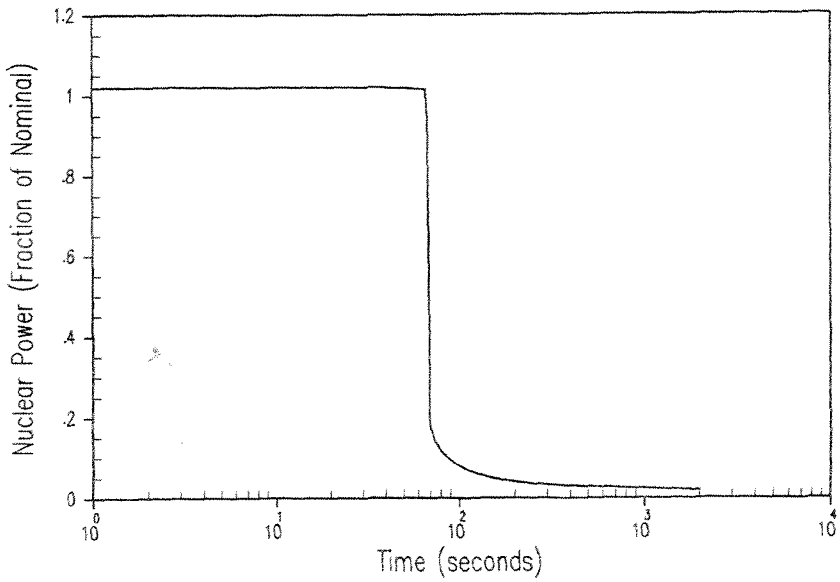


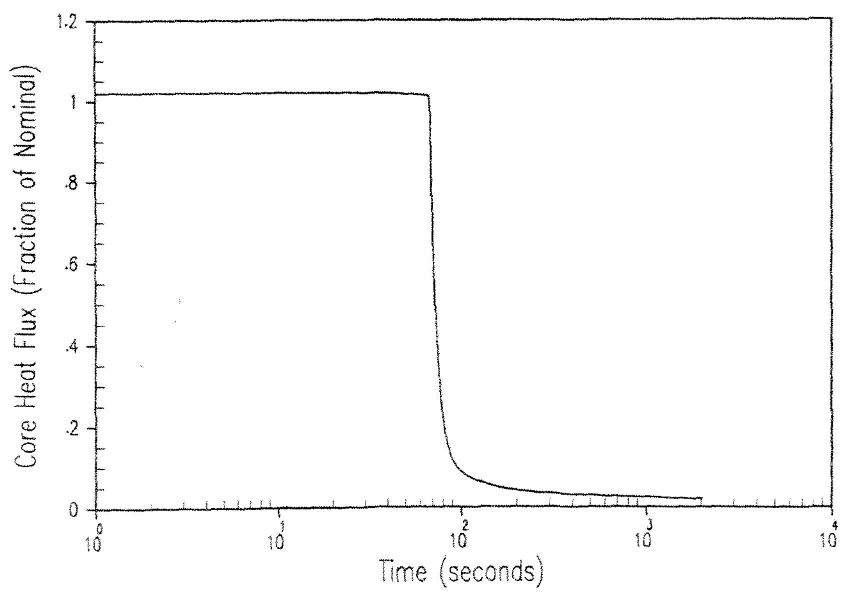
INDIAN POINT UNIT No. 2	
FEEDWATER SYSTEM MALFUNCTION EXCESSIVE FEEDWATER FLOW – HFP CONDITIONS MANUAL ROD CONTROL LOOP DELTA –T, AND CORE Tavg vs TIME	
UFSAR FIGURE 14.1–45, sht.3	REV. No. 19





INDIAN POINT UNIT No. 2	
LOSS OF ALL AC POWER, HIGH Tavg PROGRAM, PRESSURIZER PRESSURE AND PRESSURIZER WATER VOLUME vs TIME	
UFSAR FIGURE 14.1-50, sht.1	REV. No. 19

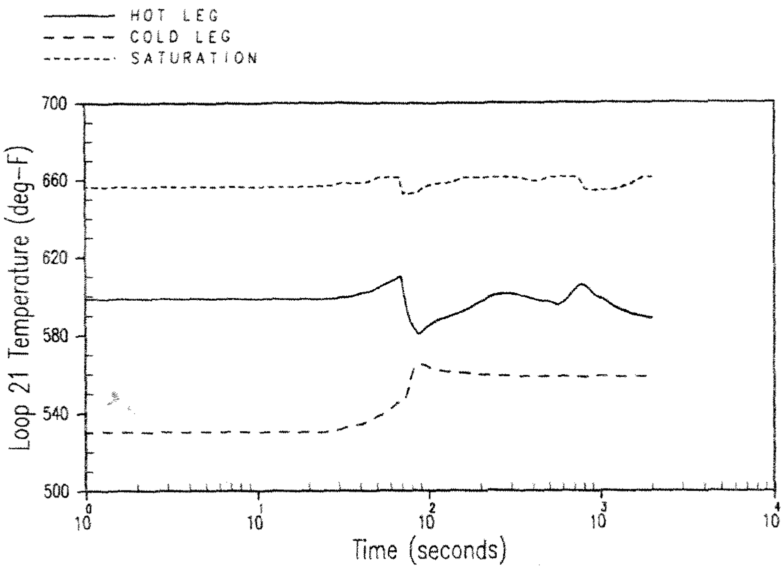


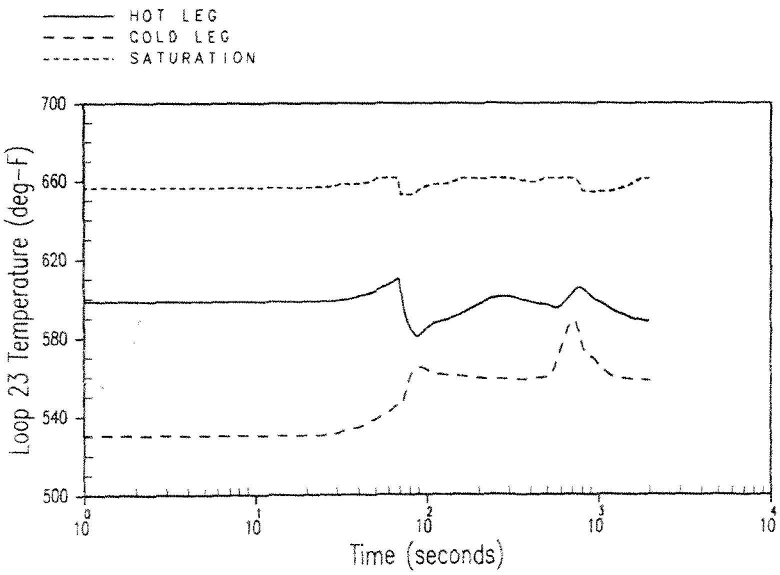


INDIAN POINT UNIT No. 2

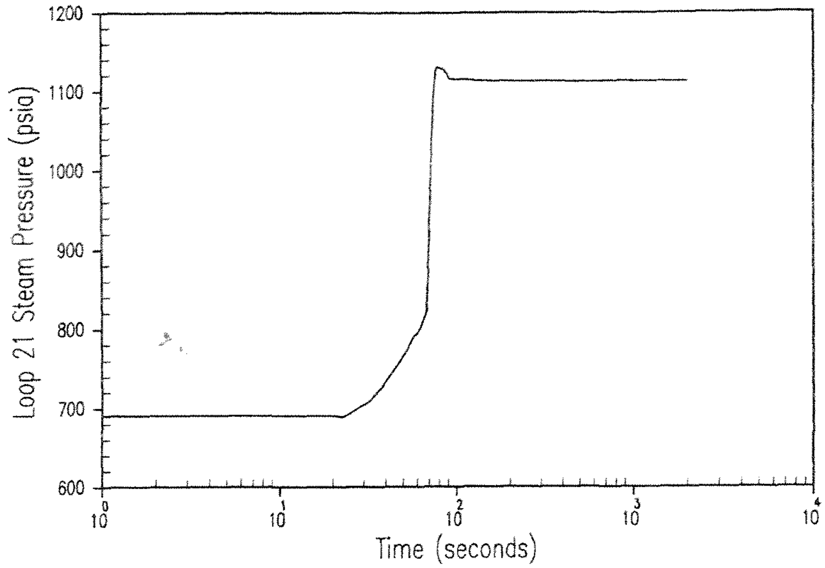
LOSS OF ALL AC POWER, HIGH Tavg PROGRAM, NUCLEAR POWER AND CORE HEAT FLUX vs TIME

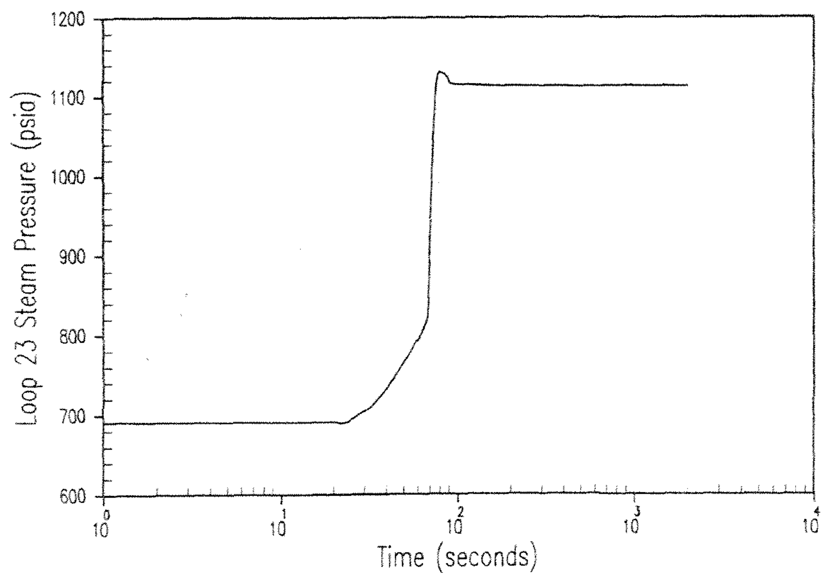
UFSAR FIGURE 14.1-50, sht.2	REV. No. 19





INDIAN POINT UNIT No. 2	
LOSS OF ALL AC POWER TO THE STATION AUXILARIES, HIGH Tavg PROGRAM, LOOP 21 AND LOOP 23 TEMPERATURE vs TIME	
UFSAR FIGURE 14.1-50, sht.3	REV. No. 19

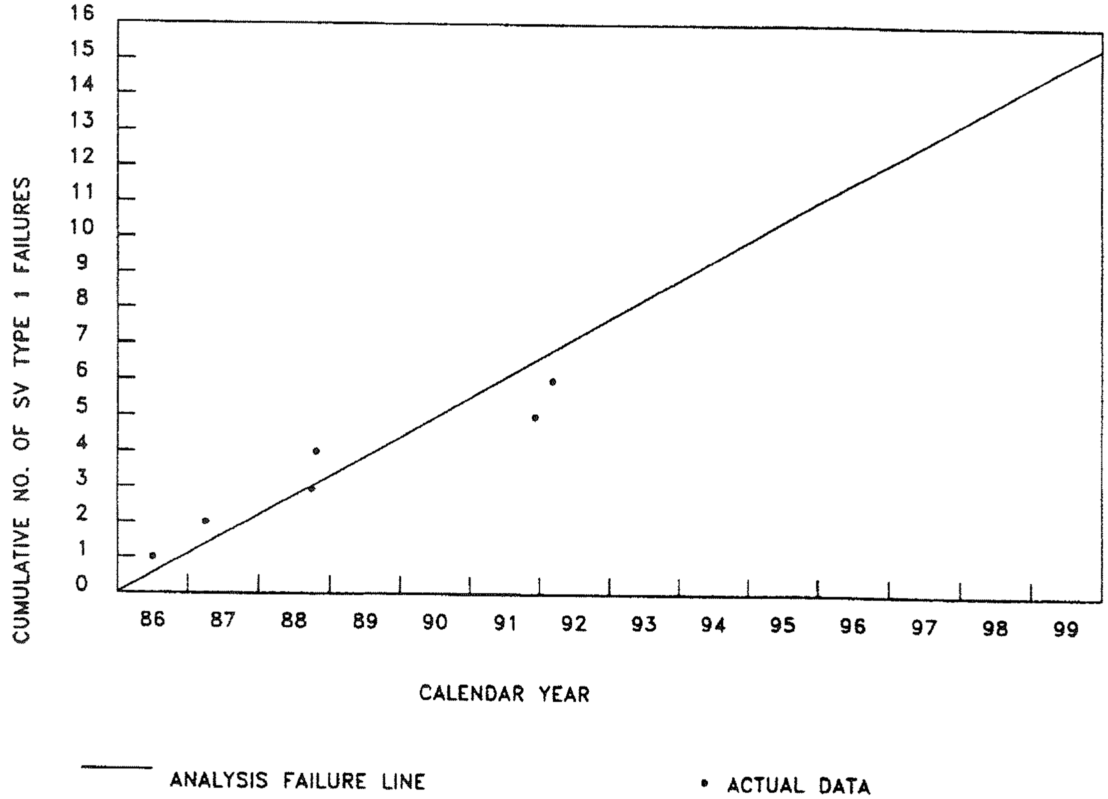




INDIAN POINT UNIT No. 2

LOSS OF ALL AC POWER TO THE STATION AUXILARIES, HIGH Tavg PROGRAM, LOOP 21 AND LOOP 23 STEAM PRESSURE vs TIME

UFSAR FIGURE 14.1-50, sht.4	REV. No. 19

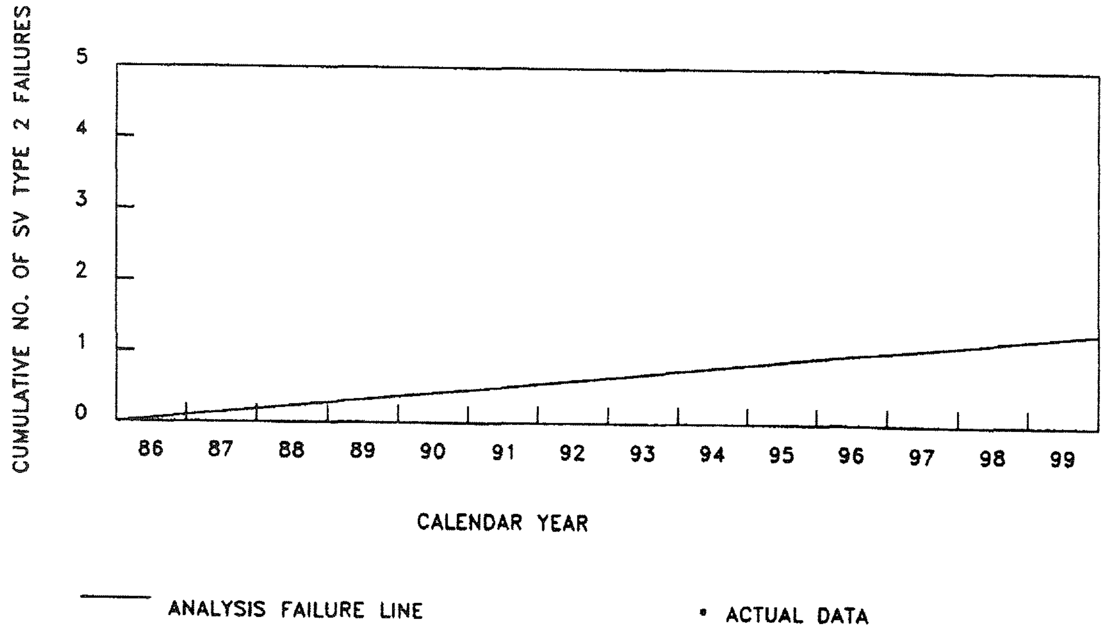


SV TYPE 1 FAILURE RATE = 2.47-06/HR

SLOPE OF ANALYSIS FAILURE LINE = [(SV TYPE 1 F.R.) * (OPERATING HOURS)] / (CALENDAR YEARS)

= [(2.47E-06/HR) * (2.917E+06 HRS)] / (6.42 CAL. YRS.) = 1.1 FAIL./CAL. YR.

INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.1-62 TRACKING B-95/96 STOP VALVE (SV) TYPE 1 FAILURES STOP VALVE DISC FAILS	
MIC. No. 2001MB1537	REV. No. 17A

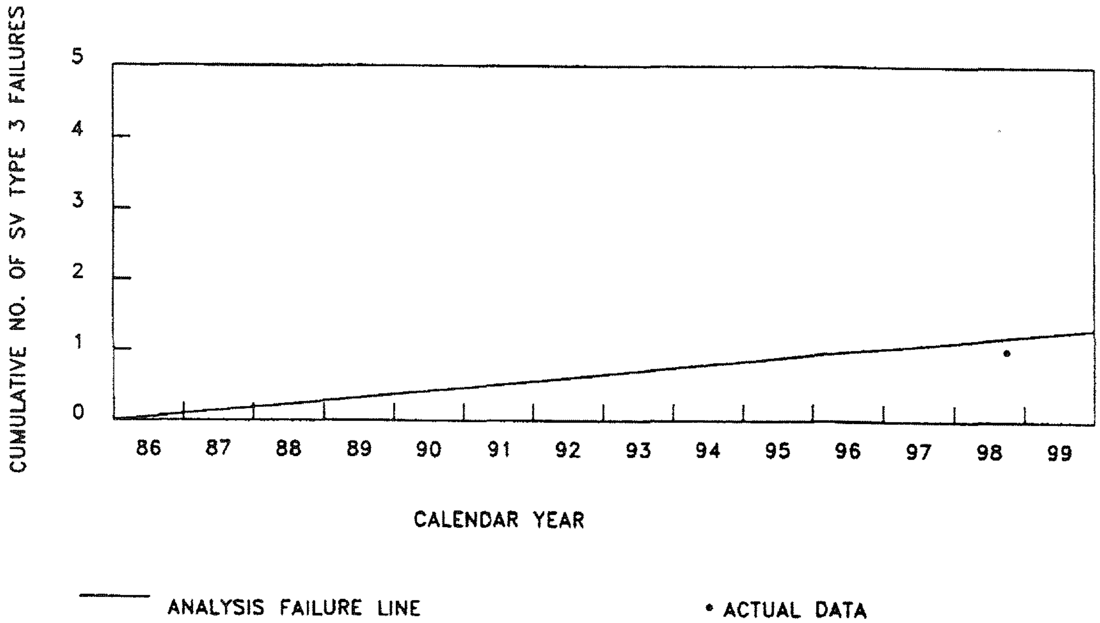


SV TYPE 2 FAILURE RATE = 2.05-07/HR

SLOPE OF ANALYSIS FAILURE LINE = [(SV TYPE 2 F.R.) * (OPERATING HOURS)] / (CALENDAR YEARS)

= [(2.05E-07/HR) * (2.917E+06 HRS)] / (6.42 CAL. YRS.) = 0.093 FAIL./CAL. YR.

INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.1-63 TRACKING B-95/96 STOP VALVE (SV) TYPE 2 FAILURES STOP VALVE SPRING FAILS	
MIC. No. 2001MB1538	REV. No. 17A

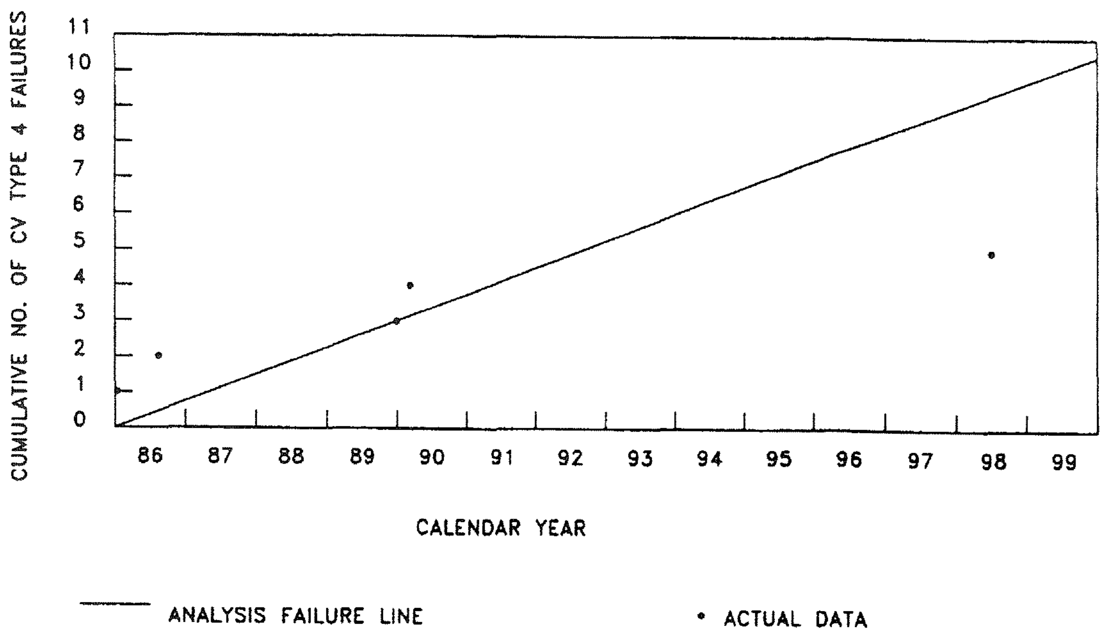


SV TYPE 3 FAILURE RATE = 2.05-07/HR

SLOPE OF ANALYSIS FAILURE LINE = [(SV TYPE 3 F.R.) * (OPERATING HOURS)] / (CALENDAR YEARS)

= [(2.05E-07/HR) * (2.917E+06 HRS)] / (6.42 CAL. YRS.) = 0.093 FAIL./CAL. YR.

INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.1-64 TRACKING B-95/96 STOP VALVE (SV) TYPE 3 FAILURES STOP VALVE STICKS OPEN	
MIC. No. 2001MB1539	REV. No. 17A

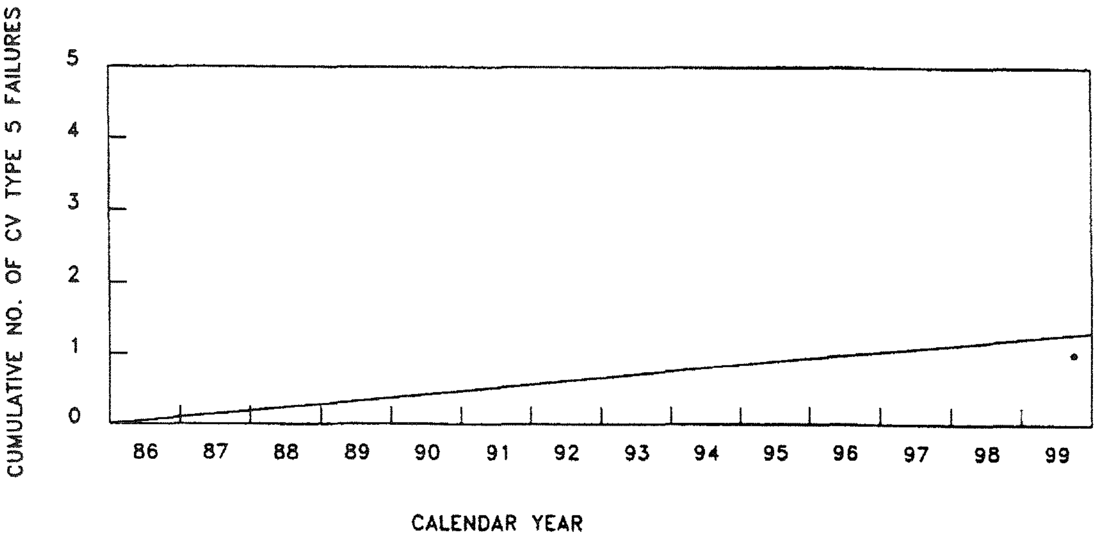


CV TYPE 4 FAILURE RATE = 1.22-06/HR

SLOPE OF ANALYSIS FAILURE LINE = [(CV TYPE 4 F.R.) * (OPERATING HOURS)] / (CALENDAR YEARS)

= [(1.22E-06/HR) * (3.925E+06 HRS)] / (6.42 CAL. YRS.) = 0.75 FAIL./CAL. YR.

INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.1-65 TRACKING B-95/96 CONTROL VALVE (CV) TYPE 4 FAILURES CONTROL VALVE SPRING BOLT FAILS	
MIC. No. 2001MB1540	REV. No. 17A



ANALYSIS FAILURE LINE

• ACTUAL DATA

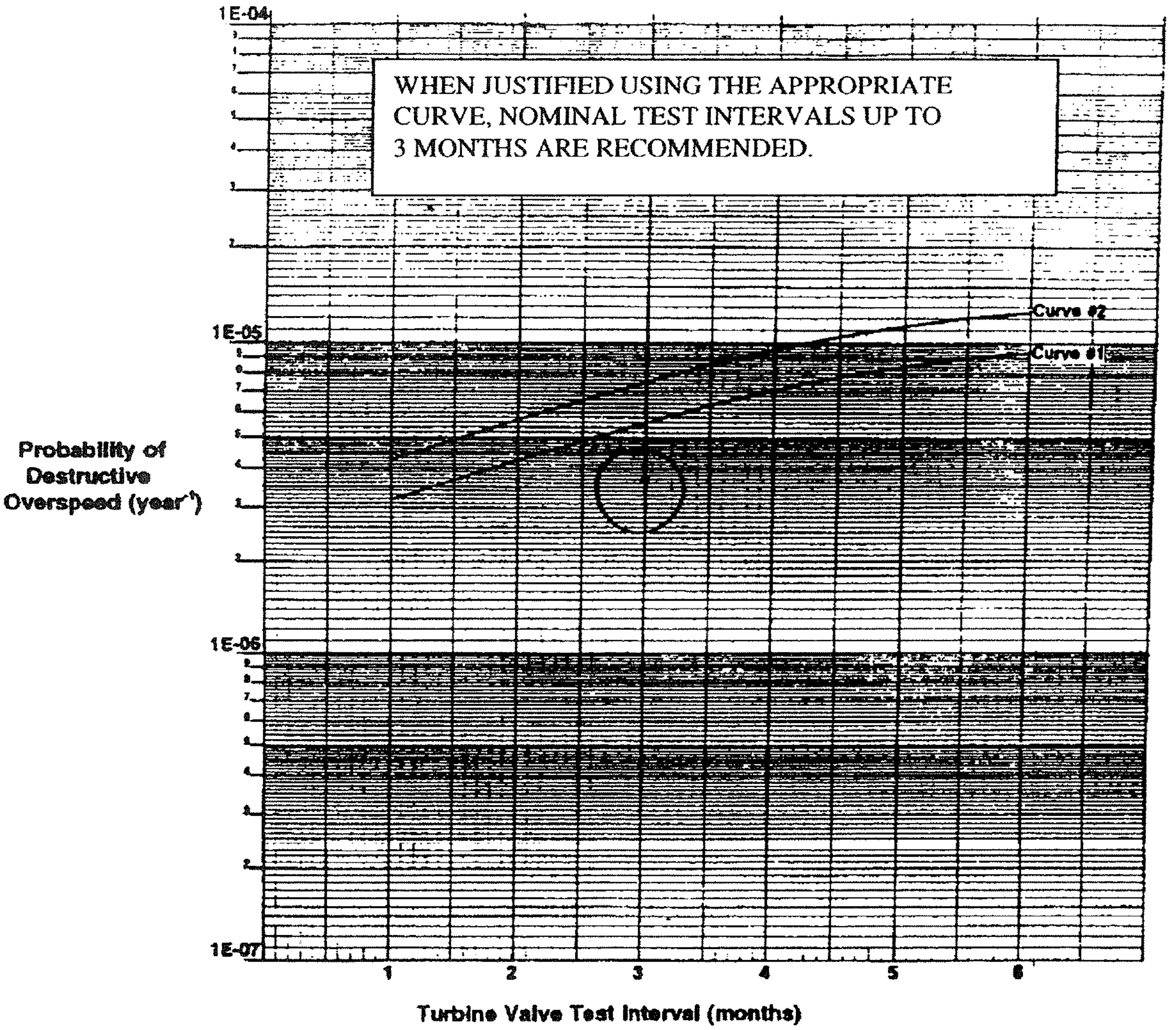
CV TYPE 5 FAILURE RATE = 1.53-07/HR

SLOPE OF ANALYSIS FAILURE LINE = [(CV TYPE 5 F.R.) * (OPERATING HOURS)] / (CALENDAR YEARS)

= [(1.53E-07/HR) * (3.925E+06 HRS)] / (6.42 CAL. YRS.) = 0.094 FAIL./CAL. YR.

INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.1-66 TRACKING B-95/96 CONTROL VALVE (CV) TYPE 5 FAILURES CONTROL VALVE STICKS OPEN	
MIC. No. 2001MB1541	REV. No. 17A

Initial Case

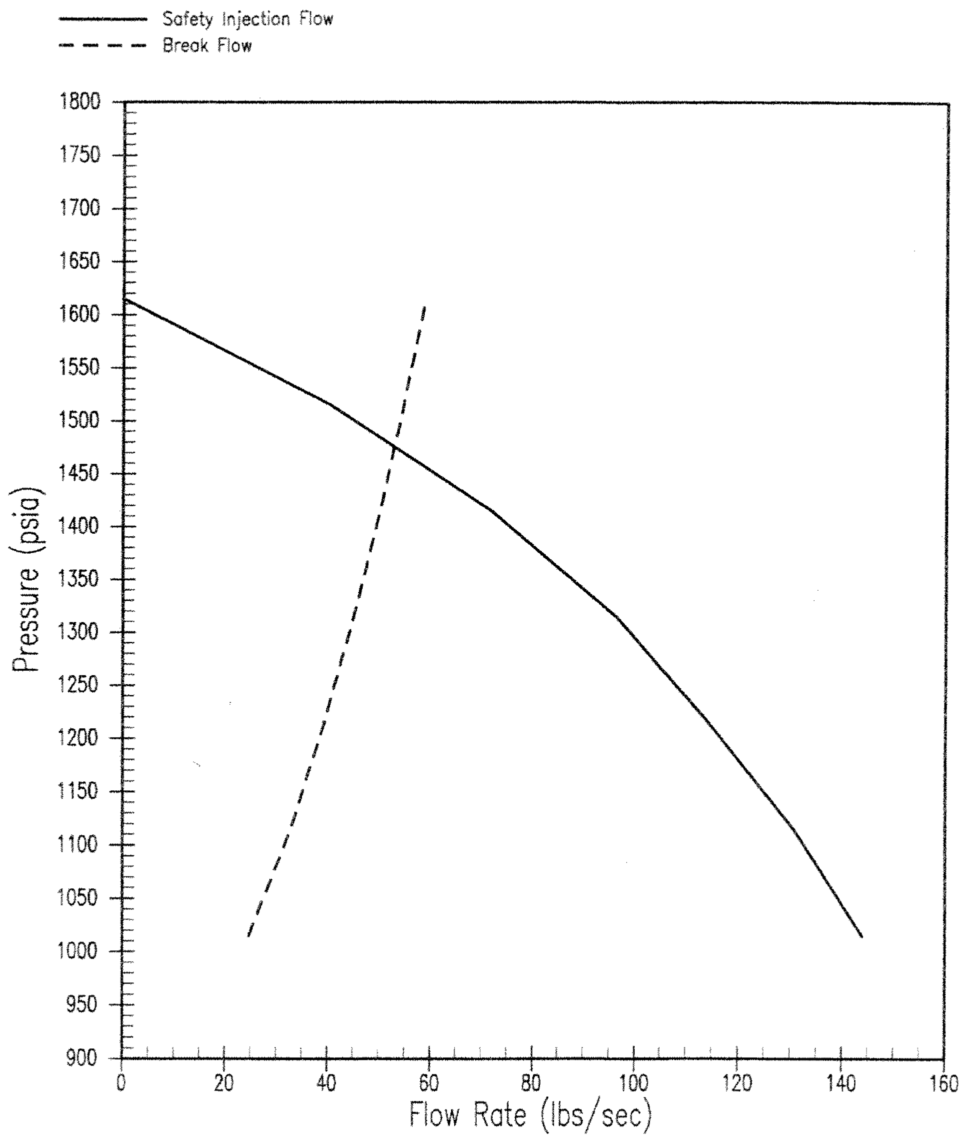


Curve #1: Surveillance of stop valve discs occurs every 18 months. Testing of valve freedom of movement occurs at intervals of 1 to 6 months (horizontal axis).

Curve #2: Surveillance of stop valve discs occurs every 24 months. Testing of valve freedom of movement occurs at intervals of 1 to 6 months (horizontal axis).

- Estimated 3.7E-06/r for 3 month test interval for Curve #2

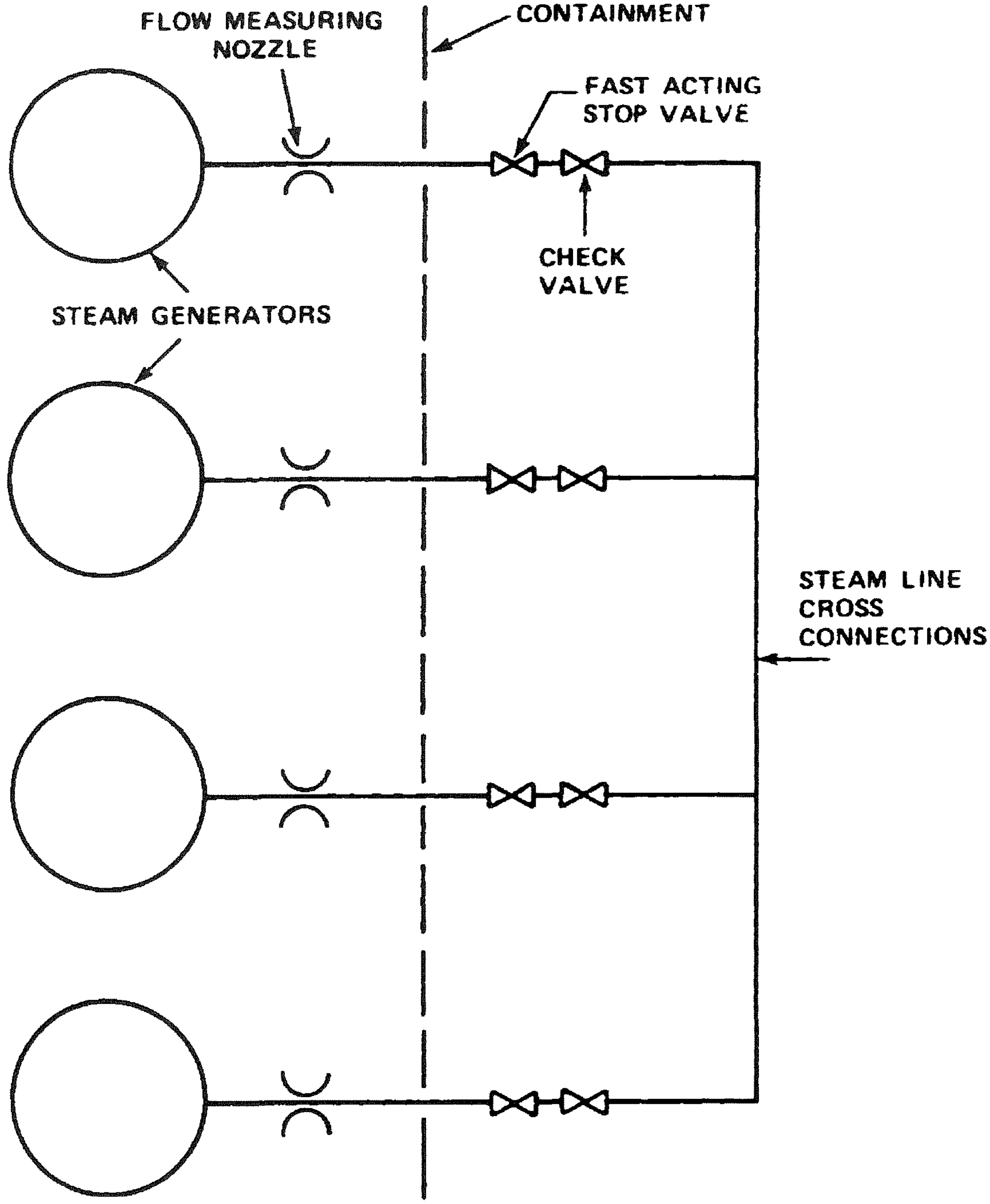
INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.1-67 ANNUAL FREQUENCY OF DESTRUCTIVE OVERSPEED FOR VARIOUS BB-95/96 TURBINE VALVE TEST INTERVAL (1-ON-1 SV-CV TURBINE / 1 OUT OF 4 STEAM PATHS)	
MIC. No. 2001MB1542	REV. No. 17A



INDIAN POINT UNIT No. 2

STEAM GENERATOR TUBE RUPTURE, BREAK FLOW AND SAFETY INJECTION FLOW VS. REACTOR COOLANT SYSTEM PRESSURE

UFSAR FIGURE 14.2-0	REV. No. 19

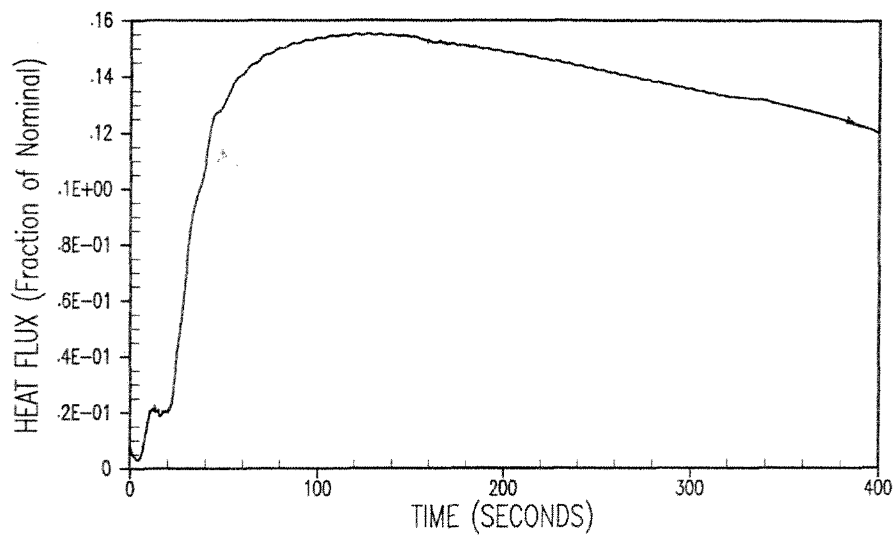


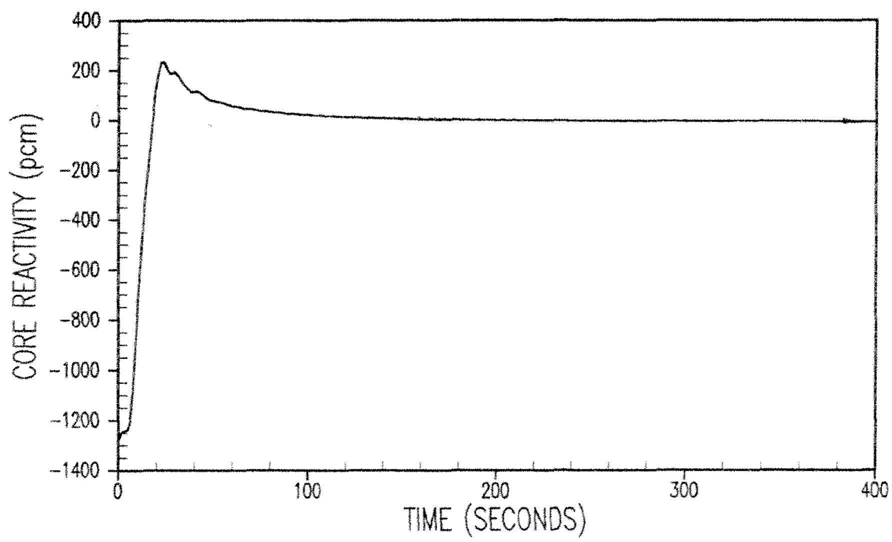
INDIAN POINT UNIT No. 2

UFSAR FIGURE 14.2-1

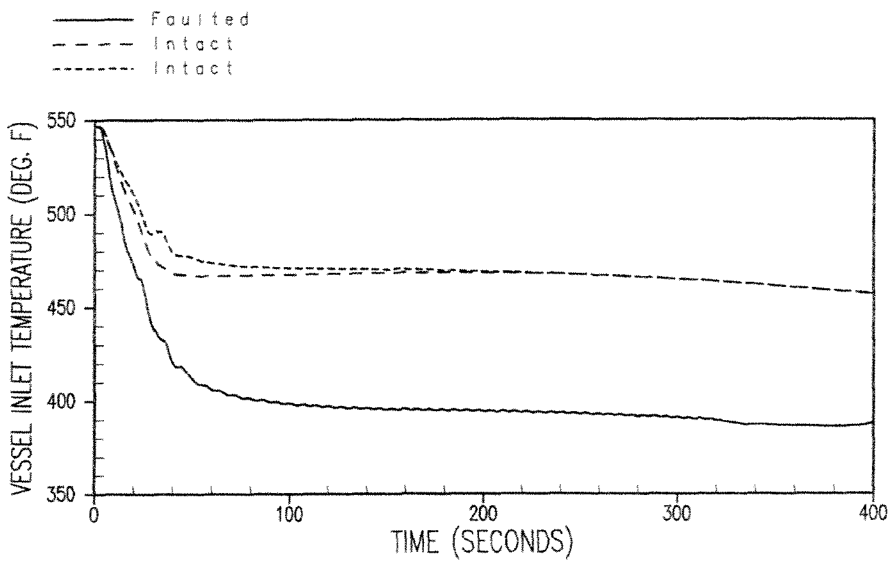
STEAM LINE VALVE ARRANGEMENT – SCHEMATIC

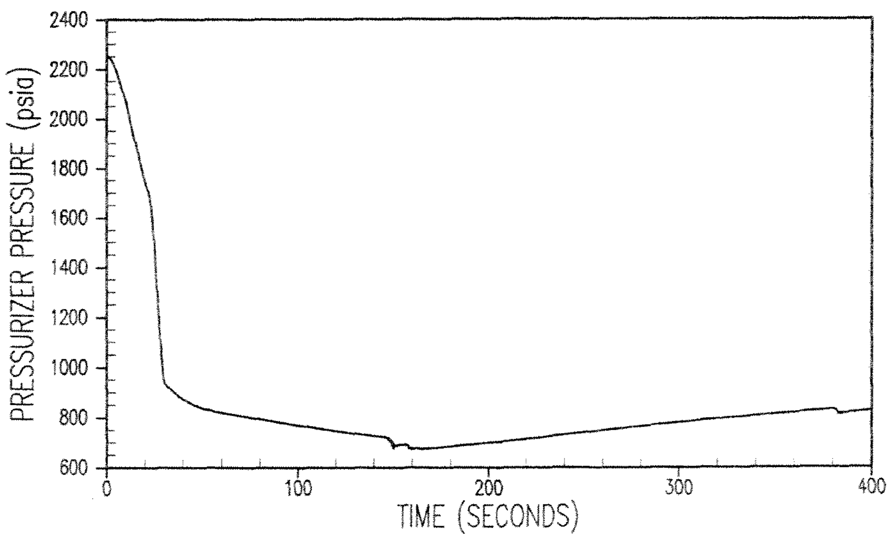
MIC. No. 2001MB1570	REV. No. 17A





INDIAN POINT UNIT No. 2	
STEAM LINE RUPTURE OFFSITE POWER AVAILABLE, EOL CORE HEAT FLUX AND CORE REACTIVITY vs. TIME	
UFSAR FIGURE 14.2-2, sht.1	REV. No. 19

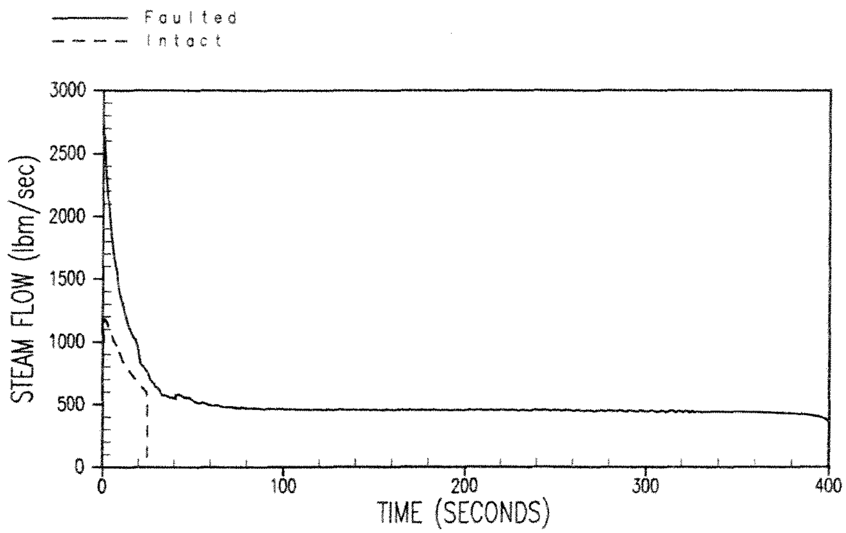


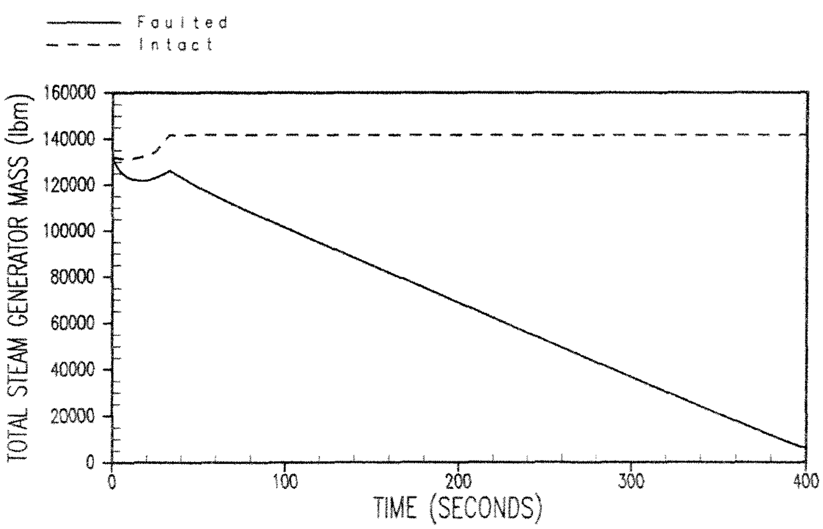


INDIAN POINT UNIT No. 2

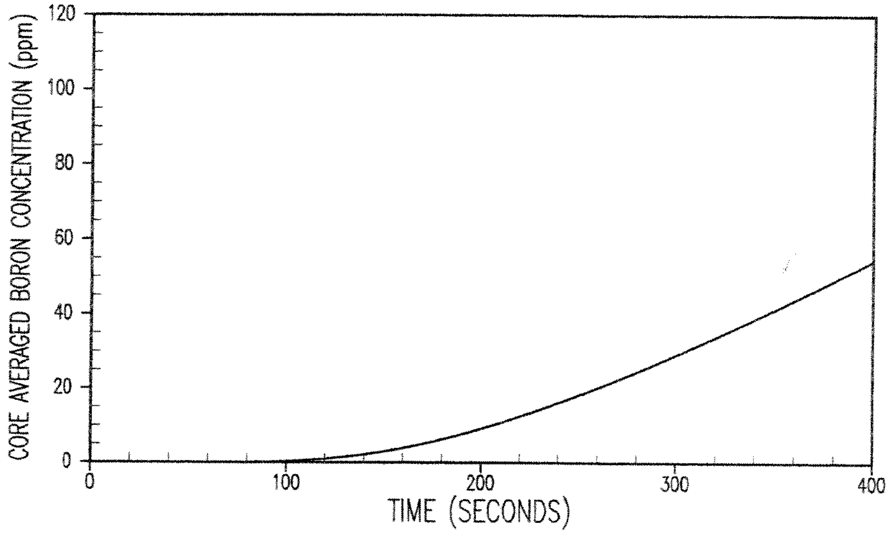
STEAM LINE RUPTURE OFFSITE POWER AVAILABLE, EOL, REACTOR COOLANT PRESSURE AND RV INLET TEMPERATURE vs. TIME

UFSAR FIGURE 14.2-2, sht.2	REV. No. 19





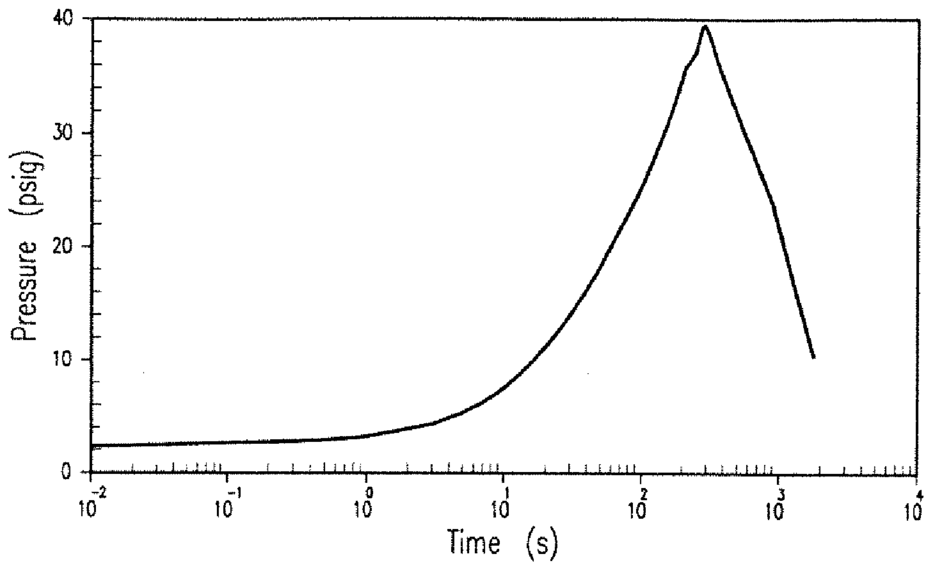
INDIAN POINT UNIT No. 2	
STEAM LINE RUPTURE OFFSITE POWER AVAILABLE, EOL, STEAM FLOW AND STEAM GENERATOR PRESSURE vs. TIME	
UFSAR FIGURE 14.2-2, sht.3	REV. No. 19



INDIAN POINT UNIT No. 2

STEAM LINE RUPTURE OFFSITE POWER AVAILABLE, EOL, CORE BORON CONCENTRATION vs TIME

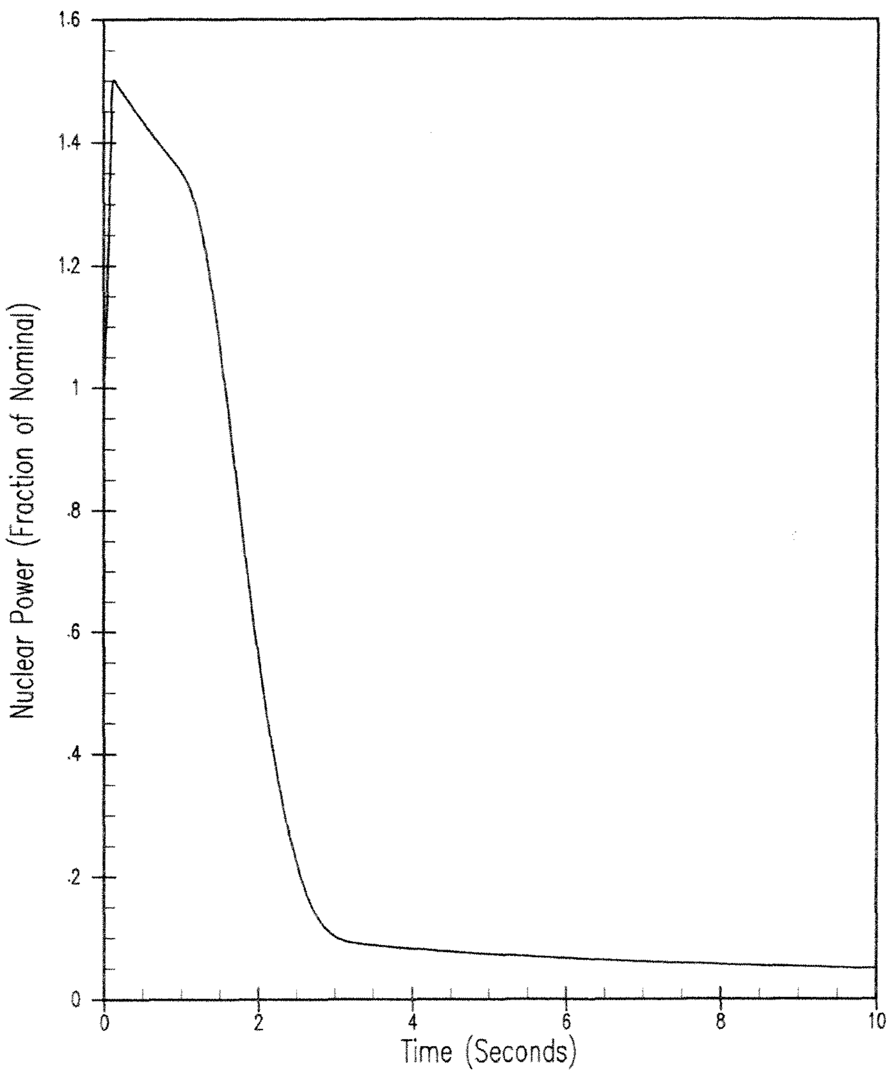
UFSAR FIGURE 14.2-2, sht.4	REV. No. 19



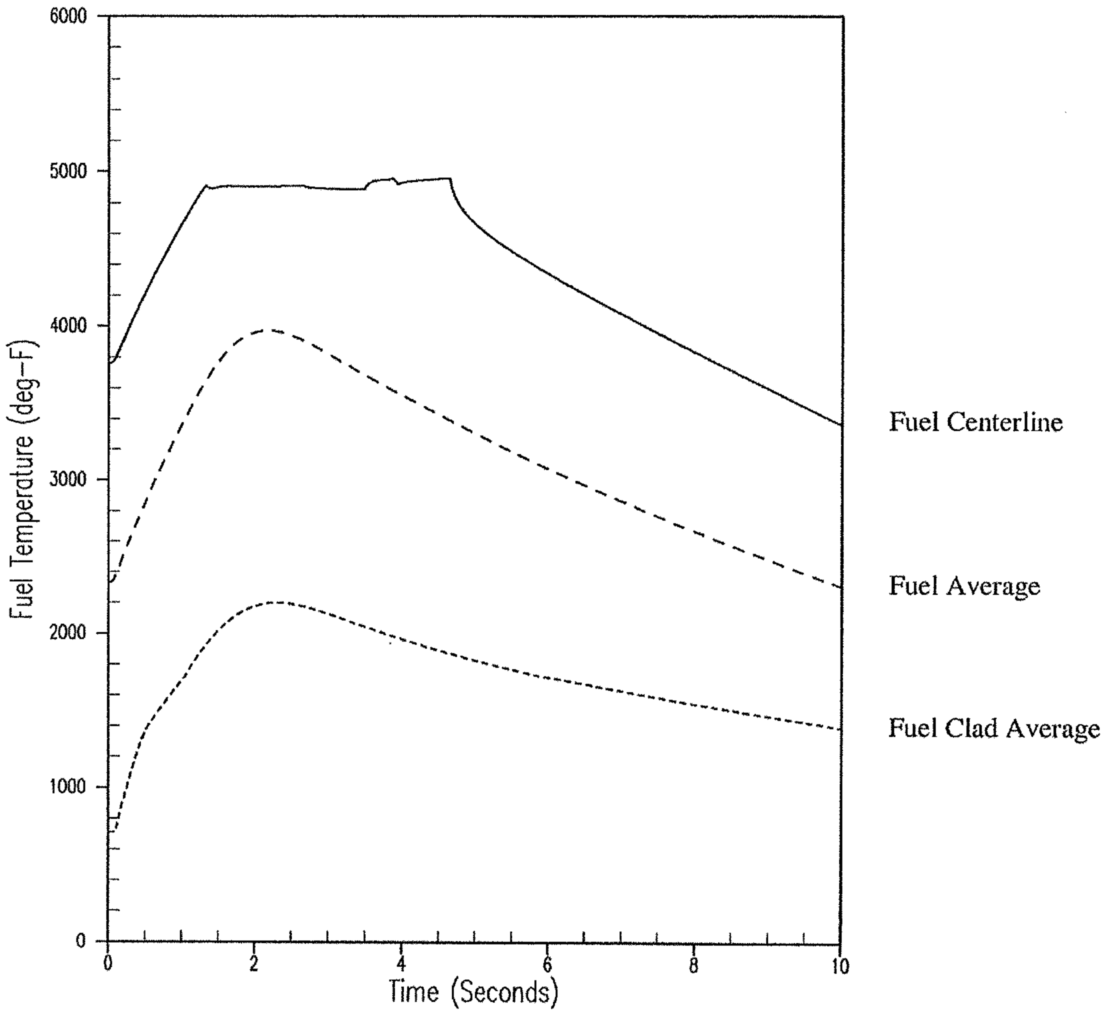
INDIAN POINT UNIT No. 2

CONTAINMENT PRESSURE TIME HISTORY
(DOUBLE – ENDED MAIN STEAM LINE BREAK
MAIN FCV FAILURE
MAXIMUM CONTAINMENT SAFEGUARDS)

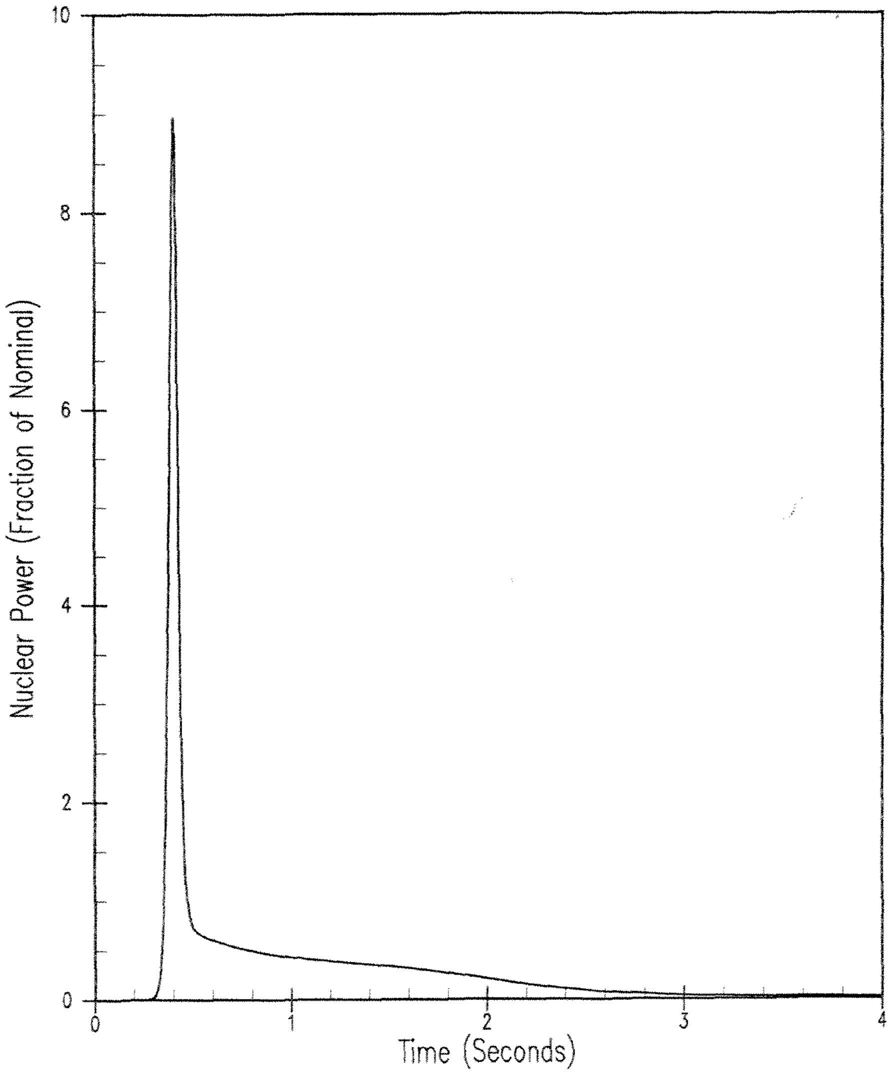
UFSAR FIGURE 14.2–7	REV. No. 20



INDIAN POINT UNIT No. 2	
ROD EJECTION ACCIDENT, BOL–HFP, NUCLEAR POWER vs. TIME	
UFSAR FIGURE 14.2–11	REV. No. 19



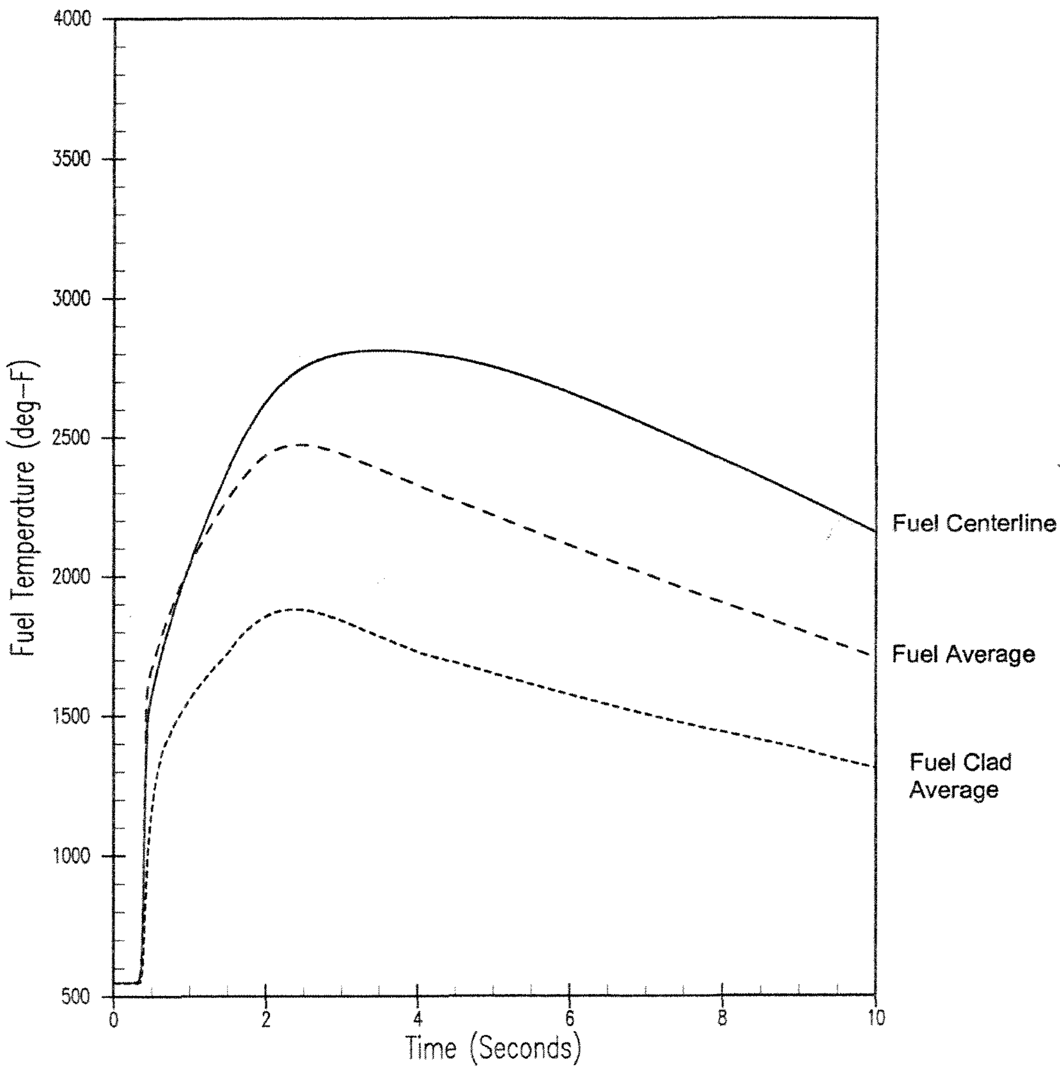
INDIAN POINT UNIT No. 2	
ROD EJECTION ACCIDENT, BOL-HFP, FUEL TEMPERATURES vs. TIME	
UFSAR FIGURE 14.2-12	REV. No. 21



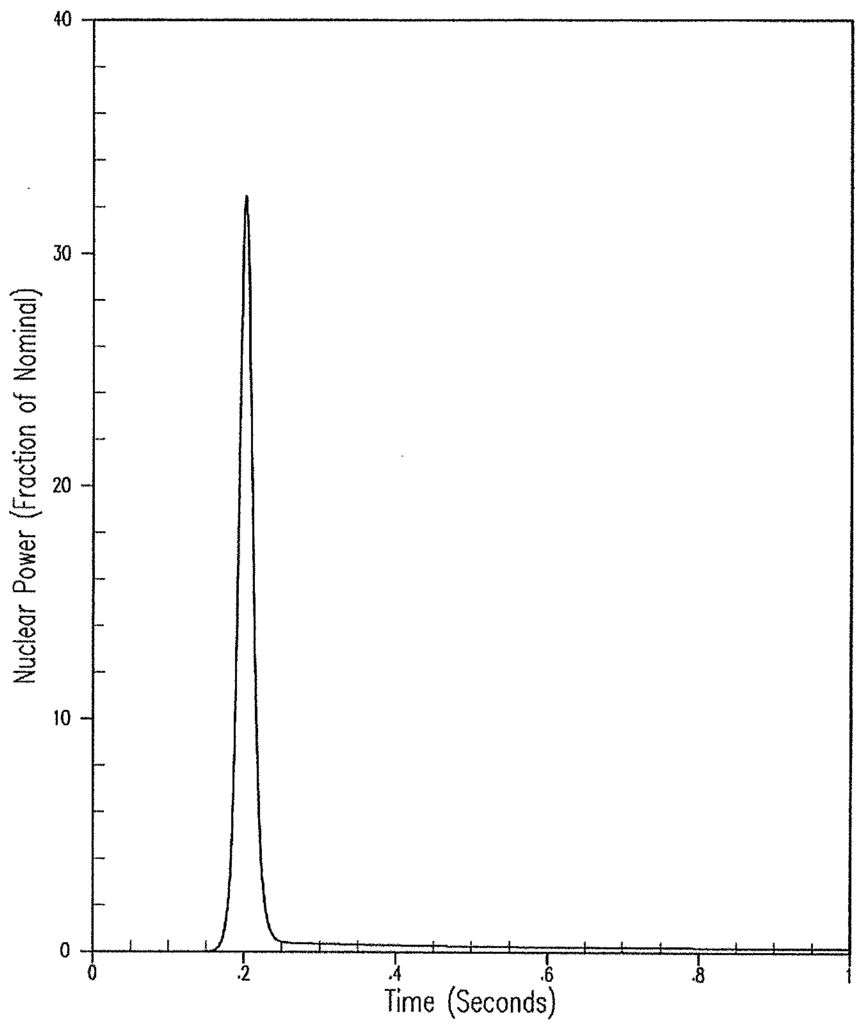
INDIAN POINT UNIT No. 2

ROD EJECTION ACCIDENT, BOL–HZP, NUCLEAR POWER vs. TIME

UFSAR FIGURE 14.2–13	REV. No. 19



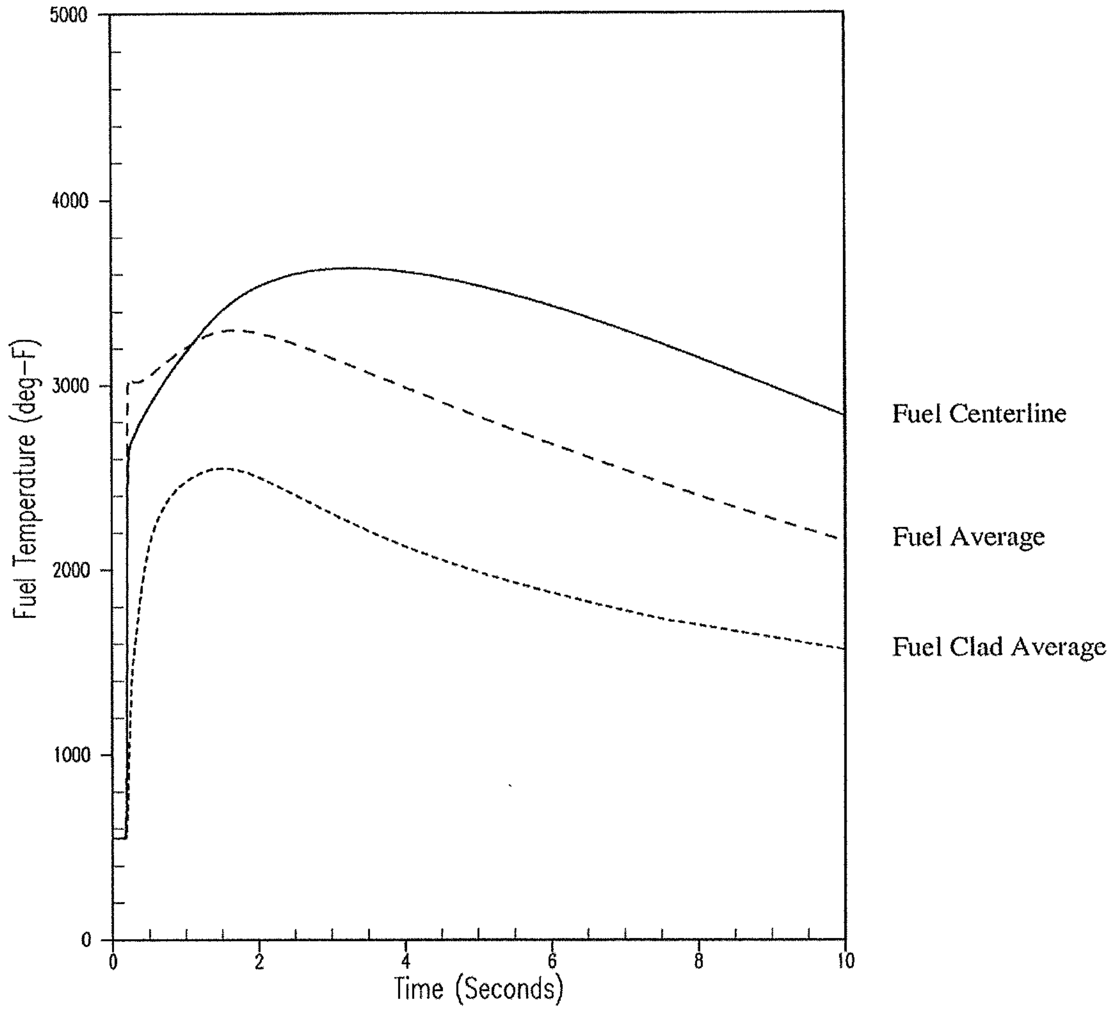
INDIAN POINT UNIT No. 2	
ROD EJECTION ACCIDENT, BOL-HZP, FUEL TEMPERATURES vs. TIME	
UFSAR FIGURE 14.2-14	REV. No. 19



INDIAN POINT UNIT No. 2

ROD EJECTION ACCIDENT, EOL-HZP,
NUCLEAR POWER vs. TIME

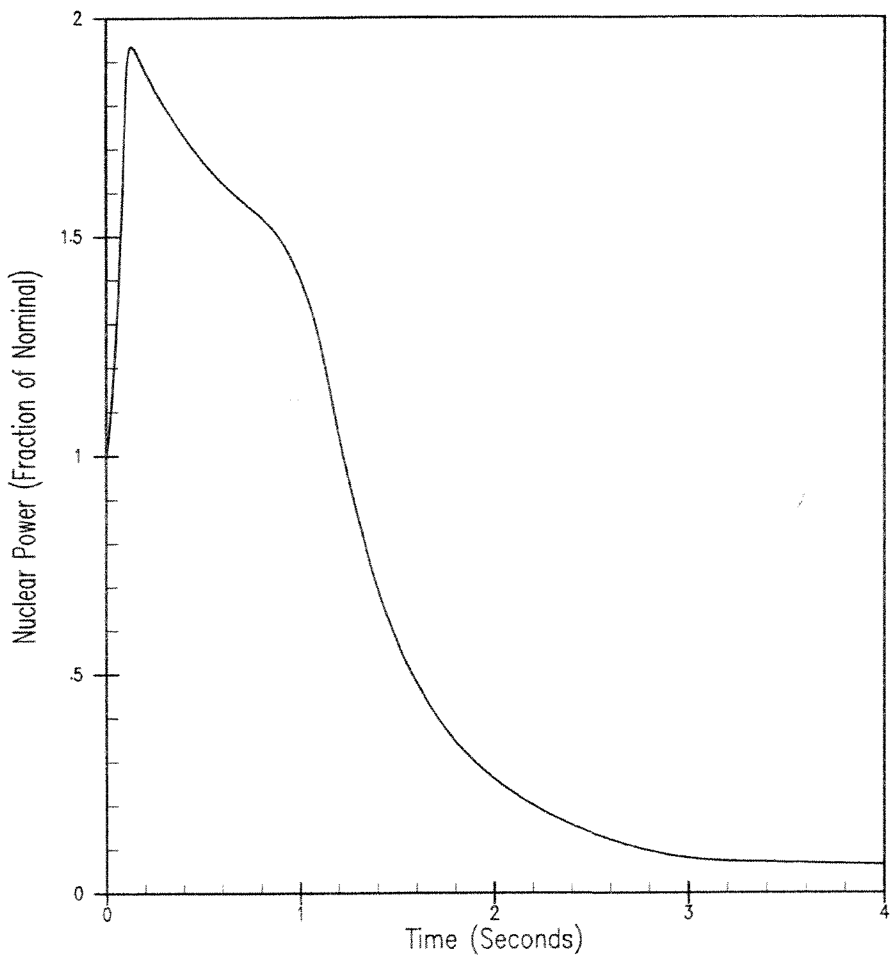
UFSAR FIGURE 14.2-15 | REV. No. 21



INDIAN POINT UNIT No. 2

ROD EJECTION ACCIDENT, EOL-HZP, FUEL TEMPERATURES vs. TIME

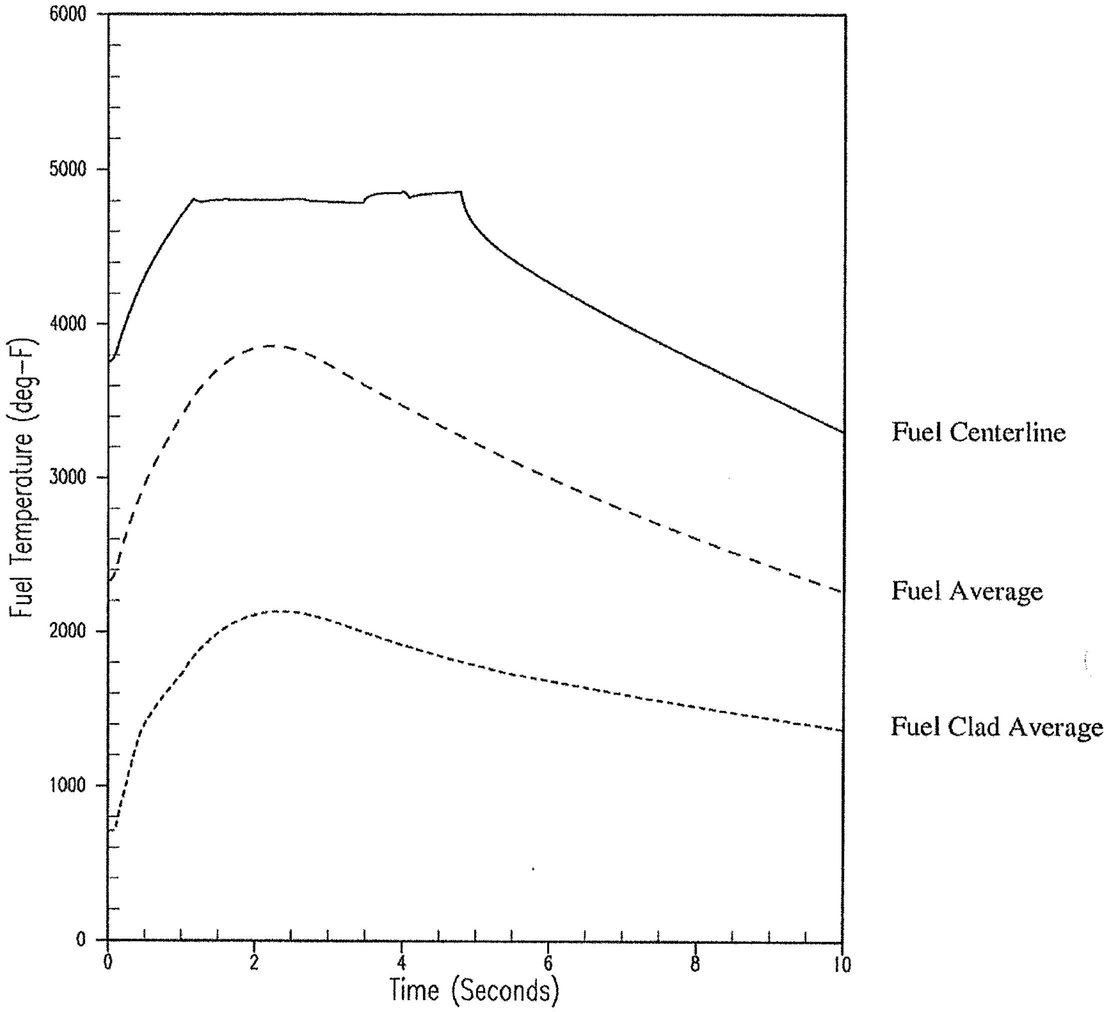
UFSAR FIGURE 14.2-16	REV. No. 21



INDIAN POINT UNIT No. 2

ROD EJECTION ACCIDENT, EOL–HFP, NUCLEAR POWER vs TIME

UFSAR FIGURE 14.2–17 | REV. No. 19



INDIAN POINT UNIT No. 2

ROD EJECTION ACCIDENT, EOL-HFP, FUEL TEMPERATURES vs TIME

UFSAR FIGURE 14.2-18 | REV. No. 21

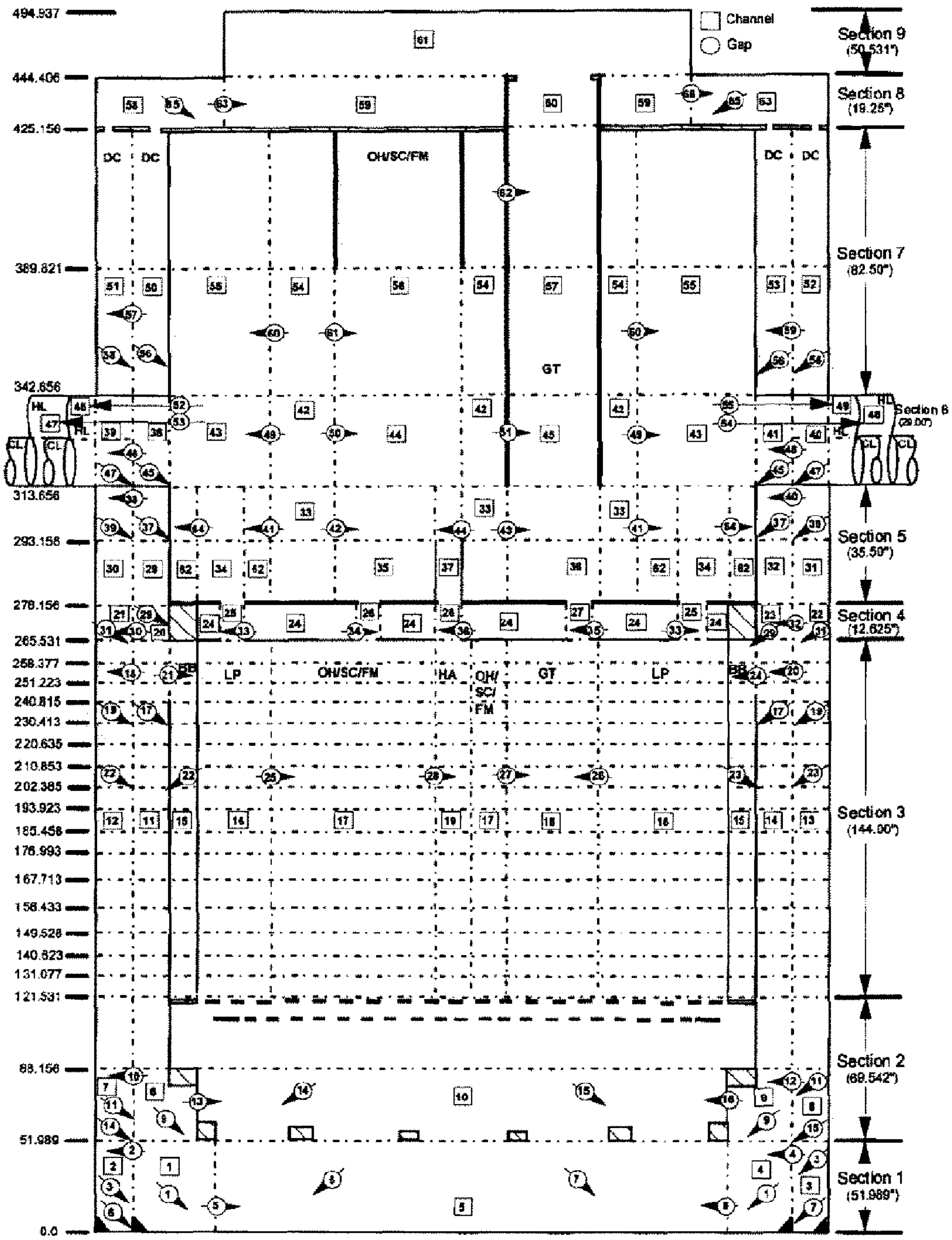


Figure 14.3-1: Indian Point Unit 2 WCOBRA/TRAC Vessel Model Noding Diagram

INDIAN POINT UNIT No. 2	
INDIAN POINT UNIT 2 WCOBRA/TRAC VESSEL MODEL NODING DIAGRAM	
UFSAR FIGURE 14.3-1	REV. No. 20

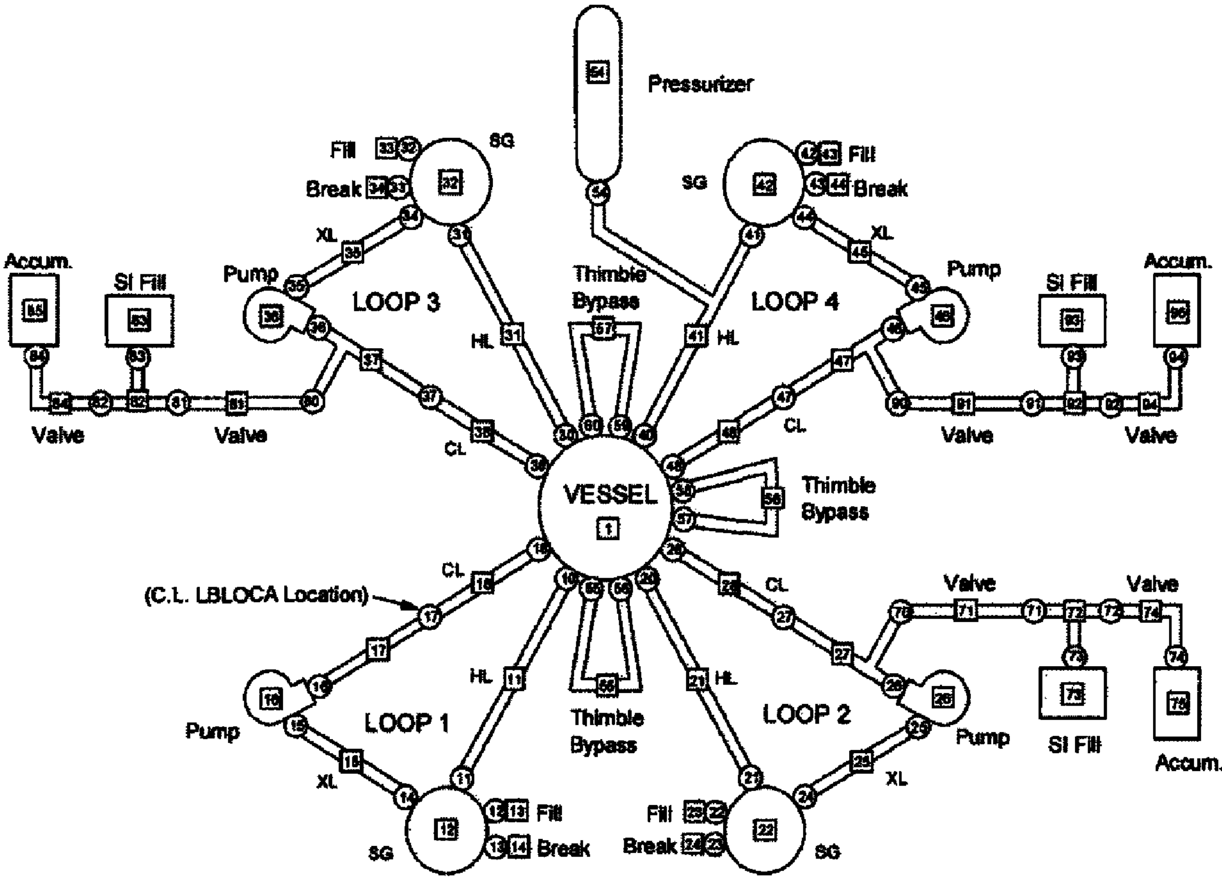
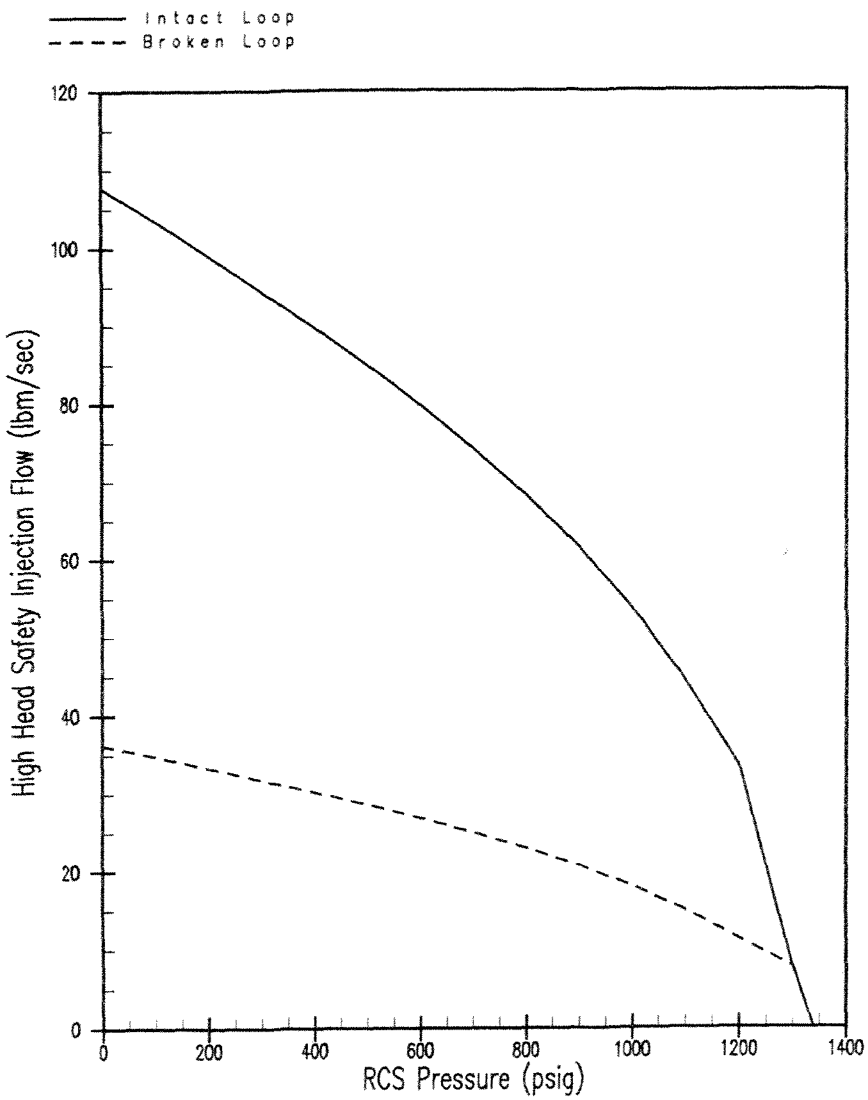
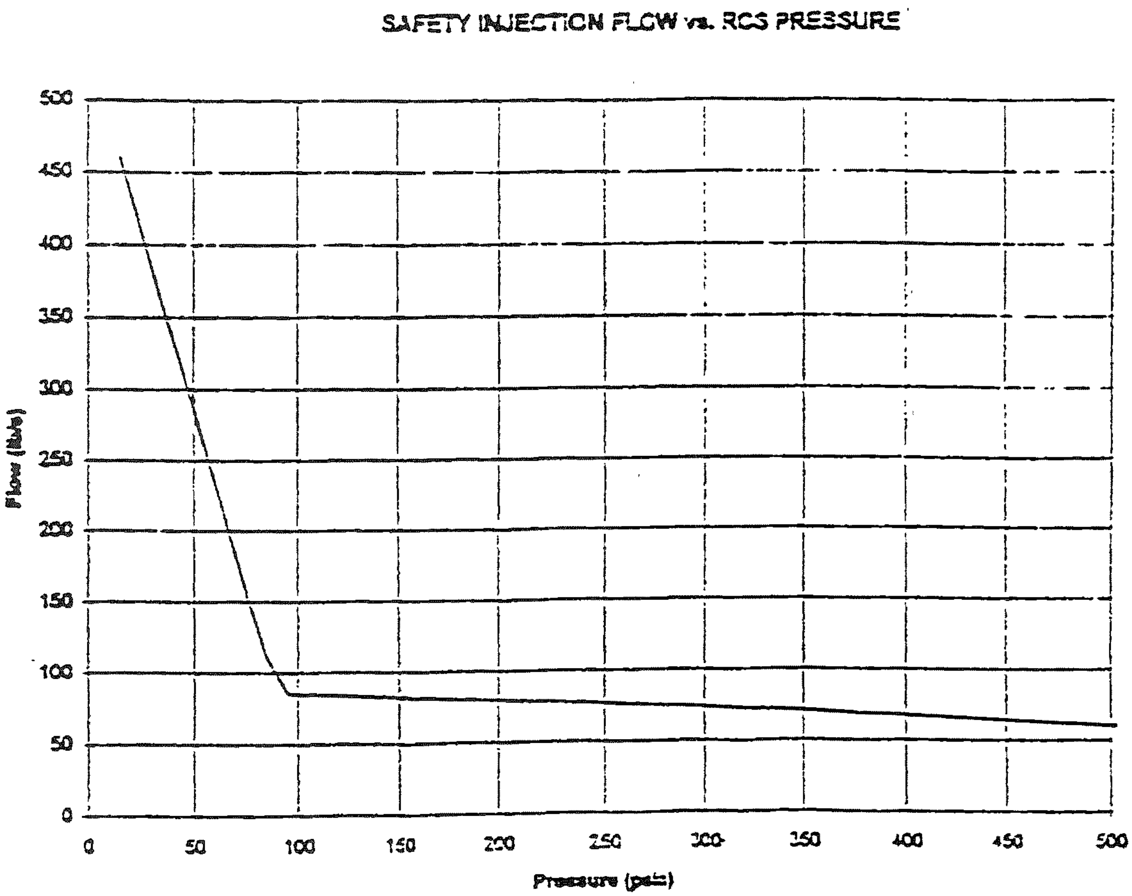


Figure 14.3-2: Indian Point Unit 2 WCOBRA/TRAC Model Loop Layout

INDIAN POINT UNIT No. 2	
INDIAN POINT UNIT 2 WCOBRA/TRAC VESSEL MODEL LOOP LAYOUT	
UFSAR FIGURE 14.3-2	REV. No. 20



INDIAN POINT UNIT No. 2	
HIGH HEAD SAFETY INJECTION FLOW RATE	
UFSAR FIGURE 14.3-3	REV. No. 19



INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.3-3A SAFETY INJECTION FLOW vs RCS PRESSURE	
MIC. No. 2000MC4204	REV. No. 17A

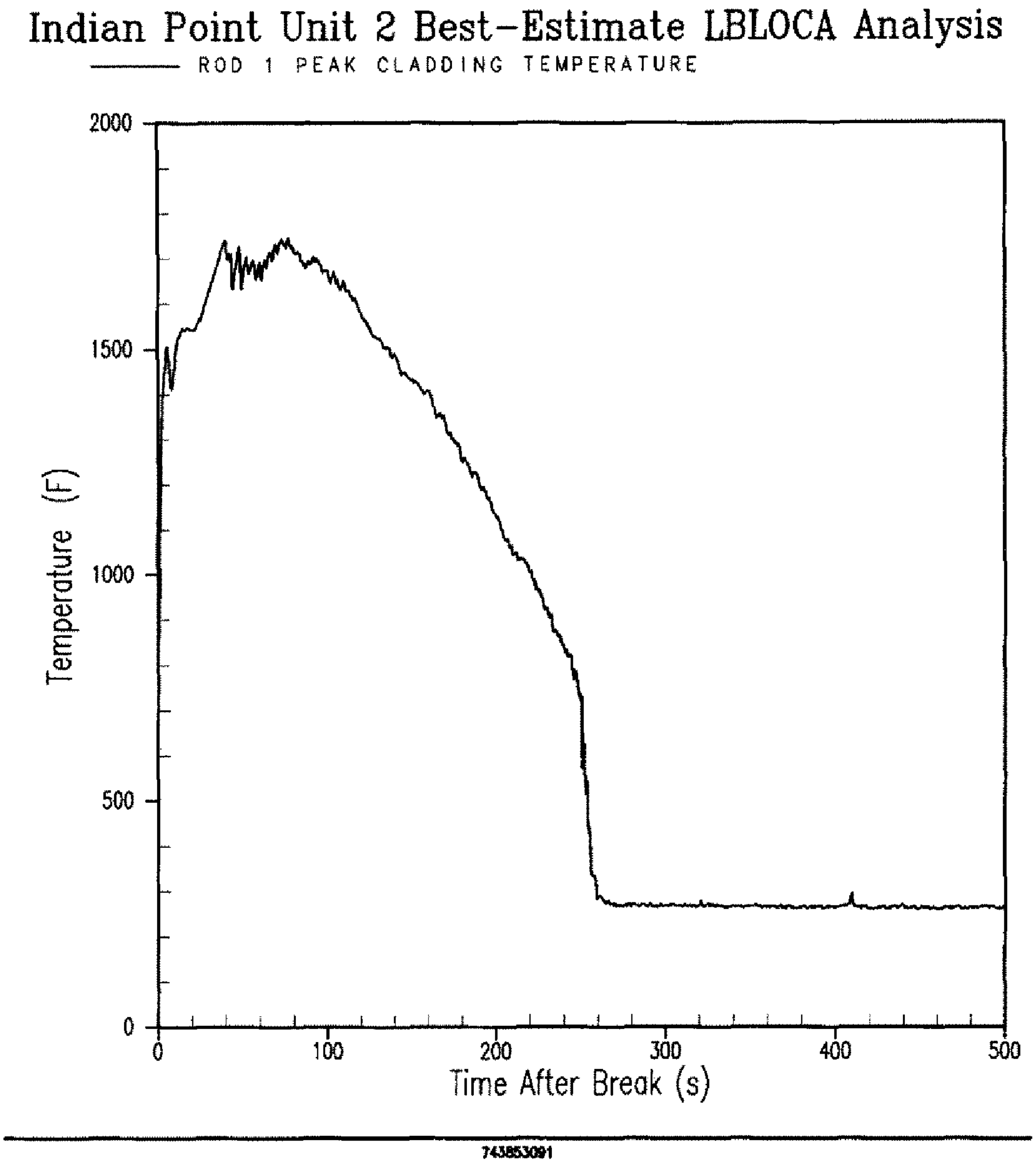
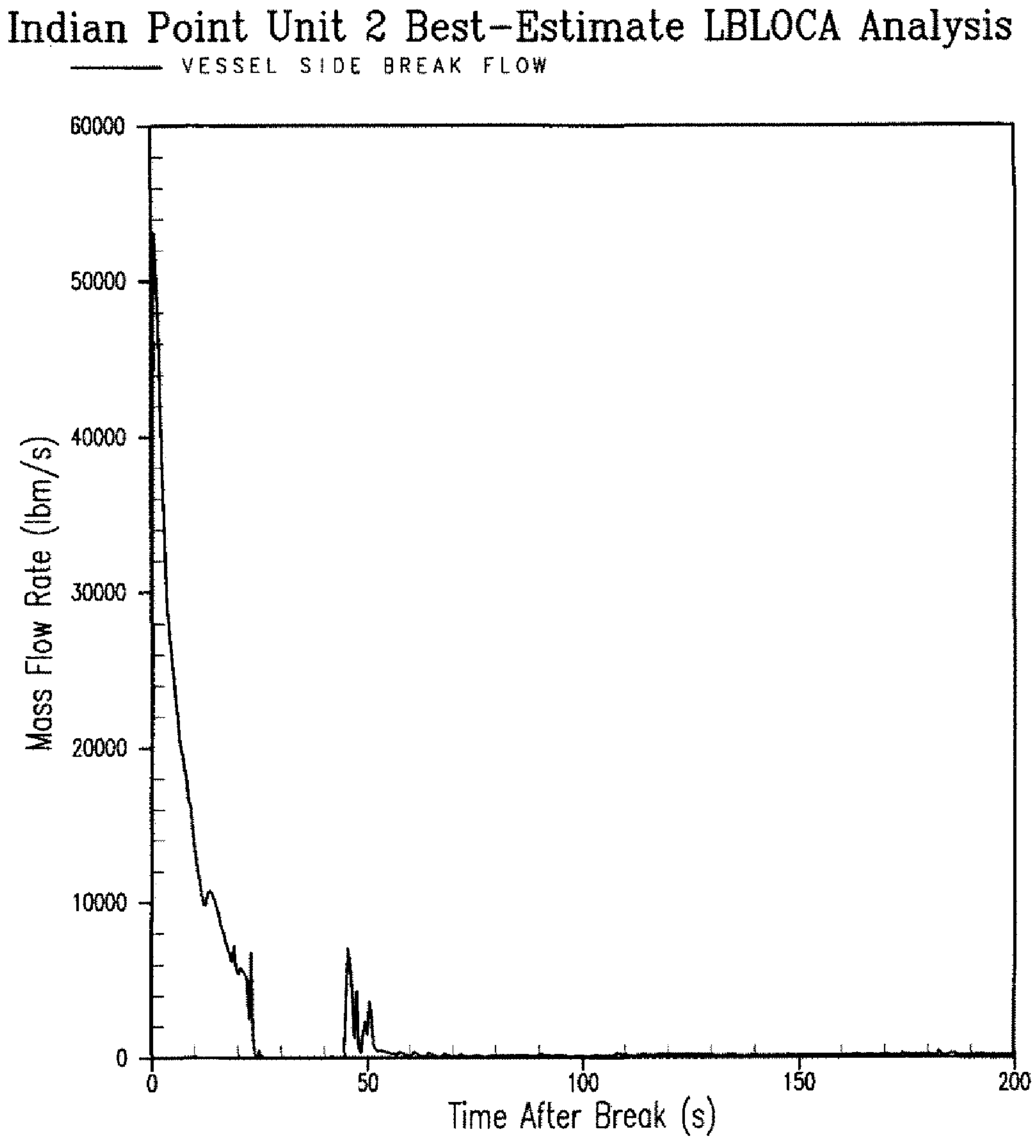


Figure 14.3-6: Peak Cladding Temperature for Reference Transient

INDIAN POINT UNIT No. 2	
PEAK CLADDING TEMPERATURE FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-6	REV. No. 20



743853091

Figure 14.3-7: Vessel Side Break Flow for Reference Transient

INDIAN POINT UNIT No. 2	
VESSEL SIDE BREAK FLOW FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-7	REV. No. 20

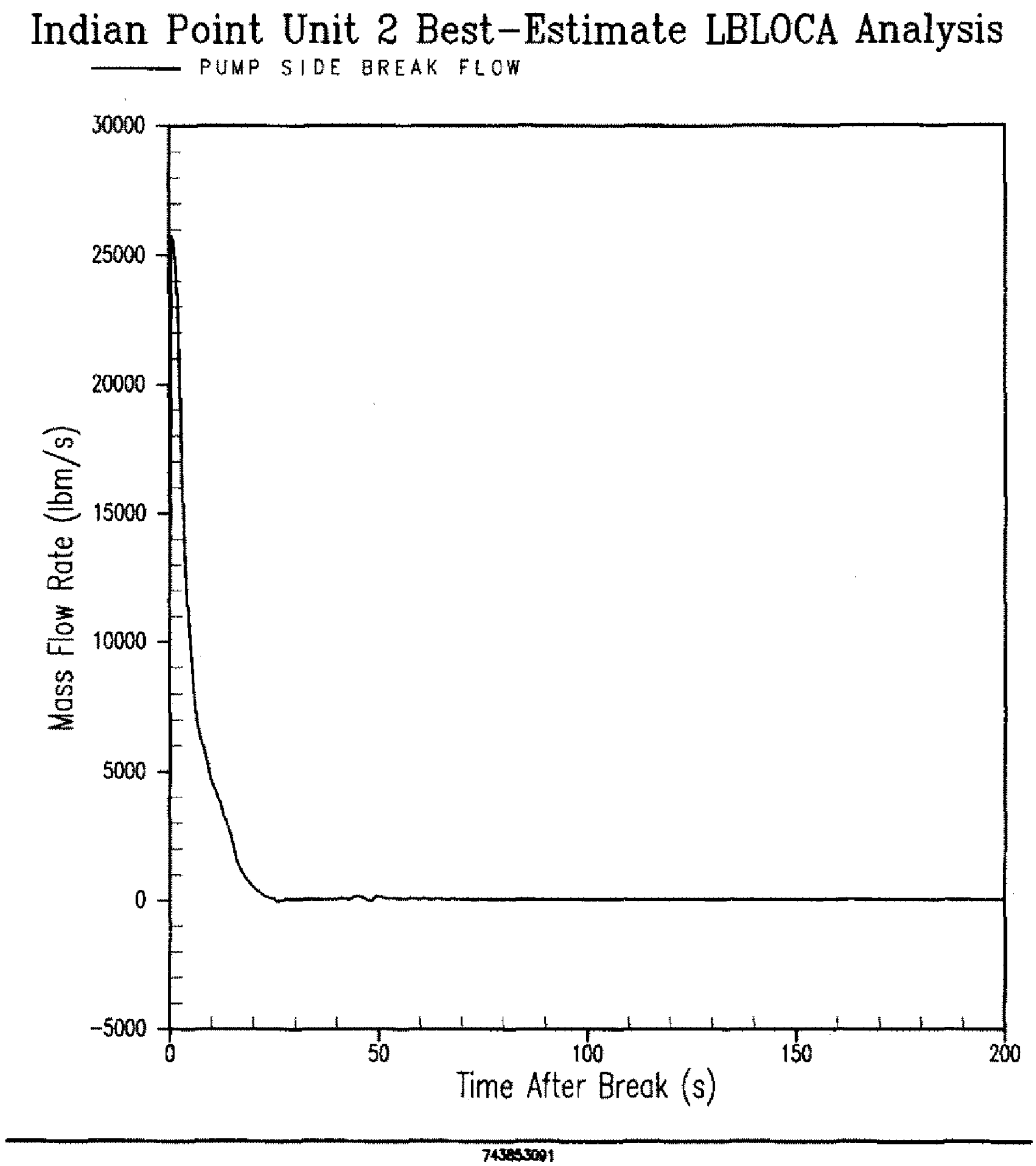
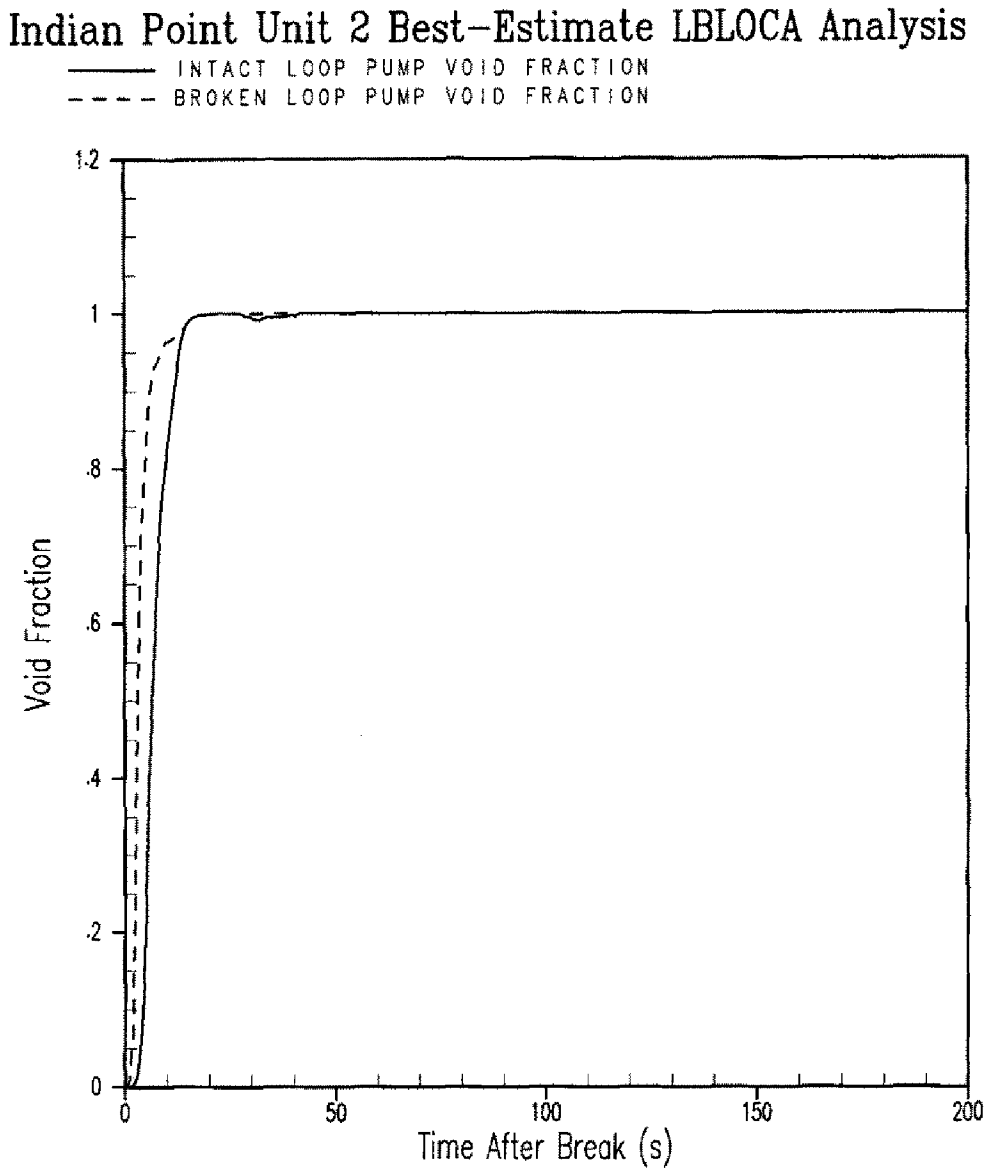


Figure 14.3-8: Loop Side Break Flow for Reference Transient

INDIAN POINT UNIT No. 2	
LOOP SIDE BREAK FLOW FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-8	REV. No. 20



15533541

Figure 14.3-9: Void Fraction at the Intact and Broken Loop Pump Inlet for Reference Transient

INDIAN POINT UNIT No. 2	
VOID FRACTION AT THE INTACT AND BROKEN LOOP PUMP INLET FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-9	REV. No. 20

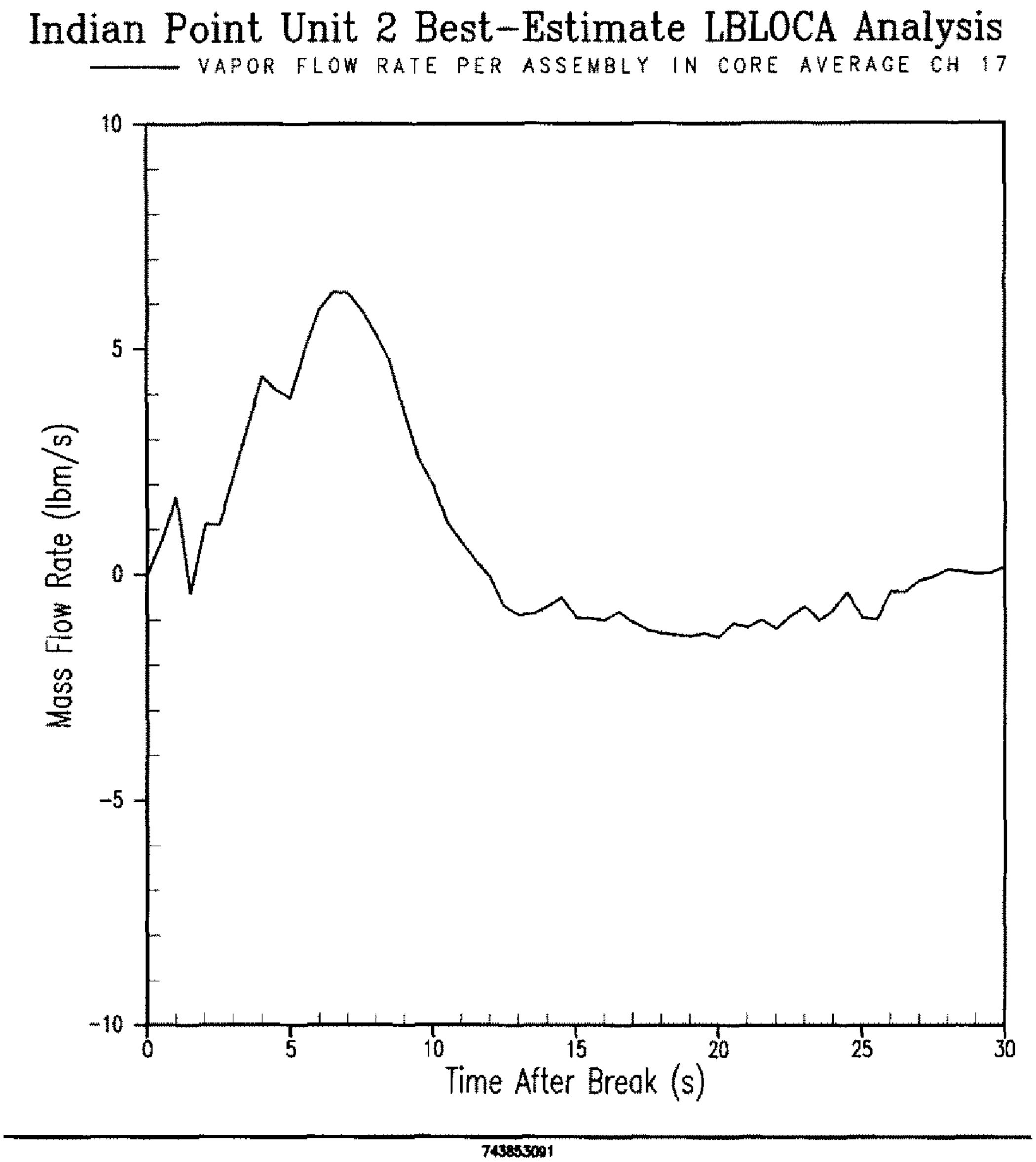


Figure 14.3-10: Vapor Flow Rate per Assembly at Mid-core in Core Average Channel 17 During Blowdown for Reference Transient

INDIAN POINT UNIT No. 2	
VAPOR FLOW RATE PER ASSEMBLY AT MID-CORE AVERAGE CHANNEL 17 DURING BLOWDOWN FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-10	REV. No. 20

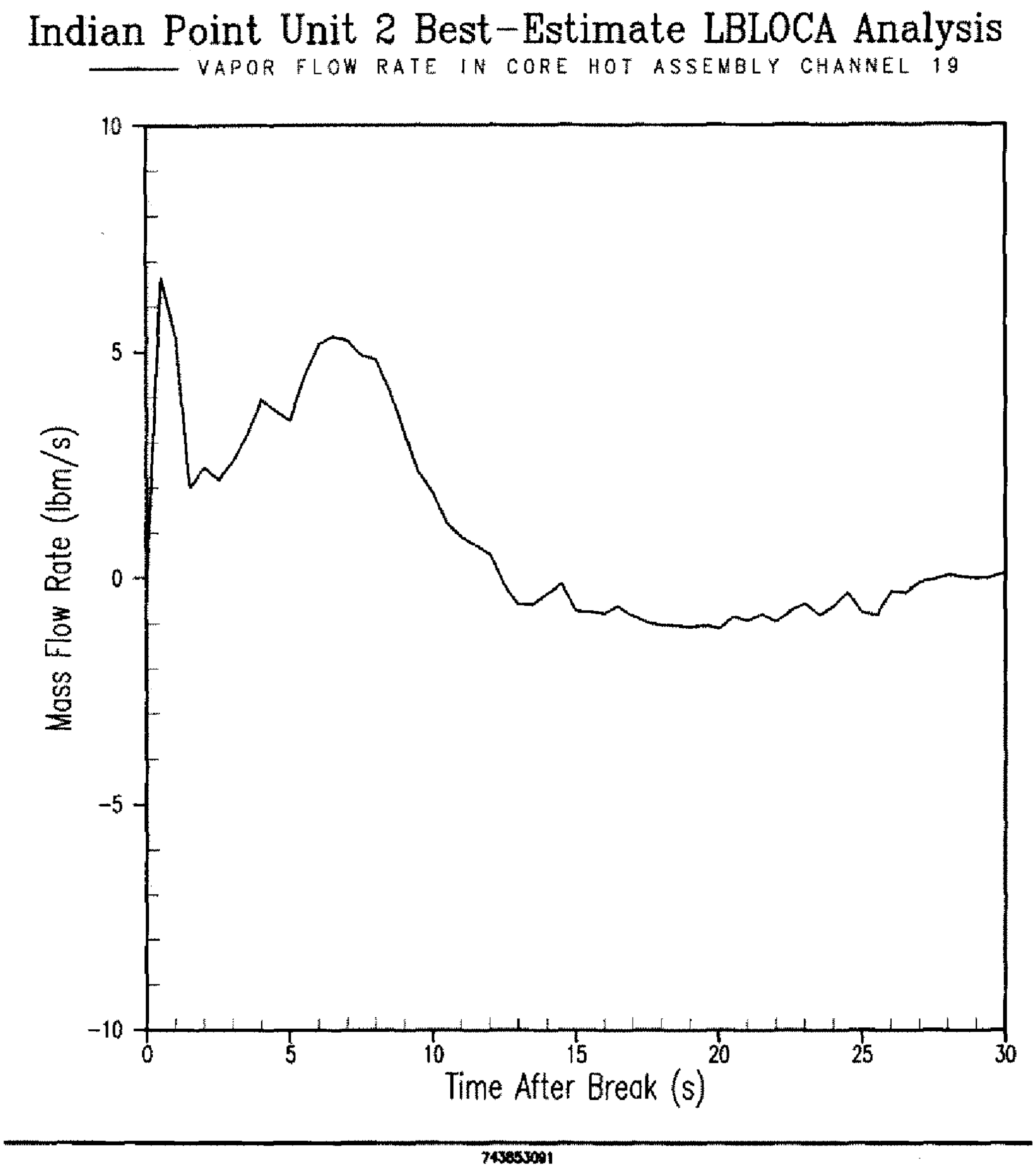


Figure 14.3-11: Vapor Flow Rate at Mid-core in Core Hot Assembly Channel 19 During Blowdown for Reference Transient

INDIAN POINT UNIT No. 2	
VAPOR FLOW RATE PER ASSEMBLY AT MID-CORE AVERAGE CHANNEL 19 DURING BLOWDOWN FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-11	REV. No. 20

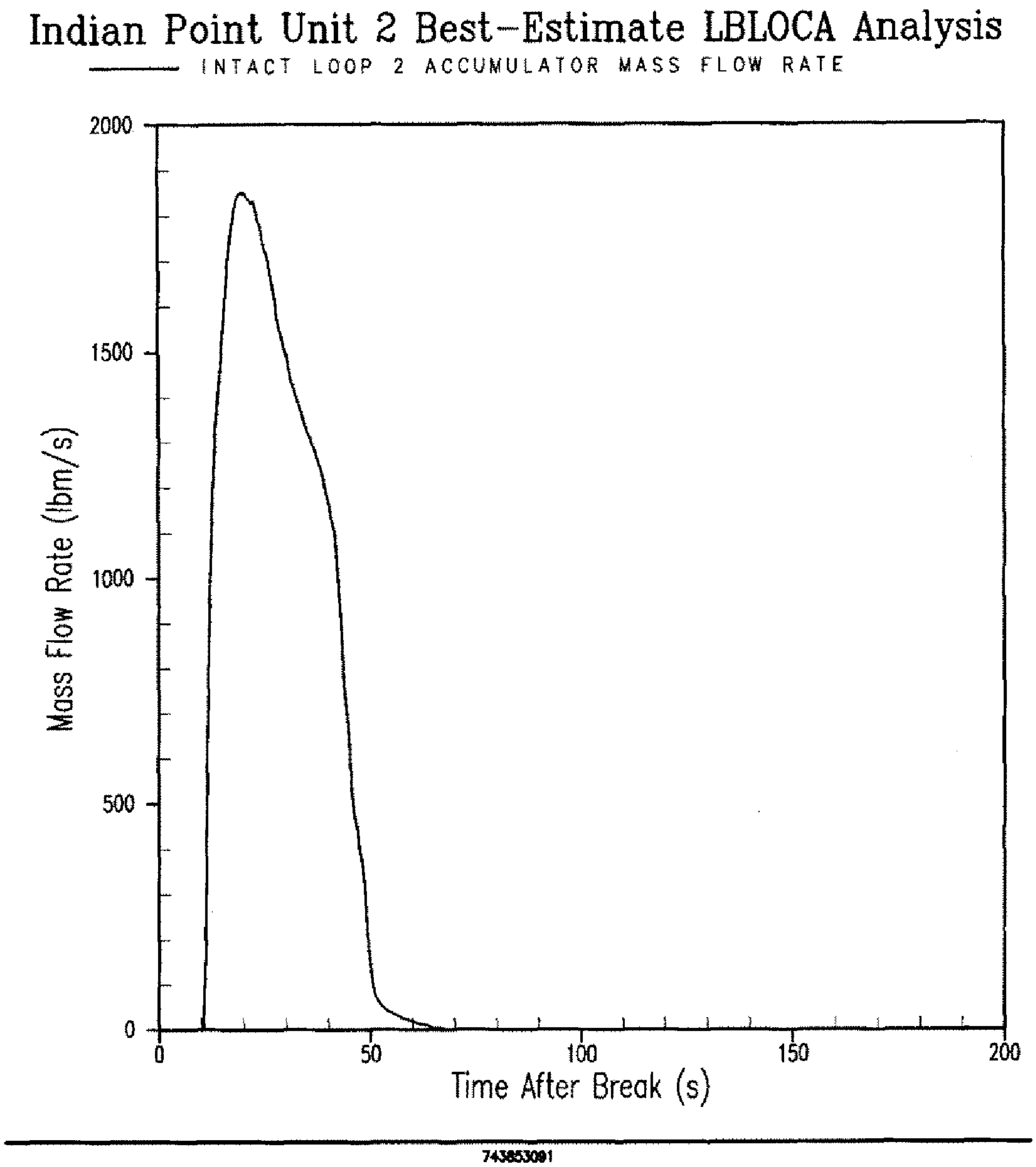
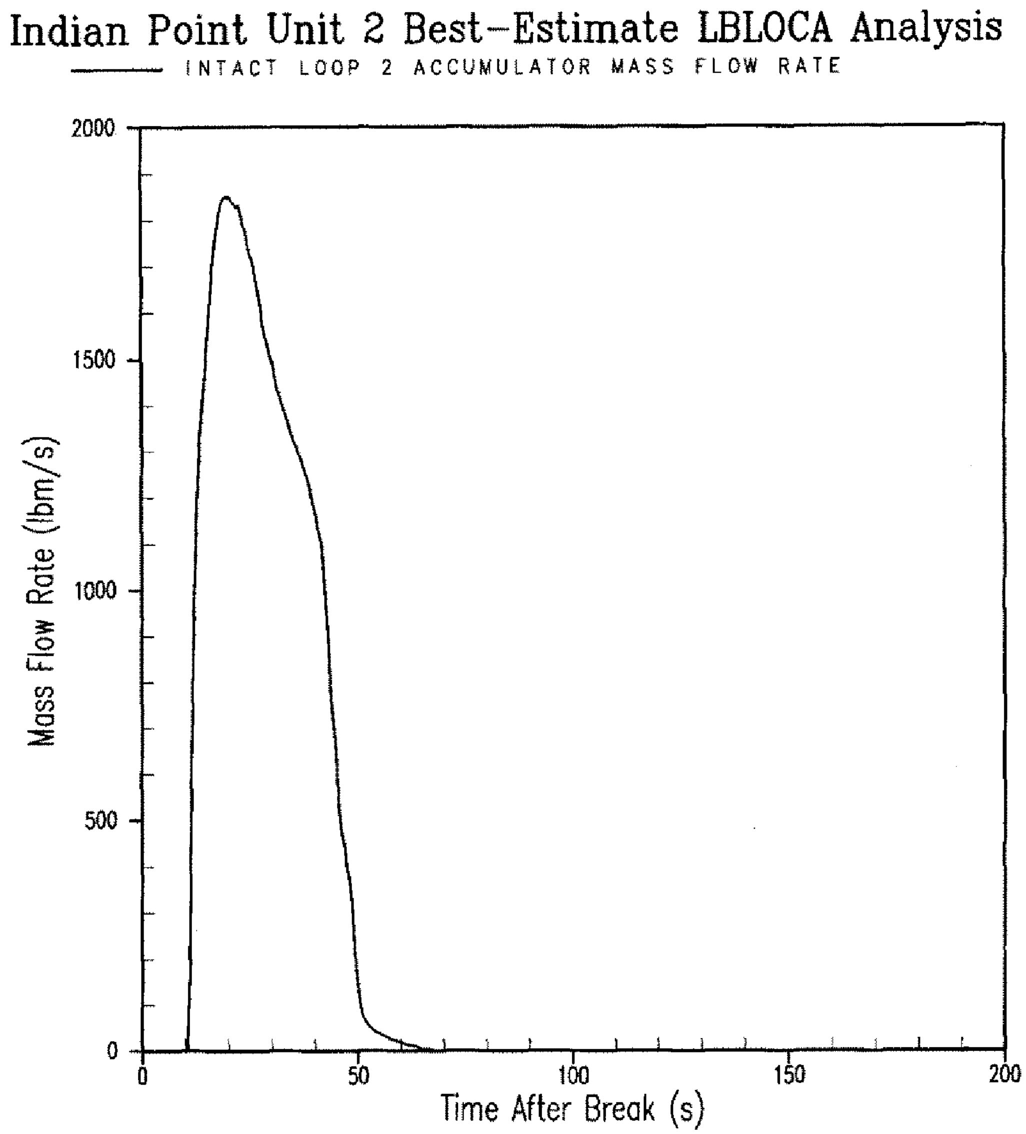


Figure 14.3-13: Intact Loop 2 Accumulator Flow for Reference Transient

INDIAN POINT UNIT No. 2	
INTACT LOOP 2 ACCUMULATOR FLOW FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-13	REV. No. 20



743853091

Figure 14.3-13: Intact Loop 2 Accumulator Flow for Reference Transient

INDIAN POINT UNIT No. 2	
INTACT LOOP 2 ACCUMULATOR FLOW FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-13	REV. No. 20

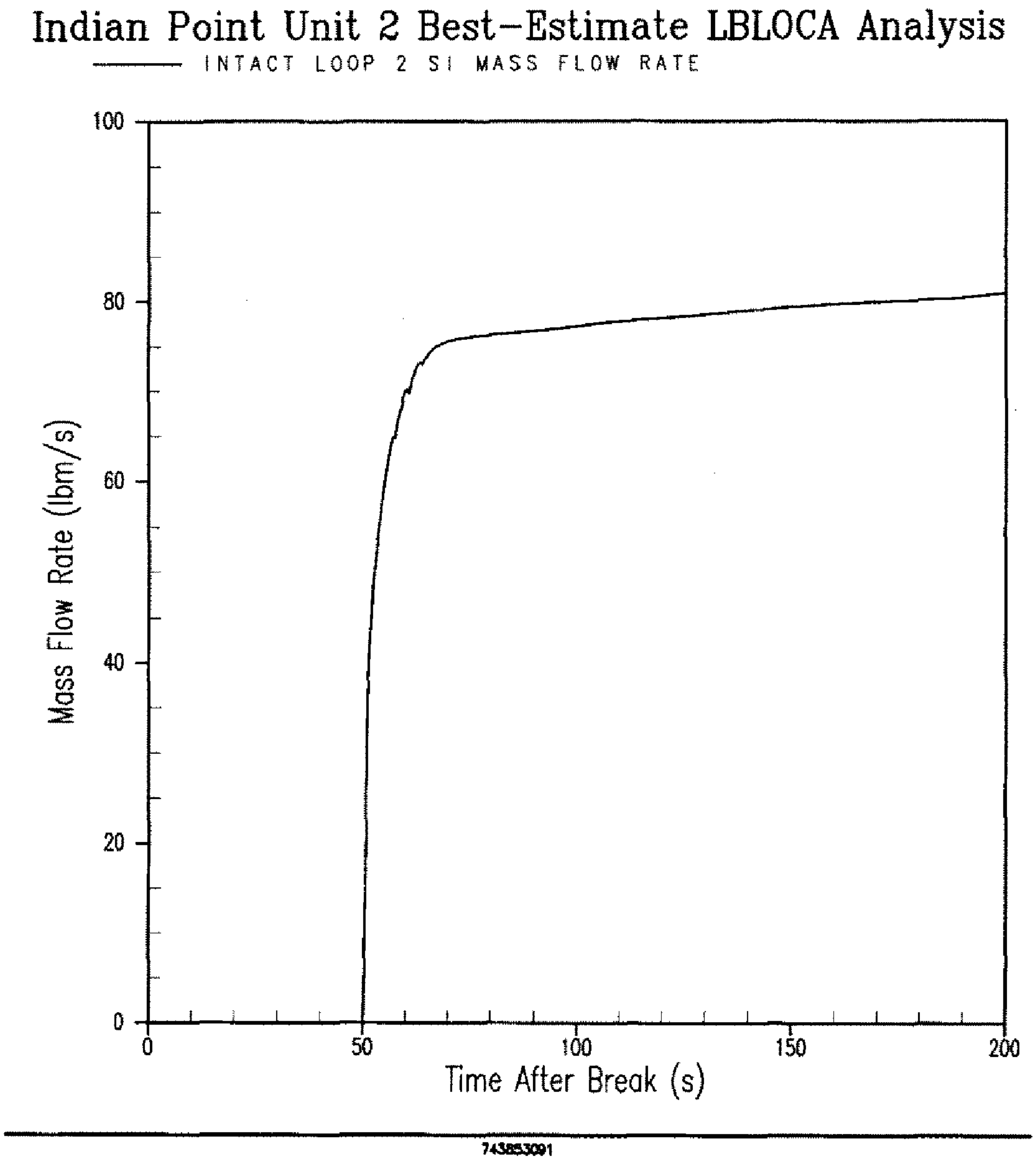


Figure 14.3-14: Intact Loop 2 Safety Injection Flow for Reference Transient

INDIAN POINT UNIT No. 2	
INTACT LOOP 2 SAFETY INJECTION FLOW FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-14	REV. No. 20

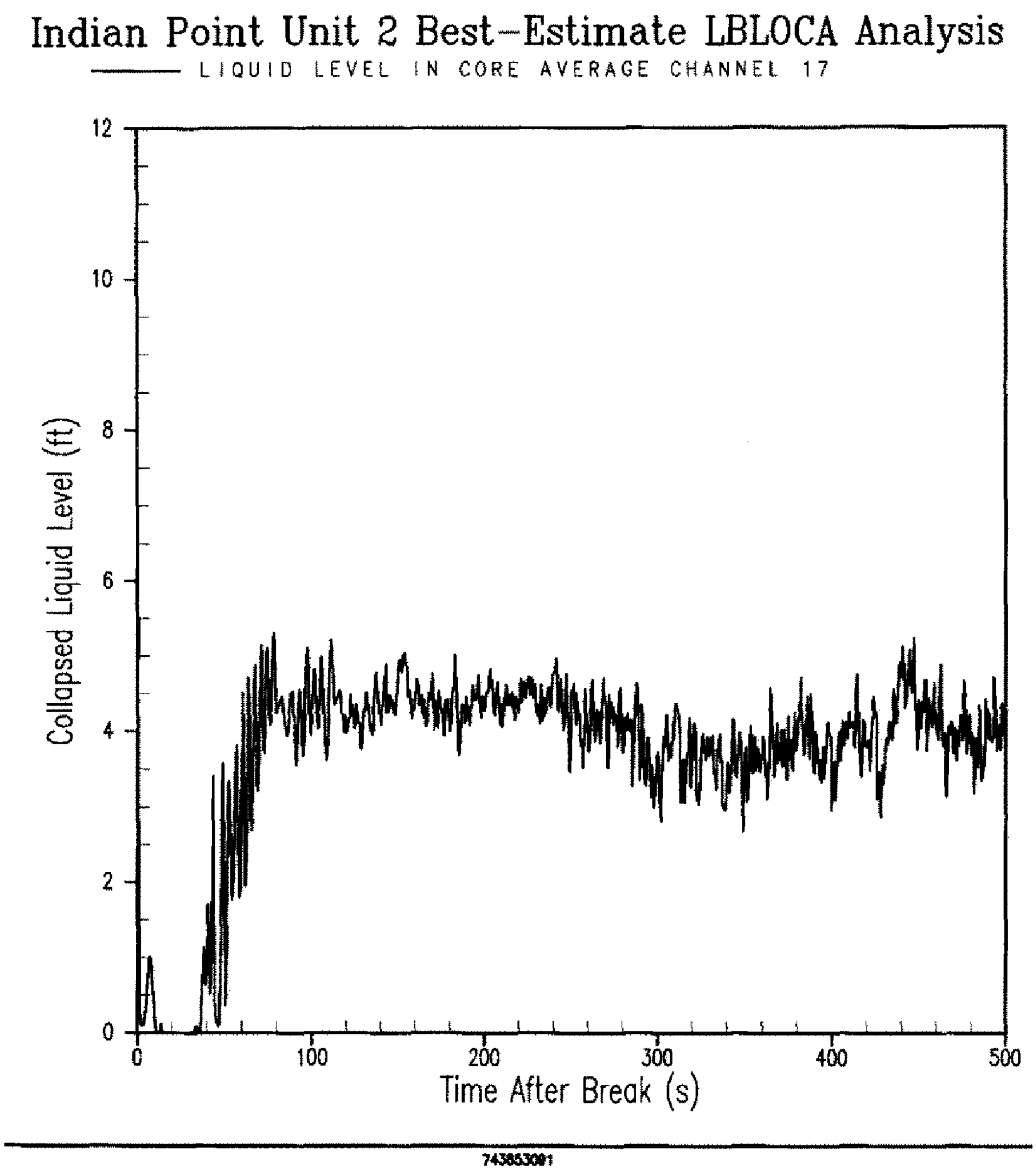


Figure 14.3-15: Collapsed Liquid Level in Core Average Channel 17 for Reference Transient

INDIAN POINT UNIT No. 2	
COLLAPSED LIQUID LEVEL IN CORE AVERAGE CHANNEL 17 FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-15	REV. No. 20

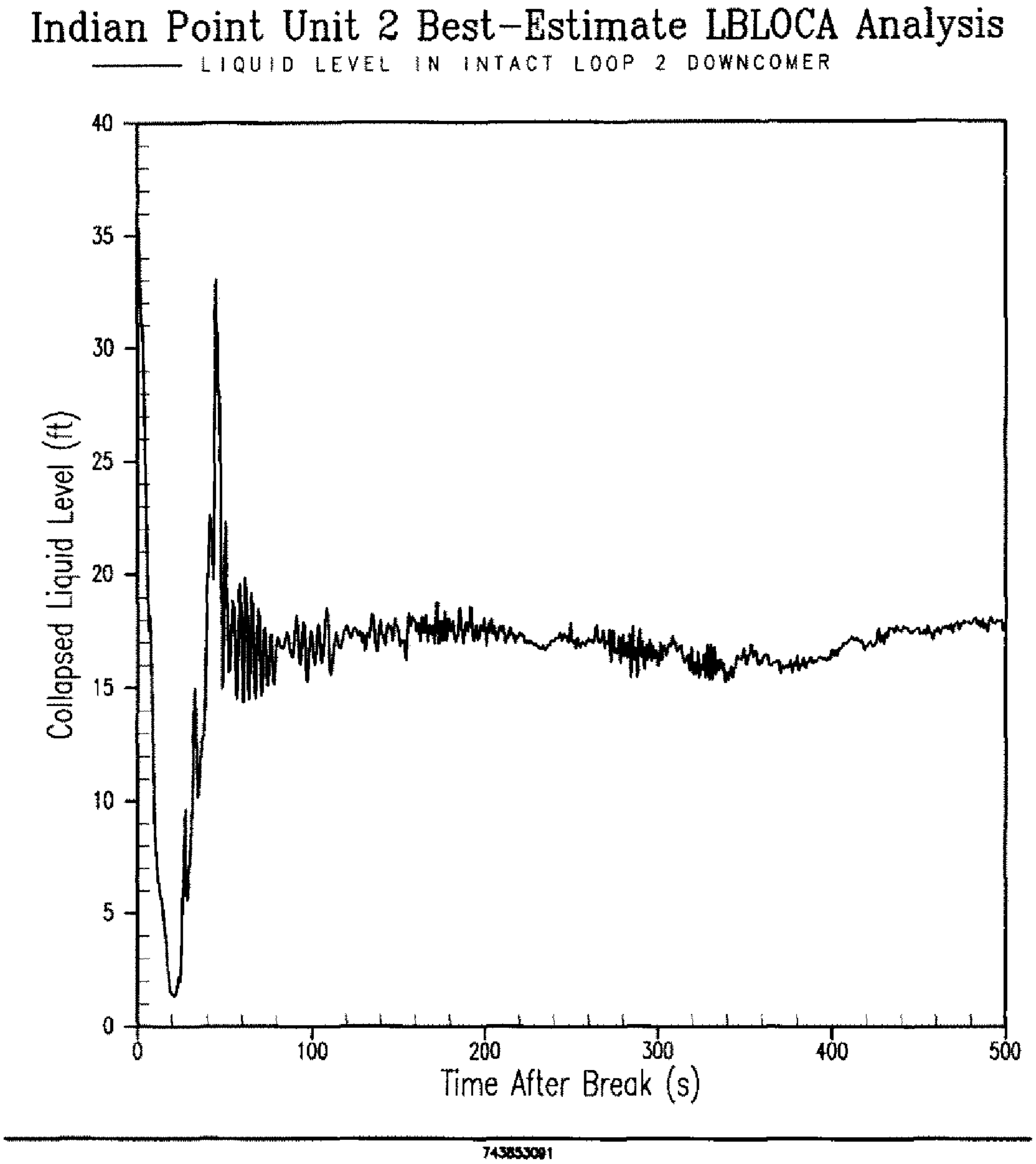


Figure 14.3-16: Collapsed Liquid Level in Intact Loop Downcomer for Reference Transient

INDIAN POINT UNIT No. 2	
COLLAPSED LIQUID LEVEL IN INTACT LOOP DOWNCOMER FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-16	REV. No. 20

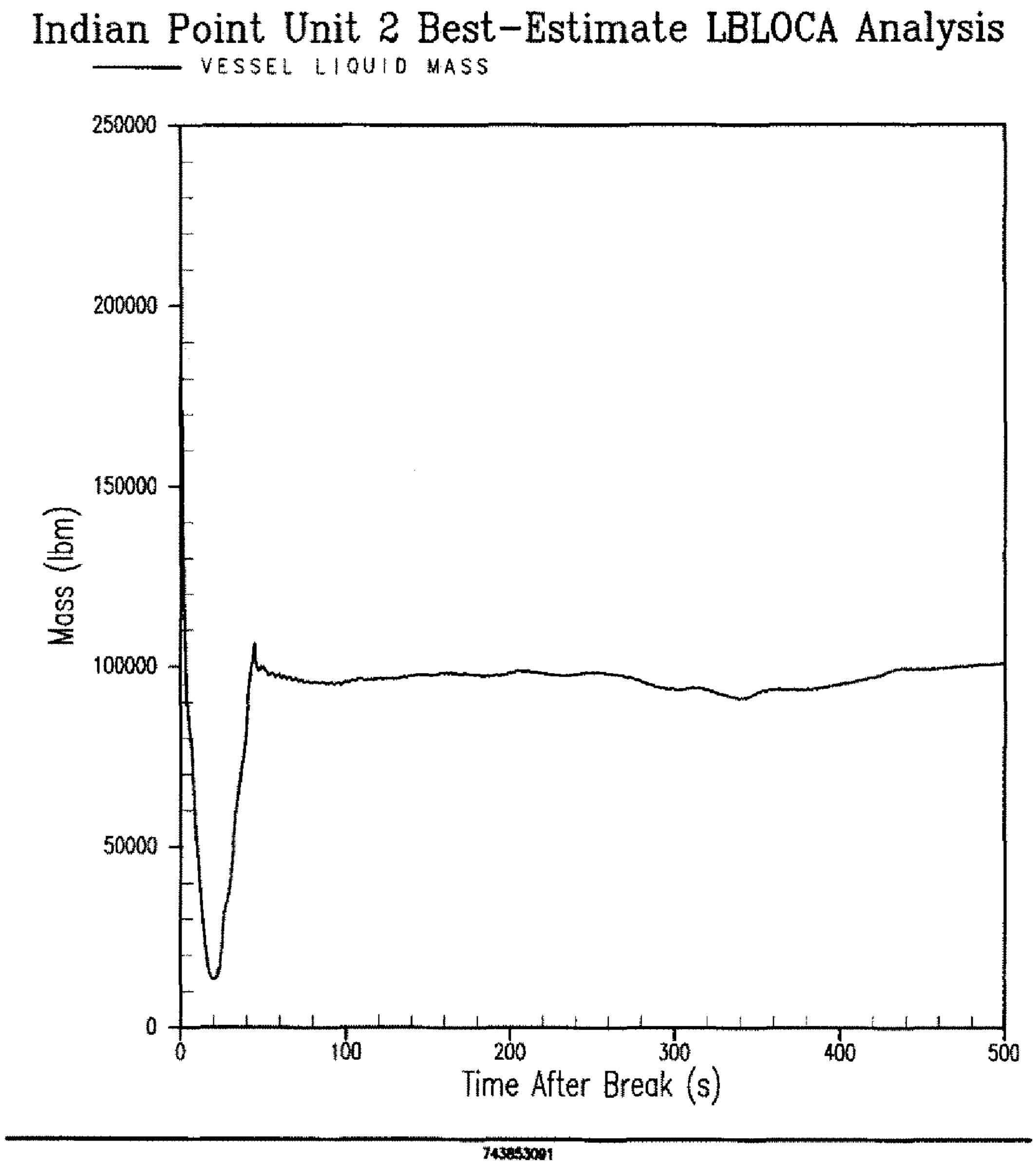
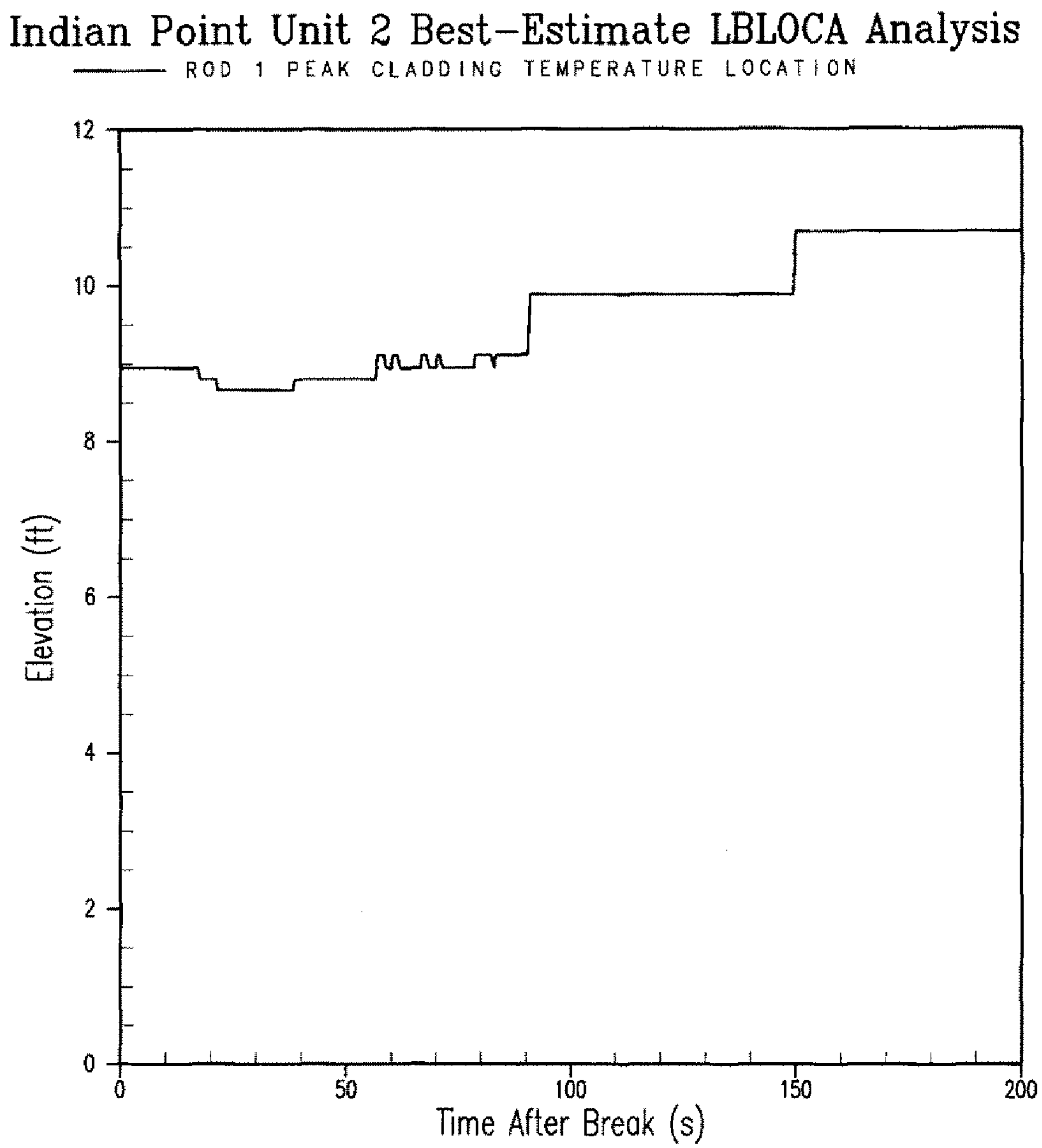


Figure 14.3-17: Vessel Fluid Mass for Reference Transient

INDIAN POINT UNIT No. 2	
VESSEL FLUID MASS FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-17	REV. No. 20



743853091

Figure 14.3-18: Peak Cladding Temperature Elevation for Reference Transient

INDIAN POINT UNIT No. 2	
PEAK CLADDING TEMPERATURE ELEVATION FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-18	REV. No. 20

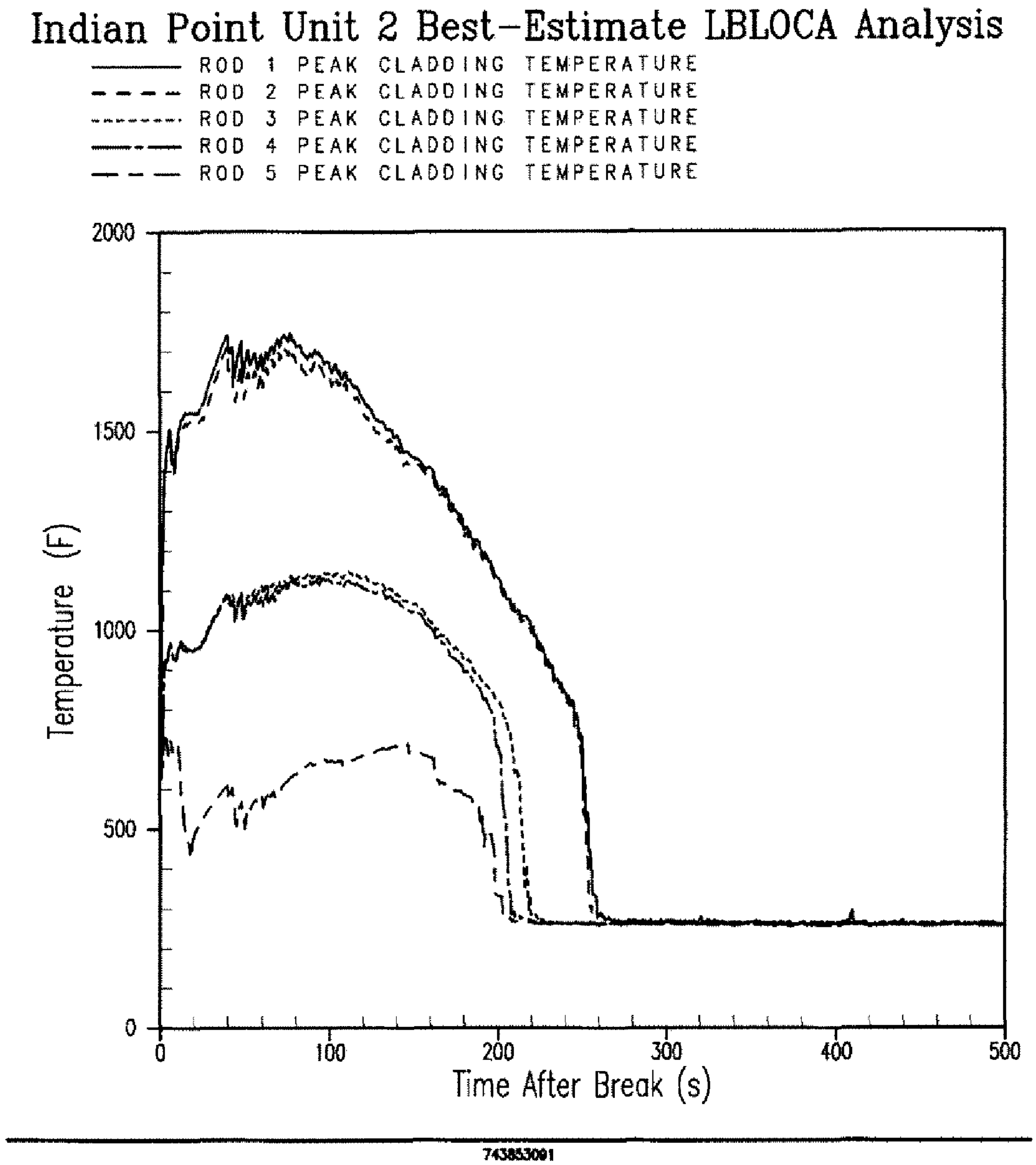
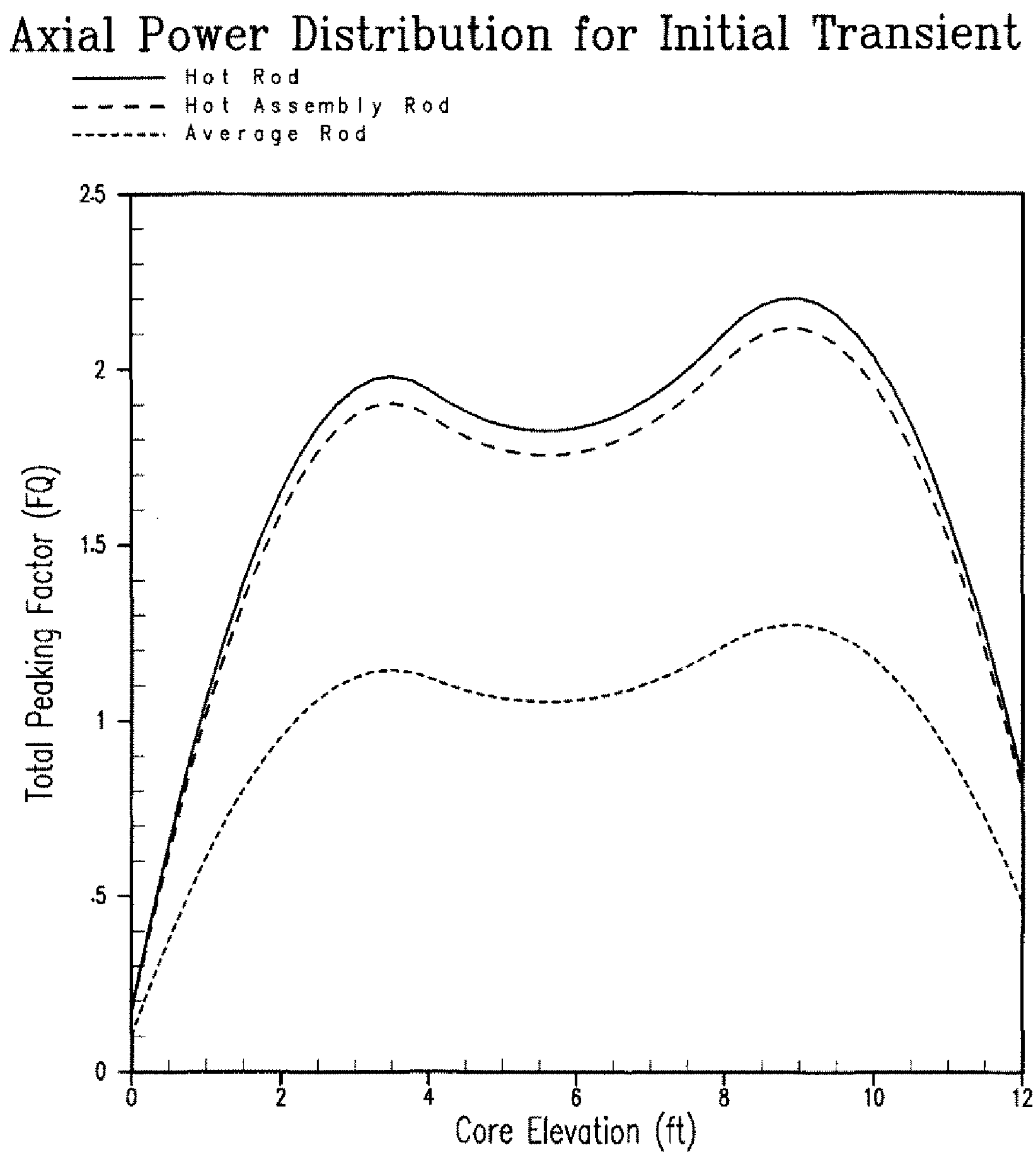


Figure 14.3-19: Peak Cladding Temperature Comparison for Five Rods for Reference Transient

INDIAN POINT UNIT No. 2	
PEAK CLADDING TEMPERATURE COMPARISON FOR FIVE RODS FOR REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-19	REV. No. 20



1896025569

Figure 14.3-20: Indian Point Unit 2 Axial Power Distribution for Initial and Reference Transient

INDIAN POINT UNIT No. 2	
INDIAN POINT UNIT 2 AXIAL POWER DISTRIBUTION FOR INITIAL AND REFERENCE TRANSIENT	
UFSAR FIGURE 14.3-20	REV. No. 20

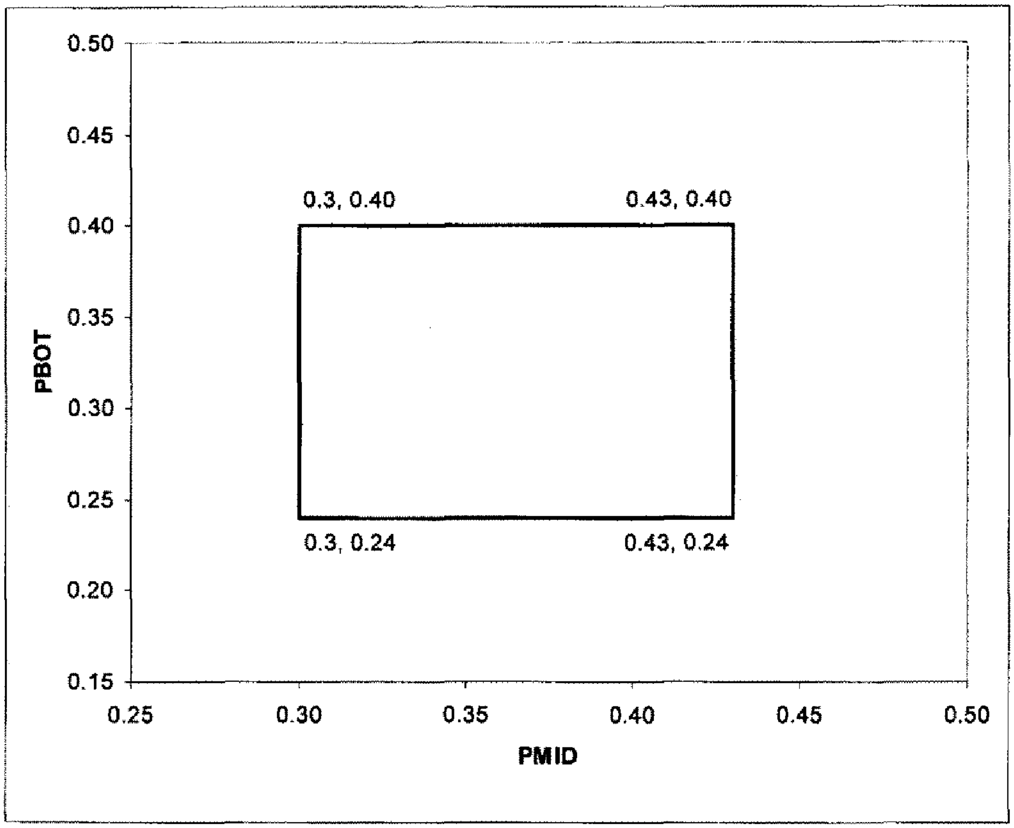
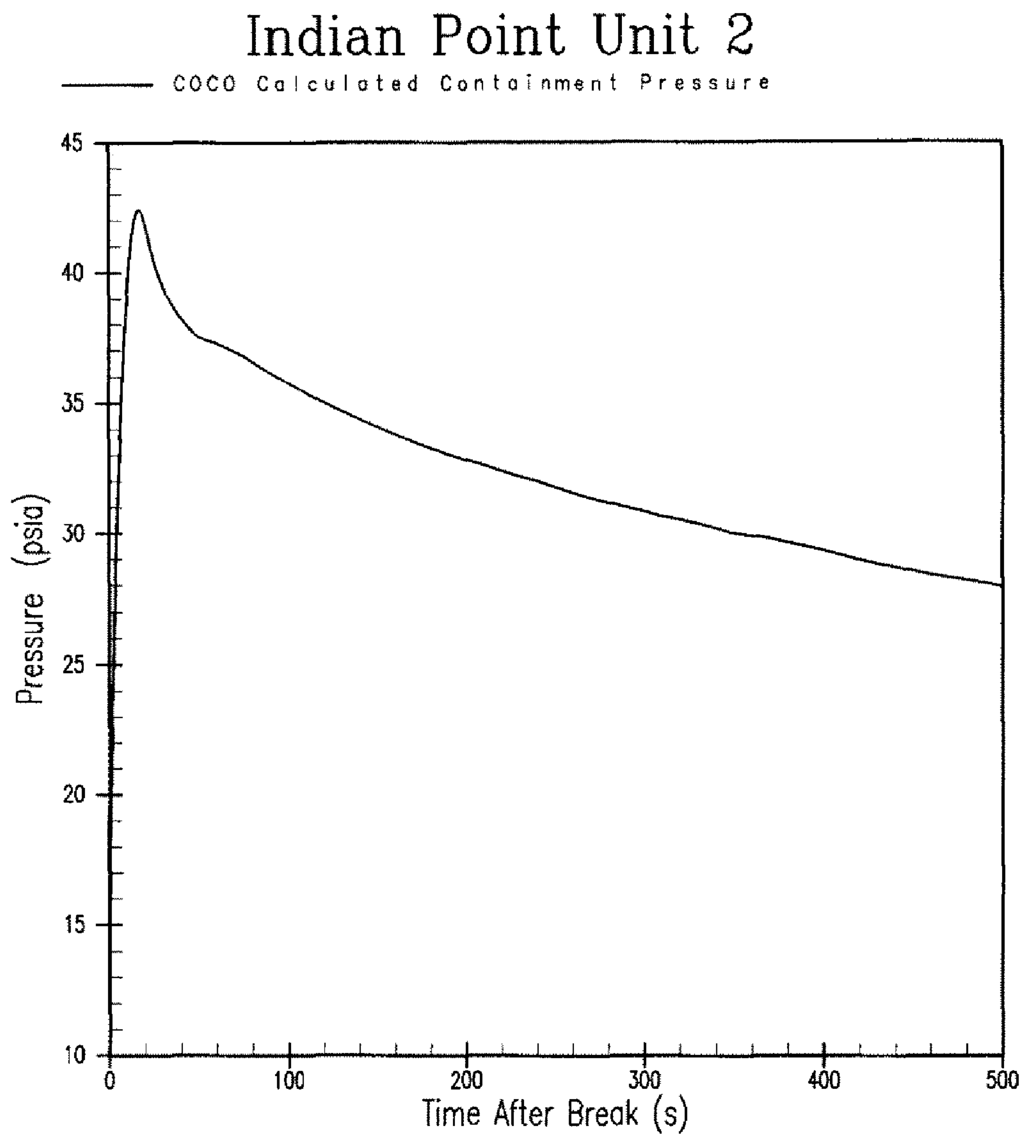


Figure 14.3-21: Indian Point Unit 2 PBOT/PMID Analysis and Operating Limits

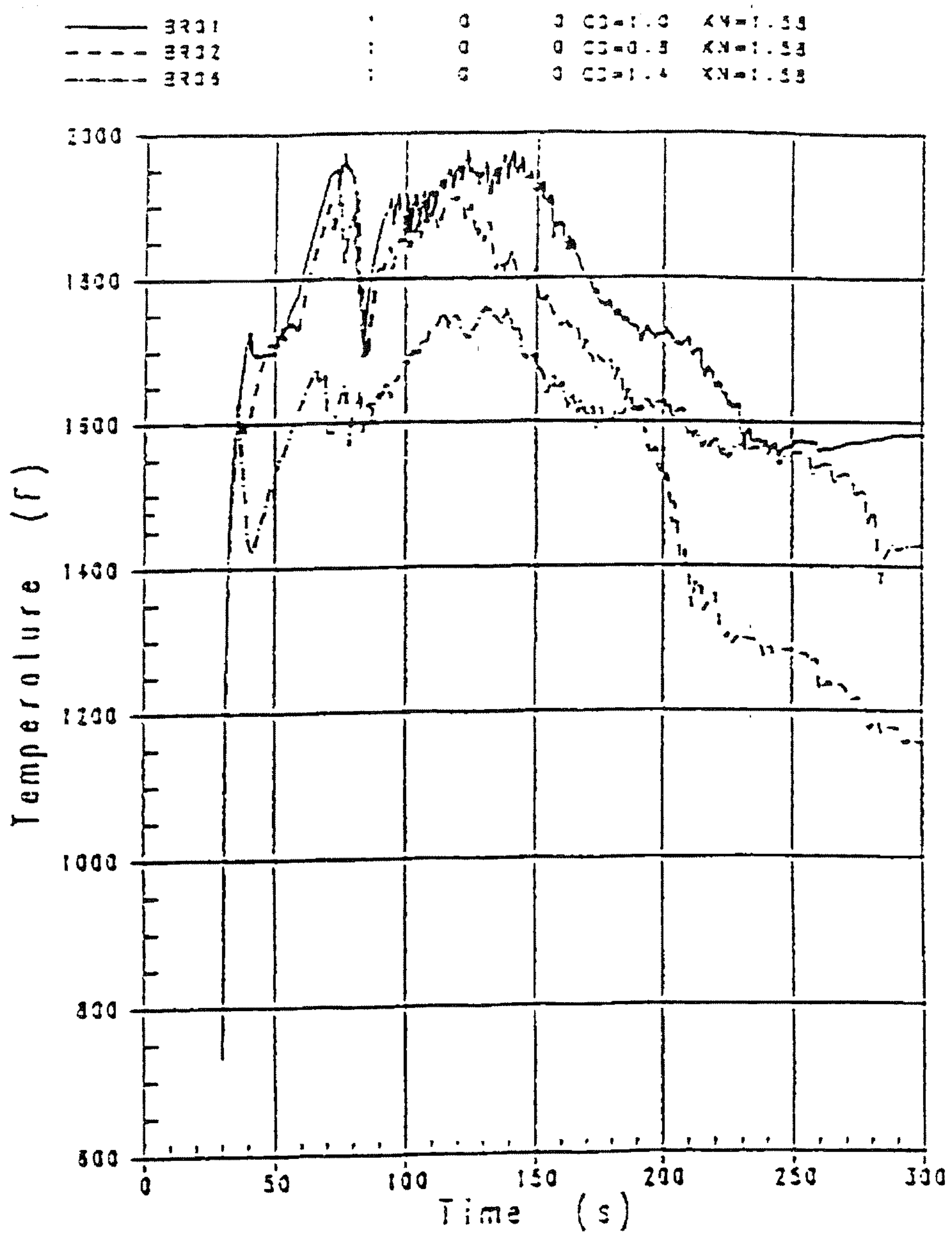
INDIAN POINT UNIT No. 2	
INDIAN POINT UNIT 2 PBOT/PMID ANALYSIS AND OPERATING LIMITS	
UFSAR FIGURE 14.3-21	REV. No. 20



1089352356

Figure 14.3-22: Indian Point Unit 2 Lower Bound COCO Calculated Containment Pressure

INDIAN POINT UNIT No. 2	
INDIAN POINT UNIT 2 LOWER BOUND COCO CALCULATED CONTAINMENT PRESSURE	
UFSAR FIGURE 14.3-22	REV. No. 20

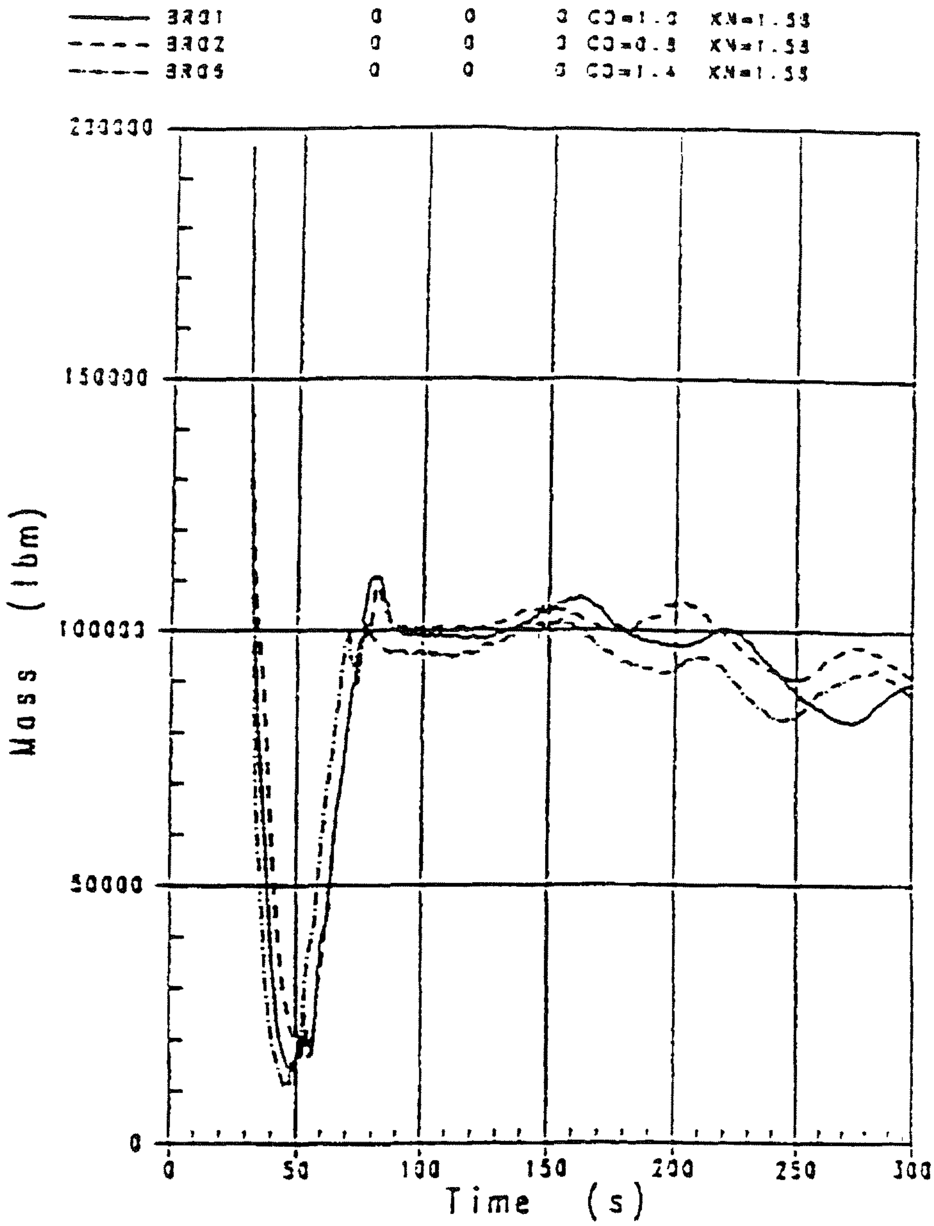


INDIAN POINT UNIT No. 2

UFSAR FIGURE 14.3–23

EFFECT OF VARYING CD,
WITH KN=1.58 AND XC=1.0 PCT
(RUN 1 vs. RUN 2 vs. RUN 6)

MIC. No. 2000MC4224	REV. No. 17A

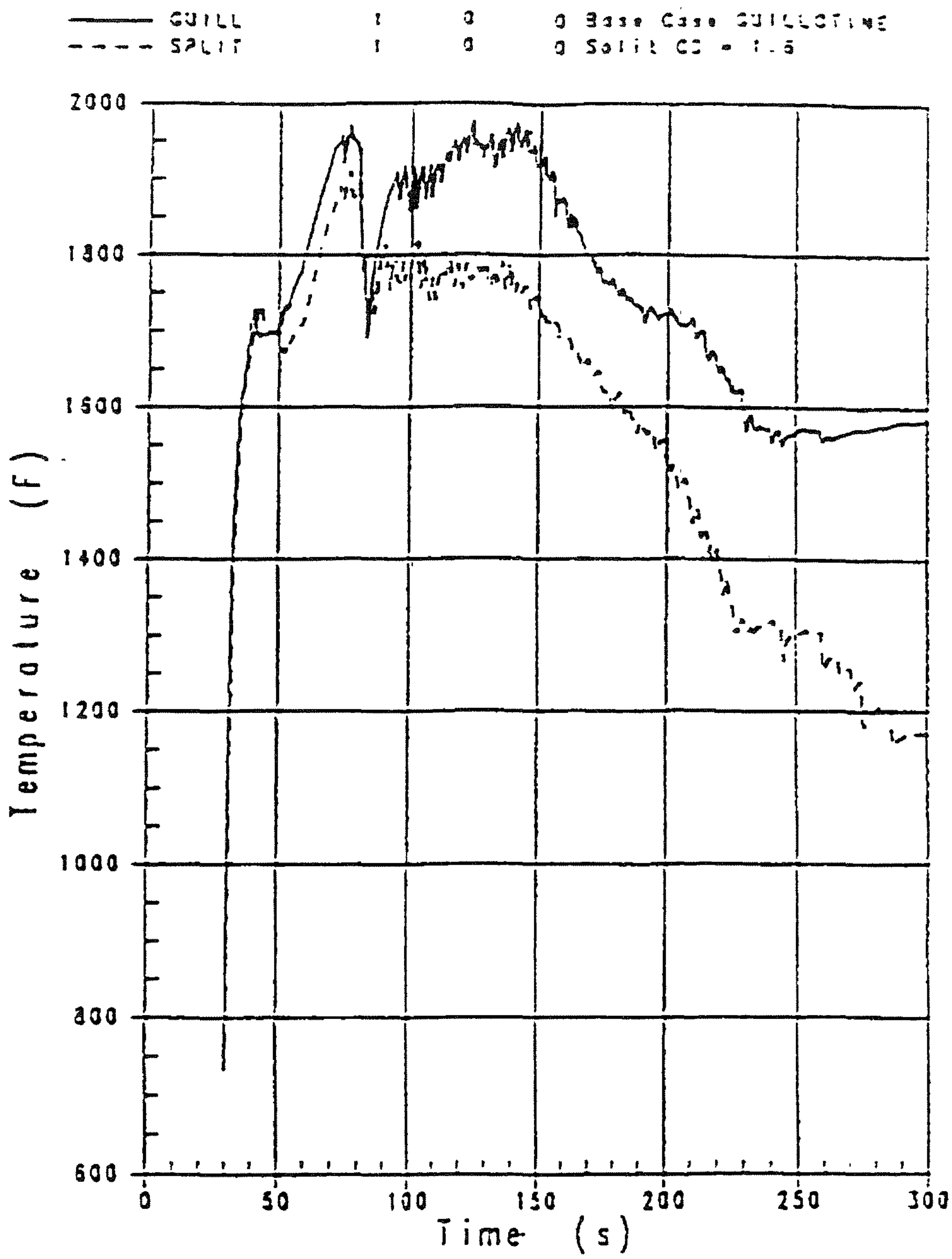


INDIAN POINT UNIT No. 2

UFSAR FIGURE 14.3-24

EFFECT OF VARYING CD, WITH KN=1.58 AND XC=1.0 VESSEL MASS (RUN 1 vs. RUN 2 vs. RUN 6)

MIC. No. 2000MC4225	REV. No. 17A

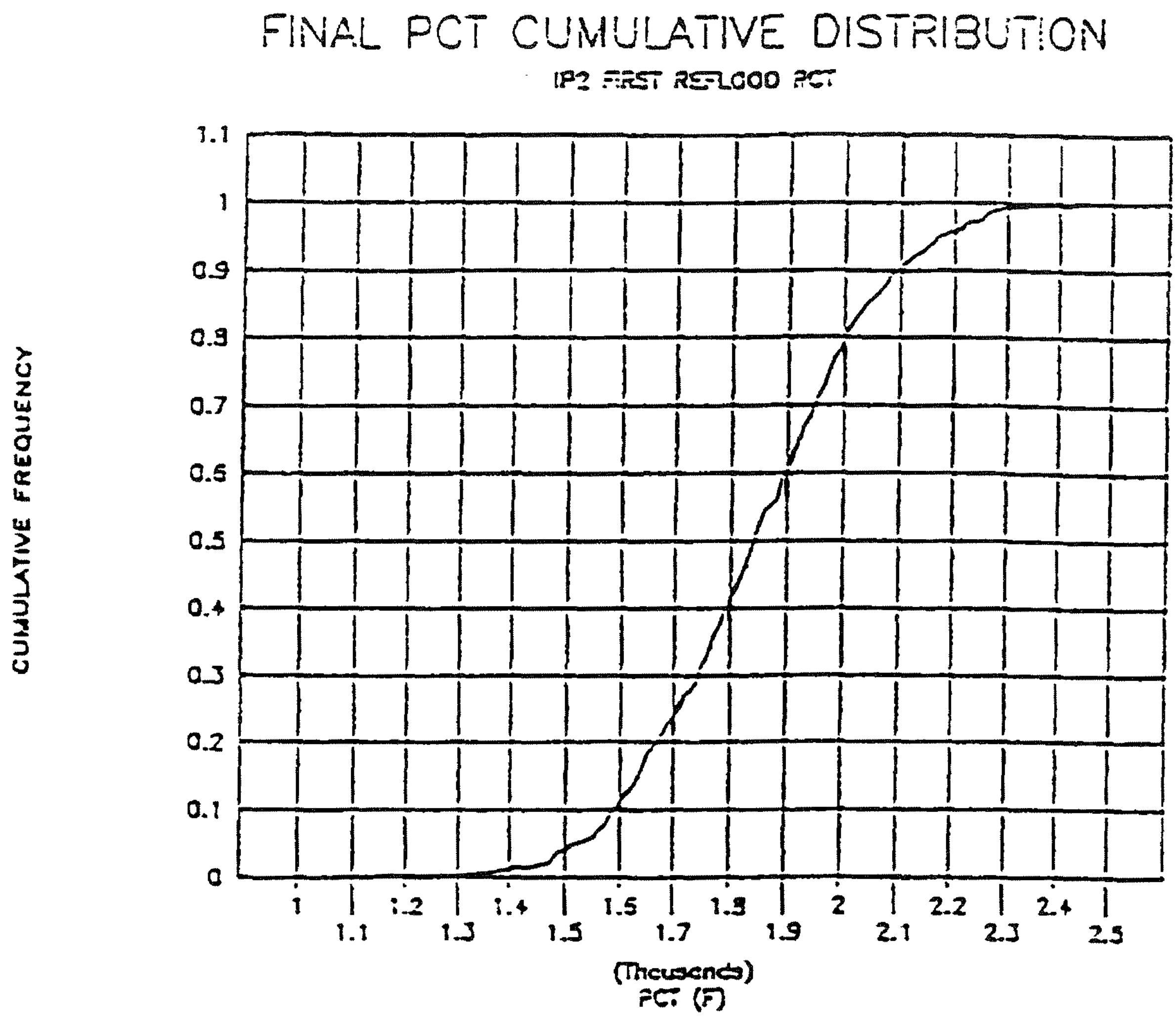


INDIAN POINT UNIT No. 2

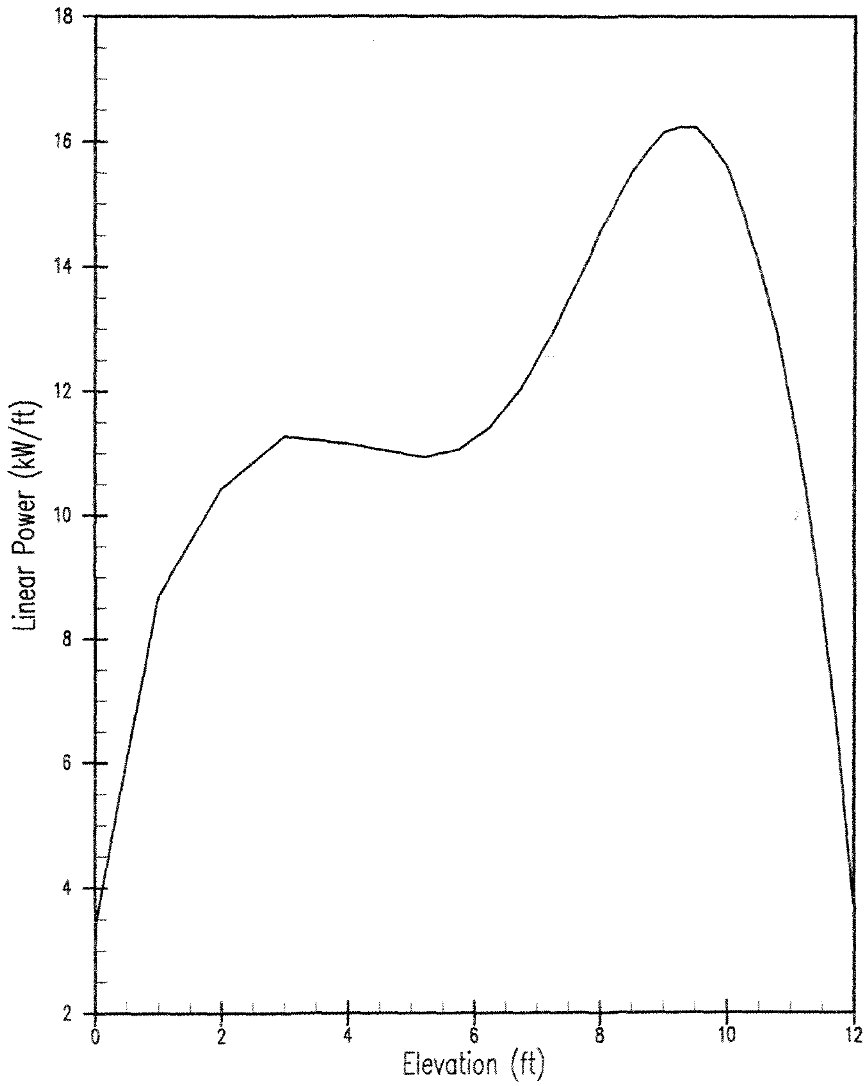
UFSAR FIGURE 14.3–25

COMPARISON BETWEEN REFERENCE GUILLOTINE BREAK AND LIMITING SPLIT BREAK

MIC. No. 2000MC4226	REV. No. 17A



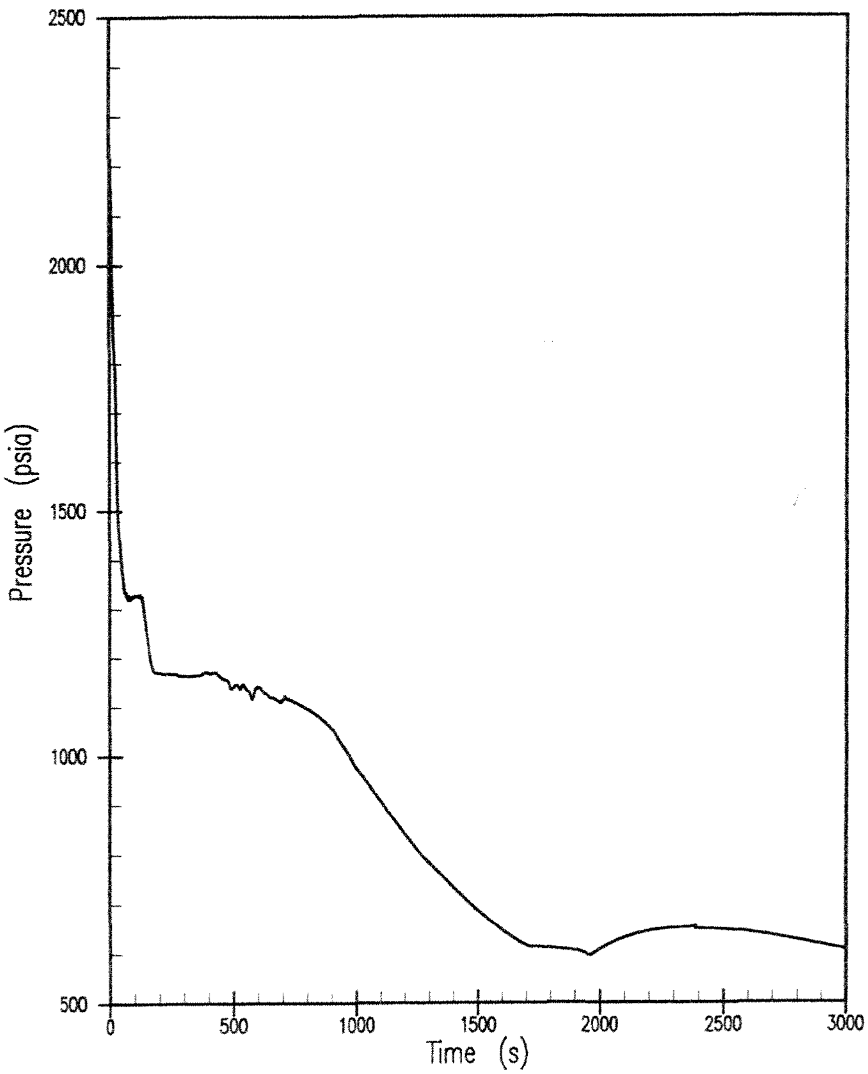
INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.3-26 PCT CUMULATIVE DISTRIBUTION- IP2 FIRST REFLOOD PCT	
MIC. No. 2000MC4227	REV. No. 17A



INDIAN POINT UNIT No. 2

SMALL BREAK LOCA
AXIAL POWER SHAPE

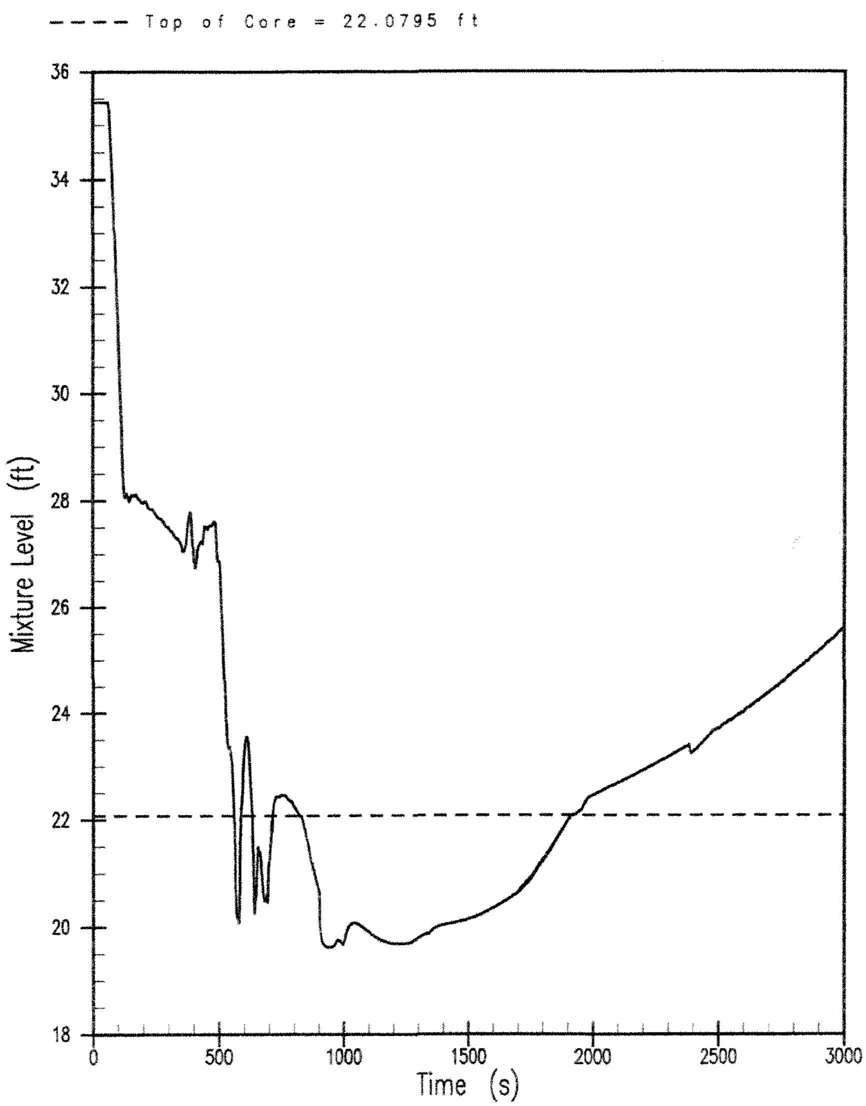
UFSAR FIGURE 14.3-53	REV. No. 19



INDIAN POINT UNIT No. 2

3.0" SMALL BREAK LOCA
RCS PRESSURE

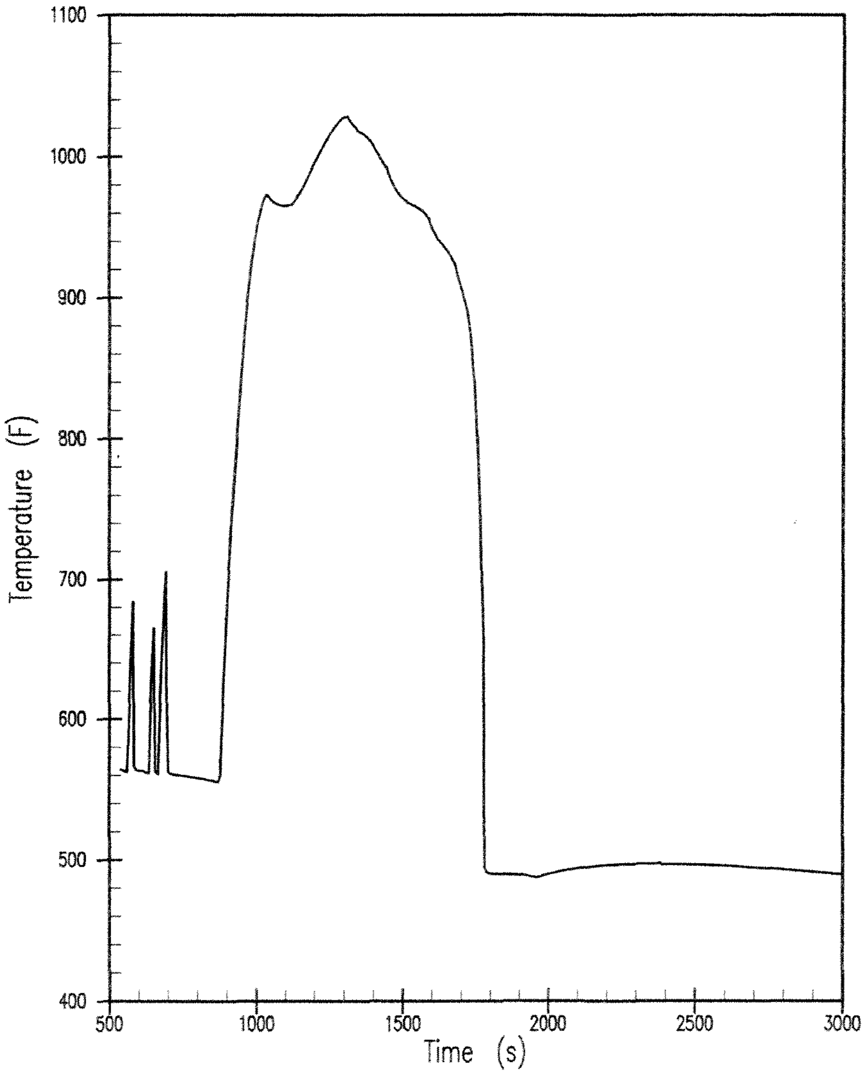
UFSAR FIGURE 14.3-54 | REV. No. 19



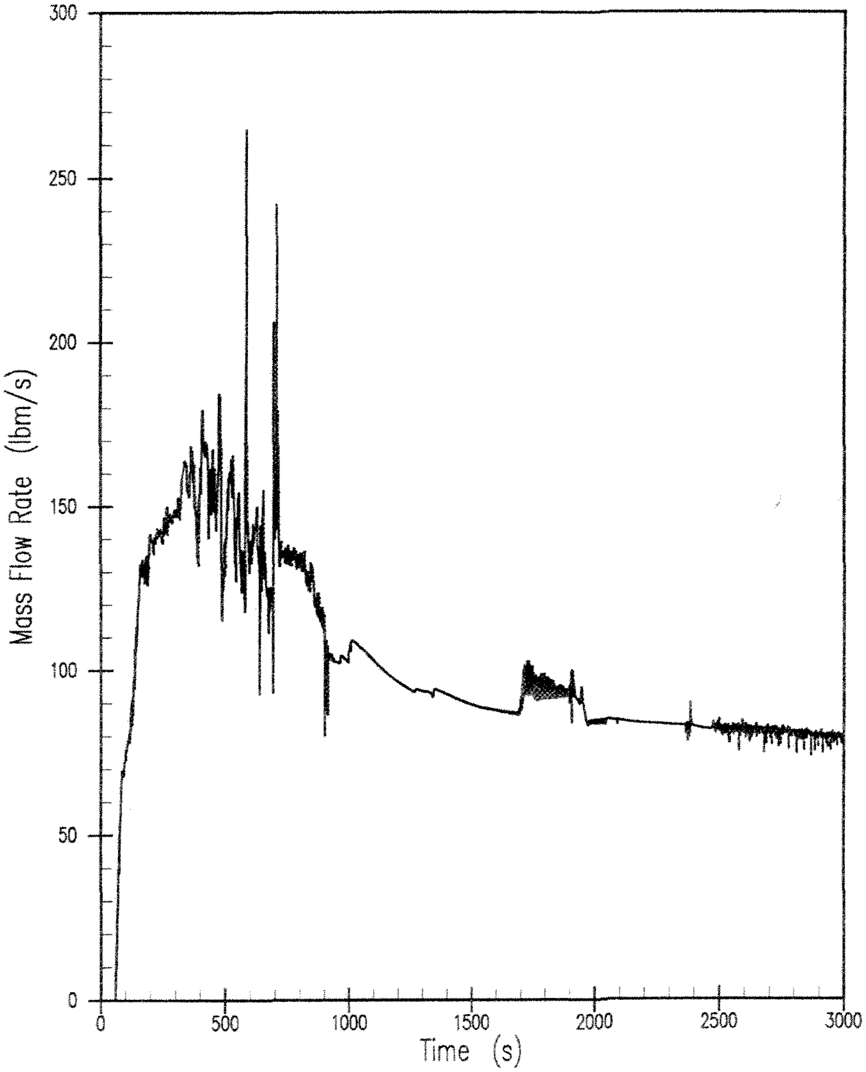
INDIAN POINT UNIT No. 2

3.0" SMALL BREAK LOCA
CORE MIXTURE LEVEL

UFSAR FIGURE 14.3-55	REV. No. 19



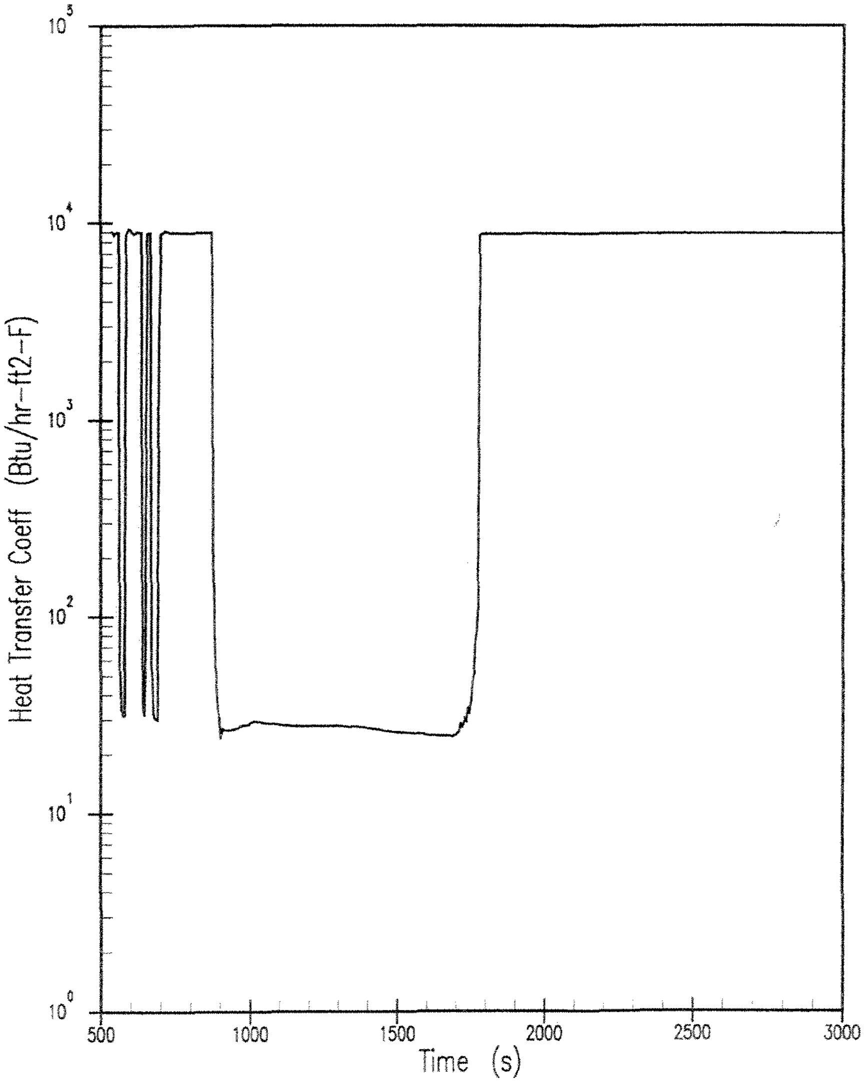
INDIAN POINT UNIT No. 2	
3.0" SMALL BREAK LOCA HOT ROD CLAD AVERAGE TEMPERATURE	
UFSAR FIGURE 14.3-56	REV. No. 19



INDIAN POINT UNIT No. 2

3.0" SMALL BREAK LOCA CORE OUTLET STEAM FLOW

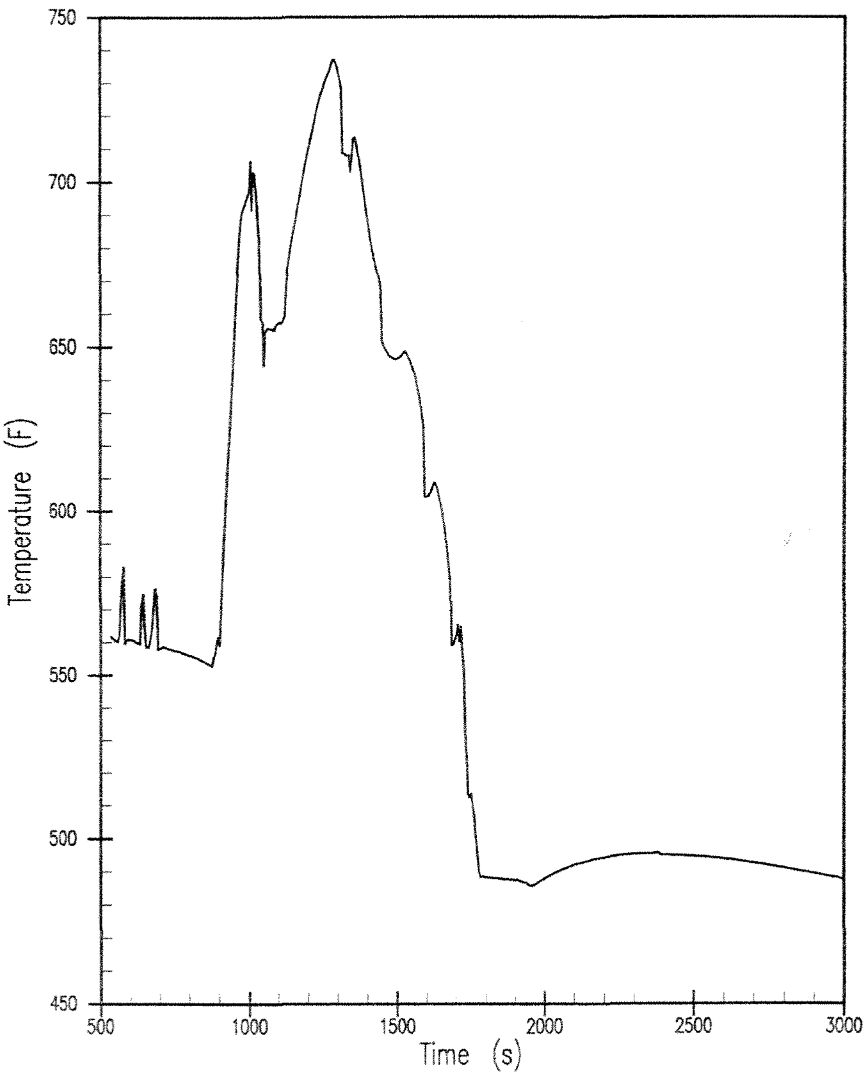
UFSAR FIGURE 14.3-57 | REV. No. 19



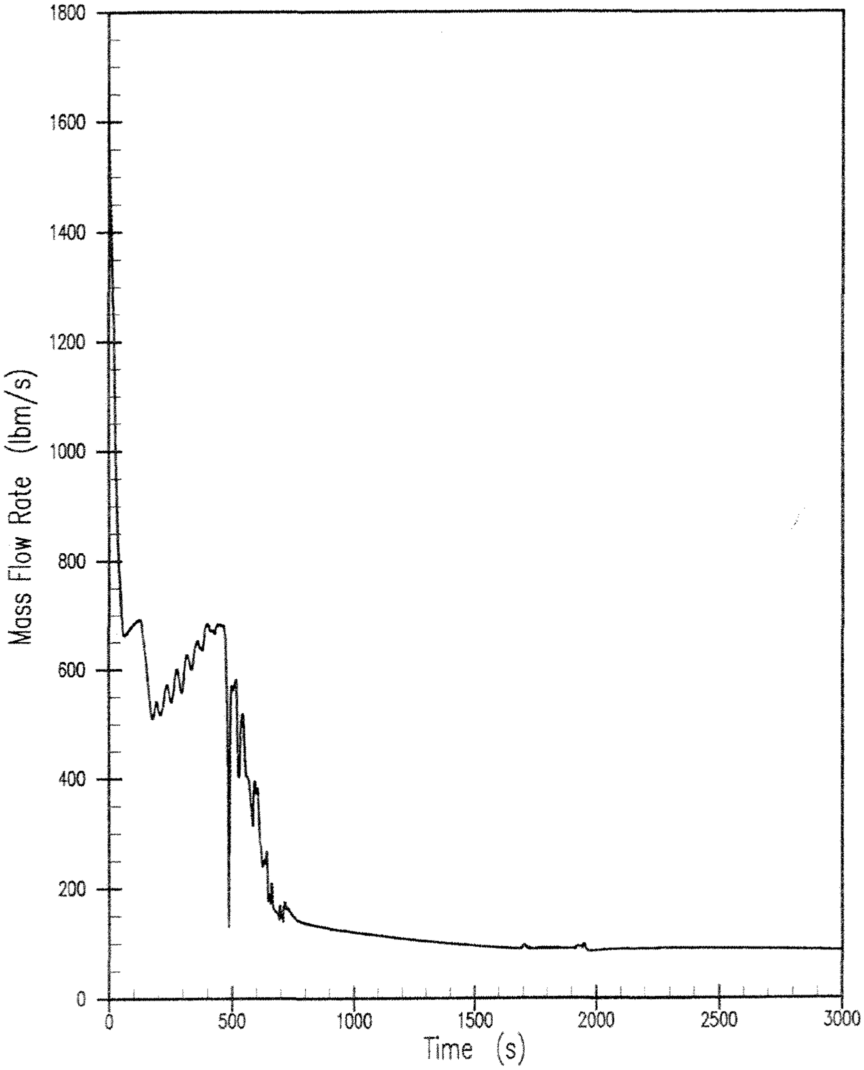
INDIAN POINT UNIT No. 2

3.0" SMALL BREAK LOCA
HEAT TRANSFER COEFFICIENT

UFSAR FIGURE 14.3-58 | REV. No. 19



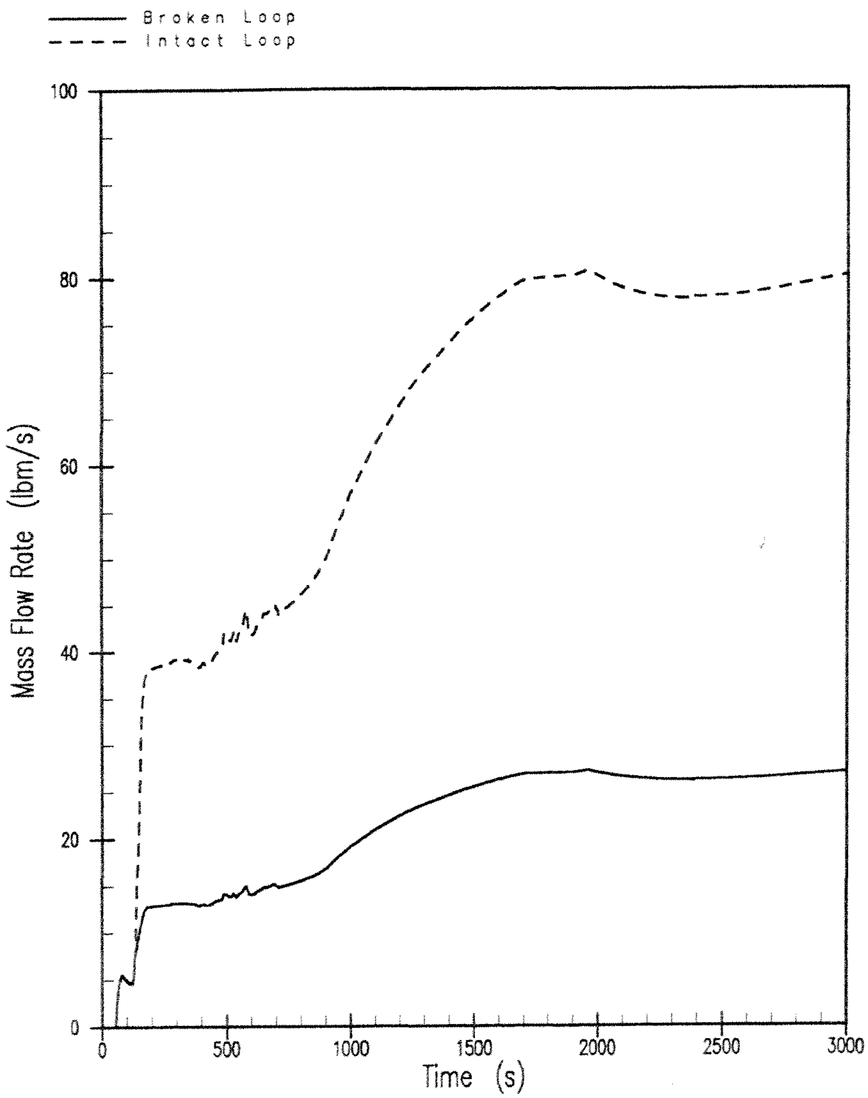
INDIAN POINT UNIT No. 2	
3.0" SMALL BREAK LOCA HOT SPOT FLUID TEMPERATURE	
UFSAR FIGURE 14.3-59	REV. No. 19



INDIAN POINT UNIT No. 2

3.0" SMALL BREAK LOCA
BREAK FLOW

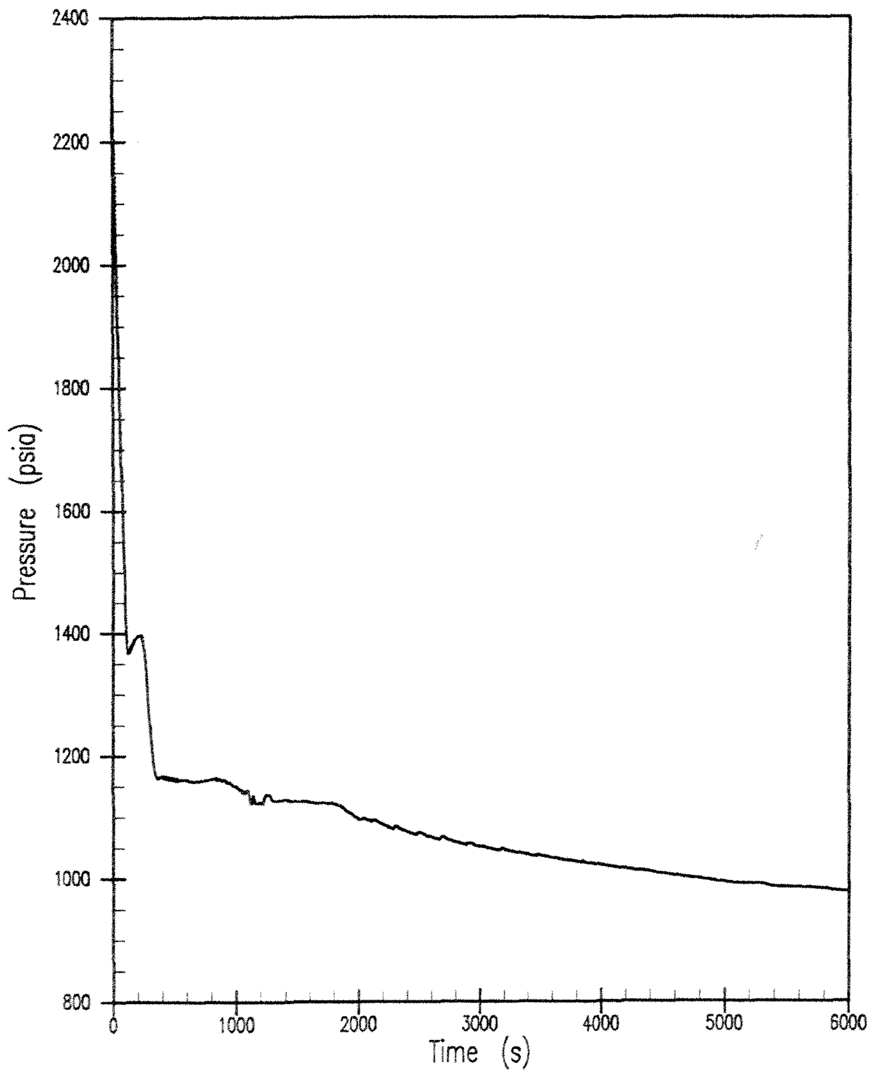
UFSAR FIGURE 14.3-60	REV. No. 19



INDIAN POINT UNIT No. 2

3.0" SMALL BREAK LOCA SAFETY INJECTION MASS FLOW RATE

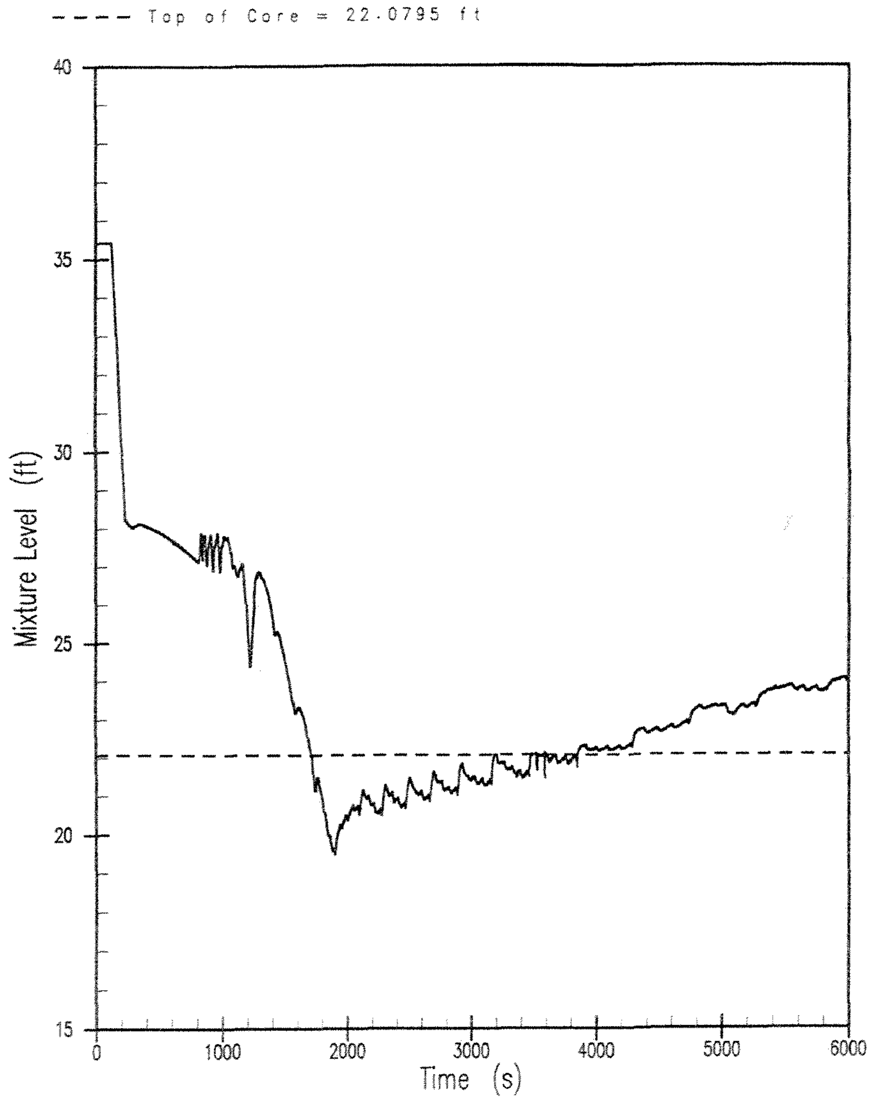
UFSAR FIGURE 14.3-61	REV. No. 19



INDIAN POINT UNIT No. 2

2.0" SMALL BREAK LOCA
RCS PRESSURE

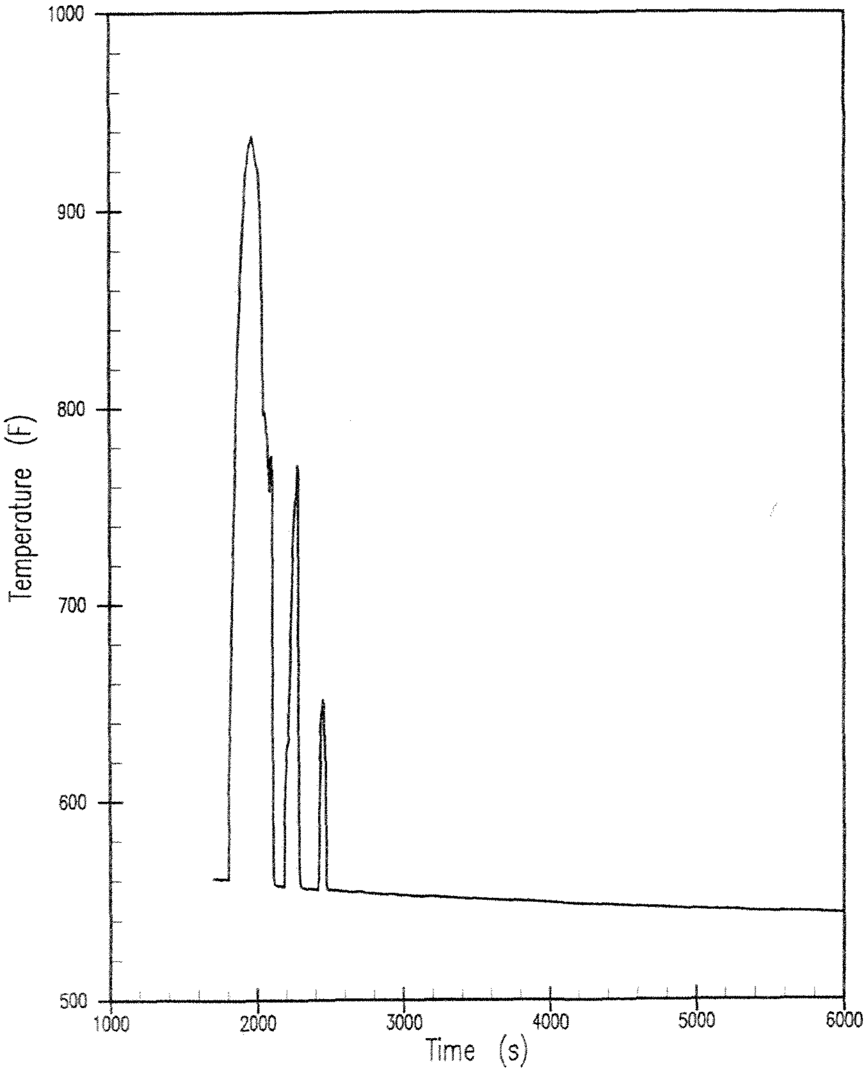
UFSAR FIGURE 14.3-62 | REV. No. 19



INDIAN POINT UNIT No. 2

2.0" SMALL BREAK LOCA
CORE MIXTURE LEVEL

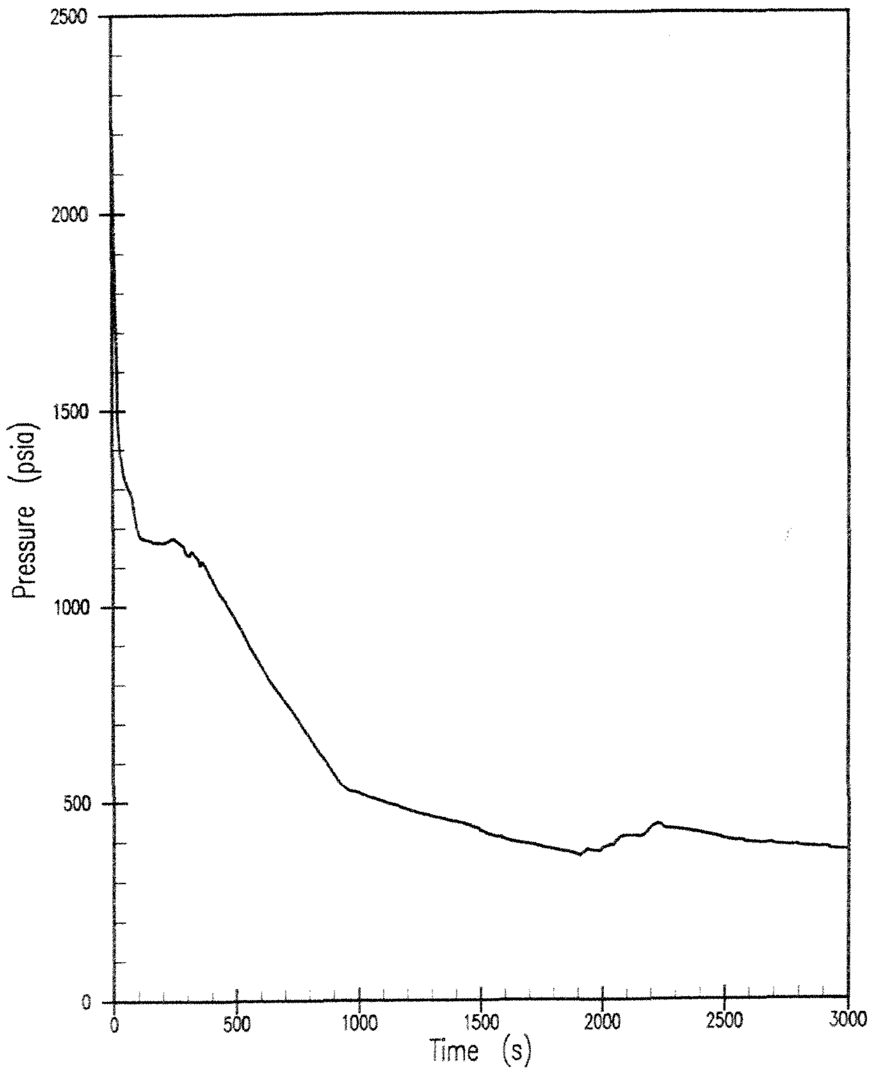
UFSAR FIGURE 14.3-63 | REV. No. 19



INDIAN POINT UNIT No. 2

2.0" SMALL BREAK LOCA HOT ROD
CLAD AVERAGE TEMPERATURE

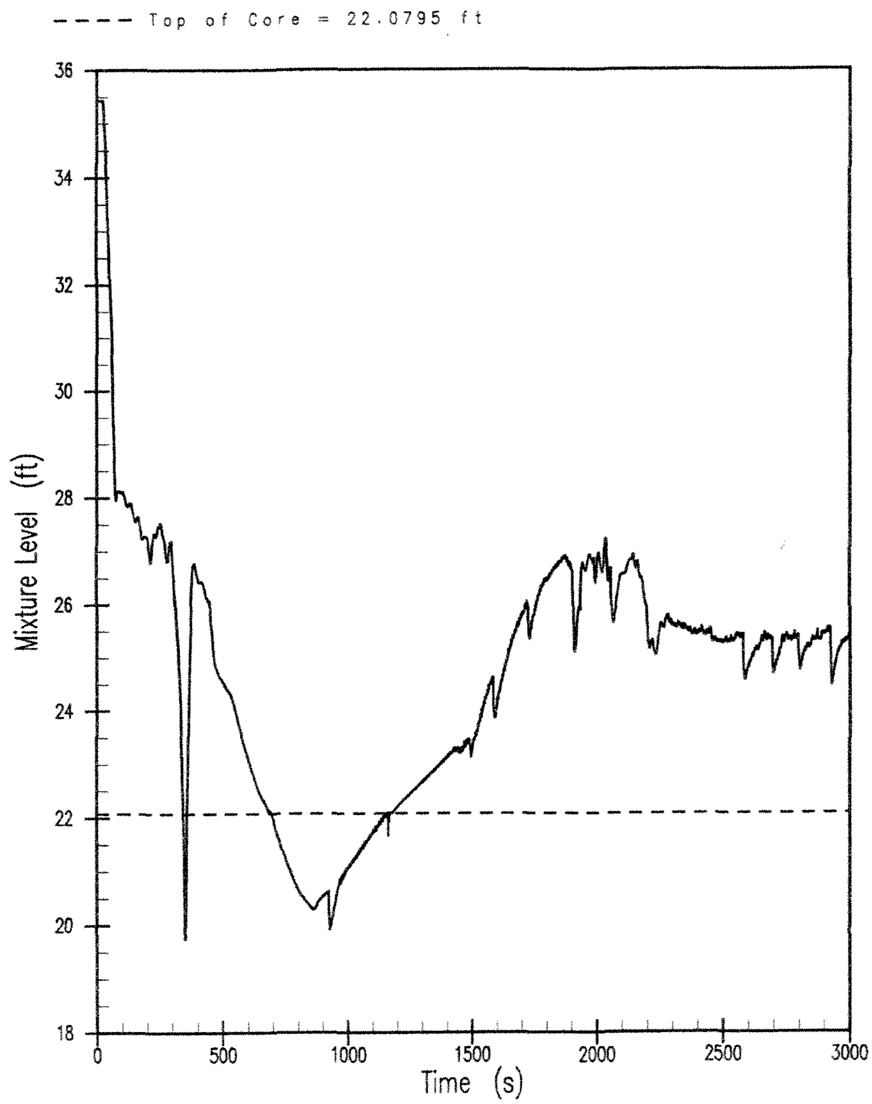
UFSAR FIGURE 14.3-64 | REV. No. 19



INDIAN POINT UNIT No. 2

4.0" SMALL BREAK LOCA
RCS PRESSURE

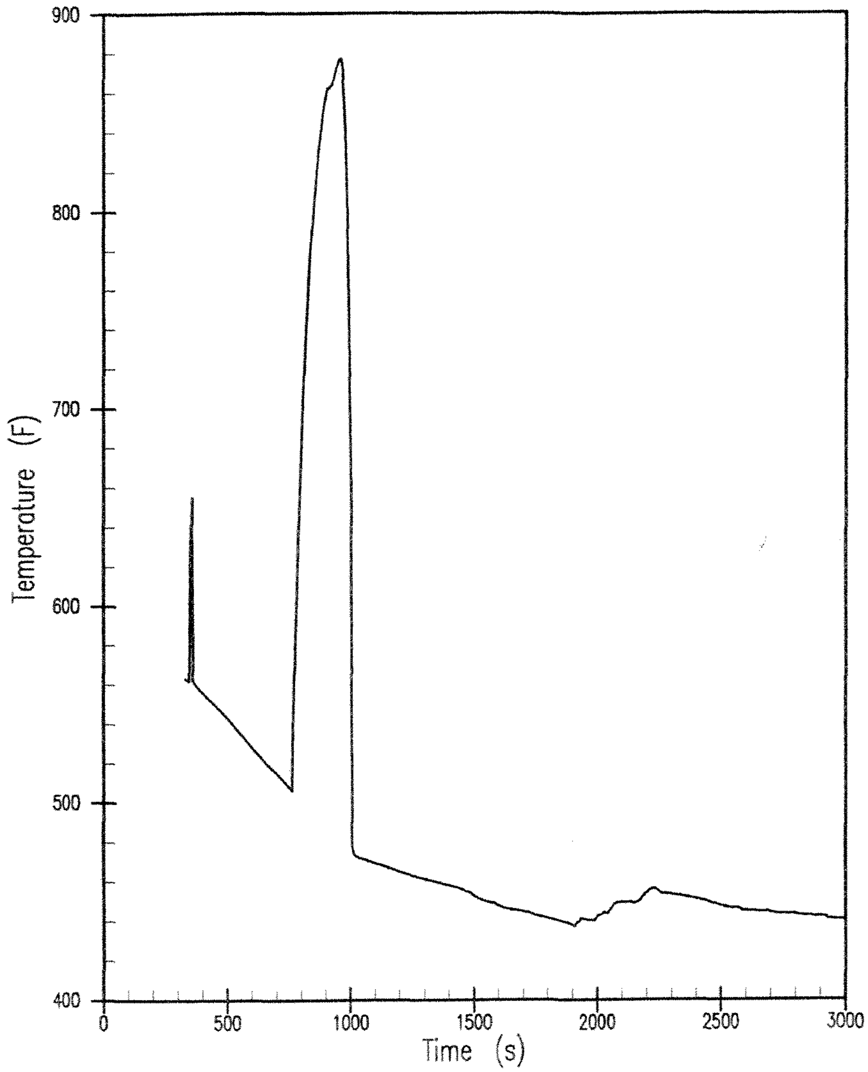
UFSAR FIGURE 14.3-65	REV. No. 19



INDIAN POINT UNIT No. 2

4.0" SMALL BREAK LOCA
CORE MIXTURE LEVEL

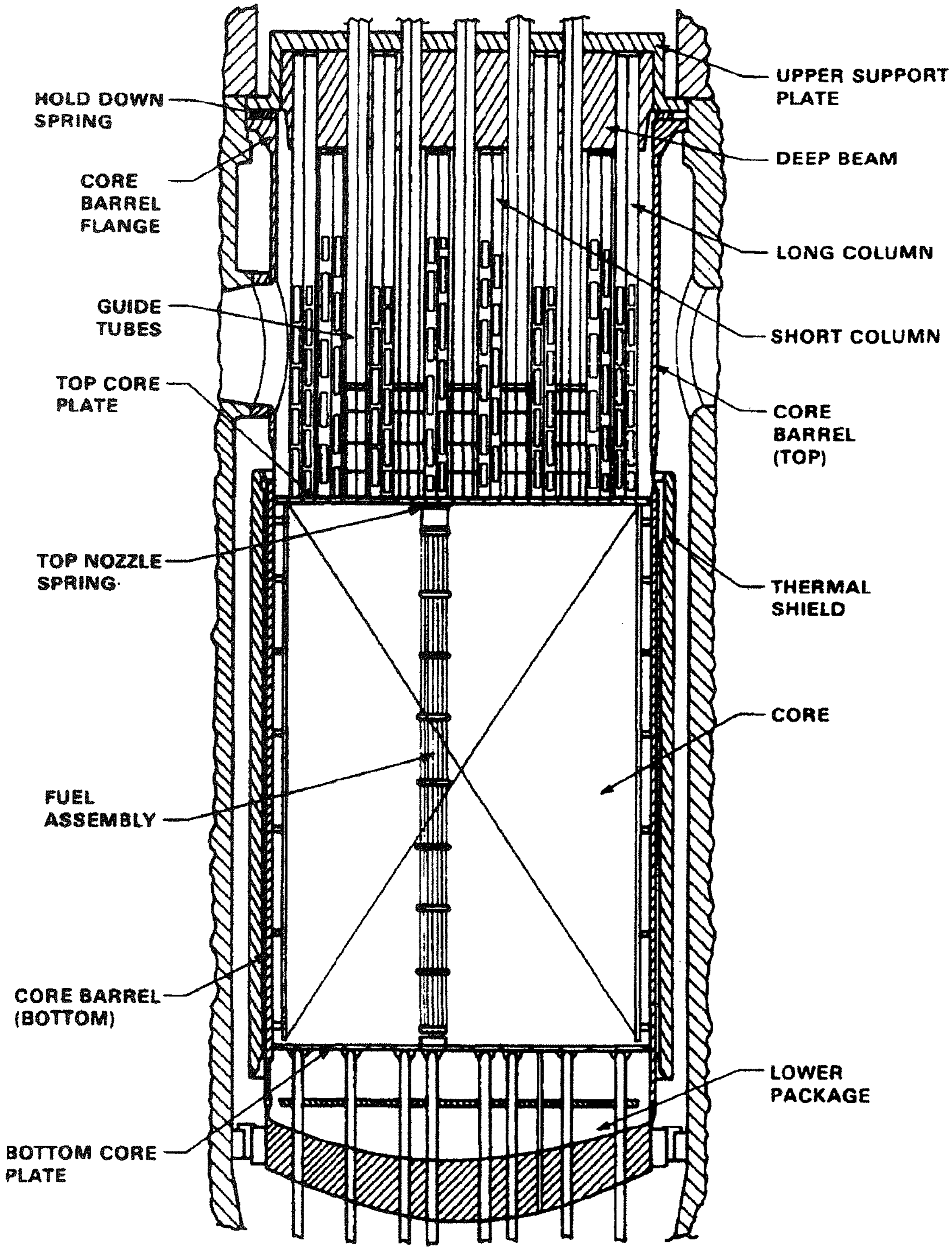
UFSAR FIGURE 14.3-66	REV. No. 19



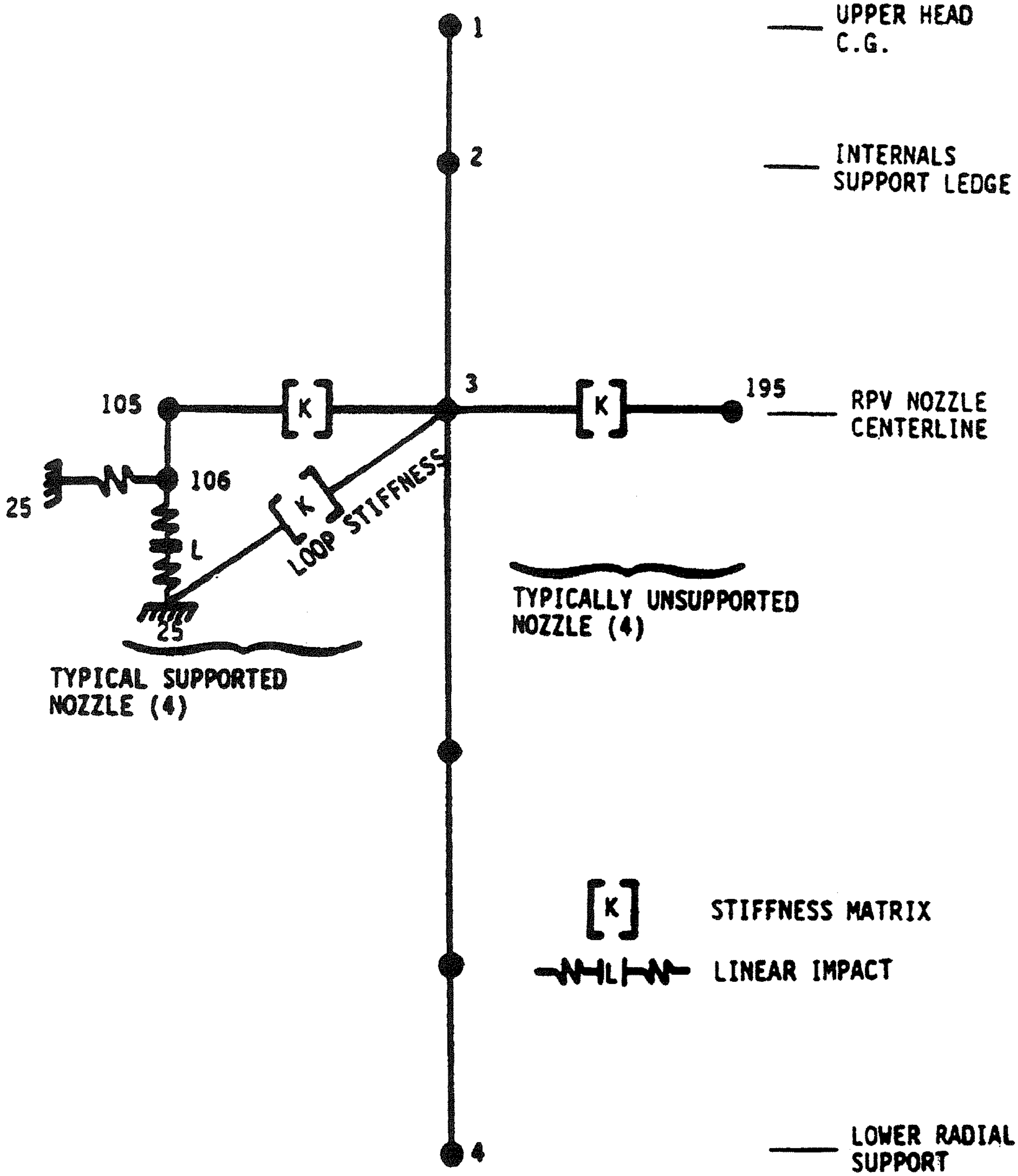
INDIAN POINT UNIT No. 2

4.0" SMALL BREAK LOCA HOT ROD CLAD AVERAGE TEMPERATURE

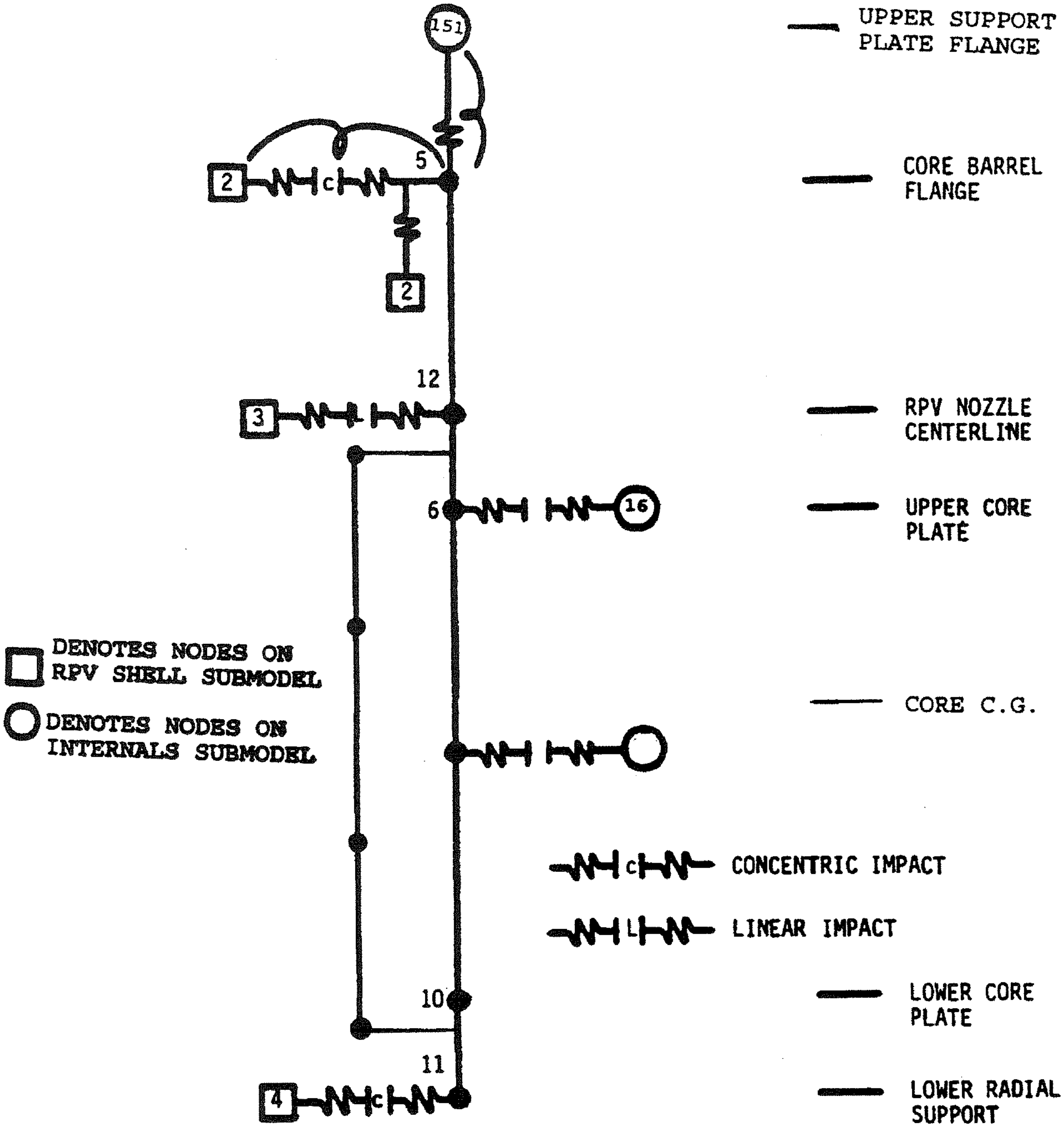
UFSAR FIGURE 14.3-67	REV. No. 19



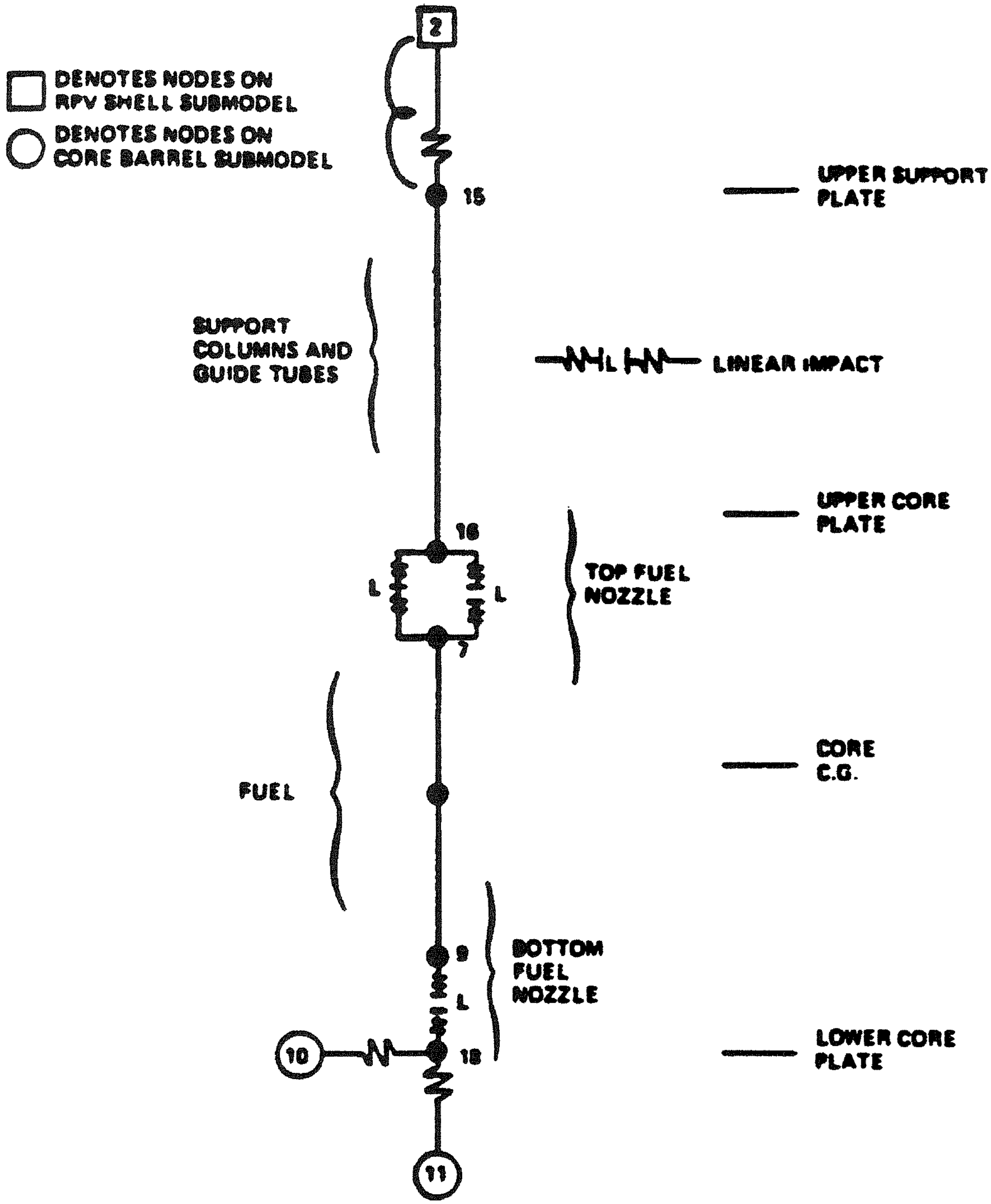
INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.3-101 REACTOR VESSEL INTERNALS	
MIC. No. 2000MC4300	REV. No. 17A



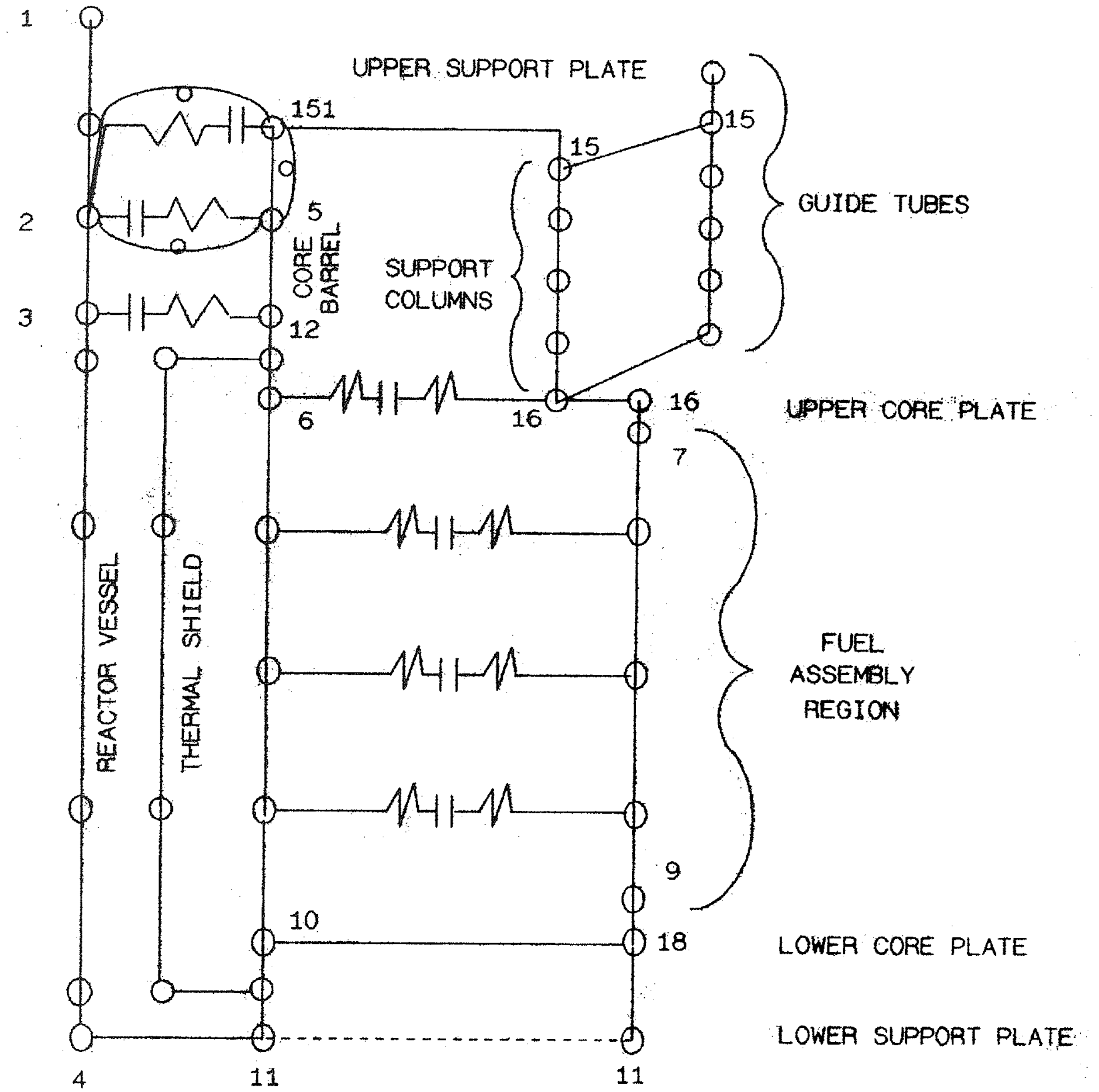
INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.3–102 RPV SHELL AND SUPPORT SYSTEM	
MIC. No. 2000MC4301	REV. No. 17A



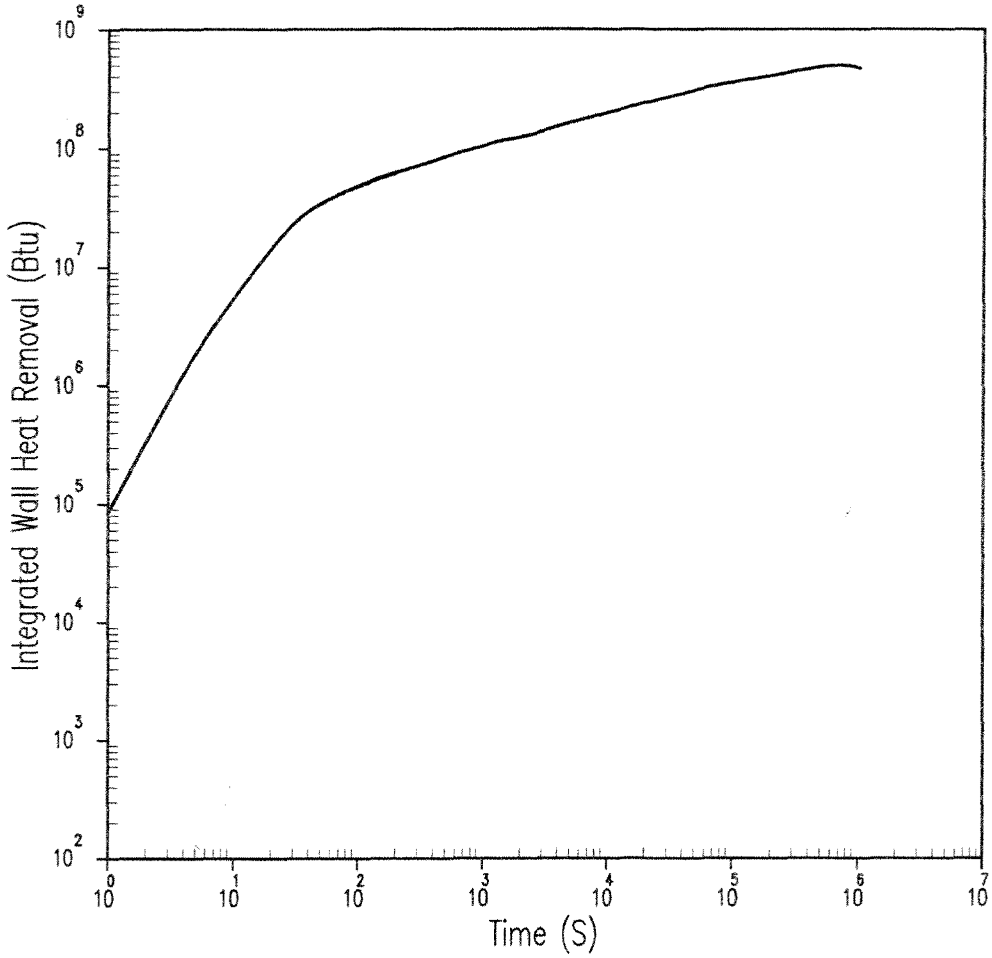
INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.3–103A REACTOR VESSEL INTERNALS CORE BARREL ASSEMBLY	
MIC. No. 2001MB1166	REV. No. 17A



INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.3–103B REACTOR INTERNALS AND FUEL	
MIC. No. 2001MB1167	REV. No. 17A



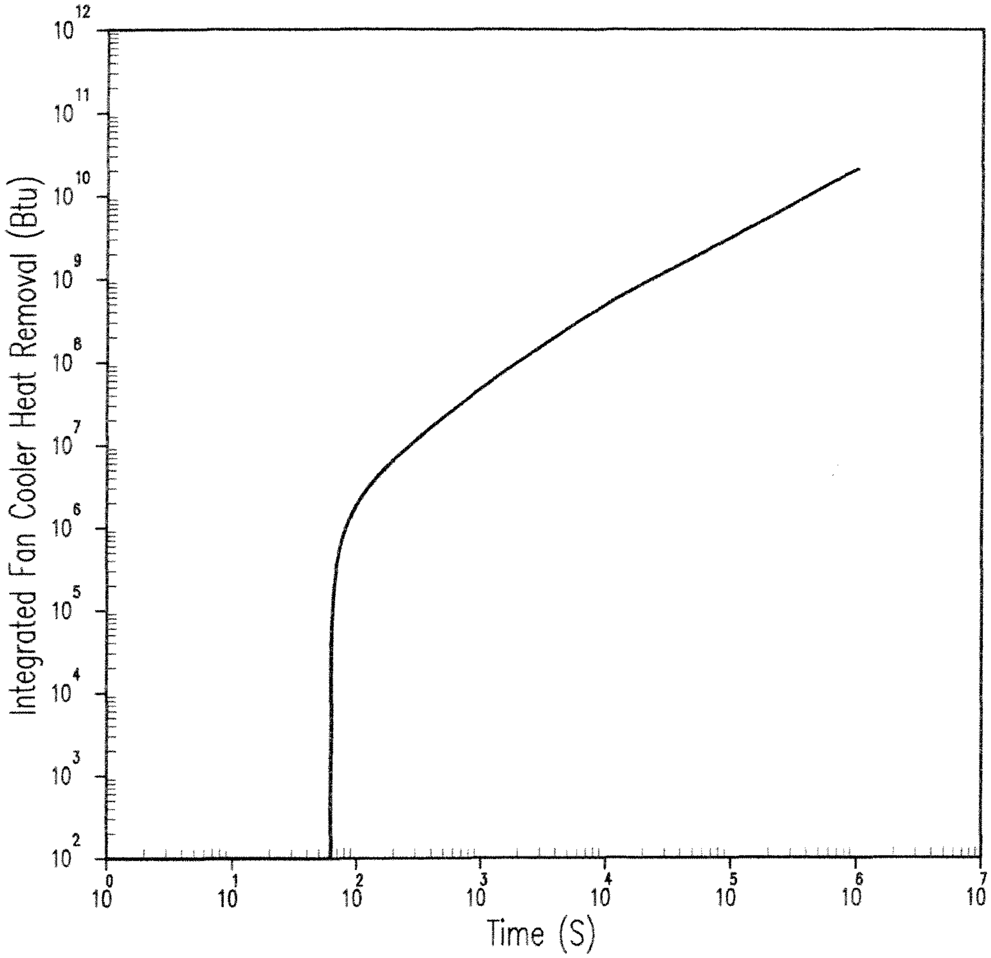
INDIAN POINT UNIT No. 2	
UFSAR FIGURE 14.3-104 RPV SYSTEM MODEL	
MIC. No. 2000MC4303	REV. No. 17A



INDIAN POINT UNIT No. 2

DOUBLE-ENDED PUMP SUCTION BREAK
FOR 3216 MWt MINIMUM SAFEGUARDS
INTEGRATED WALL HEAT REMOVAL

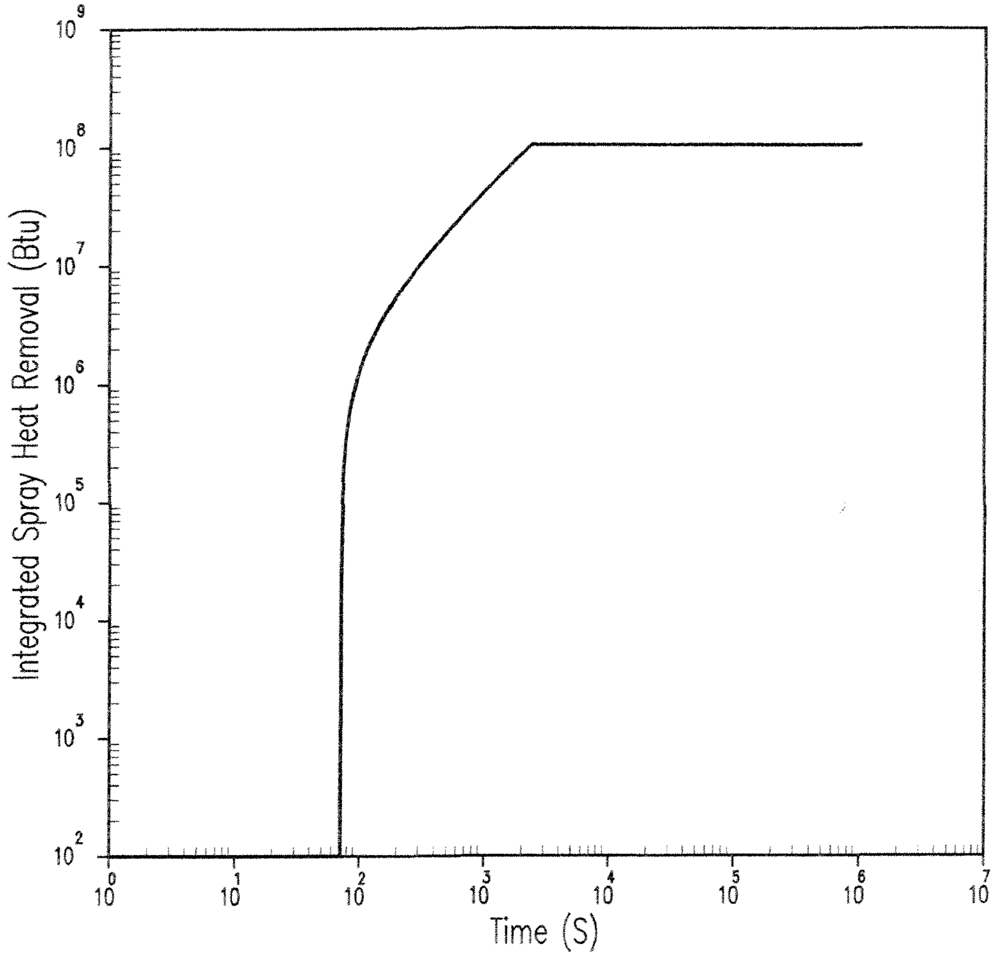
UFSAR FIGURE 14.3-105	REV. No. 19



INDIAN POINT UNIT No. 2

DOUBLE-ENDED PUMP SUCTION BREAK
FOR 3216 MWt MINIMUM SAFEGUARDS
INTEGRATED FAN COOLER HEAT REMOVAL

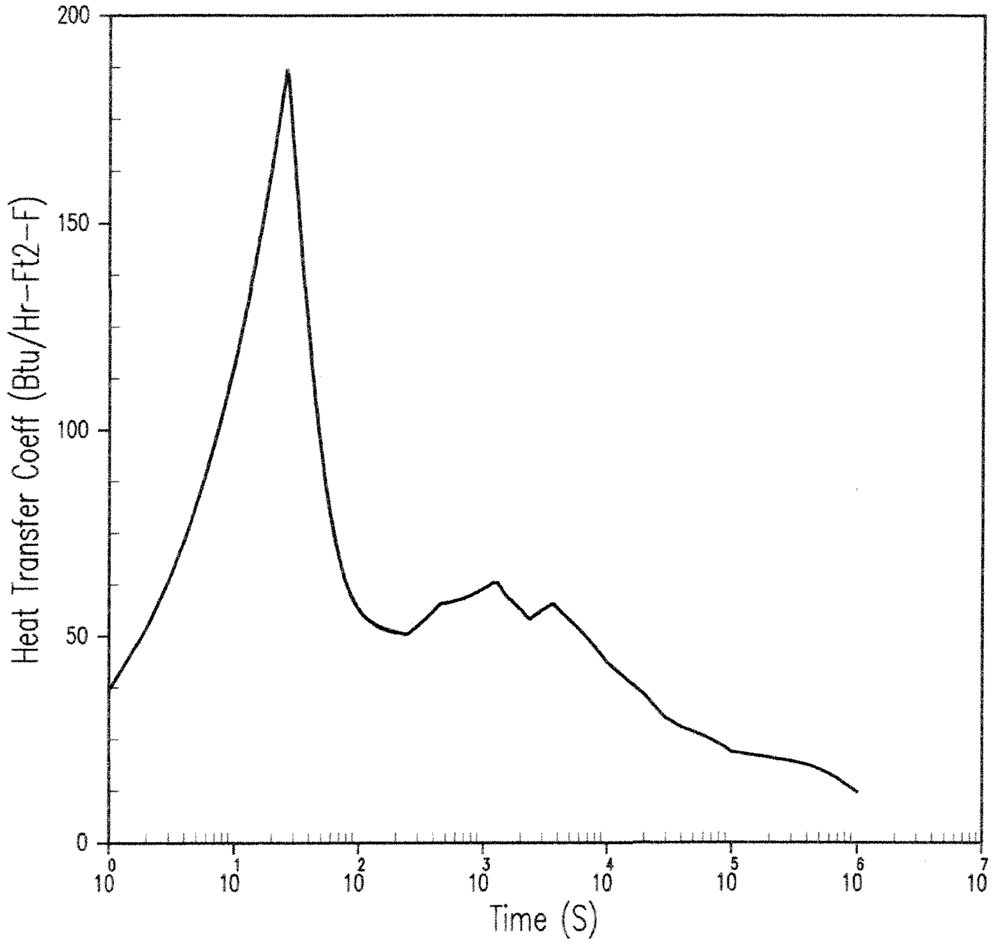
UFSAR FIGURE 14.3-106 | REV. No. 19



INDIAN POINT UNIT No. 2

DOUBLE-ENDED PUMP SUCTION BREAK
FOR 3216 MWt MINIMUM SAFEGUARDS
INTEGRATED SPRAY HEAT REMOVAL

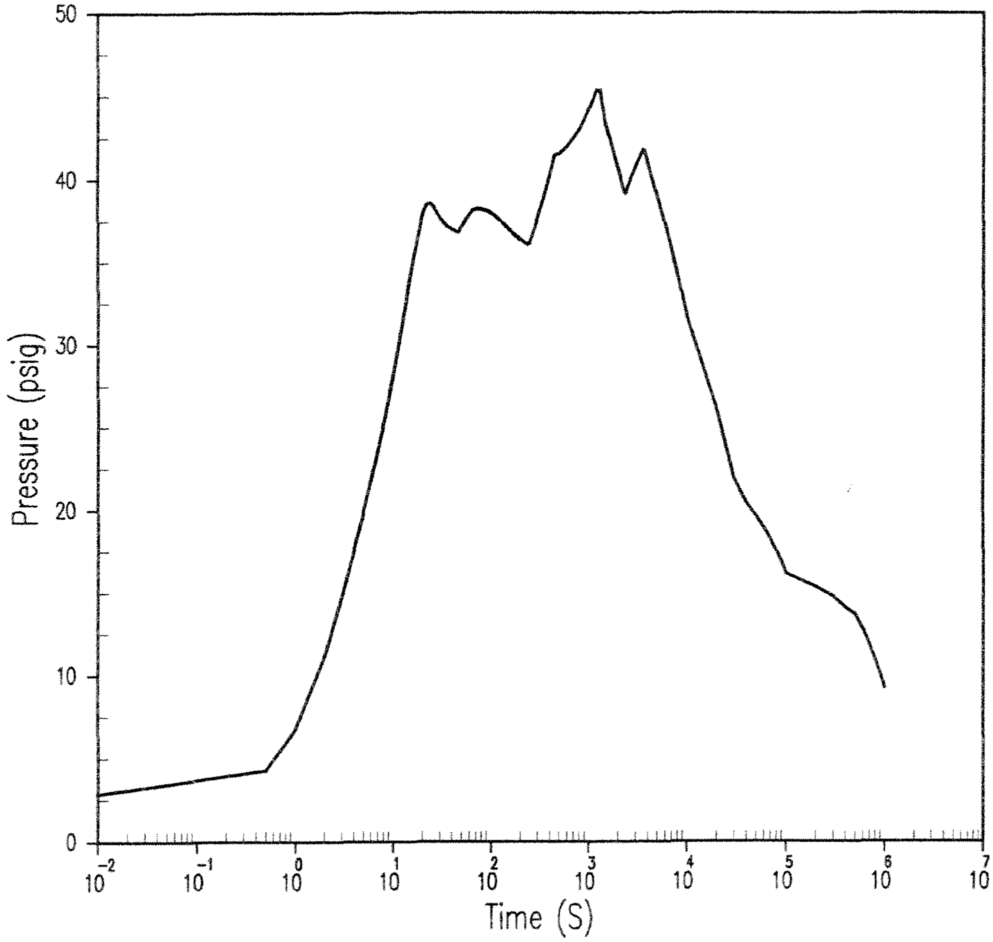
UFSAR FIGURE 14.3-107	REV. No. 19



INDIAN POINT UNIT No. 2

DOUBLE-ENDED PUMP SUCTION BREAK FOR 3216 MWt MINIMUM SAFEGUARDS STRUCTURAL HEAT TRANSFER COEFFICIENT

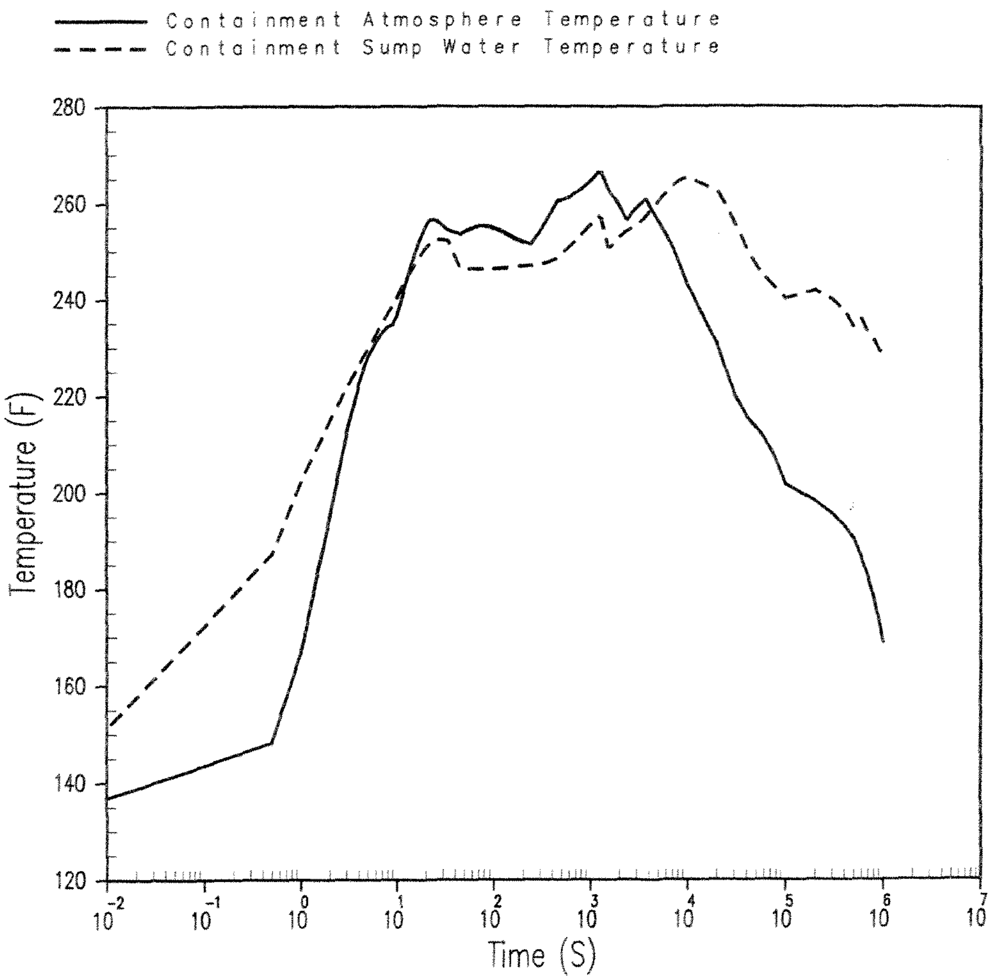
UFSAR FIGURE 14.3-108 | REV. No. 19



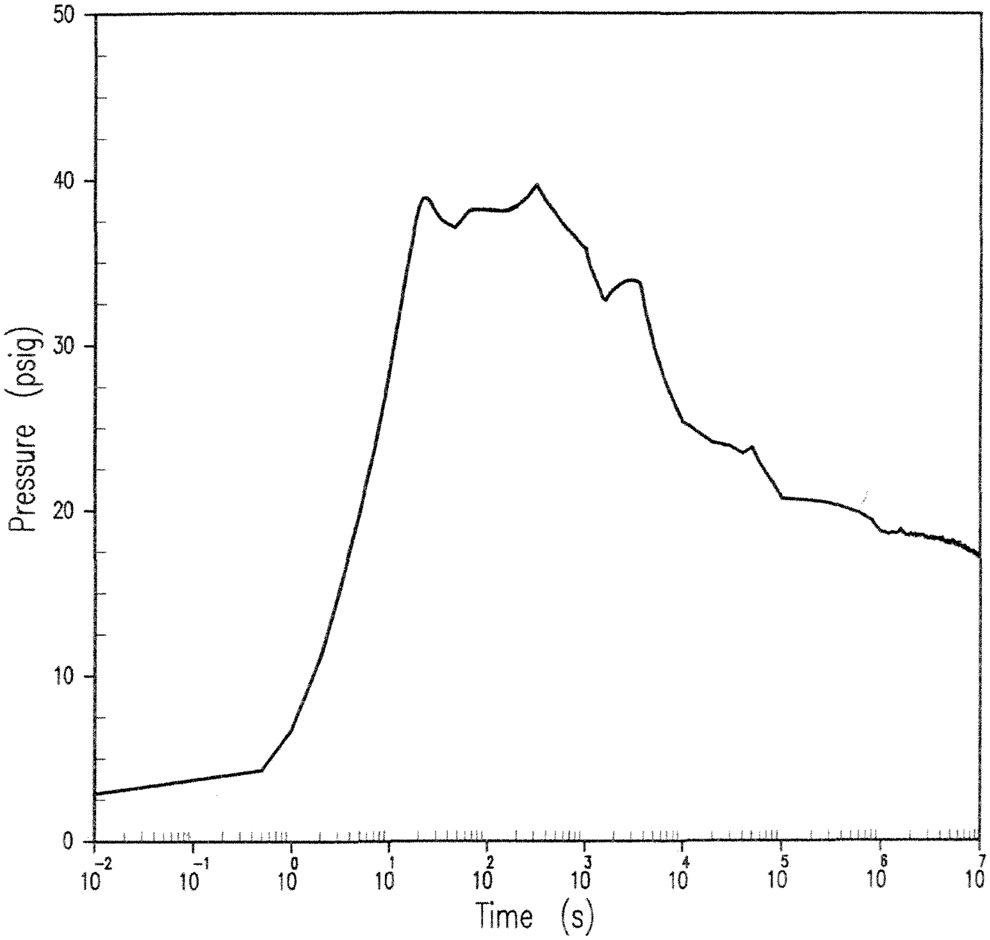
INDIAN POINT UNIT No. 2

DOUBLE-ENDED PUMP SUCTION BREAK FOR 3216 MWt MINIMUM SAFEGUARDS CONTAINMENT PRESSURE

UFSAR FIGURE 14.3-109	REV. No. 19



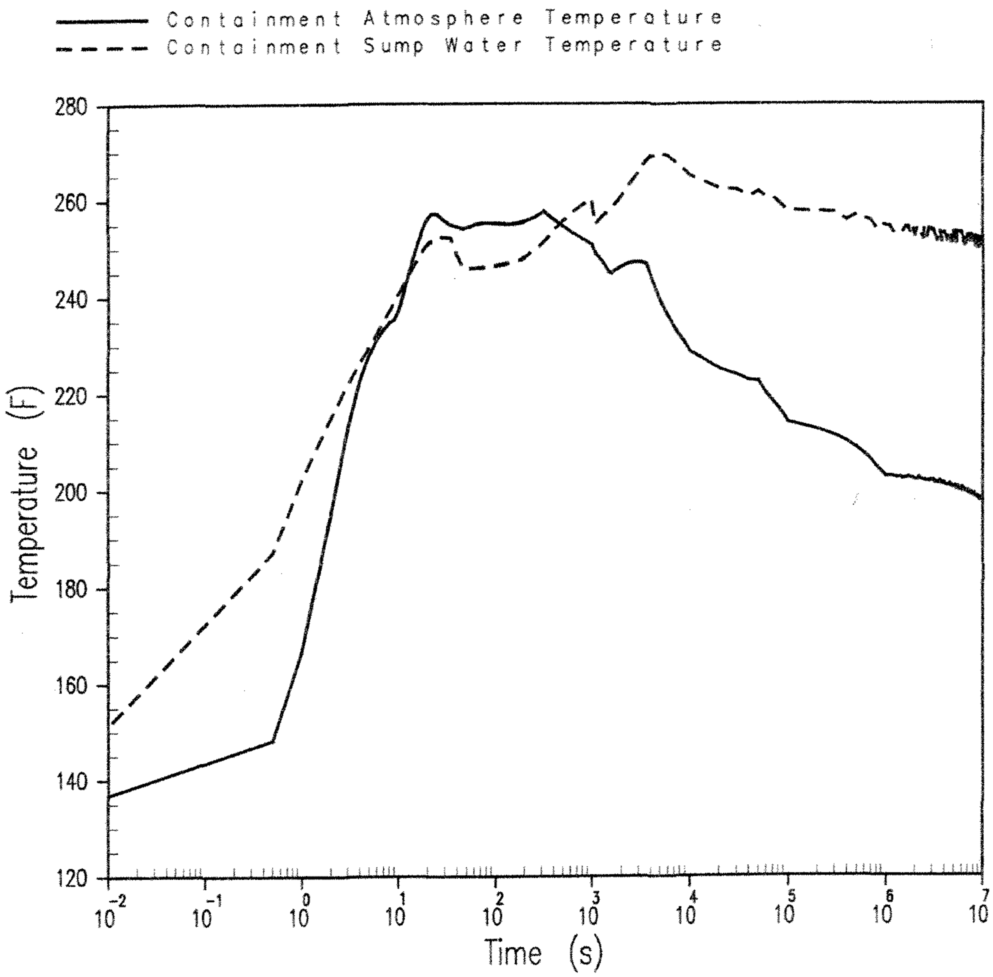
INDIAN POINT UNIT No. 2	
DOUBLE-ENDED PUMP SUCTION BREAK FOR 3216 MWt MINIMUM SAFEGUARDS CONTAINMENT TEMPERATURE	
UFSAR FIGURE 14.3-110	REV. No. 19



INDIAN POINT UNIT No. 2

DOUBLE-ENDED PUMP SUCTION BREAK FOR 3216 MWt MAXIMUM SAFEGUARDS CONTAINMENT PRESSURE

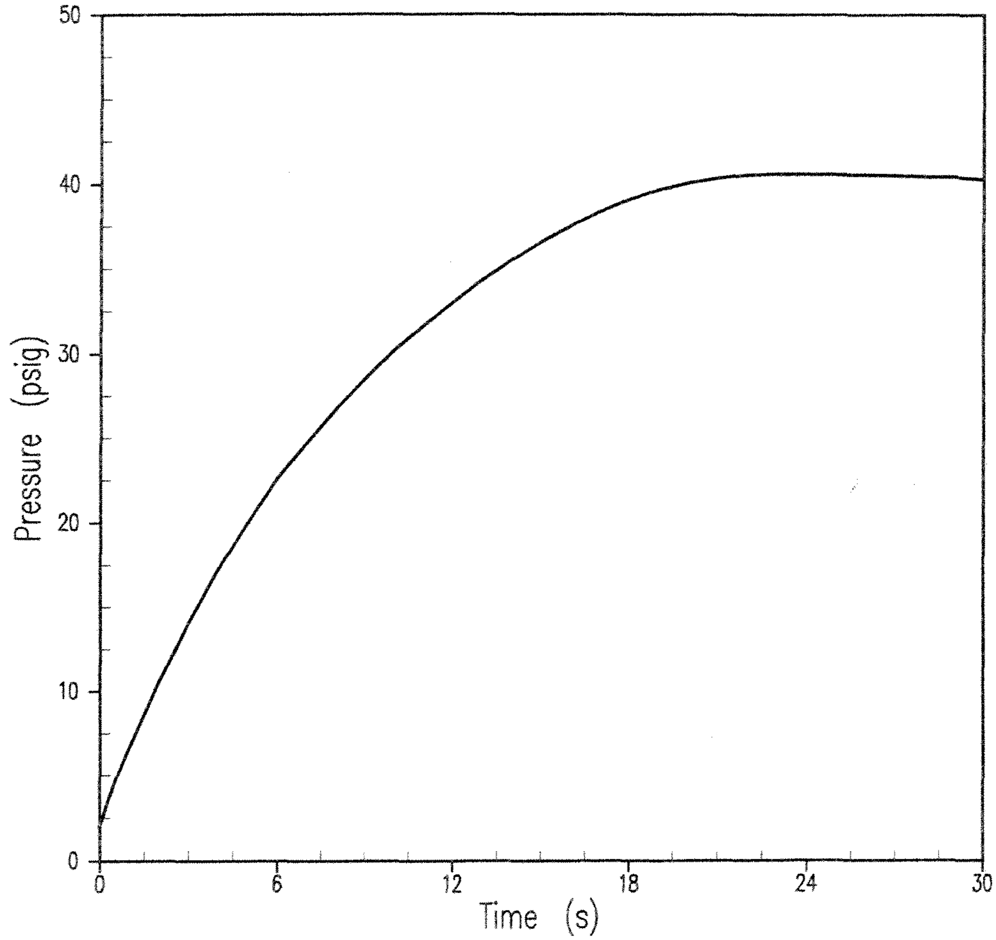
UFSAR FIGURE 14.3-111	REV. No. 19



INDIAN POINT UNIT No. 2

DOUBLE-ENDED PUMP SUCTION BREAK FOR 3216 MWt MAXIMUM SAFEGUARDS CONTAINMENT TEMPERATURE

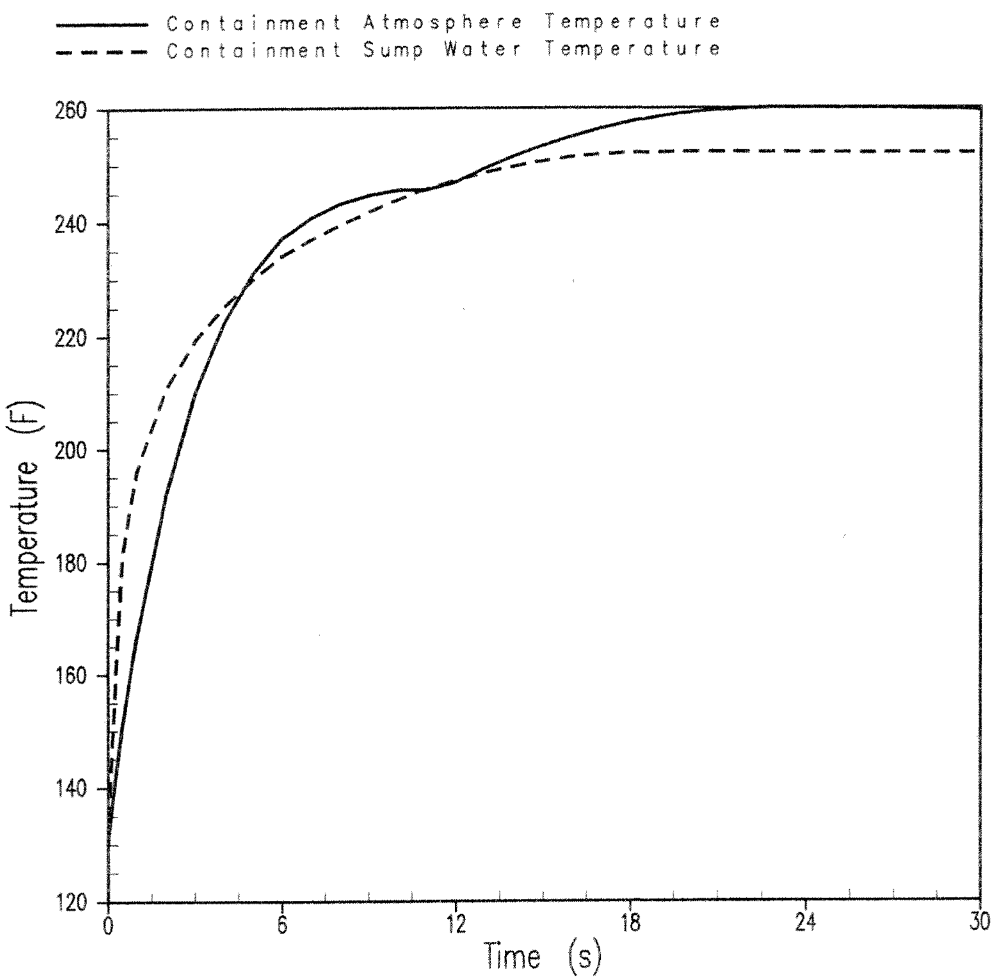
UFSAR FIGURE 14.3-112 | REV. No. 19



INDIAN POINT UNIT No. 2

DOUBLE-ENDED HOT LEG BREAK
FOR 3216 MWt CONTAINMENT PRESSURE

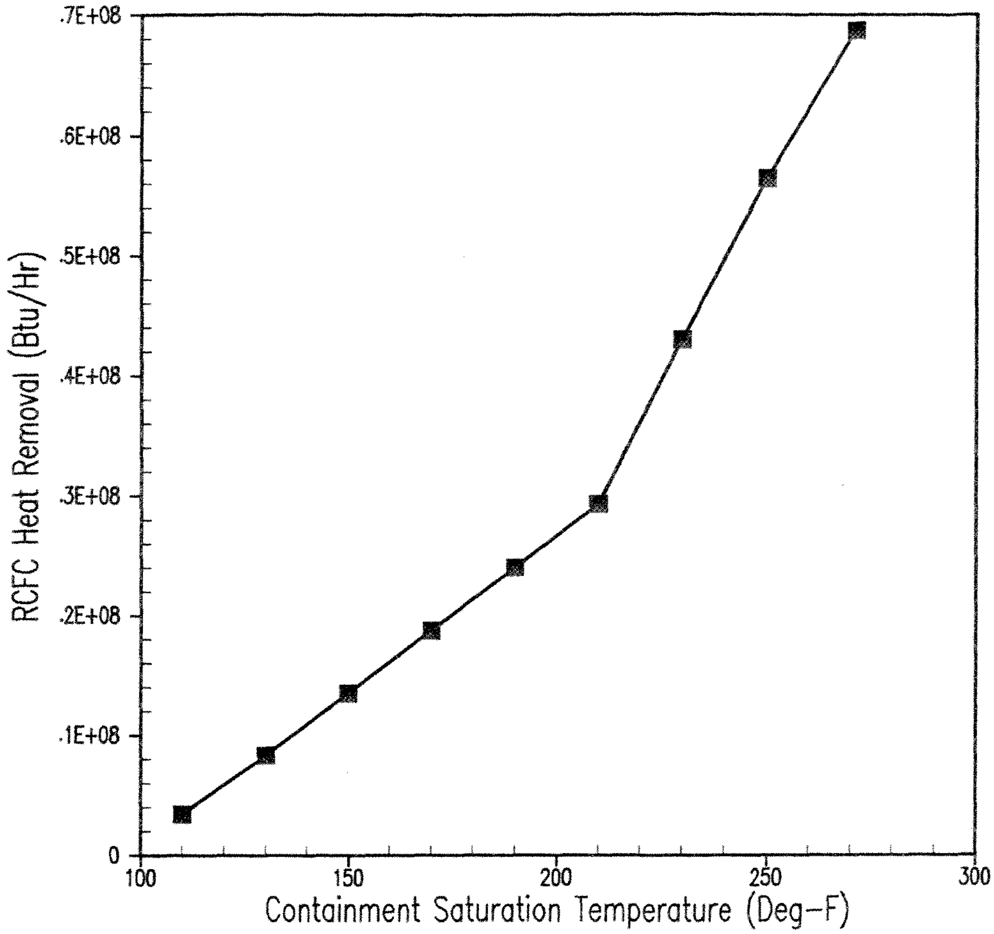
UFSAR FIGURE 14.3-113	REV. No. 19



INDIAN POINT UNIT No. 2

DOUBLE-ENDED HOT LEG BREAK
FOR 3216 MWt CONTAINMENT TEMPERATURE

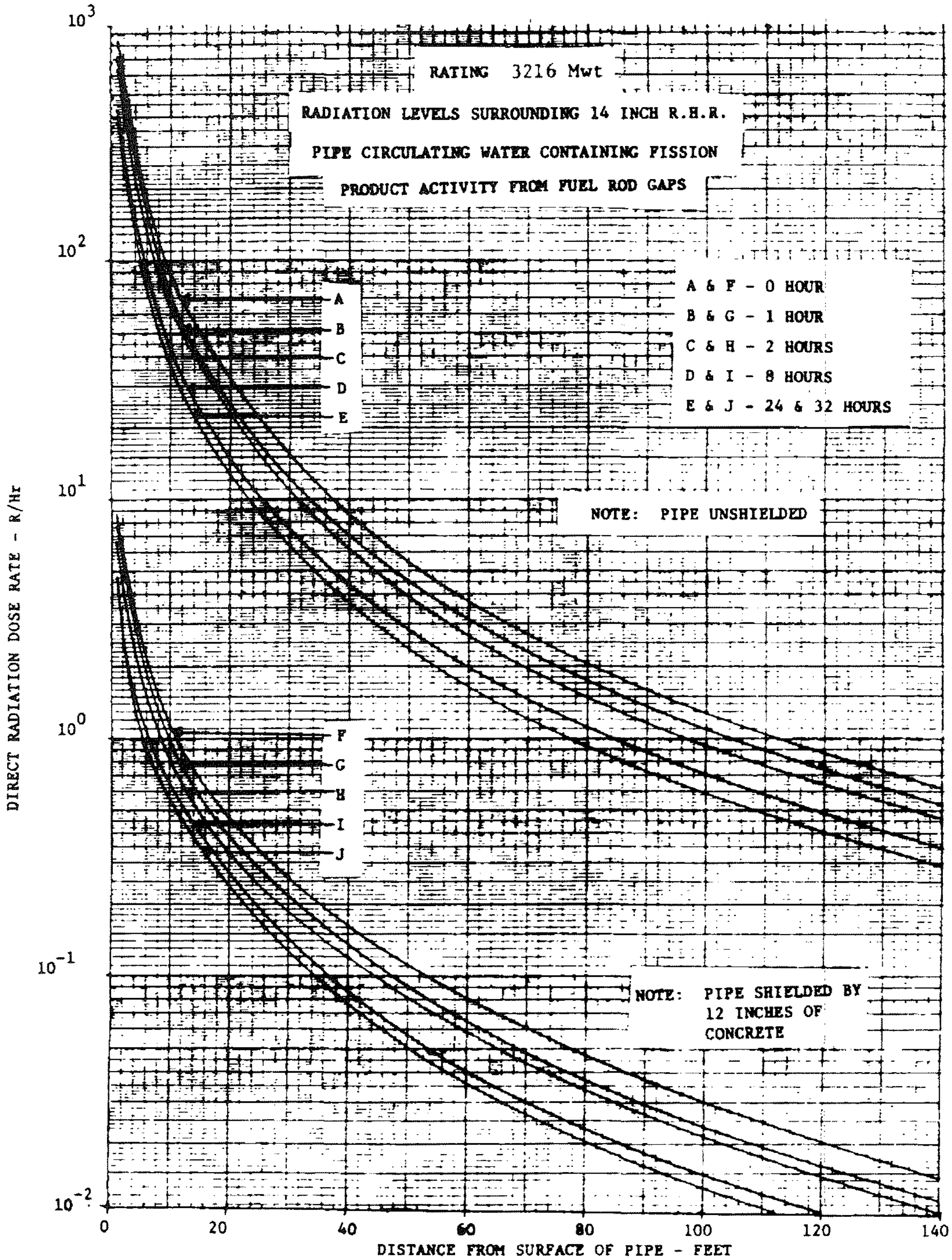
UFSAR FIGURE 14.3-114	REV. No. 19



INDIAN POINT UNIT No. 2

FAN COOLER HEAT REMOVAL AS A FUNCTION OF CONTAINMENT TEMPERATURE 95°F SERVICE WATER, 1600 GPM SW FLOW

UFSAR FIGURE 14.3-115 | REV. No. 19



INDIAN POINT UNIT No. 2

UFSAR FIGURE 14.3-129

RADIATION LEVELS SURROUNDING 14-INCH RESIDUAL HEAT REMOVAL PIPE (FIGURE RETAINED FOR HISTORICAL PURPOSES)

MIC. No. 2000MC4342	REV. No. 17A