9.6 FACILITY SERVICE SYSTEM

9.6.1 Service Water System

Design Basis

The Service Water System (SWS) was designed to supply cooling water from the Hudson River to various heat loads in both the primary and secondary portions of the plant. Provision was 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 or accident conditions. Sufficient redundancy of active and passive components was provided to ensure that cooling is maintained to vital loads for short and long periods in accordance with the single failure criteria. The system also provides backup water required for cleaning the traveling screens. A backup supply to the SWS can be provided by three non-seismic class pumps, as shown in Plant Drawing 9321-F-20333 [Formerly Figure 9.6-1A].

System Design and Operation

The Service Water System flow diagram is shown in Plant Drawing 9321-F-20333, and -27223, [Formerly Figure 9.6-1A, B, and C]. Six identical, vertical, centrifugal sump-type pumps located at the intake structure, each rated at 6000 gpm and 195 ft TDH at best efficiency point (BEP), supply service water to two independent discharge headers; each header being supplied by three of the pumps. An automatic, self-cleaning, rotary-type strainer is in the discharge of each pump to remove solids. These strainers can also be operated in the non-automatic mode. 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 non-essential loads. Table 9.6-1 identifies the design flow requirements of the Service Water System and the loads supplied by each header for various operating conditions.

Water is drawn from the river and passes under a debris wall, through a coarse screen and, finally, a fine mesh traveling ristroph screen. Electric heaters are provided in the driving head of the traveling screens, which are located inside a weatherproof building. The heaters and/or the constant motion of the screens plus the spray wash help to prevent icing of the screen panels. Each main circulating water pump is installed in an individual chamber, while the service water pumps are in a common chamber with two intakes. Each intake is capable of passing 100% of SWS demand and each is provided with a dedicated traveling screen. Openings are also provided between the service water pump chambers and the main circulating pump chamber on either side. These two openings can be opened by gates, but are normally closed.

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. Even if the main circulating pump intake were 90% blocked, that intake alone would be capable of supplying all water required for the service water pumps at design conditions. The extreme low level condition for the river at the intake structure is 4'5" below the mean sea level at the site.

With the service water pump suctions at 10'-11 3/8" below the mean sea level at the site, adequate submergence at the service water pump suctions is assured. In addition, the intake structure has been evaluated for water levels higher than the maximum level of 15 feet above the mean sea level at the site (see Section 2.5 for a discussion of the maximum river level for

IPEC00036071

the Indian Point site); no foreseeable structural damage could impair the flow of water to the pump suctions for these high water conditions.

The intake structure and the steel framed grating enclosure around the service water pumps were designed as seismic Class I, and are therefore not subject to collapse under earthquake loading. Should the facade or any other architectural (i.e., non-structural) member of the intake structure be damaged or fall into the river, the flow of water from the river to the pump suction would not be impaired.

During normal operation, the essential loads listed in Table 9.6-1 can be cooled by any one of the three service water pumps on the essential header. The non-essential loads in Table 9.6-1 can be supplied by any two of the three service water pumps on the non-essential header. By manual valve operation, the essential loads can be transferred to the supply line carrying the non-essential loads and vice versa. During cold shutdown conditions, it has been evaluated that the essential and non-essential headers can be cross-connected to allow any pump or pumps to cool the entire service water heat load, subject to restrictions on positions for key valves, as evaluated by an updated revision to the original safety evaluation that addressed this concern.

The essential loads are those which must be supplied with cooling water immediately in the event of a blackout and/or Loss-of-Coolant Accident. The cooling water for these loads is supplied by the nuclear service water header. The non-essential loads are those which are supplied with cooling water from the conventional service water header. A non-essential service water pump must be manually started when required following a Loss-of-Coolant Accident.

The component cooling heat exchangers are considered non-essential loads on the Service Water System in the sense that service water to the component cooling water heat exchangers is not required during the injection phase of a LOCA.

The only accident heat loads due to forced flow on the Component Cooling Water System during the injection phase with Black Out are motor cooling for the internal recirculation pumps and bearing cooling for the high head safety injection pumps. Both of these loads are satisfied by using the Component Cooling Water System as a heat sink.

During the switchover to the recirculation phase following a postulated Loss-of-Coolant-Accident, one Diesel Generator and one Control Building air conditioning unit will be transferred to the non-essential header (although it has been evaluated that both CRAC units may stay on the essential header) and one component cooling heat exchanger will be transferred to the essential header. Following a simultaneous incident and blackout, the cooling water requirements for all five fan cooling units and the other essential loads can be supplied by any two out of the three service water pumps on the header which is designated to supply the nuclear and essential secondary loads.

The 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 a manual shutoff valve and drain valve.

IPEC00036072

Similarly, each discharge line from the cooler is provided with a manual shutoff valve. This allows each cooler to be isolated individually for leak testing of the system in accordance with Technical Specification requirements. The ventilation cooler discharge lines are monitored for radioactivity by routing a small bypass flow from each cooler through redundant radiation monitors.

Upon indication of radioactivity in the effluent, each cooler discharge line is monitored individually to locate the defective cooling coil, which, when identified, remains isolated. The identification and isolation of an FCU or FCU motor cooler leak may be performed up until the entry into external recirculation. This is sufficient time to detect and isolate the leak, since the passive failure of a cooling coil is assumed to occur concurrently with the LOCA. The cooling coils and service water lines are a missile protected closed system inside the Containment and together with the isolation valves located just outside the Containment, satisfy the isolation criteria for containment penetrations as discussed in Section 5.2.

During normal plant operation, flow through the cooling units is throttled for containment temperature control purposes by a valve on the common discharge header from the cooling units. Two additional independent, full flow valves open automatically in the event of an engineered safeguards actuation 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.

Should there be a failure in the piping or valves at the header supply water to the containment cooling coils, one of the two series valves in the center of the header can be manually closed and service will continue on the side of the header opposite of the failure. The supply line attached to this side of the header would supply the essential loads, whether or not it did so before the failure.

Likewise, operation of at least one component cooling heat exchanger is assured 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 a blackout, the component cooling heat exchangers are not needed during the injection phase; thus they are normally fed from the non-essential supply line. During the switchover to the recirculation phase, one component cooling heat exchanger is placed in service on the non-essential header, and the other component cooling heat exchanger is placed in service on the essential header.

During the switchover scenario, valves SWN 35-1 and 35-2 are throttled as necessary to control CCW header temperatures in response to initiating recirculation flow. This action will ensure that CCW header temperatures are maintained within optimum ranges. Maximum opening is also prescribed to prevent single Service Water pump run out for plant operation with RCS temperature 350 °F and greater.

Below 350 °F, these position limits do not apply provided that: (1) two non-essential service water pumps are operating; (2) the non-essential SW header low pressure alarm is maintained clear; and (3) the valves are restored to their 27.5 and 27 degrees open positions should a reduction to single non-essential service water pump operation result.

IPEC00036073

This is achieved by the implementation of administrative controls to ensure that a dedicated Operator with direct communication from the Control Room takes manual action to restore the valves to their prescribed position limits well within 2 hours. These administrative controls also include procedural guidance and restrictions, such as not allowing this configuration with the headers being swapped or cross-tied.

The total service water flow required by the three Diesel Generator Jacket Water and Lube Oil Cooler sets during injection is 906 gpm (302 gpm per each cooler set).* Cooling water to the Emergency Diesel Generator coolers is normally supplied from the essential supply line. The Service Water Flow through the Emergency Diesel Generator (EDG) Jacket Water and Lube Oil Coolers is controlled by a manual Globe Valve installed on the inlet/outlet cover of each EDG Jacket Water Cooler. Service water flows through the coolers continuously. jThe flow rate is determined by the differential pressure across the Coolers as read on the installed gauges. The inlet valving is arranged so that each of the three diesels can be served by either of the supply lines. Furthermore, the failure of any single active or passive component per single failure criteria will not result in loss of cooling water to more than one diesel generator.

Three backup service water pumps provide cooling water from the discharge canal for the containment ventilation cooling coils, the Control Room Air Conditioners, the containment ventilation fan motor coolers, the instrument air compressors, and the diesel generator coolers in the unlikely event that a storm driven vessel damages the service water intake structure. The backup service water pumps are provided with automatic, continuous, rotary-type strainers and are manually valved to discharge to the header designated to supply the essential loads. Two of the three pumps can be powered by the emergency diesels.

> *NOTE: For recirculation, the service water flow requirement is 639 gpm total (213 gpm per each cooler).

In order to satisfy Appendix R licensing commitments, one of the backup service water pumps is designated as an Appendix R service water pump to supply cooling water to the component cooling water heat exchangers in the event of a fire. This pump is powered from the Appendix R Diesel Generator. The backup service water valve pit is protected from tornado-originated missiles by a tornado proof structure.

Plant Drawings 9321-F-20333, and -27223 [Formerly Figures 9.6-2A & B] present the flow distribution on the SWS for normal operation. Plant Drawings 9321-F-20333, and -27223 [Formerly Figure 9.6-3] shows at the flow distribution on the SWS for the injection phase after LOCA assuming maximum safeguards equipment operating. Plant Drawings 9321-F-20333, and -27223 [Formerly Figures 9.6-4A & B] indicate the flow distribution on the SWS for the recirculation phase after a LOCA, assuming maximum safeguards equipment operating.

Ultimate Heat Sink

The ultimate heat sink is the Hudson River, which is capable of providing sufficient cooling for at least the required thirty days:

(a) to permit simultaneous safe shutdown and cooldown of both operating nuclear units at the Indian Point site and maintain them in a safe condition, and

IPEC00036074

(b) in the event of an accident in one unit, to permit control of that accident safely and permit simultaneous safe shutdown and cooldown of the remaining unit and maintain it in a safe shutdown condition.

The ultimate heat sink is capable of withstanding the effects of the most severe natural phenomena associated with the Indian Point site, other site related events and a single failure of man-made structural features. The ultimate heat sink consists of a single source.

For the normal service water supply system, there are no connecting canals or conduits between the heat sink and the intake structure. The intake structure is physically located directly on the bank of the Hudson River, which is tidal at the site location. The heat sink, therefore, consists entirely of natural features.

The SWS design met the requirements of AEC Safety Guide No. 27 with respect to all natural phenomena associated with the site (earthquake, tornado, hurricane, flood, drought, and low tide).

Site related accidents such as ship collisions, airplane crashes, oil spills, and fires are not expected to affect the availability of the heat sink. Reasonable combinations of less severe natural phenomena and accidental phenomena are not expected to have significant consequences.

Failure of man-made features would have to be multiple in order to block both the fresh water flow from upstream and tidal flow from downstream. These could be postulated as bridge failures both upstream and downstream of the site. Dam failures, on tributaries to the Hudson, would not have an adverse effect of the heat sink since this occurrence would raise the water level of the heat sink.

The SWS design is not capable of accepting the highly unlikely occurrence of river diversion.

The SWS was designed to accept the rather severe combination of natural and accidental phenomena of a storm driven ocean vessel crashing into the intake structure, rendering it inoperable. In this event, the ultimate heat sink includes the Hudson River and discharge canal to supply the backup service water pumps located in the discharge canal. The backup service water pump design is not capable of withstanding the additional simultaneous occurrence of a Design Basis Earthquake, as these components are designated as seismic Class III components.

Design Evaluation

The Service Water System was designed to fulfill required safety functions while sustaining: (a) the single failure of any active component used during the injection phase of a postulated Loss-of-Coolant Accident, or (b) the single failure of any active or passive component used during the long-term recirculation phase.

The operating modes of the IP3 SWS have been identified as normal, injection post-LOCA and recirculation post-LOCA. The postulated failure conditions of the SWS must include consideration of the limiting case for each operating mode of the system. The limiting failures are:

IPEC00036075

1. Loss of the 10 inch turbine building service water supply header during normal (plus seismic) conditions.

2. Loss of instrument air (LOIA), during the post-LOCA injection phase concurrent with single active component failure.

3. Loss of a SW pump on both the essential and non-essential headers (resulting from a diesel generator failure) during the post-LOCA recirculation phase.

The flows to individual essential components for each of these cases, as calculated by the PIPEFLOW Computer Program, are presented in Table 9.6-2.

As shown by these results and as discussed in the following section, the SWS will perform its required safety function for the limiting postulated failure of each of the operating modes identified above.

In addition, as a result of the elevated river water temperature experienced during the summer of 1988, the Authority undertook an effort to permanently increase the design basis ultimate heat sink temperature from 85° F to 95° F. This effort included an evaluation of certain plant equipment ultimately cooled by service water to perform all normal and safety functions at river water temperatures up to 95° F. The evaluation concludes that all equipment required for safe plant operations serviced by 95° F service water will operate acceptably and the current safety limits affected by the SWS temperature will be met.

Postulated Breaks

The realignment of the essential service water header and the non-essential service water header during the switchover to the recirculation phase following a Loss-of-Coolant-Accident consists of connecting one diesel generator to the non-essential service water header, connecting one component cooling heat exchanger to the essential header, and connecting one control building air conditioner unit to the non-essential header.

During the recirculation phase of a Loss-of-Coolant-Accident, the following components are supplied by the essential service water header: the instrument air closed cooling water system, one control building air conditioner, a component cooling water heat exchanger, the containment fan coolers, the radiation monitoring mixing nozzle, and two of the diesel generators. The recirculation phase flow requirements for these components are identified in Table 9.6-1.

Using system alignment shown in Plant Drawing 9321-F-20333 [Formerly Figure 9-6-1A], where service water pumps Nos. 31, 32, and 33 are on the non-essential (conventional) header and service water pumps Nos. 34, 35 and 36 are on the essential (nuclear) header, the valve positions during the normal injection and recirculation modes of operation are as indicated in Table 9.6-3.

The modifications to the switchover procedure to incorporate realignment of the Service Water System consist of closing valves FCV-1112 and SWN 6 supplying service water to the Turbine Building; opening valve SWN-62-1 and closing valve SWN-62-2, thereby aligning Diesel Generator No. 31 to receive service water from the non-essential header; opening valve SWN-32 and closing valves SWN-33-1 and SWN-33-2 so that component cooling heat exchanger No. 31 receives service water from the essential header, closing valve SWN-4 supplying service

IPEC00036076

water to the circulating water pump seals and backup screen wash; and opening valve SWN-94-1 and closing valve SWN-108-3 to align one of the control building air conditioners to the non-essential header.

In addition to the system alignment required to be performed at the initiation of the recirculation phase, without a loss of instrument air, the operator must override the automatic reset of temperature control valves TCV-1104 and TCV-1105 in order to assure the flow conditions assumed in the PIPEFLOW computer code. All of the above are to be accomplished during the changeover from injection to recirculation.

Subsequent to the issuance of the Safety Evaluation Report for Indian Point 3, a pipe break analysis was performed on the Service Water System. As part of an effort to demonstrate the adequacy of replacement pumps for the Service Water System, the analysis was reviewed and the following observations were made with regard to failure criteria that should be applied to the SWS piping:

1) Failure data contained in the Indian Point Probabilistic Safety Study indicate that the probability of total failure of SWS piping during the critical 24-hour period following a LOCA does not constitute a credible event.

2) The SWS is a moderate energy fluid system. Pipe failures within such systems are postulated to be limited to small through-wall leakage cracks. The break criteria of the original analysis included guillotine and slot breaks which are exceedingly conservative for the SWS.

As a result of these observations, the SWS was reanalyzed in 1989 utilizing the PIPEFLOW computer program. On the basis of the results from this reanalysis, it was concluded that the Indian Point 3 SWS, as presently configured, will perform its safety functions under accident conditions and with the previously described postulated component failures. Table 9.6-2A provides the service water system flow distribution for the passive breaks considered during the recirculation phase of a LOCA.

The validity of the computer program PIPEFLOW, which was used in the analysis of the postulate failure conditions has been verified by comparison of results to a nationally recognized hydraulic computer code, LIQSS. The verification problem considered sufficient node points and flow branches to demonstrate the adequacy of PIPEFLOW with respect to similar nodes and branches used in the service water system model. The results of the verification showed excellent correlation of pressures and flows between PIPEFLOW and LIQSS.

As a part of the Indian Point 3 Pre-Operational Test Program, functional tests of the Service Water System were run to verify equipment performance. The results of pre-operational, functional and periodic tests for the SWS are available for inspection at Indian Point 3.

Tests and Inspections

Each service water pump was subjected to a hydrostatic test in the shop, in which all pressurized parts were subjected to a hydrostatic pressure of the greater of 1.25 times the shutoff head or 1.50 times the rated head of the pump. In addition, normal capacity vs. head tests were made on each pump.

IPEC00036077

All valves in the Service Water System underwent a shop hydrostatic test in accordance with the applicable manufacturing code or standard. Gate, globe and check valves were tested to 225 psi across the seat. Butterfly valves were tested to 200 psi across the seat. Butterfly control valves were tested to 125 psi and diaphragm valves were tested to 150 psi in 3" size and 175 psi in 2" size across the seat.

All service water piping was hydrostatically or leak tested in the field in accordance with USAS B31.1. As per the construction code record, the 1967 edition of USAS B31.1, this was accomplished using one of the two methods:

1. The piping was hydrostatically tested to 1.5 times the design pressure or the maximum test pressure of the limiting vessel or component in the section of piping to be tested, or

2. If it was not feasible to isolate a section of pipe, the piping would be slowly brought up to system operating pressure and held at pressure for a period of time to demonstrate leak-tightness

Upon commissioning, the ISI portions of the service water system were governed by ASME Section XI for ISI Class 3 piping. Per the original edition of ASME XI used at the site (1974, w. summer 1975 addenda), piping was required to be tested to 1.10 times the system design pressure. This was upheld by the 1983 edition, with summer 1983 addenda of ASME XI used in the second ISI cycle. Retests using the original construction code were also acceptable. Future tests and inspections will be performed in accordance with ASME Section XI code of record requirements as described in the IP3 Inservice Inspection Program in effect.

In 1997, the Nuclear Regulatory Commission granted Indian Point 3 use of Code Case N-416-1 from the ASME Boiler and Pressure Vessel Code for welded repairs or installation of replacement items by welding. This would involve leak testing at the system operating pressure, coupled with surface examinations at both the root pass and the final layer of a welded joint. Note that the welds in shop fabricated service water piping were liquid penetrant or magnetic particle inspected with the ASME Boiler Pressure Vessel Code, Section VIII.

Electrical components of the Service Water System are tested periodically.

An Erosion/Corrosion program using both visual and volumetric inspection methods was implemented during the 8/9 refueling outage. The visual method is accomplished by using a robotic crawler with a high resolution camera. The crawler is remotely controlled and can advance through the piping while making a video record of the internal pipe surface.

9.6.2 Fire Protection

9.6.2.1 Design Bases

The General Design Criteria presented and discussed in this section are those which were in effect at the time when Indian Point 3 was designed and constructed. These general design criteria, which formed the bases for the Indian Point 3 design, were published by the Atomic Energy Commission in the Federal Register of July 11, 1967, and subsequently made a part of 10 CFR 50.

IPEC00036078

The Authority completed a study of compliance with 10 CFR Parts 20 and 50 in accordance with some of the provisions of the Commission's Confirmatory Order of February 11, 1980. The detailed results of the evaluation of compliance of Indian Point 3 with the General Design Criteria presently established by the Nuclear Regulatory Commission (NRC) in 10 CFR 50 Appendix A, were submitted to NRC on August 11, 1980, and approved by the Commission on January 19, 1982. These results are presented in Section 1.3.

Fire Protection Criteria

> Criterion: The facility is designed so that the probability of fires and explosions and the potential consequences of such events does not result in undue risk to the health and safety of the public. Noncombustible and fire resistant materials shall be used throughout the facility whenever necessary to preclude such risk, particularly in areas containing critical portions of the facility such as containment, control room, and components of engineered safety features. (GDC 3 of 7/11/67)

Fire Prevention in all areas of the plant was provided by structure and component design which optimizes the containment of combustible materials and which maintains exposed combustible materials below their ignition temperature in the design atmosphere. Fire control requires the capability to isolate or remove fuel from an igniting source, or to reduce the combustibles' temperature below the ignition point, or to exclude the oxidant, or preferably, to provide a combination of the three basic control means. The latter two means were fulfilled by providing fixed or portable fire fighting equipment of capacities proportional to energy that might credibly be released by fire.

All areas subject to radioactive contamination or toxic combustion products were designed to rely on manual fire protection. Access to these areas is controlled by plant health physics personnel. These areas are found in the Containment Building, Fuel Storage Building, Primary Auxiliary Building, and Waste Holdup Tank Area.

Indian Point 3 was designed on the basis of limiting the use of combustible materials in construction and of using fire-resistant materials to the greatest extent possible.

The fire protection system was designed to achieve the following objectives:

1) Provide automatic fire detection in those areas where the fire danger is greatest.

2) Provide fire extinguishment by fixed systems of water, CO2 and foam, actuated automatically or manually in those areas where the fire danger is greatest.

3) Provide manually operated fire extinguishing equipment, including hose reels, and CO2, dry chemical, water, halon, foam and MET-L-X types of hand portable extinguishers

The Fire Protection System was designed in accordance with standards of the National Fire Protection Association (NFPA) and where not, deviations are identified and justified.

The Indian Point 3 Fire Protection System was designed and installed to seismic Class III standards, except for the Fire Protection System piping supports in the Diesel Generator Building, Control Building, Primary Auxiliary Building, Fan House, Auxiliary Feed Pump Room, Electrical Tunnel, Containment Building and Fuel Handling Building which was designed and/or

IPEC00036079

upgraded to seismic Class I criteria. This design was used to ensure that the Fire Protection piping in Category I areas was seismically analyzed and will not impact seismic Class I components in a seismic event. Although these piping supports were designed and/or upgraded to seismic Class I criteria, they are no classified as Category I as implied in paragraph 16.1.7 of the UFSAR.

Applicable Codes and Standards During Design Phase of the Plant

From NEPIA - MAERP: Basic Fire Protection for Nuclear Power Plants (Revised and dated March 1970).

Water Supplies

Water supply systems satisfied conditions outlined in above noted NEPIA guide under Section II, PROTECTION; A, except that the wiring arrangement was evaluated with regard to National Fire Protection Association Pamphlet No. 20 indicated in Section II,A,4.

Yard Mains and Hydrants

Yard mains and hydrants satisfied the condition outlined in NEPIA guide under Section II, PROTECTION; B.

Sprinkler and Water Spray Systems

The Lube Oil Storage Room and Diesel Generator Room wet pipe sprinkler system satisfied the conditions outlined in NEPIA guide under Section II, PROTECTION; 1, 2 D and E, and 3. The water spray systems satisfied conditions outlined in NEPIA guide under 4A and 5. The Hydrogen Seal Oil Unit listed in the NEPIA guide under 4D was protected with a system that also satisfied these conditions except that it was a foam-water instead of a water spray system. This type of system also protected the Lube Oil Reservoir, Lube Oil Storage Tank and Boiler Feed Pump Oil Console and Oil Accumulators.

Portable Fire Extinguishers and Inside Hose Connections

These two items satisfied the conditions outlined in the NEPIA guide under Section II, PROTECTION; Items D2 and D1, respectively.

Special Protection

The electrical tunnel fire protection systems satisfied the conditions outlined under Section III, A of the NEPIA Guide. This was a closed head preaction system.

Materials

The materials used in the design of the Fire Protection System are in accordance with the standards of the National Fire Protection Association (NFPA). This includes pipe, fittings, valves and hydrants. Changes to these materials are controlled under the Fire Protection Program.

On February 17, 1981, 10 CFR 50.48 and Appendix R became effective. Appendix R to 10 CFR 50 established fire protection features required to satisfy Criterion 3 of Appendix A to 10

IPEC00036080

CFR 50 with respect to certain generic issues related to nuclear power plants licensed to operate prior to January 1, 1979. As a minimum, 10 CFR 50.48 required all licensees to conform to the requirements of Section III.G., III.J, and III.O, of Appendix R which addresses fire protection of safe shutdown capability, emergency lighting, and reactor coolant pump oil collection systems, respectively. Other sections of Appendix R apply to those licensees who had open items remaining from the BTP-9.5-1, Appendix A review. The review of Indian Point 3 to BTP 9.5-1, Appendix A was completed, as documented in the NRC Safety Evaluation Reports dated March 6, 1979 and May 2, 1980.

A reevaluation of Indian Point 3 against the requirements of Section III.G of Appendix R to 10 CFR 50 was completed in August 1984. The report submitted to the NRC on August 16, 1984 described the bases on which Indian Point 3 conformed to Section III.G of Appendix R. The report provided a historical chronology of correspondence between the NRC and the Authority on Appendix R compliance by summarizing all pertinent documentation submitted to the NRC in response to 10 CFR 50.48 and Appendix R through August 1984.

The Appendix R Reevaluation was supplemented September 19, 1985 and included new exemptions to Section III.G. By letter dated June 14, 1985, an exemption from the requirements of Section III.J was requested. Additional information was provided by letters dated March 15, 1985 and September 10, 1986. By Safety Evaluation dated January 7, 1987, the NRC completed their review of the Appendix R Reevaluation and granted certain exemptions.[1] A new report was issued in May 1995 which supersedes the August 1984 report. The new report will be maintained by periodic updates.

The Fire Protection Program Plan as required by 10 CFR 50.48 is included in IPEC Administrative Procedure SMM-DC-901, "IPEC Fire Protection Program Plan." The Administrative Procedure discusses the program purpose, design, implementation and maintenance thereof. It states the fire protection objectives and defines the program bases and key elements.

SMM-DC-901 also identifies the fundamental fire protection documents and describes the method of compliance, as well as provides an explanation of the organization, responsibilities, and administrative controls which comprise the Fire Protection Program for the Indian Point 3 Nuclear Power Plant.

SMM-DC-901 has been prepared to assist in accomplishing the following objectives:

- Adhere to the requirements of Appendix R to 10 CFR 50.
- Identify those documents that provide the basis for the Fire Protection Program
- Identify the location of all commitments made by the New York Power Authority relative to Appendix A to BTP (APCSB) 9.5-1, and 10 CFR50 Appendix R.
- Identify the documents which describe plant systems and procedures required to safely shutdown and cool down the plant, in the event of a fire in any plant area.
- Facilitate identification of the documents that identify Fire Protection equipment and safe shutdown components.

9.6.2.2 Fire Areas and Fire Area Boundaries

For the purposes of establishing compliance with 10 CFR 50.48 and Appendix R, Indian Point 3 has also been divided into six distinct fire areas with physical boundaries. An additional fire

IPEC00036081

area, the yard area, has also been defined and includes the areas exterior to the plant structures. The six defined fire areas are:

1) Containment
2) Primary Auxiliary Building
3) Electrical Tunnels
4) Control Building
5) Turbine Building
6) Auxiliary Feedwater Pump Room

These fire areas have been subdivided into fire zones for the purposes of fire hazards analysis.

Relief from the requirements of Appendix R for the above listed fire areas is described in detail in References 1, 5 and 6.

Fire Barriers

Substantial fire barriers have been provided throughout the plant. An evaluation including a fire hazards analysis concluded that the basic wall, floor and ceiling structures bounding each fire area have adequate fire resistance to prevent the spread of unsuppressed fire through the barriers. The required rating of each barrier has been established based on the combustible loading and fire severity that is present on either side of the barrier as well as the function of the barrier; i.e., on exterior wall or a barrier separating defined fire areas. Generally, the rating of a fire barrier does not consider the presence of any fire detection or suppression systems on either side of the barrier. Walls specifically designed as fire barriers include the following:

1) Reinforced concrete fire barrier walls between main transformers and in some areas between main transformers and the Turbine Building. In addition, the main transformer area has reinforced concrete oil barriers below grade with broken stone fill to catch oil from transformers in the event of a spill or rupture.

2) 16" reinforcing concrete fire walls from floor to ceiling between diesel generator cubicles. In addition, the pipes trench between cubicles between cubicles is filled with compacted sand fill after pipes are installed and special fire guards are installed at floor drains connected to a connected to a common drain pipe to prevent passage of burning oil.

Common walls between adjacent plant structures are concrete or concrete block except for the Electrical Penetration Tunnel/Electrical Tunnel and Primary Auxiliary Building/Waste Holdup Tank Pit interfaces, which are separated by metal partitions.

The fire barriers separating the fire areas listed above are required for compliance with Section III.G and III.L of Appendix R to 10 CFR 50. Each fire barrier along with its construction and fire resistive rating is identified in the Fire Hazards Analysis (FHA). The FHA will be maintained by periodic updates.

Fire Barriers Penetration Protection

Fire Doors

IPEC00036082

Doors in fire area barriers throughout the plant which separate redundant safe shutdown systems or protect alternate shutdown systems from significant fire hazards, are fire rated or evaluated as being adequate.

The fire doors, frames and construction are generally three-hour fire rated, and are either: kept closed, provided with door closers and periodically inspected to ensure that the door is in the closed position; held open, provided with fire actuated release devices and periodically inspected to ensure that the doorways are free of obstructions; locked closed and periodically inspected to ensure that the door is in the closed position; or kept closed and electronically supervised to alert control room operators if the door is left open.

The doorway between the Control Room and Turbine Building operating floor is a three-hour equivalent fire door which consists of a metal plate which falls over a window on the door in the event of a fire. A windowless metal door to the outside at Elevation 55 feet of the Primary Auxiliary Building has been installed.

The north, east, and west walls surround #31 and #32 Battery Rooms on 33' elevation of the Control Building were found to be non-rated barriers. Evaluation of this configuration found that the loss of the 31 and 32 Batteries would not preclude the ability to achieve safe shutdown.

In lieu of three-hour fire-rated doors in the barriers separating the Primary Auxiliary Building from the transformer yard, a manually actuated water curtain, in conformance with NFPA 15, "Water Spray Fixed Systems," protects this opening.

The door separating the Auxiliary Feedwater Pump Room from the Turbine Building at the 18' elevation is not rated. An evaluation of this door in accordance with the provisions of Generic Letter 85-01, has demonstrated the capability of the door for fire barrier penetration protection.

Within the Control Building, fire doors are provided between diesel generator cubicles and between the cubicles and the Control Building. The fire doors are 3-hour rated, Class A fire doors which have been listed or approved by a nationally recognized testing laboratory.

Where penetrations have been created in fire doors, fire door frames or transoms, appropriately related penetration seals have been installed which maintain the rating of the fire door assembly.

Fire Dampers

Dampers which are rated for three hours of fire resistance have been installed in HVAC openings and duct work to maintain the integrity of the fire rated barriers. These barriers separate fire zones in the Control Building, Diesel Generator Building, Primary Auxiliary Building, and the Fan House. Fuse links on the fire dampers will melt at a predetermined temperature which will cause automatic closure of these dampers.

Electrical Cable and Mechanical Penetration Seals

Fire barrier penetration seals are installed with the intent that they remain in place and retain their integrity when subject to an exposure fire and subsequently, a fire suppression agent.

IPEC00036083

Electrical and mechanical penetrations in fire barriers are sealed with several types of construction materials. Silicone foam and silicone elastomer comprise the two principal types of penetration fire seals used at IP3. Fire seals in fire barriers providing area separation have been qualified to a typical design that has passed a fire endurance and hose stream test.

Results of several separate fire tests have been used to evaluate the silicone foam and silicone elastomer fire seal designs. The review methodology used to evaluate the these qualifying tests required that the tests configuration be subjected to a 3-hour fire endurance which corresponds to the standard-time-temperature curve as specified in ASTM E-119, and an acceptable hose stream test.

The tested configuration has withstood the fire endurance test without the passage of flame or gases hot enough to ignite cable, other penetrating items or seal material on the unexposed side.

The temperature levels recorded for the unexposed side were analyzed and shown to be sufficiently below the self-ignition temperatures of the cables, other penetrating items or seal material used; and the fire seal remained intact without the projection of water beyond the unexposed surface during the hose stream test. The limiting component for unexposed side temperatures was found to be cable. Seven hundred degrees Fahrenheit (700° F) has been established as the limiting temperature which is sufficiently below the self-ignition temperatures of the cables used at IP3.

Fire Wraps and Radiant Energy Shields

One-hour rated fire wraps and radiant energy shields have been installed on various cable trays and conduits in the Containment, Electrical Tunnels and PAB. The wraps consist of high temperature mineral wool blankets. The blankets have been tested satisfactorily and qualified as a one hour barrier in accordance with ASTM E-119. Additional testing has qualified the wraps for three-hour water repellency, radiation resistance and water leachable chlorides and fluorides. The radiant energy shields are comprised of marinite or transite fire board.

These protective features were added to Safe Shutdown related instrumentation in the Containment to establish compliance with Section III.G.2f of Appendix R. One-hour wraps have been installed to protect:

1) Wide Range RCS pressure transmitter PT-402 conduit from the transmitter to the electrical penetration inside containment.

2) Source Range neutron temperature flux N-31 conduit from its preamp box to the electrical penetration inside containment.

3) Wide Range RCS temperature elements and cabling for TE 413 A & B at the electrical penetrations.

4) Steam Generator wide range level instrument LT-417D at the penetrations.

5) Steam Generator wide range level instrument LT-447D at Rack 21.

Radiant energy shields have been installed at instrument racks 19 and 21 to protect steam generator wide range level transmitter LT-417D and pressurizer level transmitter LT-459,

IPEC00036084

respectively. These shields protect the instruments from the effects of a floor based fire. In addition, radiant energy shields are installed on instrument trays where twenty feet of horizontal separation does not exist between redundant safe shutdown cables.

In the PAB, the power cabling for one component cooling water pump is wrapped where it is located within 20 feet of the redundant pump's cabling. A partial height, noncombustible barrier constructed of marinite board, partially surrounds CCW pump 33. The barrier includes a fire door rated for 3 hours to facilitate access to the pump and motor. The barrier protects the pump and motor from the radiant energy generated in a floor based fire, which could impact the redundant CCW pumps.

In the Electrical Tunnels, one channel of safe shutdown instrumentation is wrapped in a one hour fire rated barrier at both ends of the Tunnels where the redundant safe shutdown channels are not separated by 20 feet or by concrete floor/ceiling assembly which separates the upper and lower tunnels.

This protection, combined with the detection and suppression systems located within the tunnels, constitutes compliance with Section.III.G.2.c of Appendix R.

Specifically, channel IV safe shutdown instrument cables exiting the containment in the upper electrical penetration area are protected in a one-hour fire rated barrier until the cables pass through the floor into the lower electrical tunnel. Pressurizer pressure and level, steam generator level, RCS loop 31 hot and cold temperature instrumentation cables routed in the JD cable trays are wrapped. Source range neutron detector conduit (N-31) is also wrapped in a one-hour barrier.

Within the Turbine building, the fire protection features installed at each of the cubicles of Manhole 33 provide separation between the power feeds to normal service water pumps and those of Back-up Service Water Pump 38. These features have been evaluated in accordance with the guidance of Generic Letter 86-10 and found acceptable.

An exemption to the requirements of Appendix R, Section III.G.2 has been granted to the extent that the redundant wide-range steam generator water level sensing lines and the redundant pressurizer level sensing lines, located inside containment, need not be separated by non-combustible radiant energy shields.

9.6.2.3 Fire Suppression Systems

The Fire Protection System for Indian Point 3 was originally designed as an extension of the Fire Protection System for Indian Point 1, owned by Consolidated Edison. After incorporation of a series of modifications the Indian Point 3 Fire Protection System was made independent from the Indian Point 1 Fire Protection System and met the criteria (GDC 3) specified in Section 1.3 (see Plant Drawings 9321-F-40903, and -40913 [Formerly Figures 9.6-9A and 9.6-9B]).

Water Supply and Distribution System

A separate fire water supply system was installed at Indian Point 3 and was connected to the Fire Protection System. The supply system consists of two 350,000 gallon storage tanks and their associated piping, electrical and instrumentation systems, which serve as the source of fire protection system water and as the supply for the Indian Point 3 makeup water treatment

IPEC00036085

facility. The supply to the tanks is from the City Water System and is automatically controlled to maintain a minimum of 300,000 gallons of water in each tank dedicated for fire protection.

The Indian Point 3 Fire Protection System is provided with one 2500 gpm motor driven fire pump (110 psig) and with one 2500 gpm diesel driven fire pump (110 psig). The motor driven fire pump is powered through a transfer switch from two sources: 480v Switchgear 312 BKR 3B (Normal) and 480v Switchgear 5A, BKR 24D (Emergency). System pressure is maintained by two motor driven jockey pumps. Control valves at the fire pumps are electrically supervised. The fire pumps are located in the fire pumphouse and are separated by a concrete wall; the jockey pumps are also located within this building.

The fire pumps are sized based on the largest water demand. The largest water demand is comprised of the largest assumed sprinkler system demand or water spray system demand plus an assumed hose stream demand of 750 gpm. The largest water demand is the assumed demand for the wet pipe sprinkler system provided for the Turbine Building, elevation 15'0", north half of the building plus an assumed hose stream demand of 750 gpm, or approximately 3,120 gpm. The design considerations used in evaluating the acceptability of the water supply and distribution system included the ability to supply the largest water demand assuming a failure of either fire pump.
The fire water distribution system is designed as a loop system to permit water flow in either direction. Sectionalizing valves are located throughout the system to permit isolating portion of the system for repairs or maintenance activities without impairing the entire system or isolating a break without affecting both the standpipe and fire suppression systems protecting a safety related area. Sectionalizing valves are shown in Plant Drawings 9321-F-40903, and -40913 [Formerly Figures 9.6-9A and 9.6-9B]. Sectionalizing valves are either post-indicator type, key operated type (i.e., a buried valve with a roadway box) or OS&Y type. The position of all valves in the fire water distribution system, except key operated valves, whose closure may cause loss of fire water supply, are supervised by either electrical tamper switches, locks and chains, or tamper proof seals, and periodically visually inspected to ensure that the valve is in its correct position. The position of key operated valves are periodically manipulated to ensure that the valve is in its correct position. Marking signs denote the location of key operated valves in the yard.

Fire protection is provided to the exterior plant areas by yard fire hydrants. Hydrants can be removed from service for repair without shutting off a portion of the fire loop, by means of auxiliary gate valves which are provided on each hydrant lateral. Hydrants exposed to traffic are provided with vehicle barricades and post-indicator valves. Hydrants are of the dry barrel type which self drain to prevent freezing of the hydrant. Hose houses are provided at each of the fire hydrants and at the test header at the pump house. Fire hose and other required equipment is provided at these hose houses. National Standard (NH) fire hose threads provided on all hoses, nozzles and fittings at hydrant hose houses are compatible with offsite fire department.

Valved branches from the underground fire loop system supply interior fire protection lines in the enclosed sections of the plant.

Fire Hose Stations

The plant fire water protection loop supplies standpipes in the following buildings:

Administrative Services Building

IPEC00036086

Radioactive Machine Shop
Primary Auxiliary Building
Fuel Storage Building
Fan House
Control Building
Auxiliary Feedwater Pump Building
Outage Support Building
Condensate Polisher Building
Auxiliary Boiler Building
Intake Structure
Security Building
Turbine Building

The standpipe are generally located in protected stairways and each contains drain valves, hose racks/ reels on each landing, and an air vent valve or venting capability.

Standpipes and hose racks/reels are located such that all portions of each elevation of the building are within 30 feet of a nozzle, attached to not more than 100 feet of 1-1/2 inch fire hose except as described below.

The Electrical Tunnels including electrical penetration areas are protected by the fire hose station on the 54 foot elevation of the Fan House and the station located on the 33 foot elevation of the Control Building, east stairway. The fire hose station in the Control Building can be augmented with 300 feet of 2 inch fire hose and valved wye to ensure coverage of all areas of the Electrical Tunnel. The pump and motor area on the waste holdup tank pit area is protected by the fire hose station located on the 41 foot elevation of the Primary Auxiliary Building. Fire hose stations inside the Containment Building are provided to protect areas containing a significant amount of electrical cable and the areas around the reactor coolant pumps (RCPs). In addition to the fire hose stations located in the east stairwell of the Control Building, the fire hose stations in the Turbine Building are located so that they can also be used to fight a fire in portions of the 480V switchgear room, cable spreading room, battery rooms, control room and Diesel Generator Building.

Control valves are provided for standpipes protecting safety related areas at the distribution header connection to allow isolation of individual standpipes without affecting other standpipes. Control valves for these standpipes are shown on Plant Drawings 9321-F-40903, and -40913 [Formerly Figures 9.6-9A and 9.6-9B].

Fire hose with national standard (NH) hose threads, nozzles and fittings, and suitable spanner and valve wrenches are provided at each hose station. Yard post-indicator valves and interior control valves are tagged to indicate the standpipe system or area served.

Water Fire Suppression Systems

The cable trays in the electrical tunnels and penetration areas are protected by preaction water spray systems which use automatic (i.e., closed head) directional water spray nozzles. Heat detectors installed in the cable trays operate the deluge valves associated with these systems. The heat detectors have a nominal setting of 165°F. The automatic directional water spray nozzles actuate at 175°F. The systems are provided with separate feeds from the yard fire water header such that failure or isolation of any section of yard piping would not incapacitate the systems.

IPEC00036087

The turbine governor and turbine generator bearings 1-9 are protected by a preaction water spray which uses automatic (i.e., closed head) directional water spray nozzles. The system deluge valve is operated by heat detectors which have a nominal setting of 190°F. The automatic directional water spray nozzles operate at 212°F.

A wet pipe sprinkler system has been provided to serve the following areas:

a) Diesel Generator Building (diesel generator sumps and day tanks)
b) Turbine Building at Elevation 15'0" and 36'9" (Turbine oil piping & general area)
c) Auxiliary Feedwater Pump Room
d) Outage Support Building
e) Auxiliary Boiler Annex Building (Boiler room at Elevations 15'0" and 35'0")
f) Administration Services Building at Elevation 15'0"
g) Receiving Warehouse (warehouse, paint vault and office area)

A preaction sprinkler system serves the Containment Access Facility Annex. Heat detectors are provided that actuate the system.

The following hazards / areas are protected by automatic water spray systems which use open spray nozzles and are designed to actuate by heat detectors:

a) Unit auxiliary transformer
b) Main transformers, No. 31 and No. 32
c) Station auxiliary transformer
d) Wall between the Turbine Building and main transformer No. 31 and the unit auxiliary transformer including the area between the main transformer No. 31 and the unit auxiliary transformer

e) Wall between the Turbine Building and the pipe bridge to the Auxiliary Feedwater Pump Building.

The following hazards/areas are protected by a manually actuated water spray system which uses open spray nozzles:

a) Main boiler feedwater pumps.
b) Charcoal filters associated with the Containment Building fan cooler units.
c) PAB door adjacent to the transformer yard

The Demineralized Water System (see Section 9.11) provides the supply of water for fire protection inside the Containment Building during normal plant operation. The system connects either one of two sources to nine fire hose racks located inside the Containment. The two sources are as follows:

1) The plant Makeup Demineralizer
2) The Fire Protection Header in the pipe tunnel area.

Portable CO_2 extinguishers are provided during maintenance periods.

The Reactor Containment has little combustible equipment. The greatest fire hazard is from the reactor coolant pump oil collection system. This system provides the capability to collect oil

IPEC00036088

from potential leakage points including oil fill points, lower central units, upper bearing cooler, lift pump and piping, and provides drainage to a container.

The Indian Point 1 Fire Protection System can be utilized as a backup to the Indian Point 3 Fire Protection System, and is tied to the Indian Point 3 system but normally valved out. Control valves on water spray, sprinklers and foam systems are electrically supervised.

Gas Fire Suppression Systems

The CO_2 Fire Protection System is provided with two ten-ton capacity low pressure tanks, a distribution header and associated piping and valves. Storage is maintained at minimum pressure of 275 psi and 0°F. An electric vaporizer is located downstream of the storage tanks for generator purging; the vaporizer has no fire suppression system function (see Section 10.2).

An automatic total flooding carbon dioxide (CO_2) fire suppression system is provided to protect the following areas:

a) 480V switchgear room
b) Cable spreading room
c) Each of the three diesel generator rooms
d) Turbine generator exciter enclosure

The total flooding CO_2 fire suppression systems are actuated by heat detectors; they can also be manually actuated by a local manual station.

A local application CO_2 fire suppression system is provided to protect the following hazards in the Turbine Building:

a) Main boiler feedwater pumps 31 and 32
b) Turbine governor, main steam and re-heat valves and generator bearings, 1, 2 and 3
c) Turbine generator bearings 4, 5, 6 and 7
d) Turbine generator bearings 8 and 9

The CO_2 fire suppression systems protecting the main boiler feed pumps are actuated by heat detectors; they can also be manually actuated by a local manual station. The CO_2 fire suppression systems for the turbine governor and bearings are individually operated by manual stations located on the turbine deck.

Each CO_2 fire suppression system incorporates two types of discharge control timers, a pre-discharge timer and a discharge timer. The pre-discharge timer is adjusted to insure sufficient time for personal evacuation following a manual or automatic system actuation. The discharge timer regulates discharge duration to ensure sufficient agent delivery. The capacity of the CO_2 tanks is sufficient for a second discharge. The systems annunciate alarm and trouble, including a loss of power, in the control room on the fire display control panel (FDCP).

Foam Fire Suppression Systems

Automatic, fixed mechanical, heat detector actuated, foam-water deluge systems are provided in the Turbine Building protecting the turbine oil storage tank, reservoir and conditioner; the boiler feed pump lube oil reservoir, oil accumulators, and oil console; and the hydrogen seal oil

IPEC00036089

reservoir. The foam systems also supply the interior hose stations located near each protected area.

Portable Fire Extinguishers

Portable fire extinguishers have been provided throughout the plant in accordance with the requirements of the NFPA standards. These extinguishers consist of dry chemical, CO_2, halon, foam, MET-L-X, and water types. The Control Room is provided with a "Class A" rated portable extinguisher.

Fire Protection System Leak Detection

Detection of leaks or breaks in the Fire Protection System is provided either by visual observation of the break or by information relayed to the Control Room.

Constant surveillance of the Turbine Building and Control Building is provided by personnel assigned to these areas. Locations outside these buildings are patrolled.

The flow of water in any part of the plant fire protection piping resulting from the use of water in any portion of the Fire Protection System or a pipe break causes a pressure drop in the piping system which automatically starts the fire pumps.

Startup of the main fire pumps is alarmed in the Control Room. Upon acknowledging the startup of these pumps, the responding operator checks for indication of water flow in any one of the water based fire suppression systems. If no apparent cause is identified, an investigation into the cause is initiated, which if necessary, will include an inspection for evidence of a pipe break.

If the break is so located that it cannot be seen or be readily isolated, sections of the Fire Protection System can be isolated under the direction of the Shift Manager. Isolation of the leak is indicated by a return to normal operation of the pressure maintenance and booster pumps or by visual indication that water flow has stopped.

The preaction water spray systems in the electrical tunnels and penetration areas are provided with a supervisory air system. The system piping is maintained under air pressure and monitored. Upon loss of air pressure due to system actuation, a leak or a pipe break, an alarm is sounded in the control room on the Fire Display Control Panel (FDCP).

Fire Drains and Associated Monitors

Fixed fire suppression systems have not been installed where their operation or failure could cause unacceptable damage to safety related equipment.

All areas provided with automatically operated fire protection have either gravity or pump drains. These drains were designed to handle the maximum quantity of spray water and/or oil (tank or pipe rupture) spills and will prevent local flooding.

In addition, all automatic fire protection systems are monitored to alarm in the Control Room when a system has been actuated by a fire or a possible false trip. Operators, on such a signal, are dispatched to the fire area and can, in the unlikely event of a partially plugged drain, control the water flow to the system by sectionalizing valves provided. Within the Diesel Generator

IPEC00036090

Building, each control panel is protected from the effects of the sprinkler system spray. An accidental operation of the sprinklers will not cause an unsafe plant condition.

At Indian Point 3, with the exception of the CAF Annex, there is no sprinkler or deluge system installed in the following radioactive or potentially radioactive areas: Containment Building, Primary Auxiliary Building, Fuel Storage Building and Waste Holdup Tank Pit. Therefore, control and/or storage of this effluent is not a requirement. In these areas, floor drains are provided which are connected to either sump or sump tank. From there, effluent is pumped to a Waste Holdup Tank.

The Containment Access Facility Annex, which is used as a handling area for contaminated material, is protected by a preaction sprinkler system. Inadvertent sprinkler discharge is not likely. Additionally, a six-inch curb is provided on the annex floor to contain potentially radioactive system effluent.

9.6.2.4 Fire Detection System

The plant has a protective signaling system that transmits fire alarm and supervisory signals to the control room where audible and visual alarms are provided. The system includes signals for actuation of fire detectors, status of most installed fire suppression systems, control and indicating lights for the fire pumps, level indicators for the fire water storage tanks, and door status indicating lights for the operator notification of critical fire doors. Electrical supervisory signals are received from tamper switches on some of the fire water system control valves.

Portions of the Fire Detection System are supplied AC power from a lighting panel which is shed on loss of offsite power. However, the lighting panel is connected to the emergency power system and, on loss of normal AC power, is immediately restored by the operator to provide illumination in critical plant areas and thus also to restore power to the detection and signaling system.

The system provides electrical supervision of circuits for detectors in areas containing equipment and electrical cables needed for safe shutdown. Other detector circuits which are not electrically supervised are tested at various frequencies between 6 and 24 months, depending on the system protected.

Smoke detectors are provided at seven locations inside the Containment Building; at each of the four reactor coolant pumps, one at the electrical penetration areas, and two in other areas containing concentrations of electrical cable. The smoke detectors are directly connected to the fire display and control panel in the Control Room.

The Control Room is provided with smoke detectors. These detectors are installed above and below the Control Room false ceiling.

Smoke detectors have also been provided in the Electrical Tunnels, electrical penetration areas, Cable Spreading Room and 480 volt Switchgear Room. Heat detectors are provided in the Diesel Generator Building, and are used to actuate water spray systems on yard transformers, foam systems on Turbine Building oil hazards, and actuate the preaction water spray systems in the electrical tunnels and penetration areas. Heat detectors are provided in charcoal filters.

Smoke detection is provided in many fire zones within the PAB and throughout the Auxiliary Feedwater Pump Room.

IPEC00036091

There are numerous areas containing significant safety-related equipment and electrical cables that are provided with fire detection. These are detailed in Section 9.6.2.9. A complete listing of fire detection systems provided in each fire area is provided in the Fire Hazards Analysis (FHA). The FHA will be maintained by periodic updates.

A discussion of detection system redundancy within some areas of interest follows:

a) Switchgear Room (Control Building, El. 15'-0" and Cable Spreading Room (Control Building, El. 33'-0").

Smoke detectors installed in these areas are wired in parallel so that the failure of one unit will not affect the integrity of the alarm system. These detection devices alarm in the Control Room.

Smoke detectors are capable of sensing the products of combustion when a fire is in the incipient stage. This time delay will permit an operator to investigate the area, make an evaluation and initiate actions to control and subsequently extinguish a fire.

Heat detectors are also installed in both rooms to activate the CO_2 fire suppression system. The heat detector actuating system consists of two detectors wired in series and the pair connected in parallel with other pairs wired in the same manner. Failure of one pair will not affect the integrity of the actuating system. The heat detector actuating system for the cable spreading room CO_2 fire protection system also initiates closure of the fire door located between the cable spreading room and the Electrical Tunnels.

b) Electrical Tunnels and Electrical Penetration Areas

Smoke detectors installed in these areas are wired in parallel so that the failure of one unit will not affect the integrity of the alarm system. These detection devices alarm in the Control Room.

Smoke detectors are capable of sensing the products of combustion when a fire is in the incipient stage. This time delay will permit an operator to investigate the area, make an evaluation and initiate actions to control and subsequently extinguish a fire.

Heat detectors installed in the cable trays in these areas are wired to operate the deluge valves associated with the water spray systems to flood the system piping.

Heat detectors are also installed in the entryway to the Electrical Tunnels to release the fire door located between the cable spreading room and the Electrical Tunnels. The automatic release system consists of two detectors wired in series and the pair connected in parallel with another pair wired in the same manner. Failure of one pair will not affect the integrity of the release system.

c) Emergency Diesel Generator Rooms

IPEC00036092

There are several heat detectors in each of the Diesel Generator Rooms for initiating an alarm in the Control Room some of which also actuate the automatic total flooding CO_2 system. The heat detector actuating systems consist of two detectors wired in series and the pair wired in parallel with other pairs wired in the same manner. Failure of one pair will not affect the integrity of the actuating system. The CO_2 heat detector actuating system also initiates closure of the EDG Room Smoke Dampers and secures the ventilation fans.

Indication of the control room alarm will summon an operator to the area in trouble. The operator will investigate and determine the reason for the alarm.

d) Primary Auxiliary Building

Smoke detectors are installed outside the Residual Heat Removal Pump rooms on the 15' elevation and within each pump room, in the vicinity of the Component Cooling Water Pumps and Containment Spray Pumps on the 41' elevation, and in each Charging Pump cubical on the 55' elevation. In addition, smoke detectors are installed in the floor area underneath the motor control center cubicles on the 55' elevation of the PAB. The installed fire detection instruments provide thorough coverage of all floor elevations in the PAB on which safe shutdown equipment is located.

9.6.2.5 Safe Shutdown Capability in Case of Fire

Several options are available to plant operators whereby safe shutdown can be achieved following a fire. The evaluation of Indian Point 3 to the requirements of Section III.G of Appendix R to 10 CFR 50 identified the necessary systems and equipment which could be utilzed to bring the plant to a safe shutdown condition given a fire in any fire area. In accordance with the rule, the availability of equipment is ensured such that the following performance goals are met:

1) Reactivity Control - insert sufficient negative reactivity into the reactor core to maintain the core subcritical with the appropriate shutdown margin.

2) Reactor Coolant Makeup - maintain the primary system water inventory to prevent unacceptable fuel failure due to cladding heatup.

3) Reactor Coolant System Pressure Control - provide overpressure protection prior to a controlled cooldown and control of pressure for adequate subcooling margin.

4) Decay Heat Removal - remove decay heat at the appropriate rate for maintaining shutdown.

5) Processing Monitoring - provide sufficient information with regard to primary and secondary system parameters necessary to ensure maintenance of safe shutdown.

6) Support Services - provide the necessary support of systems required to achieve and maintain the above performance goals.

IPEC00036093

The performance goals are met utilizing the control rods; chemical and volume control system; closed cooling water system; auxiliary feedwater system; main steam system including steam generator, code safety valves and atmospheric steam dump valves; service water system; emergency power system; and certain instrumentation.

Where feasible, redundant safe shutdown trains are located in separate fire areas. In cases where the redundant safe shutdown trains are located in the same fire area, a combination of compliance with the requirements of Section III.G.2 and III.G.3 of Appendix R to 10 CFR 50 has been ensured or exemptions have been granted.

Alternate Shutdown Capability

There are two alternative shutdown schemes credited in compliance to Section III.G.3 of Appendix R that utilize an alternate diesel generator.

One alternate shutdown scheme makes use of local control stations in the Auxiliary Feedwater Pump Room, the Primary Auxiliary Building and the Turbine Building to affect shutdown following a fire that requires safe shutdown from outside the control room. The other alternate shutdown scheme makes use of the alternative diesel generator aligned to the 480V Vital Buses to ensure safe shutdown from the control room. The alternate diesel generator is a dedicated 2500 kw diesel generator and is located in its own enclosure in the yard area north of the Auxiliary Feedwater Pump Room.

AC power generated by the alternative diesel generator can be supplied to the 6.9 kv buses 5 and 6. These buses in turn feed 6.9 kv buses 1 and 3, which supply 480v to buses 312 and 313 through stepdown transformers. The 480 V bus 312 also feeds power distribution panel PDP-TG-1, which supplies 120 V ac power via a stepdown transformer to the instrument isolation cabinets thereby providing an alternative power supply to the safe shutdown instruments. The instrument isolation cabinets are located in the upper tunnel in the electrical penetration area.

The alternative 480 V ac switchgear 312A is powered by 480 V bus 312 directly or from bus 313 through the use of a tie breaker. The switchgear 312A feeds the following selected safe shutdown components:

- CCW pump 32
- Backup Service Water pump 38
- Charging pump 31 or 32

Component Cooling Water Pump 32 Charging Pumps 31 or 32 are powered through transfer switches, which are manually operated in the vicinity of each pump, respectively. The power supply to Backup Service Water Pump 38 is direct wired.

Supporting services for the Appendix R ac power source are independent from the supporting equipment used by the three emergency diesel generators (e.g., service water cooling, 125V dc control power, starting air HVAC, and fuel oil).

The alternative power system, as previously described, is designed to be independent and sufficiently isolated from the existing emergency power system to ensure the availability of power to the safe shutdown pumps and instruments of concern in the event of fire in the Control and Diesel Generator Buildings. In the case of a fire affecting certain portions of the Primary Auxiliary Building and Electrical Tunnels which could disable emergency diesel generator

IPEC00036094

auxiliaries, the alternate diesel generator can be used to power the 480V Vital Buses to ensure safe shutdown from the control room.

In addition to the alternate diesel generator and power supply system, the capability exists to isolate the control circuits of emergency Diesel Generator No. 31, feeder breakers to 480v Buses Nos. 2A and 3A, and the tie breaker between Buses Nos. 2A and 3A. This design feature permits the operation of the normal emergency power supplies (Diesel Generator No. 31) in the event of a fire in the Cable Spreading Room or Control Room.

Switchboard type rotary selector switches in wall mounted cabinets at the Diesel Generator Control Panel for the control circuits and in floor mounted cabinets at the penetrations for the instrumentation are used. The alternate power supplies are in a floor mounted cabinet at the penetration area and they are supplied by a common 120 volt single phase source powered by Diesel Generator No. 31. When the isolation switches are in the "normal" mode, all aspects of diesel generator and 480 volt breaker control and instrument loop operation are not affected by these features. When transferring from the "normal" to "isolation" mode for these circuits, an alarm for both the diesel and the instrumentation will be initiated on the Control Room annunciator. If all the isolating switches are not operated, a local audible alarm is initiated, the "normal" indicating light is extinguished and incomplete sequence indicating light comes on. An acknowledge push button is provided to silence the audible alarm on the diesel generator isolation switch cabinet. When all the isolating switches are operated, the audible alarm will be reset and the incomplete sequence light is extinguished. The Diesel Generator and the designated breakers can be controlled only from the diesel generator panel with all remote wires passing through the cable spreading area being disconnected from the control circuit and all bypasses required for local operation mode. For the instrumentation (i.e., pressurizer pressure, pressurizer level, steam generator level, hot and cold temperature), when the isolating switches are operated, the alternate local power supply is inserted in the series loop and those sections of loop in Control and Cable Spreading Rooms are disconnected and bypassed with indication available only at the local stations in the Auxiliary Feed Pump Room and the Primary Auxiliary Building.

Instrumentation for both normal and alternate shutdown has been protected in accordance with the requirements of Section III.G of Appendix R. The plant process parameters, which are credited in the Safe Shutdown Scheme included:

a) Primary system wide range hot and cold leg temperature for loop 31.
b) RCS wide range pressure.
c) Pressurizer level.
d) Steam Generator pressure and wide range level.
e) Source range neutron flux.

The cooldown strategy is based upon a stepwise cooldown. Instrument uncertainty assumptions presume at least one fan cooler unit in service (by repair) within 8 hours of commencement of cooldown. During the cooldown, T_{cold} can be determined using local steam pressure indicators PI-2531 through PI-2534 and steam tables.

In order to minimize the effects of instrument uncertainly on pressure indication, the wide range RCS pressure indicator PT-402 will be compared against local pressure indicator PI-475 or PI-476 at the time of RHR cut-in. PI-475 and PI-476 have smaller uncertainties than PT-402. Comparing these instruments will establish a measurement bias that can be used with PT-402 throughout the remainder of the cooldown process. PI-475 and PI-476 are local pressure

IPEC00036095

gauges located on the 46' level on Containment and associated with RCS Loops 34 and 31, respectively.

Instrument isolation and transfer cabinets are located in the upper electrical penetration area. In the event of a fire in the Control Building, the safe shutdown instrumentation circuits can be isolated from the Control Building the Safe Shutdown instrumentation circuits can be isolated from the Control Building and indications transferred to the local control stations in the PAB and Auxiliary Feedwater Pump Room.

The local control station in the PAB is located outside the charging pump cubicles on the 55' elevation on Panel PL-6. Indications of pressurizer level, RCS pressure and source range neutron flux are available on PL-6. Operators at this location will control RCS boration and makeup with the charging pumps.

The local control station in the Auxiliary Pump Room, Panel PT2, is at elevation 18'6". Indications of steam generator water level and pressure, pressurized level, RCS pressure, and RCS Loop 31 hot and cold leg temperature are available at this panel.

Steam generator pressure indication is also available at the atmospheric steam dump valve local stations on the 43' elevation of the Turbine Building above the Auxiliary Feedwater Pump Room.

Local operation of the Auxiliary Feedwater Pumps would be accomplished in the Auxiliary Feedwater Pump Room for the turbine driven pump and at the emergency switchgear (in the Control Building), for the motor driven pump.

A permanent backup nitrogen supply consisting of nitrogen bottles and piping is provided for the steam generator atmospheric dump valves in the auxiliary feedwater pump room. For a fire in the auxiliary feedwater pump room, nitrogen bottles and piping connections are provided independent of the AFWP room, located on the 43' elevation of the Auxiliary Feedwater Building near each local atmospheric dump valve control station.

9.6.2.6 Emergency Lighting

Self-contained emergency lighting units are installed throughout the plant. These units supplement the normal emergency lighting, which is powered from the emergency diesel generators. In the event the emergency diesel generators are inoperable or the diesel generator supplied emergency lights are damaged due to the fire, the self-contained units will provide the necessary illumination for operators to perform safe shutdown functions.

Each emergency lighting unit is compressed of a minimum eight-hour rated battery with a charger for operation from a 120V ac source. The emergency lighting units are supplied from "normal" lighting branch circuits. Pursuant to Section III.J of Appendix R to CFR 50, units are located in areas of the plant where safe shutdown operator action will be performed. Access and egress routes to these areas are also provided with emergency light coverage. Coverage of the yard area for access and egress to the alternate diesel generator, the main and backup Service Water pumps, CST or RWST, is provided by the Security Lighting System. The Security Lighting System is powered by a propane fueled generator which provides the necessary 8-hour power supply to the lights.

IPEC00036096

An exemption from the requirements of Section III.J of Appendix R has been granted (by Reference 1 and Reference 6) which allows credit for the security lighting system in lieu of eight-hour self-contained emergency light units for yard area coverage.

9.6.2.7 Reactor Coolant Pump (RCP) Oil Collection System

An oil collection system is provided for each of the reactor coolant pump motors. Oil leakage is collected and drained to tanks (one for each motor), which are located at approximately 48'6" in the containment. Each tank can accommodate the entire oil capacity of one pump motor. The tank vents are provided with flame arrestors to prevent flashback.

For RCP 31, 32, and 34, the oil collection piping from the collection tank to the lower drip pan is permanently installed. System piping, splash shields and drip pans above the lower drip pan are removable to facilitate maintenance on pump motor. For RCP 33, the oil collection piping from the collection tank is directly connected to the system piping above and is connected by means of flexible hose to the oil collection enclosures attached to the pump motor.

The seismic capability of the oil collection system has been evaluated as part of the requirements of Section III.O of Appendix R to 10 CFR 50. The results of the evaluation demonstrate that the system will withstand the Safe Shutdown earthquake.

9.6.2.8 Fire Brigade (Manual Fire Fighting)

A five-person fire brigade is available on-site to perform manual fire fighting activities. The brigade members are trained in various phases of fire fighting through academic and "hands on training." The qualifications of each member of the brigade include satisfactory completion of training and a physical examination. The physical examination is intended to identify any condition that would prevent members from participating in strenuous activities such as fire fighting.

Yearly meetings of brigade members are held during which all classroom instruction material is reviewed. Additionally, practice sessions which provide actual experience in fire extinguishment and use of emergency breathing apparatus are provided yearly for each member. Drills are held at approximately quarterly intervals including one drill conducted on a back shift yearly. A maximum extension of 25% (three (3) months) is permitted for yearly training frequencies. A one-time change to the grace period was made for Fall 2001 yearly retraining of Security Department fire brigade members. The grace period was changed from 25% to 50% (six months). All brigade members participate in at least two drills per year. Once per year, the offsite fire fighting organizations are included in drills.

Protective clothing, portable smoke removal equipment, self-contained breathing equipment, portable hand lights, and radios are provided at strategic locations throughout the plant for use by the fire brigade. There are several self-contained breathing units on the site and a manifold cylinder emergency air supply for control room operators. Additional breathing appliance, spare cylinders and recharge capability are provided so that 10 men can be supplied for 6 hours on the basis of three air cylinders per man per hour. Breathing units are located near the Containment Air Lock, and the CO_2 flooded areas, such as the Cable Spreading Room, the Switchgear Room and the Diesel Generator Rooms and fire brigade lockers. In addition, there is an on-site compression and cascade system. Three portable smoke ejectors with a combined capacity of 1500-20000 cfm are available for fire brigade use. Portable ventilation

IPEC00036097

equipment is available for those fire scenarios where HVAC systems are lost due to a fire. Portable heating units are also available for those fire scenarios where HVAC system are lost due to a fire. Portable heating units are also available for those fire scenarios where heat tracing is unavailable and piping freezing is possible.

9.6.2.9 Fire Protection of Specific Plant Areas and Equipment

A fire hazards analysis of the facility has been performed to determine the fire loading of various plant areas, to identify the consequences of fires in safety related and adjoining non-safety related areas, and to evaluate the adequacy of the Fire Protection System. The principal features for protection of specific areas are discussed in the following paragraphs.

Primary Auxiliary Building

Elevation 15, 34 and 41 Feet

Safe shutdown-related equipment at these elevations of the Primary Auxiliary Building include the two residual heat removal pumps, and three component cooling pumps, with associated valves and electrical cables. Electrical cables for two of the three charging pumps also pass through this area.

Smoke detectors are installed in the residual heat removal, containment spray, and component cooling water pump room, and fire hose stations are provided to reach all portions of these elevations. Fire suppression capability is also provided by portable fire extinguishers.

Elevation 55 feet

Safe Shutdown equipment on this elevation includes the three charging pumps, component cooling water heat exchangers, and associated piping, valves and electrical systems. One of the panels used for shutdown if the Control Room is not habitable is located in this area.

The Authority has installed smoke detectors in the motor control center area, waste drum storage room, charging pump room and the corridor outside the charging pump rooms. Fire hose stations have been provided to reach all portions of the area. Additional fire suppression capability is provided by portable extinguishers.

The Authority has installed additional communication equipment to enhance communications within the Primary Auxiliary Building, and improve overall communications between the CVCS charging pump control panel and all other areas needed for safe shutdown of the plant during a fire, should the control room become inaccessible.

Control Building

Cable Spreading Room

This area contains power, instrumentation and control cables for safety-related systems, some of which are required for shutdown. System involved include charging pumps service water pumps, component cooling pumps, auxiliary feedwater pumps, residual heat removal pumps, and atmospheric relief valves. Equipment located in this area consist of RPS motor generator sets, DC inverters and battery chargers.

IPEC00036098

Fire detection is provided by smoke detectors located at ceiling level. Fire suppression capability is provided by water hose stations and portable fire extinguishers. Water hose stations are in the Turbine Building, and at the east end of the Control Building at the Cable Spreading Room elevation. An automatic total flooding CO_2 system actuates on signals from installed heat detectors.

Battery Rooms

Three of the four redundant safety batteries which supply DC power to safe shutdown systems are each housed in their own individual enclosure within the Cable Spreading Room. Within the cable spreading room, battery rooms 31 and 32 are located adjacent to each other separated by a concrete masonry block wall, and battery room 34 is located on an opposite wall detached from the other two battery rooms. Each battery room is constructed of concrete masonry units. The fourth battery (33) is located in diesel generator room 31. A fifth battery (36), which is a non-safety battery, is housed in a concrete masonry block enclosure within the Turbine Building Hall Extension.

Flame detectors have been installed in the three safety battery rooms and diesel generator room 31, which houses the fourth battery. Smoke detectors have been provided in Battery Room 36. Procedures specifically require a periodic check of instrumentation to verify battery room ventilation flow.

Switchgear Room

This area contains the 480 volt switchgear along with the power and control cables for both redundant divisions of safety-related equipment, including the following safe shutdown equipment: charging pumps, component cooling pumps, auxiliary feedwater pumps, service water pumps, and residual heat removal pumps.

The significant combustibles in the area are lightly loaded cable trays stacked, at most, three high. The Switchgear Room also contains instrument air compressors which have a lube oil system with several gallons of lube oil each.

The switchgear are in separate metal enclosures and separated such that an unmitigated fire in one switchgear would not affect the redundant switchgear.

Protection for this area includes an automatic total flooding CO_2 system, smoke detectors at the ceiling, portable fire extinguishers and hose stations that are nearby.

Control Room

The Control Room contains cabinets and consoles within which are cables and components for safety-related systems including those systems required for safe shutdown of the plant. Manual water hose stations and portable CO_2 extinguishers provide the extinguishment capability. Fire protection equipment also includes a fire hose station at the east end of the Control Building at the Control Room elevation. With this hose station, adequate coverage is provided in the Control Room. In addition, a portable type "A" rated fire extinguisher is available in the Control Room. Smoke detectors installed above and below the Control Room false ceiling provide adequate area-wide detection capability. Smoke detectors are also installed in Control Room walk-in panels.

IPEC00036099

Electrical Tunnels

The plant contains two electrical tunnels separated by a one-foot thick concrete barrier. In general, redundant cables are in separate tunnels. The electrical tunnels contain power, control and instrumentation cables for safety equipment located in the Primary Auxiliary Building, Containment Fan House, and Auxiliary Feedwater Building Pump House. The upper tunnel contains power cables for two of three safety injection pumps, two of three component cooling water pumps, one residual heat removal pump, two of three charging pumps, one motor-driven auxiliary feedwater pump, and control cables for atmospheric relief valves. The lower tunnel contains power cables for one component cooling pump, one residual removal heat pump, one of three charging pumps, and control cables for atmospheric relief valves.

The cable trays in the electrical tunnels and penetration areas are protected by pre-action water spray systems. The electrical tunnels and penetration areas are also provided with smoke detectors which alarm in the Control Room These systems are supplemented with portable CO_2 fire extinguishers. Fire hose stations in the Fan House and Control Building equipped with fog nozzles approved for Class C (electrical) fires, serve the electrical tunnels and penetration areas. At the Control Building end of the electrical tunnels is a common area (i.e. Electrical Tunnels entryway) where cabling from both electrical tunnels is located in two stacks of trays horizontally separated by approximately six feet. Separate pre-action water supply systems are provided for each group of trays. One train of safe shutdown instrumentation is to enclosed in a 1 hour fire wrap.

For a fire in the upper electrical tunnel, which contains circuits required to support operation of emergency diesel generator auxiliaries, the shutdown strategy is to utilize the alternate diesel generator aligned to the 480V vital buses located in the Control Building.

At the containment end of the cable tunnels in the upper electrical penetration area, all Safe Shutdown instrumentation passes out of the containment. One train of Safe Shutdown instrumentation is protected in a one hour barrier from the containment wall until it drops through the floor into the lower electrical tunnel. The metal wall surrounding the stairway between the lower and upper electrical penetration areas has been evaluated for its adequacy to protect the upper electrical tunnel/penetration area from a fire in the lower electrical penetration area. An exemption from specific requirements of Section III.G.2.a, of Appendix R applies to this wall.

Two openings have been provided in the hatchway above the upper electrical penetration area. These openings accommodate two smoke ejectors. The ventilation capability will facilitate manual fire fighting and Safe Shutdown.

Turbine Building

There is no safety related cable or equipment located within the building.

Automatic foam systems are provided for the turbine lube oil storage and reservoir, the boiler feed pump lube oil reservoir, oil console, oil accumulators, and the hydrogen seal oil unit. The foam systems have actuation alarms in the Control Room to provide fire notification to plant personnel. Foam hose stations are provided near these hazards. Manual fire hose stations and portable extinguishers are also provided throughout the Turbine Building.

IPEC00036100

Three-hour rated fire doors and dampers are provided in the barrier between the Turbine Building and Control Building. An alarm is installed on the fire doors between the Turbine Building and Control Building were upgrade to meet a three-hour fire rating. The door between the Control Room and Turbine Building is a three-hour equivalent fire rated door.

To provide overall fire protection in the Turbine Building, for areas containing lube oil lines, automatic sprinklers are provided below the operating floor on Elevation 15'0" and 36'9". Manually actuated water spray systems are provided for the main boiler feed water pumps and an automatic water spray is provided to protect the turbine governor and bearings.

Intake Structure

Six service water pumps are located within a seismically designed, steel-framed grating enclosure at the intake structure, and three back-up service water pumps are located on a platform over the discharge channel. At least one of these pumps may be required to achieve cold shutdown.

Fire hose stations are located at the North and South ends of the building at elevation 15'. Fire detection is provided by photoelectric type smoke detectors. Yard hydrants and hose are available for manual fire fighting in the area. Hose houses, equipment with fire hose and other fire fighting tools have been located in the yard area, so as to afford protection to the service water pumps.

Diesel Generator Building

The three emergency diesel generators are located in this building, along with associated day tanks and control panels. Each of the diesel generator units is located in a separate room. A set of ESF batteries is located in one Diesel Generator Room. At least one diesel generator could be utilized for safe shutdown if offsite power is interrupted. The alternate diesel generator is available for Safe Shutdown in the event the normal emergency diesel generators are disabled.

Heat detectors are provided in each Diesel Generator Room, and wet pipe automatic sprinklers are installed in the sump area beneath each diesel engine and over the fuel oil day tanks. A fire hose available in the Turbine Building can reach part of the Diesel Generator Building.

The following fire protection provisions are also provided for the Diesel Generator Building:

1) A total flooding CO_2 system which can discharge in any of the three diesel generator compartments, providing area coverage in each Diesel Generator Room.

2) A hose station in the adjacent Control Building can reach those areas in the Diesel Generator Building that are beyond the range of other hose stations.

3) Doors in the fire walls between the diesel generator cubicles are 3-hour rated fire doors having automatic closers and alarms so that the control room is alerted if the doors are left open. Additionally, the heat exchanger equipment openings between the cubicles are protected with 3-hour rated barriers.

Auxiliary Feedwater Pump Room

IPEC00036101

This area contains the two electric motor-driven auxiliary feedwater pumps, the steam turbine-driven auxiliary feedwater pump, associated valves and electrical cabling. The area also contains electrical cables for the atmospheric relief valves, and the local auxiliary feedwater control panel used for shutdown if the Control Room is not habitable. At least one of the three auxiliary feedwater pumps would be required for safe shutdown.

To provide prompt fire detection and suppression for the room, smoke detectors are provided inside the Auxiliary Feedwater Pump Room, and a hose station is provided outside the Auxiliary Feedwater Pump Room, in the Main Steam and Feedwater Piping Enclosure. Fire suppression capability in the room is provided by an area-wide, automatic wet pipe sprinkler system, portable fire extinguishers, and by fire hose from nearby yard hydrants.

Containment Building

Safety-related equipment inside the Containment Building which is required for safe shutdown includes the reactor vessel, pressurizer and steam generators; primary system piping; steam and feedwater piping; residual heat removal heat exchanger and associated valves; control rod drives; and instrumentation for pressurizer pressure and level, and steam generator level.

Charcoal filters in the Containment Building fan cooler units are protected by heat detectors and manual water spray systems that can be actuated from outside containment. Portable carbon dioxide fire extinguishers are also available for manual fire suppression.

The following provisions for fire protection are provided inside containment:

a) Fire detectors in areas containing concentrations of electrical cable and on the reactor coolant pumps.

b) Barriers to prevent a fire from causing loss of redundant instrumentation required for safe shutdown.

c) Hose stations for manual fire fighting to reach the reactor coolant pumps and areas containing a significant amount of electrical cable.

d) A Reactor Coolant Pump oil collection system which collects oil leakage.

Barriers provided inside containment to separate redundant safe shutdown instrumentation cabling have the following characteristics:

a) Testing thermal barriers are used to insulate the lower cable tray containing instrumentation cables of one channel where the redundant instrumentation cable trays are stacked above each other. The fire barrier installation conformed to a design which was tested to demonstrate a one-hour fire rating.

b) Thermal barriers, as above, are used to enclose one channel of safe shutdown instrumentation both where the cabling crosses from the stack of trays over to the penetration area, and at the penetration area.

IPEC00036102

c) One-hour barriers and radiant energy shields have been installed for safe shutdown instrumentation to achieve conformance with Section III.G.2.f of Appendix R.

Fan House

The Fan House contains the piping penetration area. Safety-related valves are located in the piping penetration area, some of which may have to be correctly aligned to achieve safe shutdown. Containment penetration cooling fans and charcoal filters are located in the Fan House, but these are not required for safe shutdown.

The area of the Fan House housing the Primary Auxiliary Building Exhaust, Containment Purge & Containment Building Pressure Relief Systems is provided with smoke detectors. Charcoal filters in the filter units are protected by heat detectors and manual water spray systems. Fire fighters have portable extinguishers available for manual fire suppression.

Smoke detectors are also installed into the valve penetration area, and fire hose stations are provided to serve the entire Fan House.

Yard Area

The yard area contains the service water pumps, the buried fuel oil for the emergency diesel generators, the condensate storage tank, and the primary and refueling water storage tanks. The oil-filled transformers adjacent to the Control Building and Primary Auxiliary Building are protected by automatic water spray systems. The doors to the yard area from the Control Building and Primary Auxiliary Building have been upgraded to fire rating. A fire damper was installed in the ventilation opening from the electrical tunnels to the yard area, and hose houses equipped with fire hose and other fire fighting tools are provided for the yard hydrants.

The design of the door from the 15' elevation of the PAB to the yard could not be upgraded to obtain a fire rating. In lieu of a fire rated door, a water spray system is installed over the door to provide the necessary fire protection.

A valve/inspection pit housing service water valves and piping is located in the crushed stone area of the main transformer yard. The pit is of substantial construction and provides adequate fire resistance to preclude the loss of safe shutdown capability in the event of a transformer fire.

9.6.2.10 Ventilation Systems and Breathing Equipment

The following systems are provided with fire-stats (thermostats) or interlocks to shut down the fan systems in the event of pre-set high temperatures or fire:

1) The control room air conditioning system is equipped with a fire-stat installed to monitor room temperature.

2) The lube oil storage room ventilation system, is equipped with a fire-stat installed to monitor room temperature.

3) The electrical tunnel ventilation fans are interlocked with the pre-action water spray systems to shutdown when the fire protection deluge valve trips.

IPEC00036103

4) The Control Building 15' elevation exhaust fans are interlocked with the CO_2 fire suppression system to shutdown when the system actuates.

5) The Control Building 33' elevation exhaust fans and battery room exhaust fans are interlocked with the CO_2 fire suppression system to shutdown when the system actuates.

6) Diesel Generator Building exhaust fans and smoke dampers are interlocked with the CO_2 fire suppression systems to shutdown / close when the associated CO_2 system actuates.

Charcoal filters are enclosed in substantial metal housings, well separated from safe shutdown systems. Those filters in the containment cooling system are equipped with automatic fire detection and remotely operated manual water deluge systems. In addition, the filters are separated from ignition sources and the amount of contained radioactive material is insufficient to cause ignition.

Each bank of carbon filters located in the containment fan cooler units is provided with a fire protection system. This system was designed to satisfy seismic requirements to preclude failure due to seismic events. The fire lines are located in the annulus of the Containment Building. This area is free of missiles. The Fire Protection System water supply is provided with two motor operated valves manually operated from the Control Room. These valves are installed in parallel for redundancy. A fire in the carbon filters may occur during an incident when access to the Containment Building is not possible due to high radiation levels. Because of the redundancies stated above, manual fire control in the area is not a requirement nor would it be considered necessary.

The Authority evaluated the effects of fires in radwaste areas as to the potential releases to the environment and found that the releases resulting from fires in these areas are acceptable low.

Fire dampers rated for 3-hour fire resistance in accordance with NFPA requirements are installed in ventilation openings between fire areas. Additional details are provided in Section 9.6.2.2.

Self-contained breathing apparatus (SCBAs) are located in areas of the plant protected by the CO_2 suppression system. Breathing appliances, spare cylinders and recharge capabilities are provided to supply 10 men for 6 hours on the basis of three air cylinders per man hour. Control room operators are provided with a manifold cylinder emergency air supply.

9.6.2.11 Combustible Material Control in Structures

All structures on Indian Point 3 were constructed of reinforced concrete, concrete block, structural steel and metal partitions, metal wall siding sandwich panels (consisting of 20GA galvanized steel backup liner panels, 1-1/2" fiberglass insulation and protected metal face sheets) and/or built-up roofing (over 1" hard board insulation on 15 lb. felt vapor barrier on metal decking). These are all noncombustible materials.

The metal wall siding has an Underwriter's label indicating that all materials have a flame spread of 50 or less. The built-up roofing adhesive for attaching insulation is fire retardant BAR-FIRE which qualifies the built-up roofing system to be classified as Factory Mutual Class I as specified.

IPEC00036104

In addition to the above construction materials, the FOAMGLASR containment liner insulation is approved by NEPIA.

Electrical cables used in the plant were required to pass the ASTM-D-470-59T vertical flame test, as well as certain other tests developed by Consolidated Edison. The data indicated that the cables used will not burn vigorously under the test conditions used. Additional details of the electrical cable combustibility testing is provided in Section 8.2.2 of the FSAR. An exemption from the Appendix R requirement for 20 feet of separation and no intervening combustibles between redundant Safe Shutdown cables has been granted, based in part on the superior flame retardant capability of the cable installed in the Electrical Tunnel.

9.6.3 Compressed Air System

Instrument Air System

The Instrument Air System (Plant Drawing 9321-F-20363 [Formerly Figure 9.6-13A and 9.6-13B]) was 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, and after an accident, the air system shall be re-established.

To meet the design criteria the following design features have been incorporated. Duplicate compressors are installed with duplicate dryers and filters throughout. In addition, a backup supply is taken from the station air system. Those items essential for safe operation and safe cooldown are provided with air reserves or gas bottles. These supplies will enable the equipment to function in a safe manner until the air supply is re established. The controls are specified to fail to a safe position on loss of air or electrical power. The compressors and essential sections of the air supply system have been designed to operate after seismic shock. The non-essential header has a flow restrictor in it to limit flow in the event of a break to the capacity of one compressor.

The system is served by two 225 scfm Chicago Pneumatic non-lubricated compressors. The compressors, filters, and air dryers are located on the ground floor of the Control Building, a Class I seismic structure. Each compressor discharges into a common air receiver. The Instrument Air System is backed up from the Indian Point 3 Station Air System.

The instrument air compressors may be operated in two modes. One mode provides for the standby compressor to come on automatically in the event of low pressure in the common air receiver. In manual mode, the compressors will load and unload at predetermined pressure settings, but the motors run continuously.

To meet current and future instrument air loads, a third non-category I compressor/dryer package is available on the 15' elevation of the Turbine Building to supply the conventional plant. The third unit has a capacity of 350 scfm and is manufactured by Joy Manufacturing Co. The compressor is a two cylinder, two stage, reciprocating, water cooled unit constructed for continuous heavy duty service. The cylinders have teflon rings which do not require lubrication, therefore the air is delivered completely free of oil contamination. This compressor can also supply the Station Air System with backup air, if necessary.

The station air backup to the Instrument Air System is filtered through oil vapor and droplet removal equipment before entering the Instrument Air System. The instrument air receiver

IPEC00036105

outlet enters one of two full capacity desiccant type dryers which reduce the dewpoint from saturation to approximately -40°F. This system is used for all indoor services where it is anticipated that the ambient temperature will not go below 50°F. Those services which are used for outdoor instrumentation and for lines which leave the Control Building and/or Turbine Building and enter the yard area to serve the Primary Auxiliary Building and Containment Building are also served through desiccant type dryers. These dryers reduce the dewpoint to minus 40°F, in order to compatible with the lowest expected outdoor temperatures.

The two 750 scfm capacity heatless air dryers are installed to ensure the ability of the existing Instrument Air system to consistently provide acceptable instrument air quality. Normally, one desiccant dryer is in operation at a time while the second dryer is in standby. These dryers are installed in the 15' elevation of the Control Building. The dryers are equipped with duplex prefilters (and automatic drain valves) and afterfilters. The dryer monitors the processed air to maintain approximately -40°F dewpoint and provides an alarm if the dryer malfunctions. The afterfilters are rated for a .9 micron (absolute) particle removal. Each desiccant dryer is rated at 750 scfm and is a dual tower type dryer. An air afterfilter set is provided on the discharge of these dryers in order to filter out any desiccant which may be carried over by possible flotation of the bed. A moisture detector is provided on the common discharge header to notify the Control Room operator in the event of high dewpoint.

A power failure to the dryer which is in service causes the dryer to go to its fail safe position (fail opened). This allows for uninterrupted instrument air flow.

In order to provide continuity of service to Class I areas in the event of an 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 operated to isolate the secondary plant and prevent pressure decay in the primary plant header.

Valve position lights in the Control Room advise the operator as to the status of all emergency bypass or makeup control valves. A manual local reset solenoid valve is provided at each emergency valve so as to require the attention of an operator at the equipment. All air and oil filters are dual type to provide maintenance during operation.

The components or systems essential to plant safety and serviced by the Instrument Air System are as follows:

1) Containment Isolation Valves
2) Cooling Water Valves for Containment Building Fan Coolers
3) Condensate Storage Tank Shut-off Valves
4) Auxiliary Boiler Feed Pump Control Valves
5) Steam Dump Valves to Atmosphere
6) Low Pressure Steam Dump Valves to Main Condenser
7) Containment Building Penetration and Weld Channel Pressurization System
8) Emergency Diesel Cooling Water Valves (Retired in Place)
9) Spray Additive Tank Outlet Valves
10) Boron Injection Tank Recirculation Valves
11) Control Room Air Conditioning Actuators

IPEC00036106

In the event of low pressure in the instrument Air System, air is automatically supplied to the Instrument Air system from the Station Air System. In the event of low pressure at any or all of the components listed as items 4,7, or 11 above, dry nitrogen cylinders automatically supply gas pressure to those components required for safe shutdown or continued operation of the plant. Additionally, a manual supply of dry nitrogen is available to operate the steam dump valves to atmosphere in the event of low instrument air system pressure.

In the event of an instrument air line rupture in the conventional plant, a restriction orifice limits the flow to 225 scfm. One compressor supplies air to compensate for the break while the spare compressor supplies the primary plant.

Station Air System

The Station Air System (Plant Drawing 9321-F-20353 [Formerly Figure 9.6-15]) is supplied by a two-stage 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 intercooler, after cooler and compressor jacket is supplied from a closed cooling water system which contains treated city water. Station air can also be supplied by the third instrument air compressor located in the Turbine Building.

The Station Air 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 will start and stop at predetermined pressure settings; but the motor continues to run. High water and high air temperature switches are connected to the control annunciator.

The Station Air System furnishes compressed air for pneumatic tools, circulating water pump priming, and miscellaneous cleaning and maintenance purposes throughout the secondary primary plants. A 900 cfm diesel driven air compressor and a desiccant air dryer were added to the Station Air System that will automatically start on low station air pressure. The compressor is located outside the Turbine Building and it is permanently piped to the station air receiver discharge piping. A check valve isolates the diesel compressor from the station air system when it is not running. The compressor can be isolated or disconnected when maintenance is required. The diesel driven air compressor can provide air to the Station Air and the Instrument Air systems upon loss of offsite power. All work is designated as Non-Category I, which is consistent with the Station Air system except for the control room alarm.

This system is backed up by the Indian Point 1 Station Air System through manually operated valve interconnection to the Indian Point 3 air receiver. The size of the connection is equal to the Indian Point 3 supply pipe. This system may also be supplemented by temporary portable air compressors connected to an outside flanged connection near the northwest corner of the Turbine Building and piped to the inlet of the station air receiver.

The system also provides for an automatic emergency supply to the Indian Point 3 Instrument Air System through an oil vapor filtering arrangement. In addition, an automatic emergency supply is supplied to the Containment Building Weld Channel and Penetration Pressurization System. The air is first filtered and then dried to –40 °F dewpoint.

Component Design and Operation Parameters

IPEC00036107

1) Station Air Compressor

2-stage, vertical angle, duplex compressor.

Modes of Operation:

a) Manual - Loads and unloads at predetermined pressure and motor continues to run.

b) Automatic - Motor stops on unloading.

Design Pressure - 135 psig

Operating Pressure - 100-125 psig

Design Capacity - 625 scfm @ 100 psig

2) Station Air Aftercooler

Single pass, tube and shell horizontal heat exchanger to cool air to within 15°F of inlet water temperature.

3) Station Air Reciever

10' long by 42" diameter receiver.

Design Pressure - 135 psig

Operating Pressure - 125 psig (max)

4) Instrument Air Compressors Nos. 31 and 32

Two (2) horizontal, single stage, double acting compressors, non-lube construction.

Modes of Operation:

a) Automatic - Motor starts when receiver pressure drops to 95 psig. Approximately ten seconds later unloader valve is energized and supplies air to systems. Motor stops at 105 psig.

b) Manual - Compressor runs continuously and is loaded and unloaded as receiver pressure varies between 100 and 110 psig.
Design Pressure - 135 psig
Operating Pressure - 100 - 110 psig
Design Capacity - 225 scfm @ 100 psig

5) Instrument Air Aftercoolers

Two (2) tube and shell horizontal heat exchangers to cool air to within 15°F of inlet water temperature, complete with cyclone moisture separators.

IPEC00036108

6) Instrument Air Receiver

10' long by 42" diameter receiver.

Design Pressure - 135 psig
Operating Pressure - 125 psig (max)

7) Desiccant Dryers

a) Two redundant 750 scfm heatless desiccant dryers Nos. 31 and 32 on the Instrument Air System are used to obtain a final dewpoint of approximately -40°F at 100 psig.

Design Pressure - 150 psig
Operating Pressure - 100-110 psig
Design Capacity - 750 scfm @ 100 psig
Duplex Coalescer Prefilter - 1200 scfm @ 100 psig
Duplex Afterfilter - 1200 scfm @ 100 psig, .9 micron absolute particle rating.

b) A regenerative air dryer in the Station Air System is used to obtain a final dewpoint of approximately -40°F @ 100 psig. A nonregenerative dryer is installed in parallel with each regenerative dryer for standby operation. The nonregenerative dryer is suitable for intermittent operation of 4 to 6 hours duration.

Design Pressure - 150 psig
Operating Pressure - 100-110 psig
Design Capacity - 45 scfm @ 100 psig

8) Filters

Two (nominal 225 scfm) prefilters and two (nominal 150 scfm) after-filters are provided for the Station Air System.

Two (nominal 45 scfm) prefilters and two (nominal 45 scfm) after-filters are provided for the Station Air System.

Emergency air makeup from the Station Air System to Instrument Air System passes through two (nominal 225 scfm) liquid oil prefilters and two (nominal 225 scfm) oil vapor prefilters.

Design Pressure - 150 psig
Operating Pressure - 110 psig (max)

9) Instrument Air Compressor No. 33

Two stage, two cylinder reciprocating compressor, non lube construction for continous heavy duty service.

Design capacity - 350 scfm at 110 psig

IPEC00036109

Rated discharge pressure - 110 psig

9.6.4 Heating System

An eight inch main steam header connects the two 50,000 lb steam per hour boilers at Indian Point 2 to the Indian Point 3 steam distribution system. The Indian Point 3 steam distribution system consists of three separate circuits. The first circuit starts upstream of the pressure reducing valve and serves the Circulating Water Priming Ejectors and the retired De-icing Steam Jet Vacuum Pumps. The second circuit starts from a connection located downstream from a pressure reducing station and upstream from a desuperheater section. This circuit serves the east and west side of the Turbine Hall, the Heater Bay and the Service Building. The third circuit starts from a connection located downstream from both the pressure reducing and desuperheatier stations. It serves the clean and dirty turbine oil storage tanks, the Fan Room, the Fuel Storage Building, the Primary Auxiliary Building, the tank pit, the Primary Water Storage Tank and the Refueling Water Storage Tank.

Provision is made for the following heating services:

1) Primary Auxiliary Building

   a) Electric strip heaters

   b) Steam unit heaters

   c) Air makeup steam tempering units

   d) Batching mixing tank

2) Purge System Containment Building

   a) Air makeup steam tempering unit

3) Fuel Storage Building

   a) Steam unit heaters for standby heating

   b) Air makeup steam tempering units

4) Waste Tank Storage Pit

   a) Air makeup steam tempering unit

5) Fan Room

   a) Steam unit heater

6) Turbine Hall

   a) Steam unit heaters

   b) Clean and dirty oil tank

IPEC00036110

c) Circulating water primary ejectors

d) De-icing steam jet vacuum pumps

7) Refueling water storage tank

8) Primary water storage tank

9) Service Building

a) Process and heating

10) Diesel Generator Building

11) Administration Building

12) Auxiliary Building

13) Radioactive Machine Shop Building

14) Liquid Radwaste Storage Building

The temperature in the Containment Building is maintained without the use of steam unit heaters. Therefore, the containment unit heaters were removed.

There is no steam heating in the Diesel Generator Building. This building is provided with thermostatically controlled electric unit heaters for standby heating service designed to maintain a minimum room temperature of 60°F when the outside temperature is approximately -5°F. Without building heat, the building temperature will be approximately 35°F.

This building except for the roof and supply and exhaust dampered openings, is built below grade. With an inside temperature of 35°F the building is subject to a heat gain from the ground and adjacent heated areas and a loss through the roof and ventilation openings. At this room temperature (35°F) and an outside temperature of -5°F, the heat gains to the building are slightly higher than the heat losses.

Each diesel engine is provided with an independently controlled 12kW electric lube oil heater, a 9 kW electric jack water heater, and a prelube circulating oil pump that circulates warm oil when the diesel unit is shutdown. Each heater and pump is controlled by an independent, local contactor and circuit breaker.

Service water supply to the engine heat exchangers is through parallel flow control valves, which are closed during normal plant operation, to prevent heat losses when the diesel unit is shutdown. The valves are provided with local control switches, and position indicating lights both local and in the control room, and are interlocked to open automatically when any unit is started (either manually or automatically).

The jacket water and lube oil heaters are sufficient to assure the engine starting capabilities at the ambient expected with loss of building heaters.

IPEC00036111

Plant Drawings 9321-F-27273, and -40573 [Formerly Figures 9.6-16 and 9.6-17] are flow diagrams and heating plans for Indian Point 3.

9.6.5 Plant Communications System

The Indian Point 3 communications system was designed to ensure the reliable, timely flow of information and action directives necessary during normal operation, and particularly for the mitigation of emergencies. Reliability of the system is provided by extensive redundancy and by alternative communications equipment; routine use of many of the systems lowers the probability of undetected system failures.

Dedicated communication links have been established for use during emergencies to preclude delays due to system swamping. A redundant power supply is provided for the communications system in the Control Room.

Public Address System

The Public Address (PA) System has two subsystems: the Plant Party Paging and the Site PA System. The system consists of three channels. Two of these channels are common to both the primary (nuclear) and secondary (conventional) portions of the plant. The third line provides an additional channel in the primary portion of the Indian Point 3 plant. Speakers for monitoring each of these lines are located in the Control Room. The Public Address System receives its power from MCC 36B through a single 3PH, 480/120V, 9KVA Sola transformer.

The Primary Auxiliary Building, Waste Holdup Tank Pit, Liquid Radwaste Storage Facility, Fuel Storage Buildings, Fan Room area, Containment Building, Auxiliary Boiler Feed Pump Building, Diesel Generator Building and tunnels are treated as the primary (nuclear) portion of the plant. The secondary (conventional) port of the plant comprises the rest of the facility.

Three handsets are located on the plant operator's desk in the Control Room. A "Page" handset is used for page purposes only and calls originating from this handset can be heard on all loudspeakers in the primary and secondary portions of the facility. The remaining two "Page-Party" handsets are used for loudspeakers paging and party-line conversations, as selected by the control room operator. A switch is provided on the control room desk, which will allow all outdoor speakers to be turned off at night.

All calls initiated from the handsets in the primary and secondary plant are heard over the party-line speaker in the Control Room. A "page" call from plant area handset will only go to the Control Room. It is possible to carry on two independent party-line conversations simultaneously between the Control Room and the primary (nuclear) areas.

A handset station is located on the Indian Point 3 plant flight panel. This station may be used on either of the three channels by selecting the desired circuit with a three-position switch mounted beside the handset.

Within the primary (nuclear) area, the handset stations are equipped with a selector switch, which allows usage of either of the two party-line channels for conversing with the Control Room operator and vice versa. At the secondary (conventional) area stations, removal of any handset from its carriage will activate a speaker through which the operator can summon the Control Room by voice communication, if so desired.

IPEC00036112

The Control Room desk is equipped with three decibel meters. One meter monitors the Page circuit; the other two monitor the Party-Line circuit. The meters will swing into the -6db area, when the circuits are in use.

A monitor console is provided for the Shift Manager. Each console is equipped with "Page" and "Party" decibel meters, which indicate when channels are in use. A speaker and speaker amplifier is also supplied. A four-position selector switch is used to select which channel shall be monitored orally, if desired. An "L" pad volume control is included so that speaker volume can be set.

Sound Powered Communication System

The Sound Powered Communication System (SPCS) consists of communication stations located throughout the plant and interconnected by cable run in suitable raceways. Stations are located throughout the plant.

Three independent communication channels are provided with each communication station having access to all three channels. A station consists of three telephone jacks, one connected to each channel. The sound powered phone is equipped with a cord and a plug. In use, the phone is plugged into one of the three jacks and can then communicate with one or more other phones plugged into the same channel anywhere in the plant. Energy to operate the system is generated by the user's voice; there is no external power source involved.

Communication stations at supervisory and control panel locations consist of three telephone jacks flush mounted on the front panel. Stations located in the field consist of a weatherproof junction box with three or more telephone jacks mounted on the cover.

Regular Telephone System

Office locations at Indian Point 3 have switchboard extensions and various locations have direct incoming lines without utilizing the switchboard. Along with normal telephone features, this system provides features such as automatic callback, call forwarding, three-way consultation, transfers and pickup of another individual phone from a remote location.

Incorporated into the regular telephone system is the Control Room Touch-O-Matic direct dial capability. Programmed into this system are organizations and parties for the Emergency Response Network, such as key emergency plant personnel, hospital, ambulance, police and fire numbers.

Con Edison Extensions

Placed in various locations throughout the facility are Consolidated Edison Extension telephones to aid in the communications between the Indian Point 3 and Indian Point 2 sites. The Control Room is equipped with an extension.

Emergency Communications Equipment

The emergency facilities for Indian Point 3 equipped with emergency communications equipment are: The Control Room (CR), the Emergency Operations Facility (EOF), the

IPEC00036113

alternate EOF (AEOF), the Technical Support Center (TSC) and the Operations Support Center (OSC).

Direct Telephone Lines (5-party and 4-party lines)

A dedicated line from the Control Room, TSC, OSC and EOF has been installed at Indian Point 3 known as the 4-party line. In the event of relocating the EOF to the AEOF, another dedicated line from the CR, TSC, OSC, EOF and AEOF has been installed at Indian Point 3 known as the five-party line. This allows the expeditious transfer of plant operation and design information during an emergency.

Direct Telephone Lines (White Plains Office to Indian Point 3)

A dedicated line connecting Indian Point 3 to the Entergy Nuclear Northeast Corporate Office is available for information transfer during an emergency condition. The telephones are located (onsite) in the TSC and (in White Plains) in the Alternate Emergency Operations Facility (AEOF).

Direct Line with Bell Annunciator

A direct line telephone links the Indian Point 2 Control Room, the Indian Point 3 Control Room, and the Emergency Operation Facility. One another can reach each location by the use of a manual ring down circuit.

Alarms

Audible alarms are a quick and effective means of communicating emergency warnings on the Indian Point 3 site. Alarms currently installed include the:

1) Containment Evacuation
2) Site Assembly
3) Fire
4) Air Raid

Each alarm provides a distinctive sound that station personnel and contractors have been trained to recognize.

Radio Communications

Radio Communication equipment used in normal plant operations will be used in an emergency to communicate with mobile units and to provide backup to the telephone system if necessary. Radio capabilities include the following:

1) IP2 Plan Radio Frequency
2) IP3 Security Radio Frequency
3) Entergy Radio System*

*NOTE: Installed by Temporary Modifications TM 92-03820-00

IPEC00036114

The Indian Point Energy Center Emergency Plan Radio Frequency permits radio communication between the EOF, AEOF, Indian Point 2 and 3 Control Rooms, Offsite Monitoring Vehicles, TSC, OSC and Security.

The Security Radio Frequency provides, during an emergency, for monitoring site security and to have direct communication with the N.Y. State Police. During normal operation, the Security force uses portable walkie-talkies for station-to-station communication and site security. There is a backup gas-driven generator at the EOF which will automatically supply AC power for the radio system if normal power is interrupted.

The Radio System consists of repeaters and portable radios, which provide communication between the OSC, dispatched in-plant teams and the Indian Point 3 Control Room.*

Paging System ("Beeper")

"Beeper" paging is used by Entergy to call in key Emergency Plan Personnel in the event of an emergency at Indian Point Energy Center.

NRC Emergency Telecommunications System (ETS)

The NRC Emergency Telecommunications System is a dedicated telephone system that connects Indian Point 3 with the NRC Operations Center (Headquarters) in Bethesda, Maryland. It is to be used for reporting off-normal incidents affecting the facility, and for providing information concerning the operation and status of the plant. Commercial telephone lines should be used as backup communications. The purpose of these lines is to provide reliable communications with the NRC. The ETS consists of the following lines:

Line	Function
1.	Emergency Notification System (ENS)
2.	Health Physics Network (HPN)
3.	Reactor Safety Counterpart Link (RSCL)
4.	Protective Measures Counterpart Link (PMCL)
5.	Management Counterpart Link (MCL)
6.	Local Area Network Access (LAN)
7.	Emergency Response Data System Channel (ERDS)

These lines are located in the following areas:

Location	Line(s)
Control Room (CR)	1
Technical Support Center (TSC)	1
Computer Room	7
NRC Office	1,2,3,4,5,6
Emergency Operations Facility (EOF)	1,2,3,4,5,6
Operations Support Center (OSC)	2

*NOTE: Installed by Temp Mod 92-03820-00

Health Physics Network (HPN) Line

IPEC00036115

This line is part of a network that includes all nuclear power plants, the NRC Regional Office and the NRC Operations Headquarters in Bethesda, Maryland. In the event of an emergency at the site, either the NRC Regional Office or Headquarters may decide to establish a direct telephone link to the licensee's dose assessment team. At such time, the HPN line will be the primary means of communicating health physics and dose assessment information from the licensee to the NRC. The HPN is a restricted network and should not be used by non-government employees at any time unless needed to report a significant event when both the line and the commercial telephone lines are out of service. HPN lines are located in the NRC Office, OSC, and EOF. These lines are all tied into the same loop and there can be used as party lines.

RECS Line Telephone Network

The Radiological Emergency Communcation System (RECS) is a dedicated line which connects the Control Rooms of Indian Point 2 and Indian Point 3 with the EOF, AEOF, the County Emergency Operation Centers and warning points within the 10 mile Emergency Planning Radius, the City of Peekskill, and the New York State Emergency Centers in Albany and Poughkeepsie (Southern District Office of Disaster Preparedness).

The RECS Line is a multipoint conferencing circuit with one drop at each of the above mentioned locations and is available 24 hours a day, 7 days a week.

References:

1. Safety Evaluation dated January 7, 1987 from S.A. Varga, Director - Project Directorate #3, Division of PWR Licensing - A, USNRC, to J.C. Brons, New York Power Authority.

2. Fire Protection Reference Manual, Volumes 1 to 4.

3. Fire Protection Plan for Indian Point 3 Nuclear Power Plant.

4. Operational Specification Manual.

5. Exemption from the Requirements of 10 CFR Part 50, Appendix R, Section III.G.2 - Indian Point Nuclear Generating Unit No. 3 (Tac No. M88323), transmitted by NRC to NYPA letter dated January 5, 1995.

6. Safety Evaluation dated March 29, 1995 from L.B. March, Director - Project Directorate I-1, Division of Reactor Projects - I/II, Office of Nuclear Reactor Regulation to W.J. Cahill, Chief Nuclear Officer, New York Power Authority.

IPEC00036116

TABLE 9.6-1

SERVICE WATER FLOW REQUIREMENTS AT 95°F*

ESSENTIAL HEADER

ESSENTIAL HEADER	FLOW EACH (GPM)	NORMAL (GPM)	INJECTION (GPM)	RECIRCULATION WITH ACTIVE FAILURES (GPM)	RECIRCULATION WITH OR WITHOUT PASSIVE FAILURES (GPM)
Containment F.C.U.	570/1400(5)	2850(4)	7000(4)	7000(3)	7000(3)
F.C.U. Motor Cooler	12	60(4)	60(4)	60(3)	60(3)
Diesel Generator	302/ 213 (9)	(6)	906(3)	426(2)	426(2)
Instrument Air Compressor Cooling	65	65(1)	65(1)	65(1)	65(1)
CR Air Conditioner Unit (2 Condensers/Unit)	52.5	105(2)	105(2)	52.5(1)	(1) 52.5/105(2)
Turbine Oil Cooler	2350	2350(1)	2350(1)	(6)	(6)
Seal Oil Cooler	100	100(1)	100(1)	(6)	(6)
BFP Oil Cooler	120	120(1)	120(1)	(6)	(6)
Component Cooling Heat Exchanger 31	Variable	(6)	(6)	2811	3721
Strainer Backwash	180(1)(7)	180(1)(7)	180(1)(7)	180(1)(7)	180(1)(7)
Total Flow Required	-	5,830	10,886	10,595	11,557

(1) 1 Unit
(2) 2 Units but all 3 not isolated
(3) 3 Units, but all 5 not isolated
(4) 5 Units
(5) 570 gpm at 120°F Cont. Temp/ 1400 gpm Accident
(6) Not Required
(7) One at a time
(8) Flow through SGBDHX-1 assumed but not required
(9) 302 gpm injection/ 213 gpm injection

* The service water flows shown in this table for the Containment FCU, FCU Motor Cooler, Diesel Generator, Instrument Air Compressor, CCWHX-31, and CCRAC Condenser represent the flow requirements for a 95°F river water temperature. All other flow requirements are based on 85°F river water temperature.

IPEC00036117

TABLE 9.6-1
(Cont.)

SERVICE WATER FLOW REQUIREMENTS AT 95°F*
NON-ESSENTIAL HEADER

NON-ESSENTIAL HEADER	FLOW EACH (GPM)	NORMAL (GPM)	INJECTION (GPM)	RECIRCULATION WITH ACTIVE FAILURES (GPM)	RECIRCULATION WITH OR W/O PASSIVE FAILURES (GPM)	APPENDIX R COOLDOWN (GPM)
Diesel Generator	302/213(9)	(6)	(6)	213(1)	213(1)	(6)
Component Cooling	Variable	3460	(6)	(6)	(6)	2500
Heat Exchanger 31	Variable	3469	(6)	4185	4967	2500
Component Cooling Heat Exchanger 32	52.5	(6)	(6)	52.5	52.5	(6)
CR Air Conditioner Condenser	800	800(1)	(6)	(6)	(6)	(6)
Screen Wash and Circ. Water Pump Seals and Bearings	700	700(1)	(6)	(6)	(6)	(6)
Turb. Build. Closed Cooling Water	2940	2940(1)	(6)	(6)	(6)	(6)
ISO-Phase, Exciter and Hydrogen Coolers	100	100(1)	(6)	(6)	(6)	(6)
SGBDHX-1	250	250(1)	(6)	(6)	(6)	(6)
SGBDHX-4	180(1)(7)	180(1)(7)	(6)	180(1)(7)	180(1)(7)	180

IPEC00036118

Strainer Backwash						
Total Flow Required	-	11,979	(6)	4,633	5,413	5180

See sheet 1 of 2 for Notes
* The service water flows shown in this table for the Containment FCU, FCU Motor Cooler, Diesel Generator, Instrument Air Compressor, CCWHX 31, and CCRAC Condenser represent the flow requirements for a 95°F river water temperature. All other flow requirements are based on 85°F river water temperature.

IPEC00036119

TABLE 9.6-2

SERVICE WATER FLOW (gpm)
UNDER MOST LIMITING FAILURE CONDITIONS

	Normal + Seismic	Post-LOCA Injection + LOIA	Post-LOCA Recirculation +Active Failure
Containment FCU's & Motor Coolers:			
31	725	1537	1528
32	730	1545	1535
33	712	1518	1509
34	701	1501	1492
35	694	1488	1479
Diesel Generator Coolers:			
31	419	379	508
32	419	379	349
33	420	380	350
Component Cooling Water Heat Exchangers:			
31	*	*	3265
32	*	*	4490
CR Air Conditioning Condensers:	123	113	121
Non-Essential Pumps:			
31	*	*	5538
32	*	*	*
33	*	*	*
Essential Pumps:			
34	*	*	*
35	7375	6354	6222
36	7357	6338	6207

*NOTE: Not used for this condition
LOIA - Loss of Instrument Air

IPEC00036120

TABLE 9.6-2A

SERVICE WATER FLOW DISTRIBUTION
ESSENTIAL HEADER
POST LOCA RECIRCULATION MODE OF OPERATION WITH PASSIVE FAILURES

ESSENTIAL HEADER ESSENTIAL	REQUIRED FLOW (GPM) HEADER CRACK LWL(GPM)	24" ESSENTIAL HEADER	20" ESSENTIAL HEADER CRACK LWL (GPM)	20" NON-CRACK LWL (GPM)
Containment FCU	7000	8299	8298	8412
FCU Motor Cooler	60	301	301	305
Diesel Generator 32	213	374	374	385
Diesel Generator 33	213	375	375	386
Instrument Air Compressor Cooling	65	135	135	137
CR AC Condenser	52.5	61	61	62
Component Cooling Heat Exchanger 31	3721	4208	4193	4307
Strainer Backwash	540	1144	1147	1153
Break Flow	-	655	501	-
Pump Flow Total	-	15,552	15,385	15,147
Average Pump Flow	-	5,184	5,128	5,049

IPEC00036121

TABLE 9.6-2A
(Cont.)

SERVICE WATER FLOW DISTRIBUTION
NON-ESSENTIAL HEADER
POST LOCA RECIRCULATION MODE OF OPERATION WITH PASSIVE FAILURES

NON-ESSENTIAL HEADER	REQUIRED FLOW(GPM)	24" ESSENTIAL HEADER CRACK LWL (GPM)	20" ESSENTIAL HEADER CRACK LWL (GPM)	20"NON-ESSENTIAL HEADER CRACK LWL (GPM)
Diesel Generator 31	213	586	586	565
Component Cooling Heat Exchanger 32	4967	5656	5656	5513
CR AC Condenser	52.5	73	73	72
SGBDHX-1	100	111	111	109
Strainer Backwash	360	1207	1207	1194
Break Flow	-	-	-	573
Pump Flow Total	-	7,633	7,633	8,026
Average Pump Flow	-	3,816	3,816	4,013

IPEC00036122

TABLE 9.6-2A
(Cont.)

SERVICE WATER FLOW DISTRIBUTION
ESSENTIAL HEADER
POST LOCA RECIRCULATION MODE OF OPERATION WITH PASSIVE FAILURES

ESSENTIAL HEADER	REQUIRED FLOW (GPM)	18" ESSENTIAL HEADER CRACK LWL (GPM)	10" ESSENTIAL HEADER CRACK LWL (GPM)	10"NON-ESSENTIAL HEADER CRACK LWL(GPM)
Containment FCU	7000	8310	8326	8385
FCU Motor Cooler	60	301	302	304
Diesel Generator 32	213	375	370	384
Diesel Generator 33	213	376	371	385
Instrument Air Compressor Cooling	65	135	135	137
CR AC Condenser	52.5	62	62	62
Component Cooling Exchanger 31	3721	4230	4243	4295
Strainer Backwash	540	1149	1199	1203
Break Flow	-	389	267	-
Pump Flow Total	-	15,327	15,275	15,153
Average Pump Flow	-	5,109	5,091	5,051

IPEC00036123

TABLE 9.6-2A
(Cont.)

SERVICE WATER FLOW DISTRIBUTION
NON-ESSENTIAL HEADER
POST LOCA RECIRCULATION MODE OF OPERATION WITH PASSIVE FAILURES

NON-ESSENTIAL HEADER	REQUIRED FLOW (GPM)	18" ESSENTIAL HEADER CRACK LWL (GPM)	10" ESSENTIAL HEADER CRACK LWL (GPM)	10"NON-ESSENTIAL HEADER CRACK LWL (GPM)
Diesel Generator 31	213	584	587	569
Component Cooling Heat Exchanger 32	4967	5657	5656	5586
CRAC Condenser	52.5	73	74	73
SGBDHX-1	100	111	111	110
Strainer Backwash	540	1207	1207	1201
Break Flow	-	-	-	310
Pump Flow Total	-	7,632	7,635	7,849
Average Pump Flow	-	3,816	3,817	3,924

IPEC00036124

TABLE 9.6-3

VALVE POSITIONS

Valve No.	Normal/ Injection	Recirculation
FCV-1111	closed	closed
FCV-1112	open	closed
SWN-6	open	closed
SWN-7	closed	closed
SWN-31	open	open
SWN-32	closed	open
SWN-33 (2)	open	closed
SWN-34 (2)	open	open
TCV-1103	modulating	modulating
TCV-1104	closed/ open	open
TCV-1105	closed/ open	open
SWN-62-1***	open/ closed	open/ closed
SWN-62-2***	open/ closed	open/ closed
SWN-62-3***	open/ closed	open/ closed
SWN-62-4***	open/ closed	open/ closed
SWN-62-5***	open/ closed	open/ closed
SWN-62-6***	open/ closed	open/ closed
FCV-1176	Retired in Place	
FCV-1176A	Retired in Place	
SWN-4	open	closed
SWN-5	closed	closed
SWN-27 (2)	closed	closed
SWN-29	open	open
SWN-30	closed	open
SWN-38	open	open
SWN-39	closed	closed
SWN-55	closed*	closed*
SWN-70 (2)	open	open
SWN-94-	closed	open**
SWN-94-2	open	open
SWN-95	open	open
SWN-108-3	open	closed**
SWN-108-6	open	closed**

* Valve disc is modified with fixed orifice to ensure minimum flow requirements to diesel generators when SI signal is received.

** Currently emergency operating procedures direct one CRAC unit to be on the non-essential header.

*** Valves are open or closed depending on EDG in operation and alignment to the essential OV non-essential header.

IPEC00036125

9.7 EQUIPMENT AND SYSTEM DECONTAIMINATION

9.7.1 Design Basis

Activity outside the core could 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 - Y 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 to be decontaminated. The products of water activation are not long lived and may be removed by natural decay during reactor cooldown and subsequent flushing procedures. Activated corrosion products are the primary source of the remaining activity.

The corrosion products contain radioisotopes from the reactor coolant that have been absorbed on or have diffused into the oxide film. The oxide film, essentially magnetite (Fe_3O_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. The contamination could be spread by various means when access is required. Contact while working on primary system components could 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 could contaminate the immediate areas and could contribute to the contamination of the equipment, tools and clothing.

9.7.2 Methods of Decontamination

Surface contaminants that 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 non-porous materials. Personnel and their clothing are decontaminated according to the standard health physics procedures.

Those areas of the plant that 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 surfaces 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 may be cleaned with a combination of chemical reverse electroplating and ultrasonic method if required.

9.7.3 Decontamination Facilities

IPEC00036126

Decontamination facilities on site 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 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 (RCA) locker room. Personnel decontamination kits with instructions for their use are in or adjacent to the personnel decontamination shower area.

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 Primary Auxiliary Building and Containment Access Facility (CAF) 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.

3) Provide purging of the Primary Auxiliary Building, CAF, and CAF Annex through roughing, HEPA, and charcoal filters to the plant vent for dispersion to the environment.

4) Provide separate exhaust ventilation for the hydrogen crib in the CAF Annex through the Annex roof.

The air exhausted by the system is filtered and monitored so that off-site dose during normal operation will not exceed 10 CFR 20 limits. These limits are specified and controlled in accordance with site ODCM.

9.8.2 System Design

The Primary Auxiliary Building is heated with thermostatically controlled steam unit heaters and electric strip heaters. Each unit has its own thermostat and the failure of one unit will not affect the operation of the others.

The Primary Auxiliary Building Ventilation System is composed of the following systems:

1) Make-up air handling system complete with fan, bypass dampers, filters, heating coils and supply ductwork.

2) Exhaust system complete with fans, ductwork, bypass dampers, roughing, HEPA, and charcoal filters.

3) Make-up air tempering unit for the waste storage tank pit.

IPEC00036127

Design parameters for the system components are given in Table 9.8-1. Plant Drawing 9321-F-40223 [Formerly Figure 6.4-2] shows the flow diagram for this system. The fire protection provisions for these systems are covered in Section 9.6.

PAB Exhaust Fan 32 is normally fed from 480V switchgear 32, Bus 6A. However, an alternate power source is provided so that the fan can be fed from 480V MCC-312A when offsite power is available during a peak accident loading condition following a design basis accident.

Branch supply ducts direct make-up air to the various floors at the east end of the Primary Auxiliary Building. This supplied make-up air is drawn into the rooms and compartments of the Primary Building and the CAF by an exhaust system, which also draws outside air through the CAF Annex.

The air is exhausted from each of the 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, HEPA and charcoal filters before discharge to the plant vent. Flow from the PAB ventilation system normally bypasses the charcoal filters, these filters are placed in service by a high radiation signal. The exhaust system has been designed to insure that air flows from the "clean" end of regions of low radioactivity level of the building through the "hot" or regions of higher radioactivity levels.

The Primary Auxiliary Building Ventilation System is divided into two separate parts: The hold-up tank pit (waste hold-up tanks and three CVCS hold-up tanks); and the remaining portions of the Primary Auxiliary Building (CAF, chemical drain tank, spent resin storage tank, gas decay tank) and engineered safety feature equipment (safety injection pumps, residual heat removal pumps, component cooling pumps). The air exhausted from each of the two separate parts of the Primary Auxiliary Building Ventilation System normally flows directly into the roughing, and HEPA filters in the exhaust fan inlet plenum. The charcoal filters are placed in service by a high radiation signal. Make-up air to this area is tempered with a steam heating coil. The roughing, and HEPA filters are installed in such a way that all gaseous flows from the PAB will pass through them. The analysis of releases from this system is contained in Chapter 11.

There are two 70,000 cfm exhaust fans (No. 31 and 32), which are common to both containment building purge system (see Section 5.3) and the Primary Auxiliary Building Ventilation System, and serve as back-up to each other. Each system has its own supply fan that operates only in its individual ventilation system. One exhaust fan is required for each supply fan operating.

The selection of the desired pair or pairs of fans is manual, using a selector switch located on the fan room control panel. All four fans can be started and stopped by the single control switch located on the fan room control panel. Each fan has indicating lights on the fan room control panel and in the main control room. An autotrip alarm is also provided. In addition, each of the fans have a "jog" push button located on the fan room control panel for testing.

The Radiation Monitoring System (RMS) room on Elevation 55'-0" of the PAB contains the RM-80 microprocessors. These microprocessors are rated at 86°F ambient for continuous operation. This room is cooled by two temporary air conditioning units located within the RMS room. These units were installed by a temporary modification and will remain in operation until a permanent mod is installed.

IPEC00036128

9.8.3 Component Design and Operation Data

The HEPA filters used in this system are designed to remove submicron particles 0.3 microns and larger with an efficiency of not less than 99.97%. The roughing filters are provided ahead of the HEPA filters to screen out large size particles and thereby prolong the life of the HEPA filter. Filters are designed and fabricated to conform to the following:

HEPA Filters

1) Nominal size - 24" x 24" x 11" deep

2) Filter Frame - 304L or 409 stainless steel all welded construction

3) Filter media - a continuous strip of fire resistant waterproof glass fibers, folded back and forth over corrugated separators

4) Separators - corrugated aluminum

5) Flow - approximately 1000 cfm per filter

6) Tests - factory and inplace tested

7) Leakage - sealed with pressure sealing tape to prevent air bypass

8) Pressure - designed for 6 inch H_2O pressure differential across filter

9) Seismic - designed to satisfy seismic design criteria

Roughing Filters

1) Nominal Size - 24" x 24" x 2" thick

2) Frame - 304L stainless steel all welded construction

3) Filter Media - fire resistant, water-proof glass fibers reinforced with stainless steel wire cloth

4) Flow - approximately 1000 cfm per filter

5) Tests - factory and inplace tested

6) Leakage - sealed with pressure sealing tape to prevent air bypass

7) Pressure - designed for 6 inch H_2O pressure differential across filter

8) Seismic - designed to satisfy seismic design criteria

Technical Specifications (TS) require charcoal and HEPA filter testing to demonstrate operability any time a fire , chemical release or work done on the filters could alter integrity. TS surveillance testing is based upon a maximum flow of 30,800 cfm (28,000 plus 10%) giving a minimum safety factor of 2 for methyl iodide removal efficiency while allowing 1% bypass. NSE

IPEC00036129

98-3-017 HVAC demonstrates, for the purpose of TS implementation, that welding is not a fire, a chemical release or work that could alter filter integrity. The NSE also demonstrates that organic components from painting and similar activities could not alter filter integrity until the organic components are above 10% by weight and concludes that filter testing shall be performed when the organic components are greater than or equal to 2.5% by weight organics. Administrative controls are required to evaluate the percent by weight of organics when activities that could generate organics are conducted.

IPEC00036130

TABLE 9.8-1

PRIMARY AUXILIARY BUILDING VENTILATION SYSTEM COMPONENTS DATA

System	Units Installed	Unit Capacity	Units Required for Normal Operation
Exhaust*			
Fan, Standard Conditions	2	70,000 cfm	1
Fan Pressure	-	12.5 in H_2O	-
Fan Motors	2	150 hp	1
Plenums (Fan)	2	70,000 cfm	1
Roughing Filters	1 Bank	70,000 cfm	1
HEPA Filters	1 Bank	70,000 cfm	1
Charcoal Filters	1 Bank	70,000 cfm	1
Supply Tempering Unit (PAB)			
Fans, Standard Conditions	1	64,900 cfm	1
Fan Pressure	1	1.5 in H_2O	1
Fan Motor	1	40 hp	1
Filters	1	64,900 cfm	1
Coils	1	64,900 cfm	1
Tempering Unit (Waste Storage Tank Pit)			
Coil complete with motor operated dampers	1	5,100 cfm	1

* These two exhaust fans are used interchangably and/or as backup for:

1) Ventilation of Primary Auxiliary Building
2) Containment Building Purge System

IPEC00036131

9.9 CONTROL ROOM AIR CONDITIONING, HEATING AND VENTILATION SYSTEM

9.9.1 Design Basis

The Control Room Air Conditioning, Heating and Ventilation System is designed to accomplish the following (operating conditions may be different, as discussed in Sections 9.9.2 and 9.9.3):

1) Maintain 75 F D.B. and approximately 50% R.H. in the Control Room under normal operating conditions.

2) Permit cleanup of airborne particulate radioactivity that enters the Control Room through either the make-up (outside air) line or by infiltration, with ≥1,500 CFM make-up outside air (O.A.) for pressurization of control room circulated through a charcoal filter.

3) Sustain seismic events

Five independent air conditioning (A/C) units also exist in the Control Room to supplement the cooling capacity of the existing A/C system during normal plant operation. These A/C units can also be used during a blackout, Appendix R Safe Shutdown, or design basis accident to maintain the required Control Room temperature. However, these units are assumed operable only during normal operation. Each supplemental unit has been installed as a category M unit and has a 3-ton capacity using a split system arrangement.

9.9.2 System Design

The Control Room Air Conditioning, Heating and Ventilation System (shown in Plant Drawing 9321-F-40593 [Formerly Figure 9.9-1]) consists of the following equipment:

1) Two direct expansion, water-cooled air conditioning units complete with fans and roughing filters. Each unit sized to provide 60% of the refrigeration capacity required.

2) A filter unit consisting of casing, roughing filters, HEPA filters and charcoal filters.

3) Two charcoal filters booster fans each with a capacity of 2,000 cfm for 100% redundancy.

4) Duct system complete with dampers, controls and associated accessories to provide for three (3) different systems of air flow.

5) One kitchen and locker room exhaust fan and miscellaneous electric sill-line heaters.

6) Category M, locally mounted, supplemental cooling units are capable of supplying heat to the Control Room.

All doors in the Control Room lead to enclosed areas (turbine building, control building stairwell, locker room and pantry), not to the outside.

IPEC00036132

The exhaust fan in the kitchen and locker room ventilation system is designed to stop when the control room air conditioning system is placed in the incident mode of operation. A gravity type damper in the ductwork will prevent back flow.

The Control Room is isolated during emergencies as described in Section 9.9.3. In addition, all openings around cables are sealed airtight with a fireproof compound, and the control room door has a three-hour equivalent fire rating. As the control room is constructed of concrete, infiltration or exfiltration through walls, floor and ceiling is negligible.

A 35 cfm air make-up was calculated as the flow required to provide a slight positive pressure in the control room. It was based on a wind velocity of approximately 2.25 miles per hour and 88 linear feet of 1/16 inch wide cracks around the doors, etc., as stated in Section 14.3.5. The use of this low wind velocity is justified for this application because control room doors do not open to the outside. Normally, infiltration calculations are made on the basis that doors open to the outside and with wind velocities of 15 miles per hour. If this installation were assumed to be operating under these conditions, the make-up air requirements would become approximately 545 cfm. Revised dose calculations have assumed a ≥1,500 cfm of make-up air and the CCR HVAC System was modified to provide this quantity of filtered make-up air in system MODE 3.

A Control Room leakage test has shown that infiltration leakage will not exceed 700 cfm. It was determined that the dampers would better function if adjusted to provide a flow of ≥1,500 cfm. This ensures that a slight positive pressure is maintained in the Control Room but would not exceed the thyroid dose limits during an accident due to increased make-up air flow.

The air conditioning system was balanced during initial construction, with the aid of dampers, so that all flows met the design requirements within ±5%. During an incident, the gravity damper in the locker room exhaust system closes, and the exhaust fan in the locker room exhaust system stops. The remaining make-up air will exhaust through cracks and the relief damper, which is weighted to permit selection of control room pressure.

The fresh air intake duct supplying make-up air to the Control Room is provided with air operated dampers to direct this air through carbon filters or close off this supply to the control room completely.

All equipment, except the kitchen and locker room exhaust fan, is located in the Control Building. The air conditioning units, booster fans and carbon filter unit are located on the first floor at elevation 15'-0". The locker room exhaust fan is located in the Control Building Fan Room on elevation 27'-0".

The air conditioning units are normally supplied with cooling water from the essential service water header. All fans, except the locker room exhaust fan, will be powered from one of the buses serviced by the emergency diesel generators and will start automatically following a blackout. The locker room exhaust fan does not run under incident conditions. Operator action is not required to prevent unacceptable temperatures to safety-related equipment located in the Control Room.

The air conditioning system was designed so that functional capacity of the Control Room is maintained at all times, including the period during a blackout or DBA. Control Room safety equipment is specified to a temperature of 120°F. This accounts for the temperature rise due to the enclosed cabinets. The design condition for maintaining "functional capacity" of the Control Room dictates that the ambient temperature for safety equipment located in this room shall not

IPEC00036133

exceed 108.2°F for short term operation associated with a loss of one air conditioning unit. Exceptions are evaluated in NSE 95-3-032, Revision 1.

System Dampers A, B, D1, D2, F1, and F2 are air operated, receiving motive power from the Instrument Air System. The instrument air supply is not redundant. To permit continued operation in the event of loss of instrument air, a backup nitrogen cylinder will supply motive power for a minimum of 24 hours.

The fresh air intake for the Control Room air conditioning system is located in the east wall of the control building below the electrical tunnel between elevations 30'-0" and 18'-0". This intake is protected from tornado generated missiles by an enclosure formed by the electrical tunnel floor above and concrete walls on the south and east sides. Make-up air enters this enclosure horizontally from the north.

With the system in the 10% incident mode, intake air from the atmosphere to the Control Room passes through charcoal filters in the control room ventilation system. The recirculation duct was blocked by the installation of a spool piece with blank off plate, therefore, the Control Room air is no longer being recirculated through the charcoal filters during the 10% incident MODE.

The charcoal filter unit for use in the control room air conditioning system, during "incident" conditions, consists of the following components designed to remain functional under earthquake conditions:

1) Air tight metal casing reinforced with structural steel shapes. The casing is provided with flanged inlet and outlet openings at each end as well as two air tight access panels. The access panels are mounted on the side of the casing, one upstream from the filter location and one downstream.

2) The filter package is made up of two roughing filters, two HEPA filters and two carbon filters. All filters are provided with gaskets or pressure sealing to prevent air from by-passing filters.

   a) The roughing filter frames are of welded construction and fabricated from stainless steel. The filter media consists of a mat of fire resistant waterproof glass fibers reinforced with stainless steel wire cloth.

   b) The HEPA filter frames are of welded construction and fabricated from stainless steel. The core of the filter is constructed by folding a continuous strip of fire resistant waterproof glass fiber filter media back and forth over corrugated aluminum or impregnated asbestos separators.

   c) Carbon filter frames are made from stainless steel. Filter cells are of the pleated type with a minimum one inch thick carbon bed.

   The installed Nuclear Grade Activated Charcoal is tested in accordance with ASTM D3803-1989, per the IP3 response to Generic Letter 99-02. Technical Specification (TS) surveillance testing of the 2 inch beds is based upon a maximum flow defined by dose calculations giving a minimum safety factor of 1.81 for methyl iodide removal efficiency while allowing a 1% bypass.

IPEC00036134

On the loss of one air conditioning unit, the control room temperature will rise to approximately 106°F, with all lights, except emergency lights turned off. These temperatures are lower than the maximum tolerable upper limit of 108.2°F stated above, and show that the "functional capacity" of the Control Room will be maintained under all conditions, including the loss of one air conditioning unit.

The fire protection provisions for this system are covered in Section 9.6.

There is a remote probability that three (3) toxic chemical vapors (anhydrous ammonia, carbon dioxide, chlorine) could reach the Control Room air intake following a release of these gases to the atmosphere as a result of an accident, in sufficient concentration as to cause a potential hazard to the Control Room personnel.

There are two systems that will alert the Control Room operator of the presence of these toxic chemical vapors. The first system consists of a set monitors that are located in the Control Room HVAC air intake. Separate chlorine, ammonia and oxygen probes are provided to detect the presence of these gases in the outside air intake. The oxygen monitor is used to indirectly monitor changes in carbon dioxide levels. An air sample is extracted from the outside air intake duct, analyzed in an airtight enclosure and exhausted back to the air intake. The detector and monitor are mounted in the air conditioning equipment room in the Control Building at El. 15'0". An alarm on panel SM in the control room is provided that will alarm on detection of these toxic gases, equipment trouble or loss of power. In addition, continuous digital LED readout is provided in the air conditioning equipment room for each detector.

The second system and its monitors are located in the Control Room and monitor Control Room atmosphere for low oxygen levels and for high levels of chlorine and ammonia. The system contains a central control and alarm panel that provides continuous indication of oxygen, chlorine and ammonia levels. Detectors are located near the fire display and control panel in order to monitor the atmosphere in the operator's area.

The supplemental Control Room air conditioning system shown in Plant Drawing 9321-F-40593 [Formerly Figure 9.9.1] consists of the following equipment (1 of 5 units shown for drawing simplification):

1) Five independent direct expansion air conditioning (A/C) units each having a nominal 3-ton capacity, consisting of a wall-mounted evaporator section located in the Control Room, and an air-cooled condenser located on the Control Building roof.

2) Each evaporator section contains a cooling coil, as well as an electric heating coil, capable of providing cooling and/or heating upon demand.

3) Each evaporator drain system consists of a condensate collection sump, level switch, and drain line, with a gravity check valve.

4) Five closed loop refrigeration circuits, each consisting of copper tubing using Refrigerant 22.

9.9.3 System Operation

IPEC00036135

The Control Room Air Conditioning, Heating and Ventilation System (See Plant Drawing 9321-F-40593 [Formerly Figure 9.9-1]) will operate as follows:

1) Normal Conditions

The two air conditioning units operate in parallel to supply as required to maintain the Control Room set temperature. Approximately 1500 cfm of the circulated air is fresh outside air makeup. All circulated air bypasses the carbon filters. An exhaust fan for ventilating the locker room is interlocked to operate in conjunction with the air conditioning system.

2 Incident Conditions

a) ≥1,500 CFM outside air circulated through the carbon filter.

b) With 100% recirculated air.

On a Safety Injection signal, the system will automatically be placed in the incident mode of operation (2) (a) above, as follows:

One of the filter booster fans will start, damper "B" will operate to provide ≥1,500 cfm outdoor air to the carbon filters; the locker room exhaust fan will stop. In the event that the first booster fan fails to start, the second booster fan will start after a predetermined time delay. A firestat actuation during this incident MODE will trip the running filter booster fan and prevent the stand-by filter booster fan from starting. The system can, and should, be operated in this mode for as many hours or days required, as determined by the operator.

If for any reason it is required or desired to operate with 100% recirculated air, the system can be placed in the 100% Recirculation Mode of operation (2) (b) by local or remote manually operated switches.

The control circuit is designed to permit local control of the entire air conditioning system from elevation 15'0" in the Control Building and remote control from the Control Room proper. The control station at elevation 15'-0" will include a selector switch that will permit operation of the controls from elevation 15'-0" only when the selector switch is in the local position.

In the event of fire, portable air cylinders and a manifold cylinder emergency air supply have been provided for Control Room operators (see Section 9.6.2).

Any or all five of the supplemental Control Room air conditioning units may operate to provide cooling or heating, as required.

9.9.4 Tests and Surveillance

The following test procedure was used on start-up to verify that the control room air conditioning system would operate in accordance with the design criteria and objectives:

1) Verify the operation of the air conditioning units:

a) Verify cooling water to units

IPEC00036136

b) Verify the installation of filters

c) Verify operation of controls on:

1) Cooling Cycle

2) For various modes of operation:

Normal-Outside air (15%) makeup

Incident-Outside air (15%) makeup, filtered through carbon filters.

Incident-100% Recirculated air (0% through carbon filters)

d) Verify operation of remote controls including start-stop push button motor control with selector switch

e) Verify operation of all dampers

f) Verify operation of kitchen and locker room exhaust fan

2) Verify operation of booster fan and filter package unit

a) Verify the installation of roughing, HEPA and charcoal filters

b) Verify the operation of back-up booster fan

3) Verify operation of firestat

The surveillance tests that are performed to assure proper operation and availability of emergency control room air filtration (carbon filters) system are presented in the Technical Specifications.

The surveillance test will assure the filtration system is adjusted to allow a minimum flow of greater than 1,500 cfm make-up air (damper B) for the duration of the accident (30 days) when accounting for filter degradation during that time (and an initial one (1) accumulated day of monthly functional testing time) and assuming an initial differential pressure drop across the filtration unit of 2.0" WC.

Technical Specifications (TS) require charcoal and HEPA filter testing to demonstrate operability any time a fire, chemical release or work done on the filters could alter integrity. NSE 98-3-017 HVAC demonstrates, for the purpose of TS implementation, that welding is not a fire, a chemical release or work that could alter filter integrity. The NSE also demonstrates that organic components from painting and similar activities could not alter filter integrity until the organic components are above 10% by weight and concludes that filter testing shall be performed when the organic components are greater than or equal to 2.5% by weight organics. Administrative controls are required to evaluate the percent by weight of organics when activities that could generate organics are conducted.

9.10 BREATHABLE AIR SYSTEM INSIDE CONTAINMENT

IPEC00036137

9.10.1 Design Basis

The Breathable Air System (BAS) inside Containment is designed to provide a source of clean breathable air for maintenance personnel at selected locations inside the Containment Building. The Breathable Air System is a non-category I system except for the penetration into containment.

9.10.2 System Design

The system consists of a compressor package, refrigerant dryer, a breathing air purifier, moisture traps, air hose manifolds, and associated valves, piping and instrumentation. The air purifier assures that the air quality conforms to the standards required by OSHA. The air from the compressor is cooled by an aftercooler. High air temperature is prevented by interlocking high air temperature and low lube oil pressure signals to the Breathing Air Compressor Controls. Signals for deviation from normal operating parameters are relayed to an annunciator panel.

9.10.3 System Operation

Breathable air is provided inside containment through a spare penetration line (see Table 5.2-3), which consists of a six-inch sleeve capped by a blind flange at each end.

Prior to using the Breathable Air System, the two blind flanges must be temporarily removed and replaced with two temporary flanges that have adapters to mate with the BAS piping. After connection of the BAS piping, the system is ready to operate.

When the BAS is no longer required, the temporary flanges are replaced with the permanent blind flanges and leak tested in accordance with 10 CFR Part 50, Appendix J requirements, to satisfy the containment integrity criteria provided in the Technical Specifications.

9.10.4 Special Testing Requirements Prior to Operation

Testing was performed prior to operation in accordance with ANSI B.31.1. Functional tests were performed on alarms, systems and components.

9.11 DEMINERALIZED WATER SYSTEM INSIDE CONTAINMENT BUILDING

9.11.1 Design Basis

The Demineralized Water System Inside Containment is designed to provide a source of water for decontamination and for hydrostatic testing and flushing. The system also provides standby fire protection inside containment.

9.11.2 System Design

The piping for the system is arranged to supply water to the distribution system in containment from either of two (2) sources. Only one source will be used at any one time. The two sources are as follows:

1) From the Plant Make-up Demineralizer (Class III Line).

IPEC00036138

2) From the Fire Protection Header located in the pipe tunnel area (Class III Line).

The lines from these sources run into a 3" header, which reduces to a 2" header at the Containment Isolation Valves. These isolation valves are wired to receive a Phase "A" containment isolation signal (for details on these valves refer to Section 5.2). The line then becomes Class III at the first weld joint inside the Containment Building.

All pipe supports design and materials, both inside and outside of the containment building, are seismic Class I.

The distribution headers and lines within containment supply water to electric water heaters, to a number of hot or cold water hose connection locations, and to nine (9) fire hose racks. The system is designed to protect cables necessary for safe shutdown of the reactor.

9.11.3 System Operation

During normal operation, the system provides standby fire protection (see Section 9.6 for a description of the facility's Fire Protection System). During refueling and maintenance, the system is utilized for decontamination (hot water) and for hydrostatic testing and flushing (cold water).

9.11.4 Special Testing Requirements Prior to Operation

Leakage testing was performed prior to operation in accordance with ANSI B.31.1.

IPEC00036139

CHAPTER 10

STEAM AND POWER CONVERSION SYSTEM

10.1 DESIGN BASIS

10.1.1 Performance Objectives

The turbine-generator system consists of components of conventional design, acceptable for use in large power stations. The equipment is arranged to provide high thermal efficiency with no sacrifice to safety. The component design parameters are given in Table 10.1-1.

The equipment in the turbine-generator system under the Stretch Power Uprate Project conditions produces a gross output of approximately 1,065,000 KWe. The calculated maximum gross output is 1,093,500 KWe. Heat balance diagram at 1,093,500 KWe, maximum calculated is shown on Figure 10.1-1.

The Steam and Feedwater System is designed to remove heat from the reactor coolant in the four steam generators, producing steam for use in the turbine generator. The Steam and Feedwater System can receive and dispose of, in its cooling systems and through power operated 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 system design provides means to monitor and restrict radioactivity discharge to normal heat sinks or the environment such that the limits of 10 CFR 20 are not exceeded under normal operating conditions nor in the event of anticipated system malfunctions.

One turbine and two motor driven auxiliary feed pumps are provided to ensure that adequate feedwater is supplied to the steam generators for reactor decay heat removal under all circumstances, including loss of power and normal heat sink. Auxiliary feedwater flow can be maintained until either loss of power is restored, or reactor decay heat removal can be accomplished with emergency power sources. Auxiliary feedwater pumps and piping are designed as Class I seismic components.

10.1.2 Load Change Capability

The Reactor Control System can handle transmission system disturbances that cause electrical generation step load increases of 10% and ramp increases of 5% per minute within a power range from 15% to 100% without reactor trip, subject to possible Xenon limitations late in core life. Similar step and ramp load reductions are possible for the changes from 100 to 15% of full load (maximum guaranteed load). The Reactor Coolant System can sustain a complete loss of load from full power with reactor trip (see Section 7.2). In addition, the turbine bypass and steam dump systems make it possible to accept a turbine load decrease of 10% to 50% of full power at a maximum turbine unloading rate of 200% per minute without reactor trip (see Section 7.3.2).

The 10% to 50% of full power at a maximum unloading rate of 200% per minute without reactor trip (depending on full power tavg) is handled by the steam bypass, condenser, and reactor rod control systems. The reactor control system handles 10% of the load decrease while the remainder of the load decrease is handled by the steam bypass and the condenser systems.

IPEC00036140

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 failure, containment isolation, circulating water loss of flow) to accommodate turbine trip steam rejection requirements. Condenser isolation occurs automatically with the existence of high pressure (low vacuum). In such a case the turbine trips and heat removal capability is provided by atmospheric dump valves and code safety valves. Also, in case of condenser tube leaks, one side of any condenser may be manually isolated and the hotwell dumped without reducing the condenser heat removal capability.

The Steam and Power Conversion System environmental discharges under normal operations are made through the condenser air ejector or the steam generator blowdown system. All such discharges to the environment are monitored for secondary radioactivity. The monitors ensure that any radioactivity discharged will be within 10 CFR 20 limits.

10.1.4 Secondary Functions

The Steam and Power Conversion System provides steam for the auxiliary steam driven feedwater pump and for the operation of the air ejector. The turbine bypass system is designed to dissipate the heat in the reactor coolant following a full load trip. This heat is removed by means of the steam bypass through the condenser to the circulating water and by steam dump through the power operated relief and safety valves in the event of loss of vacuum in the condenser.

IPEC00036141

TABLE 10.1-1

STEAM AND POWER CONVERSION SYSTEM COMPONENT
DESIGN PARAMETERS

Turbine-Generator	
Turbine Type	Four element, tandem-compound six-flow exhaust
Turbine-Generator Capacity (kW)	
Nominal SPU Value	1,065,000
Maximum calculated	1,093,500
Generator Rating (kVA)	1,125,600
Turbine Speed (rpm)	1800
Condensers	
Type	Radial flow, single pass, divided water box
Quantity	3
Condensing Capacity (lbs of steam/hr)	7,230,000
Condensate Pumps	
Type	8 stage, vertical pit type, centrifugal
Quantity	3
Design Capacity (each-gpm)	7860
Motor Type	Vertical Induction
Motor Rating (hp)	3000
Feedwater Pumps	
Type	High Speed, barrel coring, single stage, centrifugal
Quantity	2

IPEC00036142

TABLE 10.1-2
(Cont.)

STEAM AND POWER CONVERSION SYSTEM COMPONENT DESIGN PARAMETERS

Design Capacity (each-gpm)	15,300
Pump Drive	Horizontal steam turbine
Drive Rating (hp)	8350
Auxiliary Feedwater Source	360,000 gallons assured reserve in 600,000 gallon condensate tank. Alternate supply from city water system.
Auxiliary Feedwater Pumps	3 (one steam turbine driven, two electric motor driven)
Design Capacity (each-gpm)	800 (turbine driven) 400 (motor driven)

IPEC00036143

10.2 SYSTEM DESIGN AND OPERATION

The Steam and Power Conversion System Process Flow Diagram is shown on Figure 10.2-1. Process and Instrumentation Diagrams for the following systems: Main Steam; Condensate and Boiler Feed Pump Suction; Condensate Polishing; Boiler Feedwater; Extraction Steam; Heater Drains and Vents; Moisture Separator and Reheater Drains and Vents; Condenser Air Removal and Water Box Priming; Circulating Water; Chemical Feed,; Auxiliary Steam and Condensate for Nuclear Equipment; Auxiliary Steam Supply and Condensate Return; and Steam Generator Blowdown and Blowdown Recovery Systems are shown on Plant Drawings 9321-F-20173, -20183 Sh. 1 & 2, -20193, -20203, -20223, -20233, -20253, -20263, -20383, -27273, -40573, -27293, and -24063 [Formerly Figures 10.2-2 through 10.2-13, and 10.2-47 and 4].

Heat Balance diagrams at loads of 1,068,701 kW(e); 1,021,793 kW(e); 1,000,630 kW(e); 766,350 kW(e); 510,897 kW(e); and 255,448 kW(e) are shown on Figures 10.2-14 through 10.2-19.*

*NOTE: These figures are based on original plant equipment and are provided for historical purposes only.

10.2.1 Main Steam System

The Main Steam System conducts steam in a 28 inch pipe from each of the four steam generators within the reactor containment through a swing disc type isolation valve (referred to henceforth as Main Steam Isolation Valve or MSIV) and a swing disc type non-return valve (referred to henceforth as Main Steam Check Valve or MSCV) to the turbine stop and control valves. The Main Steam Isolation and (non-return) Check Valves are located outside of the Containment. The four lines are interconnected near the turbine. The design pressure of this system is 1085 psig at 600 F. A steam flow-meter (flow venturi) is provided upstream of the Main Steam Isolation and (non-return) Check Valves in the line from each steam generator to measure steam flow. Steam flow signals are used by the automatic feed-water flow control system (see Chapter 7). The flow venturi also limits the steam flow rate in the event of a steam line break downstream of the venturi. Steam pressure is measured upstream of the Main Steam Isolation and (non-return) Check Valves.

The MSIV's contain free swinging discs that are normally held out of the main steam flow path by an air piston. They are designed to close in less than five seconds. Air receiver tanks are provided in the instrument air piping to the MSIV operators to compensate for pressure transients in the instrument air system in order to prevent spurious MSIV closure. The MSIV's are automatically closed (closure of the valves initiates unit trip) on receipt of the following signals from the steam line break protection system:

1) After delay (maximum of 6 seconds) High steam flow in any two out of the four steam lines, coincident with low steam line pressure or low T_{avg}; or

2) Two sets of two-of-three high-high containment pressure signals [energize to actuate]; or

3) Manual actuation (one at a time).

Tests on the Main Steam Isolation Valves and the Main Steam Check Valves performed by the manufacturer were:

IPEC00036144

1) Tight seating at 1200 psi maximum and 50 psi minimum differential pressures

2) Stem gland leakage not to exceed 1 cc of water per hour per inch of stem diameter when subjected to a hydrostatic leak test pressure of 1100 psig, or not to exceed 0.03 SCFH of air per inch of stem diameter with a differential pressure of 80 psi

3) Non-destructive testing.

The basis for the Main Steam Isolation Valves' and the Main Steam Check Valves' design leakage rates was the Manufacturer's Standardization Society Specification MSS-SP-61 and standard industry criteria for steam leakage rates. The acceptance criteria for shop tests and stem leakage rates were that steam valve glands be designed and packed so that leakage along the stem does not exceed 1 cc of water per hour per inch of stem diameter when subjected to a hydrostatic leak test pressure of 1100 psig, or 0.03 SCFH of air per inch of stem diameter with a differential pressure of 80 psig. The basis for this criterion was sound, up-to-date engineering practice, and was acceptable to valve manufacturers and used by them in the design and fabrication of their products.

The air operated Main Steam Isolation Valves are tested at refueling intervals to verify their ability to close within the specified time upon receipt of a closure signal. See Section 3.7.2 of the Technical Specifications.

Testing of Main Steam Isolation Valves under steam flow conditions is not justified. This testing would cause a severe transient and the collapse of steam bubbles in the steam generator shell side resulting in a low-low water level plant trip. Also, because of the valve design, the valves cannot be reopened against any differential pressure across the valve. The valve operator was designed only to close the valve during steam flow conditions. Thus a valve test at steam flow conditions would necessitate bringing the plant to shutdown conditions after each valve test.

The Main Steam Check Valve, as any swing type check valve, closes upon reverse flow of steam in case of accidental pressure reduction in any steam generator or its piping.

Each steam line is provided with a venturi-type restrictor. The flow restrictors are designed to increase the margin to Departure from Nucleate Boiling (DNB), and thereby reduce fuel clad damage by limiting steam flow rate consequent to a steam line rupture and thereby reducing the cooldown of the primary system.

Design criteria for the steam line flow restrictors were:

1) Provide plant protection in the event of a steam line rupture downstream of the restrictor. In such an event, the flow restrictor reduces steam flow rate from the break, which in turn reduces the cooling rate of the primary system. This increases the margin to DNB and fuel clad damage.

2) Minimize unrecovered pressure loss across the restrictor during normal operation (less than 5 psi at approximately 120% of rated steam flow).

3) Withstand the number of pressure and thermal cycles experienced during the life of the plant.

IPEC00036145

4) Maintain restrictor integrity in the event of double-ended rupture of a main steam line immediately downstream of the restrictor.

In addition to meeting these criteria, the restrictors also:

1) Reduce thrust forces on the main steam piping in the event of a steam line rupture, thereby minimizing the potential for pipe whip.

2) Serve as a flow element for steam flow measurement.

3) Limit containment pressurization in the event of a main steamline break inside containment.

Each restrictor is a 304 SS venturi. The complete restrictor assembly was fitted inside a length of main steam pipe and attached to the pipe by a circumferential weld at the discharge end as shown in Figure 10.2-20. Materials, welding and inspection requirements applied in fabrication of the restrictors conform to USAS B31.1 requirements.

Being fitted inside a length of main steam pipe, a flow restrictor is not a pressure boundary component except for flow element throat pressure taps that are similar to other small branch connections on the main steam lines. In addition, component integrity was assured by satisfaction of B31.1 requirements. Approved weld procedures, welders test qualifications, inspection procedures and materials, and a quality assurance program were used in the design and fabrication of the venturi nozzle.

The main steam flow restrictors are not a part of the main steam system boundary. However, all tests or inspections of the restrictors required by USAS B31.1 were performed in the fabricator's shop.

The system is classified as Class I for seismic design up to and including the Main Steam Check Valves.

The steam break incident is analyzed in Chapter 14.

Turbine Steam Bypass

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 means of two 20-in main steam bypass lines. One bypass line runs 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 capacity of 500,000 lb/hr at an inlet pressure of 650 psia. The bypass values, in conjunction with the NSSS Control Systems, can accommodate a 50% load rejection from 100% power without reactor trip for full power Tavg values of 564oF and above (see Section 7.3). The turbine bypass steam capacity is nominally 40% of full-load steam flow at full-load steam pressure. The large number of small valves is installed to limit the maximum steam flow should one valve stick open. A potential uncontrolled plant cooldown is thus eliminated. Local manually operated isolation valves are provided at each control valve.

IPEC00036146

The local manually operated isolation valves at each turbine steam bypass control valve are locked open. Since the dump valves are required to open wide in approximately three seconds, it would not be feasible to attempt to open the subject valves. These valves are provided for maintenance purposes and for isolation of a failed open valve.

On a turbine trip with reactor trip, the pressure in the steam generators rises. To prevent overpressurization without main steam safety valve operation, the twelve 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. In the event of a turbine trip, all valves open fully in three seconds. 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 valve. This operation is described further in Chapter 7.

With loss of offsite power, the plant can be put in the hot shutdown condition in accordance with plant operating procedures and held there safely until outside power is restored, at which time a normal cooldown may be performed in accordance with operating procedures.

In the unlikely event that cold shutdown must be achieved before outside power is restored, this can still be accomplished. During the period of holding hot shutdown, the operator will manually load all equipment necessary for plant cooldown; all equipment and systems used for normal cooldown will be available except reactor coolant pumps and steam dump to condenser.

The cooldown would follow the same sequence of events as in the normal operating procedure for cooldown to cold conditions, with the following exceptions:

1) Circulation in the Reactor Coolant System is via natural circulation rather than by one reactor coolant pump.

2) Steam is dumped to the atmosphere rather than to the condenser. Cooldown rate will be slightly less than if steam were being dumped to the condenser due to the lower rate of steam dump.

3) When reactor coolant temperature and pressure are low enough to permit operation of the residual heat removal loop, cooldown rate would be maintained at less than 50 F/hr to reduce temperature differences between loops.

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 achieved 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 twelve temperature controlled bypass valves open on turbine trip or large load reduction. The valves are interlocked to prevent opening unless the following conditions are established:

1) The circulating water pump for the particular condenser section is running

IPEC00036147

2) The condenser vacuum must be above the allowable set point

3) Loss of load interlock

The reason for condenser vacuum allowable setpoint is not based on the condenser shell and tubes but on the main turbine design. This setpoint has been established on information from the turbine manufacturer. The automatic vacuum trip for the main turbine is 18" Hg. In conjunction with this trip, the condenser dump valves are blocked when condenser pressure rises to 25" Hg. Therefore, the trip is provided for turbine protection. The condenser tubes are protected from steam impingement by an interlock with the circulating water pump breakers. The variation in steam flow from the dump system with increased condenser pressure to 25" Hg is not significant. Critical pressure drop exists from the main steam line to the condenser. With critical pressure drop, the steam flow rate is independent of downstream pressure and is only dependent on upstream pressure.

The loss of load interlock prevents actuation of the steam dump system for small load variations. The interlock allows steam dump for load reductions greater than 10%. This channel is independent of the steam dump control system.

The steam bypass system was designed to prevent spurious opening of the bypass valves by requiring more than one actuating signal (as in noted in Chapter 7). This will be the case only on those instances where bypass would be desirable, such as: (a) turbine trip or loss of load greater than approximately 10% and (b) cooldown, heatup and maintenance of hot shutdown via header pressure control.

Steam Relief to Atmosphere

If the condenser 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 by the code safety and power operated relief valves.

There are five code safety valves and one power operated relief valve on each of the main steam lines located outside of the Reactor Containment and upstream of the MSIV's and MSCV's.

The five code safety valves per steam main consist of four 6-inch by 10-inch and one 6-inch by 8-in. These valves are set to open at 1065, 1095, 1110 and 1120 psig, respectively. The total relieving capacity of all 20 code safety valves is 15,108,000 lb per hr or 108% of the rated steam flow, according to Tech Spec Basis, Amendment #91. Discharge from each of these 20 valves is carried to the atmosphere through individual vent stacks.

The single power operated relief valve on each steam main is 6 in. Together, these valves are capable of releasing the sensible and core decay heat to the atmosphere. The valves are automatically controlled by pressure or may be manually operated from the main control board. Two indicating lights located above the relief valve controllers confirm their respective positions. The total relief capacity of the four valves is 2,467,000 lb per hour at 1020 psig. This capacity exceeds 10% at the rated steam flow. Discharge from each of these four valves is carried to the atmosphere through individual vent stacks. Functionally, these valves are part of the Auxiliary Feedwater System and are necessary to go from hot to cold shutdown.

IPEC00036148

The power operated relief valves may be used to release the steam generated during reactor physics testing, operator license training, and plant hot standby operation if the Turbine Bypass System is not available.

The design and installation criteria for mounting of the main steam safety and relief valves was similar to that described for pressure relieving devices in Section 4.2.3. At the main steam safety and relief valves specific provisions include: extra strong weldolet type header connections reinforced with weld build-up at the junction point, the weldolet size is two pipe sizes larger than the valves inlet size, a double extra strong reducer is used between the weldolet and the valve inlet, and the valve discharge is oriented to minimize reaction loads. Main steam pipe whip restraints were designed to allow their use as thrust restraints where required.

The following highlighted information is deemed to be "Historical" in nature and is not meant to be used or updated. It refers to, and utilizes, a methodology that is no longer applicable to Indian Point 3. The Alternate Source Term methodology that is currently applied to dose assessment at IP3 does not require the type of evaluation contained in the highlighted section below.

[Historical Information] Detailed piping stress analysis has been performed, taking into consideration the cumulative effect of all valves relieving simultaneously. This analysis has proven stresses to be within allowable code limits in all cases.

During any year of normal operation, it is not expected that there will be any necessity for steam relief to the atmosphere. The plant can be taken through most transients without need for atmospheric relief. The only credible cause for atmospheric relief would be the loss of the condenser. This could be caused by loss of air removal capacity or loss of cooling water. Both of these occurrences are unlikely and would require minimal time to correct. For a two- hour repair time and the plant maintained in a hot shutdown condition, the amount of steam dumped to the environment would be roughly 400,000 pounds.

If there is a loss of offsite power requiring that the plant be brought to a cold shutdown condition, the amount of the steam dump would be 1.4×10^6 pounds from the time power is lost to the time the Residual Heat Removal System is brought into operation 6 hours later. This includes the two hours at hot shutdown conditions.

The maximum quantity of radioactivity calculated to be released during each of the above postulated occurrences is given in Table 10.2-2. Releases were calculated for two cases:

a) The case in which the secondary side water contains an I-131 activity of 0.35 uCi/cc

b) The case in which the maximum expected fuel defects (0.2%) and steam generator tube leakage (20 gpd) are present. These anticipated levels of fuel defects and steam generator tube leakage were based on operating experience at Westinghouse plants employing Zircaloy-4 fuel rod cladding and Inconel steam generator tubes. A blowdown rate of 12.5 gpm per steam generator was used in the analysis for both the design case and the expected case.

Based on 1 percent fuel defects, the amount of radioactivity that would be released during either the 2-hour steam dump of 400,000 lb or the 6-hour steam dump of 1,400,000 lb is given in Figures 10.2-21 and 10.2-22 as a function of primary-to-secondary leak rate.

IPEC00036149

For the case when the reactor is operating at the design limit of 1% defective fuel, and using accident meteorology, site boundary thyroid doses of 3.7 rem and 5.7 rem and site boundary total body doses of 0.47 rem and 0.90 rem for the 2-hour and 6-hour steam dumps, respectively, have been calculated. The whole body dose (due to gamma radiation) would be much less than this total body dose.

With the simultaneous occurrence of approximately 0.2% fuel defects and steam generator tube leakage of approximately 20 gpd, and using average meteorology, the anticipated doses for the steam dumps would be:

	2-hour steam dump	**6-hour steam dump**
Thyroid dose	0.02 mrem	0.03 mrem
Total Body Dose	0.0004 mrem	0.0007 mrem

The Indian Point 3 steam dump system is arranged to avoid steam dump to the atmosphere in all cases with the exception of the loss of the main condenser. The plant can heat up, cooldown, trip, and take a load reduction without steam dump to the atmosphere as long as the main condensers are available. The plant was designed as practically as possible to avoid steam release to the atmosphere.

Under expected plant operating conditions, the doses at the site boundary are only a small fraction of those specified in 10 CFR 20 for the cases in which steam dump is necessary.

Neither the steam bypass valves nor the power operated relief valves are required for safety. A typical response of the Reactor Coolant System to a condition in which all power operated relief valves, both on the Reactor Coolant System and the Main Steam System, are assumed to be inoperative is given in Section 14.1.8. These analyses show, both for beginning and end of core life, that no hazard is presented to the integrity of the Reactor Coolant System or the Main Steam System and that the minimum DNBR remains well above 1.30, indicating no fuel clad damage, even assuming that the Reactor Coolant System and Main Steam System power operated relief valves, as well as the pressurizer spray and steam dump system, are inoperative. Operation of the power operated relief valves, pressurizer spray, and steam dump system are not required for safety. The Main Steam System safety valves provide a limiting device to the transient and are sized to take a minimum of 100% at the maximum calculated steam flow without exceeding 110% of design pressure. The pressurizer safety valves are conservatively sized to take the maximum flow resulting from a loss of external load, assuming no direct reactor trip, without Reactor Coolant System pressure exceeding permissible ASME code valves.

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 Main Steam Isolation Valves. The steam pressure is reduced to 600 psig for the turbine by a pressure control valve.

Auxiliary steam for the turbine gland steam supply control valve, the three steam-jet air ejectors, the heater 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 upstream of the turbine stop valves. Pressure reducing stations are used for the priming

IPEC00036150

and main air ejectors. Temperature control valves are provided in the steam line to the reheaters.

The design pressure and temperature for this system are 1085 psig and 600°F, respectively.

Four combination moisture, Preseparators/Special Cross Under Pipe Separators (MOPS/SCRUPS) were installed to improve cycle efficiency.

The preseparator is a concentric chamber in the crossunder pipe whose upper end is open, constituting a cyclindrical gap. The preseparators are located directly at each HP turbine exhaust. Together with transport steam, the moisture flowing along the wall of the HP turbine exhaust is forced into the gap of the preseparator.

This moisture is drained within the apparatus to the SCRUPS. The transport steam is separated from the moisture and flows through a channel to the SCRUPS. The SCRUPS consists of turning vanes on which moisture droplets form a film that is removed together with transport steam through slots in the turning vanes. The turning vanes are hollow, and the separated moisture and transport steam flow through them to an outer chamber. There the steam separates from the moisture and leaves the MOPS/SCRUPS together with the transport steam from the MOPS.

The steam flows as extraction steam to feedwater heaters No. 35. The separated moisture is drained together with the moisture from the MOPS through a drain nozzle. Each MOPS/SCRUPS has a separate drain line equipped with a check valve. The four drain lines are routed via a common header to the heater drain tank. The drain piping is provided with a loop seal to prevent steam from flowing back to the MOPS/SCRUPS or to the heater drain tank.

The MOPS/SCRUPS reduces the moisture content of the wet steam exhausting from the HP turbine. This reduction results in lower pressure loss in the crossunder pipe with subsequent decrease in station heat rate and a reduction in the erosion-corrosion rate of the crossunder pipe walls.

There are six horizontal-axis, cylindrical shell, combined moisture separator steam reheater assemblies. Partially dried steam from the outlet of the moisture preseparators enters each assembly at one end. Internal manifolds in the lower section distribute the steam. The steam then rises through a moisture separator where most of the remaining moisture is removed and is drained to a drain tank. The steam leaving the 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 LP turbine elements. The tube bundle is supplied with main steam from upstream of the turbine throttle valves, which condenses in the tubes and leaves as condensate. Condensate from the reheater assemblies flows to the heater drain tank and is directed to the suction line of the boiler feedwater pumps together with the drains from the moisture preseparators and from feedwater heaters Nos. 35 and 36.

Steam from six extraction openings in the turbine casings is piped to the shells of the three parallel strings of feedwater heaters. The first point extraction originates at the high pressure turbine casing and supplies steam to the shell of feedwater heaters No. 36 (high pressure). The second point extraction originates at the high pressure turbine exhaust (cross under) piping and the moisture preseparator units, upstream of the moisture separator reheaters, and supplies steam to high pressure feedwater heaters No. 35.

IPEC00036151

The third, fourth, fifth, and sixth point extractions all originate at the low pressure turbine casings and supply steam to feedwater heaters Nos. 31, 32, 33, and 34 (all low pressure), respectively.

Non-return valves are provided in all but the two lowest pressure steam lines corresponding to feedwater heaters No. 31 and 32, which are mounted at the neck of the turbine.

To prevent turbine overspeed from backflow of flashed condensate remaining in the heaters after a turbine trip, these reverse-current, air cylinder operated valves are equipped with balancing counterweight. They close automatically upon a signal from the turbine trip circuit. Since the low pressure fifth and sixth point extraction lines to feedwater heaters Nos. 31 and 32 are located entirely in the condenser shells, they are not provided with non-return valves.

To prevent low pressure turbine overspeed, low pressure steam dump valves are provided in the high pressure turbine exhaust to the moisture separators. These valves discharge to the condenser on turbine trip.

Testing of the low pressure steam dump system was performed at plant power levels of 50% and 85-100% of the license application rating. This testing was accomplished in conjunction with the loss of load trip tests listed in Table 13.3-1. The test was performed by measuring the peak turbine speed achieved following an immediate and total loss of electrical load with the plant operating at full licensed power. The design condition for the loss of load was based on the turbine trip being delayed until functioning of the mechanical or IEOPS trips. However, turbine trip actually occurs at an earlier time due to operation of the turbine trip solenoid valves triggered by the loss of load. Since it would not be prudent to disable the turbine trip solenoid valves for testing, the measured peak speed was mathematically corrected to the speed that would have been achieved had the solenoid trip failed. These corrected speeds were then compared to the predicted turbine responses. All test results were satisfactory.

Steam Generator Blowdown

Each steam generator is provided with a drain connection at the bottom and two 2.5 inch blowdown connections to control the concentration of solids in the shell side of the steam generator. The two blowdown connections are at the same level, but on opposite sides of the shell. Each of the three connections contains a manual isolation valve. Piping from the three connections join to form a 4 inch stainless steel blowdown header for each steam generator. (See Plant Drawing 9321-F-27293 [Formerly Figure 10.2-47A].)

Four individual blowdown headers are routed from the respective steam generators to the PAB. Each header contains two air operated containment isolation valves. Each blowdown header downstream of the containment isolation valves contains a venturi flowmeter, and a tee connection allowing flow to be diverted to either the blowdown flash tank or the blowdown recovery system.

Steam generator flow is measured using a venturi flowmeter (FE-545 through 548) with split range local dP transmitters (FT-545 A & B through 548 A & B) installed downstream of the isolation valves in the PAB.

These transmitters provide a signal to the totalizer (FY-545 through 548) and controller (FIC-545 through 548) units that calculates a true flow in each SGBD line using instantaneous changes in process flow and temperature. All four totalizers and controllers are mounted on the SGBD panel, located at elevation 15' -0" of the Turbine Building. The RTDs (TE-545 through 548) installed downstream of the venturi flowmeter in each SGBD line, provide instantaneous temperature input to the totalizers in the SGBD panel.

IPEC00036152

An interconnection between the 4" SGBD lines and the 3/8" SGBD Sample tubing was installed during RO9. This interconnection allows for the 4" SGBD lines to be filled from the Sample System. This modification was installed to prevent water hammer during SGBD restart above cold shutdown. There are two paths for each of the four blowdown lines: to recovery system or to flash tank. Manually / locally operated isolation valves located in PAB, control the path to the flash tank. Remotely / manually air operated flow control valves control the path to the recovery system from the steam generator blowdown panel. These valves are procedurally controlled to be operated selectively to prevent simultaneous blowdown to both the flash tank and the recovery system.

The steam from the blowdown flash tank is vented directly to the atmosphere. The condensate in the flash tank is routed to the main service water return header where it is ultimately discharged to the Hudson River. Flow elements are installed in the vent piping, blowdown discharge piping and city water supply piping for monitoring and heat balance calculations. FT-538 instrument loop meets the requirements of Regulatory Guide 1.97 and is used for radiation dose assessment in the event of a steam generator tube leak or rupture. A drain at the bottom of the blowdown flash tank will allow draining of potentially contaminated fluid to sump tank #31 and subsequently to the liquid waste processing system.

The blowdown flow from each steam generator to the recovery system is remotely/manually controlled from the steam generator blowdown recovery panel by means of an air-operated flow control valve in each of the four blowdown lines. The Steam Generator Blowdown Recovery System (Plant Drawing 9321-F-24063 [Formerly Figure 10.2-48]) consists of two heat exchangers, a filter and demineralizer package, and associated piping, valves and instrumentation. During normal system operation, the blowdown flow from all four steam generators is routed to the recovering heat exchanger (SGBDHX-3) in the Turbine Building.

The recovering heat exchanger (SGBDHX-3) utilizes condensate flow from the discharge of the No.32 feedwater heaters to cool the blowdown flow and recover as much heat as possible. This heat exchanger is designed to recover approximately 65% of the maximum theoretically recoverable heat during the period of nominal continuous blowdown (1% of feedwater flow) at 100% power.

The blowdown flow exiting this heat exchanger is routed through a non-recovering heat exchanger (SGBDHX-4) also located in the Turbine Building. This heat exchanger utilizes service water to cool the blowdown flow to 120 F for subsequent treatment in the filter and demineralizer package and final discharge to the drains collecting tank.

The pressure in the blowdown piping system upstream of and including SGBDHX-4 is maintained by means of a pressure control valve located at the outlet of SGBDHX-4. This back pressure minimizes flashing and enhances flow control. Immediately downstream of the pressure control valve the flow path divides. One path routes the flow to the blowdown demineralizer package.

The other path bypasses demineralizer and diverts the blowdown flow to the drains collecting tank for treatment of the blowdown by the condensate polisher during periods when the polisher is operating. Additionally, the air-operated isolation valves for these flow paths permit a pressure and temperature declassification in the downstream piping.

The total blowdown flow rate can be maintained between 0.2% and 1.0% of the total feedwater flow rate. For operation at 100% power this corresponds to volumetric blowdown rates between

IPEC00036153

48 and 240 gpm from all four steam generators. The blowdown recovery system design basis is 300 gpm for four steam generators. This provides for occasionally higher blowdown rates should they be required to reduce solids concentration. The replacement steam generator design permits up to 230 gpm continuous blowdown flow to be drawn from any single blowdown nozzle over the entire design life of the steam generators, or up to 335 gpm through a single nozzle over a cumulative one year period. There are two blowdown nozzles on each steam generator.

Redundant area temperature sensors are provided at three selected locations in the PAB in the vicinity of the blowdown recovery piping for detection and mitigation of a high energy line break. Specifically, two RTDs are located in each of the three following areas:

1) 55' -0" elevation of the piping penetration area,

2) 35' -0" piping tunnel (mini-containment area), and

3) 18' -0" elevation of the Heat Exchanger Room.

These RTDs are electrically interlocked with the actuation circuitry for the blowdown containment isolation valves and will automatically close these valves upon detection of high temperature in any of these areas. In addition, these RTDs will initiate an alarm in the Control Room upon high temperature detection.

Steam generator sample lines are taken from the blowdown headers inside the containment (see Plant Drawing 9321-F-27293 [Formerly Figure 10.2-47A]). Small flows from the sample lines are combined and monitored for radiation (See Plant Drawing 9321-F-27293 [Formerly Figure 10.2-47B]). In the event of a high radiation signal, both diaphragm valves in the sample and blowdown liens will close automatically prior to Blowdown Flow being released to the environment. If significant radioactivity is present in the steam generator blowdown from Indian Point 3, this flow could be routed to Indian Point 1 for treatment (see Section 11.1 for details on this intertie).

Sources of radioactivity releases from the Steam and Power Conversion System (SPCS) of Indian Point 3 are shown in Figure 10.2-23.

Isolation of Steam Generator Blowdown from event initiation is assumed for both Loss of Normal Feedwater (Section 14.1.9) and Loss of All A.C. Power to the Station Auxiliaries (Section 14.1.12).

10.2.2 Turbine Generator

The Turbine Generator Building General Arrangement Drawings are shown in Plant Drawings 9321-F-20043, -20053, -20063, -20093, -20083, -20073, and –20103 [Formerly Figures 10.2-40 to 10.2-46]. The original turbine generator had a guaranteed capability of 1,021,793 kW at 1.5" Hg absolute exhaust pressure with zero percent makeup and six stages of feedwater heating. The unit operates at 1800 rpm with steam supplied ahead of the main stop valves at 720 psia, 506°F and enthalpy of 1,200 BTU/lb. Steam is admitted to the turbine through four stop valves and four control valves. The expected throttle flow at 1,093,500 kW is 13,136,870 lb of steam per hour.

IPEC00036154

The turbine is a four-casing, tandem compound six-flow exhaust unit with 44-inch last row blades. It consists of one double flow High Pressure (HP) element in tandem with three double flow Low Pressure (LP) elements. Steam, after passing through the stop and control valves, passes through the high pressure element, exhausts through the moisture preseparators, flows through the moisture separator reheaters and then to the LP elements.

WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," provides the methodology used to determine the frequency of testing for the turbine stop and control valves. Westinghouse report WOG-TVTF-93-17 (8/6/93), "Update of BB-95/96 Turbine Valve Failure Rate and Effect on Destructive Overspeed Probabilities," revised the valve failure data in WCAP-11525 requiring a decrease in the stop valve test interval to satisfy regulatory approved overspeed probability criteria.

High Pressure Turbine

The Indian Point 3 turbine generator is rated and guaranteed to a steam flow equal to the licensed thermal power of the NSSS. The turbine is designed to pass 5% additional flow.

The HP turbine rotor was replaced during the 2004 Refueling Outage (2R16) in order for the HP turbine to be able to accommodate the increase in steam flow caused by the power uprate. The original nozzle block design was removed and replaced with an inner cylinder design with directional inlet vanes. The new design also incorporated an all Rateau blade designed rotor.

In the large size turbine that is applied to the nuclear cycle, the reaction type stage is inherently more efficient. For this reason, it is desirable to maximize the work performed in the reaction stages. Therefore, in order to increase the proportion of work performed by the reaction stages, the impulse chamber pressure must be increased.

The desired increase in impulse chamber pressure was accomplished by installing new stationary blading and by adjusting the gauging of the proper number of stationary rows in the HP blade path.

In summary, the HP Optimization Program included:

1) Two new nozzle blocks

2) Two new rows of triple pin control stage blades

3) Ten new rows of stationary blades (five (5) GVN and five (5) GNN)

4) Four new rows of reaction blades (two (2) GVN and two (2) GNN)

Based upon HP turbine optimization calculations, the anticipated heat rate improvements were set at 10 btu/kw-hr for the new steam generators and 63 btu/kw-hr for the HP turbine optimization program for a total improvement of 73 btu/kw-hr plus or minus the test tolerance of 18 btu/kw-hr. The HP turbine optimization modification acceptance test was successfully carried out in July 1989. This test demonstrated the heat rate decrease equal to or larger than the minimally acceptable 73 – 18 = 55 btu/kw-hr.

Low Pressure Turbine

IPEC00036155

During the 1990 Refueling outage, the existing three low pressure turbines (stationary and rotating components) were replaced with three (3) ASEA Brown Boveri (ABB) low pressure turbines.

The ABB turbines incorporate design improvements that significantly reduce stresses and utilize materials of lower yield strength. This results in a turbine that is resistant to stress corrosion cracking and low cycle fatigue. Additionally, several performance-related design features have been incorporated to improve the overall efficiency of the turbines. These design features will result in an increase in the power output of the unit.

Turbine Oil System

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 form 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 mechanism at 300 psig. A motor driven bearing oil pump is also provided to supply oil whenever there is 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 AC motor driven oil pump is provided for turning gear and emergency operation. A DC motor driven oil pump operated from a station battery provides additional backup to ensure a supply of lubricating oil to the machine. An AC motor driven generator seal oil pump is furnished for normal operation with a DC 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.

The turbine is coupled to a single, hydrogen inner cooled generator and rotating rectifier exciter. The generator is rates at 1,125,600 kVA, 3 phase, 60 cycles, 22 kV, 90 percent power factor, and 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 720 psia, saturated, 1,200 BTU/lb enthalpy steam conditions.

Bulk Hydrogen Storage

Hydrogen truck is connected to system as primary supply.

A removable section of pipe is provided between the pressure control station and the stator. This piping section is supplied as a safety precaution to avoid an explosive hydrogen-air mixture in the generator. Ventilation piping is provided with isolation valves to ensure correct purging of gases from the stator.

Before maintenance work is performed on the generator, the hydrogen gas must be evacuated from the system. Since hydrogen and air form an explosive mixture, air cannot be used to purge the system. Inert carbon dioxide gas is used for the purpose of purging the generator.

IPEC00036156

The Indian Point 3 purging requirements are satisfied with a carbon dioxide gas vaporizing system, and can also be satisfied by the Indian Point 2 CO_2 gas vaporizing system through a 2.5-inch supply line from the Indian Point 1 intake structure area.

Downstream of HS-PCV-1002 where hydrogen pressure has been reduced to an intermediate 125 psig, there is an emergency crossover connection with Indian Point 2. This crossover may be used to transfer quantities of low-pressure hydrogen to or from Indian Point 3 during generator-filling applications, or as an emergency source of supply.

Pressure gauges and vents are provided to facilitate this operation. Additional operating notes are listed on the Hydrogen-CO_2 system flow diagrams. (See Plant Drawings 9321-F-20403, 20443, and -20453 [Formerly Figures 10.2-24, 10.2-25 and 10.2-26].)

Turbine Generator Inservice Inspection Program

Base loaded units are normally operated for 5 to 6 years before overhauling, unless there is specific intelligence from operating parameters (such as unusual vibration, pressure and temperature variations throughout the steam path, or bearing temperature indications) that indicates the need for an earlier inspection. An outline of procedures for performing turbine and generator inspection is included in their operating and maintenance manuals.

If any crack is found in the blading, the blade must either be replaced or cut off in the cracked section or at the blade root section.

Depending upon the physical arrangement of the blading and the contour surfaces that are to be inspected, any of the following non-destructive techniques might be used: magnaflux, magnaglo, and red dye penetrant.

A detailed and very careful ultrasonic inspection of all turbine components was performed in the preassembly and assembly stages. Turbine operating experience indicates the occurrence of a turbine originated missile to be highly unlikely, however, the plant has been designed to withstand the consequences of a turbine missile.

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 were 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

IPEC00036157

6) Hand trip.

Each stop valve has limit switches that operate position lights on the main control board. There are similar limit switches in the electrical interlock system that operate the turbine trip auxiliary relay and the reactor trip breakers.

Test switches on the main control board permit test closure of each valve. The valve operation can be observed from within the turbine front-end enclosure. Periodic tests exercise the stop valves and ensure their ability to close during an emergency.

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.

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 over-speed trip before the control valves can be opened

3) A second load limit device without reset is furnished to give redundancy of load cutback following a rod drop

4) The governing emergency trip valve, actuated when the stop valves are tripped, to close the control valves

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 control 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 run back signal. This is described further in Chapter 7.

IPEC00036158

The pre-emergency device functions similar to the normal governing devices by operating the control valves in case of abnormal operating conditions in the auxiliary governor. This pre-emergency 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 valve are as follows:

1) Overspeed emergency governor

2) Solenoid trip (actuated by reactor trip breakers opening, electrical faults and a manual push button)

3) Low condenser vacuum trip

4) Low bearing oil trip

5) Thrust bearing trip

6) Hand trip at unit.

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 tripping speed. Its 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 line non-return valves is also actuated by the autostop pressure.

The autostop valve is also tripped when any one of the protective devices is actuated. The protective devices include a low bearing oil pressure, solenoid, thrust bearing, and low vacuum trips. These devices are all included in a separate assembly, but are connected hydraulically to the over-speed trip valve. An additional protective feature includes a turbine trip following a reactor trip.

When unit load is greater than the P-8 setpoint, trip of the turbine generator initiates a reactor trip to prevent excessive reactor coolant temperature and/or pressure.

A dropped rod control cluster assembly signal as indicated by either a rapid decrease in nuclear flux or by the rod bottom bi-stables, initiates automatic turbine load cutback. This is described in greater detail 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 into six separate screen wells. The water flows through Ristroph travelling screens where fish and debris are collected and returned to the river. Modified baskets employing bucket features collect and lift fish to be returned to the river. Additionally, the head section of the screen employs five (5) spray wash headers; three (3) low pressure fish

IPEC00036159

sprays, and two (2) high pressure debris sprays for debris removal. Each screen well is provided with the ability to install stop logs to allow dewatering of any individual screen well for maintenance purposes.

The water from each individual screen well flows to a variable speed motor driven, vertical, circulating water pump. Each of the six condenser circulating water pumps provides 140,000 gpm at 29 ft TDH when operating at 360 rpm and 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 through a thermal discharge dispersion arrangement designed to minimize recirculation and thermal effects. A temperature recorder has been installed in the discharge canal to monitor temperature and provide a record of plant thermal effluents. Radiant heaters are also supplied for the screens. The extreme low level conditions for the river at the intake structure is 4'-5" below the mean sea level at the site. With the circulating water pump suctions at 20.5 feet below the mean sea level at the site, sufficient submergence for the circulating water pump suctions is provided. (See Plant Drawings 9321-F-20123, and -20113 [Formerly Figures 10.2-27 and 10.2-28].)

From the study in response to IE Bulletin No. 81-03, the Authority has concluded that neither Corbicula sp. nor Mytilus sp. is present in the Hudson River in the vicinity of Indian Point 3 (see IPN-81-36, May 21, 1981). The Authority performs an inspection of various circulating water system inlet boxes at least once per refueling cycle and monitors circulating water system temperatures on a regular basis. These activities and the close monitoring of the spread of these aquatic species in the Hudson River will serve to prevent blockage or degradation of the plant's cooling system as a result of aquatic species intrusion.

To prevent disabling the vital 480 Volt electrical switchgear in the adjoining Control Building in the event of flooding due to circulating water system line or expansion joint failure, a four foot high dike is erected around the entrance to the elevation 15' of the Control Building from the Turbine Hall. Based on one circulating water pump operating at rated flow discharging into the Turbine Hall with no water escaping from the building, it would take approximately twenty minutes before the water level would reach the top of the dike.

In addition to this, redundant level alarm switches are installed in the pipe tunnel at Elevation 3' 3" of the Turbine Hall. These switches will sense high water in the pipe tunnel and give an indication in the Control Room.

These two features allow the operator at least twenty minutes to investigate a problem and take appropriate action by shutting down the circulating water pumps.

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 four-minute 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 described below. The Titanium metal tubes are rolled and welded into solid titanium tube sheets. Water box manholes are provided for access. Provision is made for condensing the main feedpump drive turbine exhaust. The condensers have steam turbine

IPEC00036160

bypass condensing arrangements to condense turbine bypass steam for controlled startups and to condense residual and decay heat steam following a shutdown.

Condenser level instrumentation consists of:

1) Hotwell level transmitter with electronic transmitter and impulse piping
2) Separate hotwell level alarms
3) Extreme low level alarm

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 strings of feedwater heaters and provide the suction supply to the feedwater pumps.

For each condenser, one four element, two-stage air ejector with separate inter-condenser and common after-condensers is provided. For normal air removal, one air ejector unit is required per condenser. The ejectors function by using steam from the main steam system supplied through a pressure reducing valve. The air ejector exhaust 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 non-condensable 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 non-condensing 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.

10.2.6 Condensate and Feedwater System

The Condensate and Feedwater System is designed to supply a total of approximately 13,283,282 lb of feedwater per hour to the four steam generators at a turbine load of 1022 MW(e). This system, as shown on Figure 10.2-1 is composed of:

1) A condensate system that collects and transfers condensed steam and the drains from four stages of 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 feedwater heaters No. 35 and No. 36 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

IPEC00036161

unavailable. The flow is equivalent to that required from makeup because of reactor core decay heat removal requirements.

The main steam and feedwater lines are protected from reaction forces caused by a failure in the Reactor Coolant system pressure boundary by the steam generator support system, which is designed to resist reactor coolant blowdown loads combined with seismic and normal loads without exceeding yield strength of the structural steel.

The steam generator support structures are box sections with each vertical side made up of structural steel sections to form a vertical truss. These structures are designed to withstand longitudinal and guillotine breaks in the Reactor Coolant System boundary.

Condensate System

The condensate system transfers condensate and low pressure heater drains from the condenser hotwell through the condensate polisher and five stages of feedwater heating to the suctions of the main feedwater pumps.

Three 1/3 size condensate pumps, arranged in parallel, take suction from the bottom 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 condensate 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 TDH when operating at 1170 rpm. A split mechanical seal 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 performance characteristic of the pump is given in Figure 10.2-29. The condensate pumps are operated by manual controls on the main control board.

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. This recirculation will maintain condenser vacuum and turbine steam seals during startup, shutdown, and at very low loads. 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-inch condensate header divides into three 14-in lines downstream of the gland steam condenser. These lines carry the condensate through the tube sides of three parallel strings of two LP feedwater heaters. The flow to the remaining three strings of three LP heaters is through a common 24-in pipe. After the No. 35 feedwater heaters, 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 manual gate valves at the inlet and outlet of the string of heaters.

IPEC00036162

The condensate makeup and surge systems operate to maintain normal water level in the condenser hotwell.

The makeup system connects the 600,000 gallon capacity condensate storage tank to a diffusing pipe in the condenser shell. This line contains an air operated valve that automatically opens on low level in the condenser hotwell to pass makeup water from the tank to the condenser. Two redundant isolating valves will close to the condenser makeup when the condensate storage tank level reaches 360,000 gallons. This will ensure a reserve of condensate for the auxiliary feedwater pumps that will hold the plant at hot shutdown for 24 hours following a trip at full power.

The condensate surge system connects the condenstate 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 hotwells contain 114,000 gallons, which is equal to approximately 5.5 minutes condensate flow at 1022 MW(e) load.

The drains from the No. 36 feedwater heater flow to the heater drain tank. Normal condensate level is maintained in the No. 36 heaters by diaphragm operated level control valves.

The drains from the No. 35 feedwater heaters flow by gravity directly to the heater drain tank. There are no level control valves in the drains from these heaters.

The heater drain tank receives gravity drains directly from the four moisture preseparators via a single drain header. Check valves are provided in the drain lines just before they are manifolded into the common drain header.

The heater drain tank also receives drains from the shells of moisture separators through separate gravity flow drain lines. Air cylinder operated swing check type non-return valves in these drain lines close on turbine trip.

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 fourteen-stage, vertical, enclosed suction-type pumps. Each pump is rated at 4150 gpm and 720 ft TDH 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.

IPEC00036163

When a high level occurs in the heater drain tank, a diaphragm operated valve opens to discharge the excess condensate from the heater drain tank directly to the shell of a condenser. A spare condenser connection and control valve is provided. An alarm sounds in the Control Room. The alarm is to alert the operator that inflow is greater than outflow at the heater drain tank and/or that the automatic level controls have failed. The cable runs direct via conduit and tray to Supervisory Panel SD. The heater drain tank has a 5660 gallon storage capacity at normal water level or approximately ¾ minute storage of drains at a load of 1022 MW(e).

Drains from the No. 32, No. 33, and No. 34 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. Heater Nos. 33 and 34 are equipped with an alternate high level drain that discharges from the condensing zone of the heaters. This is to eliminate the high flow velocities and accompanying flashing experienced in the subcooling zones of these heaters during plant power transients.

Drains from the No. 31 feedwater heater 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.

A high level drain to the condenser is provided for No. 31 and No. 32 feedwater heaters in the event of a tube break.

Condensate Polishing System

The Condensate Polishing System (CPS) is designed to remove dissolved and suspended solids from the condensate in order to maintain the feedwater quality required for the steam generators.

The Condensate Polishing System is not required for safe shutdown of the reactor, has no safety-related function, and is designed as non-nuclear safety equipment. The system was tested and inspected in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code.

The CPS, as shown in Plant Drawing 9321-F-20183, Sh. 2 [Formerly Figure 10.2-3B], is installed within the existing condensate system between the condensate pumps and the first stage of feedwater heaters. The system is designed for a maximum capacity of 19,745 gpm with an inlet maximum pressure of 700 psi at 140°F. The system consists of six Service Vessels, six condensate post filters, an external resin regeneration system, and piping, valves, instrumentation and controls for proper operation.

Normally, five service and five condensate post filter vessels are in service, and one service and one condensate post filter vessel are on standby.

During normal operation, 100 percent of the condensate flow is passed through the service vessels and filtered through the condensate post filters. Although all the condensate passes through the service vessels, individual service vessels may or may not contain ion exchange resin, based on the condensate and feedwater pH control program in use. Condensate that passes through a service vessel that contains no ion exchange resin will allow filtering of the condensate through the condensate post filters. The reason for this is that none is bypassed around the service vessel.

IPEC00036164

The service vessels are arranged for parallel flow operation. Any one vessel can be removed from service for the regeneration of resin or for maintenance at any time. The regeneration system consists of the resin separation and cation regeneration vessel, an ion regeneration vessel and resin mix and hold vessel. The service vessel effluent is sent to the condensate post filters to remove any resin fines or crud that is carried out into the effluent. After that, condensate post filter effluent is pumped to the feedwater heaters using the condensate booster pumps. When plant conditions permit, the condensate booster pumps can be secured or placed in standby if desired

The high and low total dissolved solids (TDS) sumps in the condensate polisher building collect the wastewater generated by the condensate polisher facility. Waste with a high conductivity is directed to the high TDS sump while wastes with a low conductivity are directed to the low TDS sump. The waste in the tank is neutralized by the addition of acid or caustic until a pH in the range of 6-9 is reached. When the proper pH is obtained, the waste is discharged through the plant discharge canal. If high radioactivity is detected, the discharge is automatically terminated.

The Condensate Polishing System is designed to allow for semi-automatic operation and/or remote manual operation from a main control panel in the condensate polisher facility. Instrumentation to monitor conductivity, differential pressure, and flow are provided to determine system operation status. Specific conductivity, and cation conductivity are monitored and recorded at the effluent of each of the polisher vessels. pH monitoring is provided on the auxiliary panel for the waste treatment facility.

Condensate Polisher System chemistry is designed to the limits given in Table 10.2-8.

Condensate Storage Tank

The condensate storage tank supplies water to the Auxiliary Feedwater System, main condenser hotwell, and to the Seal Injection System for pumps and valves exposed to the condenser vacuum. Two redundant level controllers and level indication in the Control Room are provided for the condensate storage tank. The tank is provided with a nitrogen blanket in the air space above the liquid to reduce the amount of dissolved oxygen in the condensate.

The head space of the tank will be maintained at a nominal positive pressure of 0.5 inches Water Column (WC) by the nitrogen atmosphere. To ensure the condensate storage tank is operated within its analyzed pressure limits, the tank is equipped with two QA Category 1 safety-related 100% capacity breather valves on the dome. The breather valves are set to open at nominal pressure on both the vacuum side and positive pressure side.

The Nitrogen Supply System (NSS) is classified as QA Non-Category 1 since it does not perform any safety-related function. However, a QA Category 1 restriction orifice is installed in the nitrogen supply piping downstream of the NSS to protect the condensate storage tank from excessive ingress in the event of a failure of the NSS control station.

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.

IPEC00036165

The main feedwater pumps are single-stage, horizontal, centrifugal pumps with barrel casings. Each pump is rated at 15,300 gpm and 1830 ft TDH when operating at 4875 rpm. Seal water injection is used for shaft sealing. Bearing lubrication for each feedpump and its turbine drive, as well as turbine control, is accomplished by an integral oil system mounted on the pump base. Normal circulation of the oil is by a motor driven pump. The lubricating/control oil system includes a reservoir, a cooler, and two motor driven oil pumps. Low lubricating oil pressure, sensed by three pressure switches per pump and having 2-out-of-3 logic, trips the turbine/pump combination. Surges in the control oil portion of the system are dampened by the 80 gallon oil accumulators. Each main feedwater pump is driven through a flexible gear type coupling by an 8350 hp horizontal steam turbine using 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. See Figure 10.2-37 for the pump characteristic curve.

Low suction pressure reduces the 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. Hi-hi discharge pressure causes the boiler feedpump turbines to trip.

High main feedwater pump bearing temperatures are alarmed in the Control room but do not, however, 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. A pre-startup treatment (filtering) system capable of removing corrosion products from the feedwater/condensate system piping and components accumulated during plant shut-downs is connected to the 30" common feedwater header downstream of the high pressure heaters. The filtrated water is recirculated to the condenser hotwells.

Shutoff valves at the inlets and outlets of the feedwater heaters permit a heater train 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.

Steam Generator Internal Feed Ring and Regulator Modifications

A cross section of the feedwater ring is shown in Figure 10.2-30. The design includes features to preclude the rapid drainage of the feedwater ring when the water level in a steam generator falls below the ring. This prevents a cold water-steam interface from forming in either the feedwater ring or the connected 18-inch feedwater piping, and should preclude the initiation of water hammer type shocks due to steam condensation. Plan and elevation views of the feedwater ring are shown on Figure 10.2-32.

The design consists of 36 flow holes (2-inch diameter) located in the top of the ring. Short J-bend pipes were welded to each flow hole to direct the feedwater vertically downward. As an additional measure against water hammer and thermal stratification, the feed ring is elevated several inches above the feedwater inlet to the steam generator.

IPEC00036166

The steam generator feedwater metering and regulating stations measure, indicate, record and control the water level in each of the four steam generators. Figure 10.2-34 shows the Feedwater Regulating System (one of four typ.) which, in turn, shows the low flow bypass regulator. 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 set point.

The deviation of level measurement from this set point positions the feedwater control valve accordingly. Totalized steam flow controls the speed of the main feedwater pump turbines.

Piping restraints were installed on two of the feedwater lines to the steam generators that have the longest horizontal radial run inside the Containment Building to limit pipe movement in the vicinity of the containment penetration. Figure 10.2-33 shows the feedwater piping to the steam generator. Clearances in the penetration whip restraints on all four feedwater lines are sited to prevent "rebound" type stressing of the pipe in the event of water hammer shock.

Hydraulic dampers were installed on the main feedwater regulators to preclude rapid closure of these valves which might cause water hammer. These dampers will not, however, adversely affect the closing time of the valves during normal operation. In addition, the plug trim on the main feedwater regulator valves was designed to provide improved low flow control characteristics.

Reactor Trip

A reactor trip is actuated on a coincidence of steam flow-feedwater flow mismatch coupled with 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 feedwater valves move to the fully opened position to provide an additional heat sink for the reduction of reactor coolant temperature to the no-load average temperature value. The valves remain fully open until average Tavg temperature reaches a predetermined setpoint value equal to or greater than 544 F.

The feedwater control system is an electronic analog instrumentation system. Readout and control equipment are as follows:

1) A wide range level recorder (one two-pen recorder for each of two pairs of steam generators), calibrated for cold conditions in the steam generator, permits observation of one level essentially over the full height of each steam generator shell. In addition, a level indicator is provided at various local control stations for safe shutdown of the plant in the event the Control Room is uninhabitable.

2) A direct reading, three-pen recorder in the Control Room records steam generator level and the steam and feedwater flows (in pounds per hour) for each steam generator.

3) Each flow channel and each narrow range level channel is indicated on the main control board.

IPEC00036167

4) Each feedwater controller has one manual control station. This unit consists of an auto/manual transfer switch and an analog output control that serves as the valve position signal when in "Manual." The "Automatic" set point is pre-set but adjustable in the instrument rack.

Other manual control stations are used to position auxiliary feedwater regulating valves.

Auxiliary Feedwater System

The Auxiliary Feedwater System (AFS) is used for manual plant startup. It also supplies high pressure feedwater to the steam generators. This feedwater supply is needed to maintain sufficient water inventory in the steam generators to allow removal of decay heat from the Reactor Coolant System by secondary steam releases in the event that the Main Feedwater System is inoperable. To achieve this, the head generated by the auxiliary feedwater system pumps is sufficient to deliver feedwater into the steam generators at the highest first safety valve pressure setting plus accumulation. Redundancy of auxiliary feedwater supply is provided by utilizing two pumping loops using two different types of motive power to the pumps.

One auxiliary feedwater loop utilizes a steam turbine driven pump and the other utilizes two motor driven pumps. The capacity of each loop is sufficient to ensure that at least two of the four steam generators will not boil dry and that the Primary Coolant System will not relieve water through the pressurizer relief/safety valves following a loss of main feedwater flow.

The two motor driven pumps receive automatic start signals from the engineered safeguards circuits. All three pumps receive start signals from the low-low steam generator level circuitry. Steam flow to the turbine for the steam driven pump must be throttled manually in order to bring the unit up to speed and prevent damage to the pump. In addition, the steam driven pump discharge flow control valves are manually opened as necessary to provide adequate auxiliary feedwater flow.

The steam turbine driven pump loop was designed to supply 800 gpm of feedwater flow to the steam generators, conservatively assumed to be 596 gpm in the relevant Chapter 14 analyses. The design performance characteristic of the pump is shown in Figure 10.2-35. Steam to drive the turbine is supplied from two of the main steam lines from a point upstream of the main stream isolation valves. Each supply line is provided with a stop check valve, suitable for manual isolation. Downstream of the stop check valves the lines merge into a single supply line to the turbine of the steam driven pump. This single supply line is provided with two isolation valves in series. Main steam is at steam generator outlet pressure, which is reduced to the pressure of the steam driven pump turbine (approximately 600 psig, as necessary to achieve the required pump flow rate) by a pressure control valve.

The steam supply for the auxiliary feedwater pump turbine is ensured under all conditions, except in the event of:

1) Failure in the single supply line to the auxiliary feedwater pump turbine anywhere downstream of the stop check valves

2) Failure of the auxiliary feedwater pump pressure relief valve at low pressure in the steam generator

IPEC00036168

3) Closure of the two automatic isolation valves from a high temperature signal in the building

The system design ensures a steam supply to the auxiliary feedwater pump turbine in the event of:

1) Failure of one main steam line upstream of the stop check valve. The stop check valves prevent flow to the broken main.

2) Failure of the pressure reducing valve. This valve fails open on loss of control (either through the loss of electrical power or air supply); the turbine pressure relief valve ensures that sufficient steam flows to the turbine while maintaining a safe pressure at the turbine. This applies at safety valve set pressure plus accumulation in the steam generator.

Protection of the Main Steam System has been provided in the event of a failure downstream of the stop check valves by limiting the take off points at the steam main to 3-inch nominal pipe size. This restricts the consequences of the rupture of this pipe to a release of steam less severe than that resulting from the sticking open of a safety valve.

Protection of the AFS from lack of water to pump suctions is provided by operator action. If it is discovered that one or both of the valves in the single auxiliary feedwater supply from the CST are closed in MODES 1, 2, or 3, then the AFS is immediately placed in manual mode. The AFS is returned to automatic mode once a water supply has been restored.

Feedwater is supplied by the steam turbine driven pump to all four steam generators through individual feedwater regulating valves that are controlled either from the main control board or locally at the valves. The drive unit is a single stage turbine, capable of quick starts from cold standby, and is connected directly to the pump. This 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 motor driven pump loop utilizes two pumps with ring lubricated ball bearings. Each pump has a design capacity of 400 gpm, but conservatively assumed to be 340 gpm (343 gpm for Loss of Normal Feed/Loss of AC Power events), and their discharge piping is arranged so that each pump supplies two steam generators. The design performance characteristics for these pumps is given in Figure 10.2-36.

One motor driven pumps has sufficient capacity to maintain a sufficient water inventory in the steam generators to which it is connected, preventing relief through the primary coolant system pressurizer relief valve following a reactor/turbine trip. Thus, in the remote chance of loss of the steam driven pump, a single motor driven pump is adequate to ensure safety of the public. The motors are of open drip-proof design. In the event of complete loss of power, electrical power is restored automatically from the diesel generators.

The three auxiliary feedwater pumps are located in an enclosed room in the Auxiliary Feedwater Building that houses the area of the main steam and feedwater penetration, immediately outside of the Reactor containment (see Figures 10.2-30 and Plant Drawing 9321-F-20143 [Formerly Figure 10.2-38]). The distribution piping is seismic Class I throughout. The piping was designed to ensure that a single failure will not compromise the system function.

IPEC00036169

All components within the AFS boundary were designed to seismic Class I criteria, as noted in Section 16.1. This includes designing for the Design Basis Earthquake and pipe breaks (pipe whip). The AFS has tornado protected pumps and redundant water supplies, as discussed in Section 16.2.

The possibility of internally generated missiles from the auxiliary feedwater steam driven pump turbine has been evaluated. The evaluation findings note that missiles generated at destructive overspeed could penetrate the turbine casing and that there are possible targets that require protection from such a missile. In view of this, a shield around this turbine was designed. The system is otherwise protected from a main turbine missile by incorporation of redundant water supplies, missile protected pumps and redundant, separate pipes feeding the four steam generators.

Protection of the AFS from excessive vibration and overheating is provided by means of a 2-in recirculation line without flow restricting fixed orifices. Pressure reducing control valves, shut-off isolation valves and check valves were sized to minimize vibration and pipes were routed to minimize bends. The control valves were designed to fail open.

Single Failure Criteria

Redundant auxiliary feedwater supply is provided by using two pumping systems with independent motive power sources. In the event of a complete loss of offsite power, electrical power to the motor driven pumps is supplied by the diesel generators. The turbine driven pump is completely independent of the motor driven pumps and there are redundant power supplies to the motor driven pumps.

The three auxiliary feedwater pumps can be started remotely-manually from the Control Room or locally at the pump room. Thus, provision exists for manual initiation on the component level, but no such provisions exist for initiating the system as a whole.

The water supply source for the AFS is also 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 main turbine cycle systems; however, a minimum water level is maintained that is sufficient to remove residual heat generation for 24 hours at hot shutdown conditions.

An alternate supply of water to the pumps is provided by a connection to the 1.5 million gallon city water storage tank. The city water storage tank shall have a minimum volume of 360,000 gallons of water to provide alternate supply to the AFS.

Various isolation devices were provided to ensure separation of the instrumentation and control circuits to assure that single failure criteria are met. The control and protection circuitry involves steam generator level, safety injection initiation, main boiler feed pump controls, blackout initiation and breaker controls.

Actuation

The motor driven pumps are actuated by any one of the following:

1) Low-low level in any steam generator

IPEC00036170

2) Loss of 480 VAC bus voltage on bus 3A (ABFP 31) or bus 6A (ABFP 33) (non-SI blackout)
3) Safeguards loading sequence
4) Trip of either main boiler feed pump
5) Manual actuation from the Control Room
6) Manual actuation locally at the pump room.
7) AMSAC

The steam turbine driven pump is actuated by any one of the following:

1) Low-low level in two of the four steam generators
2) Non-SI blackout signal
3) Manual actuation from the Control Room
4) Manual actuation locally at the pump room.
5) AMSAC

The AFS is able to remain in operation should evacuation of the Control Room become necessary.

Flow Monitoring Instrumentation

Flow measurement devices are installed in the discharge lines to each of the four steam generators with indication in the Control Room. The functioning of the pumps may also be monitored locally by direct visual observation. Auxiliary feedwater flow information and valve position indication in the Control Room allow the operators to properly route the discharge flow from the pumps through two remote, manual discharge valves.

Testability

Periodic testing requirements of the Auxiliary Feedwater System are discussed in Section 10.4 and in the Technical Specifications.

System Chemistry

Steam generator water chemistry is maintained within the limits given in plant procedures based on EPRI PWR secondary water chemistry guidelines. A Secondary Side Water Chemistry Monitoring System has been installed for this purpose. Hydrazine, morpholine and/or ethanolamine are added to the condensate for oxygen control and to maintain the pH, respectively. Boric acid is added into the steam generators via the main and auxiliary feedwater headers.

Radiation Levels

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 containment is possible.

Under normal operating conditions, no radioactive contaminants are present in the Steam and Power Conversion System. It is possible, however, for this system to become contaminated through steam generator tube leaks. In this event, any contaminant is detected by monitoring

IPEC00036171

the steam generator shell side blowdown sample points and the condenser air ejector discharge.

Anticipated long term continuous operation of the plant is expected to include operations with fuel rod clad defects in the equivalent of 0.2% of the fuel rods, coincident with a primary to secondary leak rate of 20 gpd. For these expected conditions, the radiation levels at various locations in the Steam and Power Conversion System were calculated at the time of the initial license application (1975) on the basis of the assumptions listed in Table 10.2-3. The shielding design data and the estimated isotopic strengths for the various steam and power conversion system components are provided in Tables 10.2-3 and 10.2-5, respectively.

Table 10.2-6 lists the calculated radiation levels around various components of the Steam and Power Conversion System during operation with 0.2% equivalent fuel rod defects and a primary to secondary leak rate of 20 gpd. Assuming continued operation with primary system activity based on defects in 1% equivalent fuel rods, the maximum allowable primary to secondary leakage would be 0.9 gpm. This leak rate is not a maximum allowable short-term primary to secondary leak rate but a calculated maximum based on continued operation for one year with 1% equivalent fuel defects and the maximum allowable Xe-133 air concentration at the site boundary. The radiation levels at various locations for the Steam and Power Conversion System components were calculated in a like manner to that previously described for expected conditions for the assumed 1% equivalent fuel rod defects and a 0.9 gpm leak, and are presented in Table 10.2-7.

10.2.7 Codes and Classifications

The pressure retaining components or compartments of components comply, at a minimum, with the codes detailed in Table 10.2-1.

IPEC00036172

TABLE 10.2-1

CODES AND CLASSIFICATIONS

System Pressure Vessels and Pump Casing	ASME Boiler and Pressure Vessel Code, Section VIII
Steam Generator Vessel	ASME Boiler and Pressure Vessel Code, Section III*
System Valves, Fittings, and Piping	USAS Section B31.1 Pressure Piping Code * *

NOTE:

* The shell side of the steam generator conforms to the requirements for Class 1 vessels and is so stamped as permitted under the rules of Section III.

** Portions of QA Classification Non-Category I pipe systems may be exempted from the mandatory post weld heat treatment requirements of ANSI B31.1 by NSE-98-3051. This NSE applies to P11 and P22 material with component wall thickness 0.625" and less.

IPEC00036173

TABLE 10.2-2

ACTIVITY RELEASE DURING STEAM DUMP

	Activity Release (Curies)	
	2 Hour Steam Dump	6 Hour Steam Dump
Case 1: 0.35 μCi/cc of I-131 in secondary side water (Technical Specifications limit)		
I-131	7	10.7
Xe-133 equivalent	1060	2023
Case 2: Anticipated release based on 0.2% fuel defects and 20 gpd steam generator tube leakage		
I-131 equivalent	0.0017	0.0025
Xe-133 equivalent	0.4	0.7

IPEC00036174

TABLE 10.2-3

ASSUMED SYSTEM PARAMETERS

Core thermal power (maximum calculated)* - MW(t)	3216
Equivalent fuel rod defects - %	0.2
Primary to secondary leak rate – gpm	0.014 (20 gpd)
Steam flow rate – lbs per hour	1.395×10^7
Steam quality - %	99.75
Continuous blowdown rate (total 4 steam generators) – gpm	12.5 each
Mass of secondary water in 4 steam generators – lbs	3.21×10^5
Volumetric source geometry used	Equivalent cylinder
Steam generator iodine decontamination factor	100
Steam generator noble gas decontamination factor	1.0
Steam Generator decontamination factor for Mo and Cs	400

*NOTE: The license application core thermal power rating was 3025 MW(t). Thus any radiation levels experienced will be slightly less than those indicated.

IPEC00036175

TABLE 10.2-4

COMPONENT SHIELDING DESIGN DATA

Item	Self Absorption Media	Wall Thickness	Material
Steam Piping	Steam (0.039 gms/cc)	0.912 inches	Carbon Steel
Turbine	Steam (0.039 gms/cc)	3.0 inches	Carbon Steel
Condenser Air Ejector	Air (ρ=1.3 x 10^{-3} gms/cc)	0.375 inches	Carbon Steel
Condenser	Water (ρ=1.0 gm/cc)	0.75 inches	Carbon Steel
Feedwater Piping	Water (ρ=1.0 gm/cc)	0.938 inches	Carbon Steel
Blowdown Tank	Water (ρ=1.0 gm/cc)	0.50 inches	Carbon Steel

IPEC00036176

TABLE 10.2-5

ESTIMATED ISOTOPIC SOURCE STRENGTHS FOR
STEAM AND POWER CONVERSION SYSTEM COMPONENTS

Isotope	Steam Piping & Turbine μCi/cc	Condenser Air Ejector μCi/cc	Condenser & Feedwater Systems μ Ci/gm	Blowdown System μ Ci/gm
Kr-85	2.6×10^{-8}	4.2×10^{-5}	---	---
Kr-85M	7.5×10^{-9}	1.2×10^{-5}	---	---
Kr-87	4.4×10^{-9}	7.1×10^{-7}	---	---
Kr-88	1.3×10^{-8}	2.1×10^{-5}	---	---
Xe-133	1.0×10^{-6}	1.6×10^{-3}	---	---
Xe-133M	1.1×10^{-8}	1.8×10^{-5}	---	---
Xe-135	2.2×10^{-8}	3.5×10^{-5}	---	---
Xe-135M	6.8×10^{-10}	1.1×10^{-6}	---	---
Mo-99	2.5×10^{-8}	---	6.0×10^{-7}	2.4×10^{-4}
I-131	4.8×10^{-8}	---	1.2×10^{-6}	1.2×10^{-4}
I-132	3.8×10^{-9}	---	9.6×10^{-8}	9.4×10^{-6}
I-133	5.6×10^{-8}	---	1.4×10^{-6}	1.4×10^{-4}
I-134	1.0×10^{-9}	---	2.6×10^{-8}	2.6×10^{-6}
I-135	1.9×10^{-8}	---	4.8×10^{-7}	4.7×10^{-5}
Cs-134	1.5×10^{-9}	---	3.7×10^{-8}	1.5×10^{-5}
Cs-137	7.4×10^{-9}	---	1.8×10^{-7}	7.4×10^{-5}

IPEC00036177

TABLE 10.2-6

STEAM AND POWER CONVERSION SYSTEM COMPONENTS
GENERAL RADIATION LEVELS BASED ON EXPECTED PLANT OPERATION*

Equipment	Dose Rate On Contact mr/hr	100 mr/week Access Time Hrs/week
Steam Piping	<0.01	Unlimited
Turbine	<0.01	Unlimited
Condenser Air Ejector	0.05	Unlimited
Condenser	<0.01	Unlimited
Feedwater Systems	<0.01	Unlimited
Blowdown Systems	0.02	Unlimited

*NOTE: 0.2% equivalent fuel defect
20 gpd primary to secondary leakage

TABLE 10.2-7

STEAM AND POWER CONVERSION SYSTEM COMPONENTS
GENERAL RADIATION LEVELS BASED ON MAXIMUM PERMISSIBLE LIMITS*

Equipment	Dose Rate On Contact mr/hr	100 mr/week Access Time Hrs/week
Steam Piping	<0.05	Unlimited
Turbine	<0.05	Unlimited
Condenser Air Ejector	16.	6
Condenser	<0.05	Unlimited
Feedwater Systems	<0.05	Unlimited
Blowdown Systems	3.6	28

*NOTE: 1% equivalent fuel defects
0.9 gpm primary to secondary leakage

IPEC00036178

TABLE 10.2-8

INFLUENT AND EFFLUENT QUALITY OF THE CONDENSATE POLISHING SYSTEM

	INFLUENT TYPICAL VALUES	EFFLUENT TYPICAL VALUES
		H:OH cycle
	ppb	ppb
Sodium as Na	1.0	0.5
pH control amine	4500(1)	5.0
CO_2 as $CaCO_3$	40	10
Iron as Fe	10	-
Copper as Cu	1.0	-
Total Iron & Copper	-	1
Chloride as Cl	20	0.1
Sulfate as SO_4	1.0	-
Hydrazine	100	-
Conductivity μmho/cm @ 25°c	4 to 10	-
pH @ 25°c	6.0 to 9.0	-

(1) Typical for morpholine. Other pH control amines will require different concentrations.

IPEC00036179

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:

a) Turbine Trip

1. Generator/electrical faults.
2. Low condenser vacuum.
3. Turbine thrust bearing failure.
4. Turbine low lubricating oil pressure.
5. Turbine overspeed.
6. Reactor trip.
7. Manual turbine trip.
8. High steam generator water level.
9. Safety injection actuation.
10. Main Steam Isolation Valve not fully open.
11. Independent overspeed protection system.

b) Automatic Control Actions

1. High level in steam generator stops feedwater flow.
2. Normal and low level in steam generator modifies feedwater flow by continuous proportional control.

c) Principal Alarms

1. Low pressure at feedwater pump suction.
2. Insufficient vacuum in condenser.
3. Turbine thrust bearing failure.
4. Turbine low lubricating oil pressure.
5. Turbine overspeed.
6. Low level in steam generator.
7. High level in steam generator.
8. Steam flow – feed flow mismatch coincident with low steam generator level.

IPEC00036180

A reactor trip from power requires subsequent 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 via 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 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 trips, decay heat removal would continue to be assured by the steam-driven, and two motor-driven (via diesel generator) auxiliary feedwater pumps, and steam dumped to atmosphere via the main steam safety and atmospheric dump valves. In this case feedwater is available from the condensate storage tank by gravity feed to the auxiliary feedwater pumps. The minimum 360,000 gallons of water in the condensate storage tank is adequate for decay heat removal for a period of at least 24 hours. A back-up source of feedwater is available from the city water system.

The analysis of the effects of loss of full load on the Reactor Coolant System is discussed in Chapter 14.

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, the motor driven auxiliary feedwater pumps are automatically started. The second main feedwater pump remaining in service will carry approximately 65 percent of full load feedwater flow when operated at full speed. 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 started. If Reactor Coolant System conditions reach trip limits, the reactor will trip.

Main Steam pressure relief is required at the system design pressure of 1085 psig. The number of safety valves, their operation and settings are discussed in Section 10.2.1. The pressure relief capacity is equal to the steam generation rate at maximum calculated conditions (116% of the rated steam flow).

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 Chapter 14. The steam break accident analysis is also presented in Chapter 14.

10.3.3 Single Failure Analysis

A single failure analysis has been made for all active components of the system that have an emergency function. The analysis, which is presented in Table 10.3-1, shows that the failure or malfunction of any single active component will not reduce the capability of the system to perform its emergency function.

For those spaces containing safety related systems, the Turbine Generator Building is designed to withstand a 360 mile per hour tornado or the O.B. or D. B. earthquake. Collapse of any portion of the remainder of this building will therefore have no effect on any safety related systems and structures.

IPEC00036181

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 rated design flow of the turbine pump is twice the rated flow of a motor driven pump, and one motor driven has sufficient capacity to prevent relief of fluid through the primary side relief valves. Thus adequate redundancy of auxiliary feedwater pumps is provided.
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 Check Valve in series. Hence a failure of an Isolation or Check Valve will not permit the blowdown of more than one steam generator irrespective of the steamline rupture location.
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. Hence one valve can only pass <4% of the steam generator steam flow and there is no hazard in the form of an uncontrolled plant cooldown if a bypass valve sticks open.

IPEC00036182

10.4 TEST AND INSPECTIONS

The Main Steam Isolation Valves are tested at regular intervals as established in the Technical Specifications. Closure time of 5 seconds has been and will be continually verified.

These valves serve to limit an excessive reactor coolant system cooldown rate and resultant reactivity insertion following a main steam line break incident. Their ability to close upon signal is verified at periodic intervals. A closure time of 5 seconds from receipt of closing signal was selected as being consistent with expected response time for instrumentation as detailed in the steam line break incident analysis.

The two motor driven auxiliary feedwater pumps can be tested at any time. The steam driven auxiliary feedwater pump may be tested when the plant is above cold shutdown and steam at 600 psi is available. Each pump will deliver water from the condensate storage tank through its feedwater control valves to the feedwater lines to the steam generators. Verification of correct operation is made both from instrumentation within the main control room and by direct visual observation of the pump. The frequency of testing is specified in the Technical Specifications.

IPEC00036183

CHAPTER 11

WASTE DISPOSAL AND RADIATION PROTECTION SYSTEMS

11.1 WASTE DISPOSAL SYSTEM

11.1.1 Design Bases

The General Design Criteria presented and discussed in this section are those that were in effect at the time when Indian Point 3 was designed and constructed. These general design criteria, which formed the bases for Indian Point 3, were published by the Atomic Energy Commission in the Federal Register of July 11, 1967, and subsequently made a part of 10 CFR 50.

The Authority has completed a study of compliance with 10 CFR Parts 20 and 50 in accordance with some of the provisions of the Commission's Confirmatory Order of February 11, 1980. The detailed results of the evaluation of compliance of Indian Point 3 with the General Design Criteria presently established by the Nuclear Regulatory Commission (NRC) in 10 CFR 50 Appendix A, were submitted to NRC on August 11, 1980, and approved by the Commission on January 19, 1982. These results are presented in Section 1.3.

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 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (GDC 70 of 7/11/67)

Liquid, gaseous, and solid waste disposal facilities were designed to achieve discharge of radioactive effluents and offsite shipments of radioactive materials in accordance with applicable governmental 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 quantity of radioactivity, with an isotopic breakdown if necessary. Before any attempt is made to discharge radioactive wastes, they are processed as required and then released under controlled conditions. The system design and operation were 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.

The bulk of the radioactive liquids discharged from the Reactor Coolant System are processed and retained inside the plant by the Chemical and Volume Control System recycle train. This minimizes liquid input to the Waste Disposal System that was designed to process relatively

IPEC00036184

small quantities of generally low-activity level wastes via the Liquid Radwaste Processing System skid. Processed water, from which most of the radioactive material has been removed, is discharged from the Waste Disposal System through a monitored line into the circulating water discharge.

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.

Spent resins from the demineralizers, filter cartridges, and other contaminated solid wastes are packaged and stored on site until shipment for offsite disposal. Suitable containers are used to package these solids at the highest practical concentrations to minimize the numbers of containers shipped for burial.

Solid radioactive wastes in the form of dry activated waste (DAW) or solidified (or dewatered) resins may be stored in the Interim Radwaste Storage Facility prior to offsite shipment. The facility is a non-safety, non-seismic concrete structure located west of the access road leading to the Meteorological Tower. Pursuant to Generic Letter 81-38, the facility was designed and constructed in accordance with Appendix A or NUREG-0800 to minimize impact of storage to the public and the environment. Adequate shielding is provided to limit the offsite doses to less than 5 mrem/year. In addition, the facility incorporates the ALARA methodology of Regulatory Guides 8.8 and 8.10. Storage capacity was designed to store a volume or radwaste equivalent to that generated in a five year period. Individual waste packages may be stored for a period of up to 5 years. If required, application for extension of the 5 year limit or expansion of storage capacity shall be made in accordance with 10 CFR 30.

The four steam generators originally installed in the plant were replaced during the Cycle 6/7 refueling outage in 1989. These vessels (as well as one original primary system elbow, which was also replaced) are internally contaminated, and are currently stored on site in the Replaced Steam Generator Storage Facility. The above-ground reinforced concrete storage structure provides adequate shielding to limit offsite doses from direct radiation shine and "skyshine" to less than 5 mrem/year. Building contact dose rates are low enough to permit classification outside the building perimeter as an unrestricted area. The facility is classified as non-safety and non-seismic, and is constructed of noncombustible materials. It is completely sealed with no provisions for ventilation; however, a locked locally alarmed labyrinth entrance is provided in order to permit periodic surveillance.

The four original steam generators are stored completely intact, with all openings sealed with welded steel closure plates or bolted steel covers. The replaced primary elbow is also sealed at both ends with welded steel plates. On this basis, there will be no liquid or gaseous effluents released to the environment for the duration of storage of these components. The facility is designed to house the components until the entire plant is decommissioned.

11.1.2 System Design and Operation

The Waste Disposal System Flow Diagrams are shown in Plant Drawings 9321-F-27193, Sh. 1 & 2, 9321-F-27303, -27233, and -27253, [Formerly Figures 11.1-1A, B, 11.1-2A and 11.1-3]. Typical Performance Data are given in Table 11.1-1. (The IP3 Technical Specifications, section

IPEC00036185

5.6.3, requires that a Radioactive Effluent Release Report be submitted to the NRC. The data in Table 11.1-1 is from the report submitted to the NRC on February 15, 1991. As part of the review of the Authority's application to extend the IP3 operating license expiration date, the NRC reviewed IP3 solid waste shipments data for the period of 1986 to 1990. The NRC's conclusions were contained in an Environmental Assessment, issued by letter dated June 25, 1992.)

The Waste Disposal System was designed to collect and process all potentially radioactive primary plant wastes for removal from the plant site, within the limitations that were established by applicable governmental regulations. During system operation, 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 and they are released under controlled conditions. A radiation monitor is provided to maintain surveillance over the release operation, but the permanent record of activity releases is provided by radio-chemical analysis of known quantities of waste. The system was designed to process wastes generated during continuous operation of the primary system assuming that fission products, corresponding to defects in one percent of the fuel, escape into the reactor coolant. The liquid inventory of the plant is maintained within acceptable limits and releases are well below the limits of 10 CFR 20.

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.

11.1.2.1 System Description

Liquid Processing

The Waste Holdup System collects low level, radioactive liquid waste from throughout the facility and holds the waste until such time that it can be processed. The system consists of three tanks: the 24,500 gallon Waste Holdup Tank No. 31, which is located in the Waste Holdup Tank Pit, and the two 62,000 gallon Waste Holdup Tanks No. 32 and No. 33, which are located in the Liquid Radwaste Storage Facility. Waste Holdup Tanks No. 32 and No. 33 are connected in parallel to tank No. 31 and are provided with a pumped recirculation/spraying system to minimize precipitation of particulates and the accumulation of crud.

The Liquid Radwaste Storage Facility that houses Waste Holdup Tanks No. 32 and No. 33 is an underground concrete structure 75 feet long x 39'-6" wide x 24'-7" high. The 62,000 gallon tanks are supported on concrete piers. A sump pit is located in one of the corners of the building. To service the water tanks, and to interconnect the building with the Waste Holdup Tank Pit, a system of platforms is provided. In addition, an opening of 2'-6" x 7'-6" through the Waste Holdup Tank Pit wall forms the entrance from the Liquid Radwaste Storage Facility to the Waste Holdup Tank Pit. An emergency exit is provided by two openings in the roof of the structure, which is protected by a concrete penthouse. The two buildings are separated by a minimum 3 inch joint filled with seismic filler. The seismic joint adequately ensures that in a seismic event both structures will react independently.

The building is supported on hard rock. The foundation consists of a rigid 2'-0" thick slab that is waterproofed. The waterproof membrane is laid upon a 4" concrete base. A 2 inch protection of concrete is placed over the waterproofing. The walls of the building are also waterproofed and they consist of reinforced concrete. The 3' thick reinforced concrete roof was poured on a steel deck and beam system.

IPEC00036186

The location of the opening in the Waste Holdup Tank Pit wall is such that it will not affect the structural integrity of the buildings. The east wall was designed to withstand a soil pressure of more than 24 feet. Locating the Liquid Radwaste Storage building adjacent to the Waste Holdup Tank Pit wall removes all of the earth pressure and the resultant stresses. The additional stresses imposed by the penetration are less than those that were imposed by the original loading condition. Therefore the net result is a safer condition of stress in the east wall.

To add operational flexibility in the event that the holdup capacity of the liquid WDS is exceeded, water from the holdup tank can be pumped to a demineralization system. This system consists of a series of pressure vessels containing activated charcoal and anion, cation and macro-reticular resins, and a pump to deliver water to the monitor tanks of the Chemical and Volume Control System. In addition, the Waste Holdup Tank pits are provided with a submersible pump tied to the inlet to waste tank No. 31.

During normal plant operation the Waste Disposal System processes liquids from the following sources:

a) Equipment drains and leaks

b) Radioactive chemical laboratory drains

c) Decontamination drains

d) Demineralizer regeneration

e) Floor drains

The system also collects and transfers liquid drained from the following sources directly to the Chemical and Volume Control System for processing:

a) Reactor coolant loops

b) Pressurizer relief tank

c) Reactor coolant pump secondary seals

d) Excess letdown during startup

e) Accumulators

f) Valve and reactor vessel flange leakoffs

The valve and reactor flange leakoff liquids flow to the Reactor Coolant Drain Tank. The reactor coolant drain tank water can drain directly to the containment sump or can be discharged directly to the CVCS holdup tanks by the reactor coolant drain pumps. TheSe pumps also return water from the refueling canal and cavity to the Refueling Water Storage Tank. To minimize contamination of the RWST, RCDT, and RCDT Pumps resulting from refueling operations, a filter system has been provided for the refueling cavity return flow to the Refueling Water Storage Tank. (See Section 9.3)

IPEC00036187

Where plant layout permits, waste liquids drain to the waste holdup tanks by gravity flow. Other waste liquids including floor drains drain to the sump and/or sump tank and are discharged to the waste holdup tanks by pumps operated automatically by a level controller.

If the preliminary analysis by sampling indicates that the liquid is suitable for discharge, it can be pumped from the waste holdup tank to the monitor tanks of the Chemical and Volume Control System (FSAR Section 9.2). When one monitor tank is filled it is isolated, and the waste liquid is recirculated and sampled for radioactive and chemical analysis while the second tank is in service. If analysis confirms that the contents are suitable for discharge, the waste liquid contained in the monitor tank is pumped to the service water discharge; otherwise, it is returned to the waste holdup tanks for reprocessing.

Although the radiochemical analysis forms the basis for recording activity releases, the radiation monitor provides surveillance over the operation by preventing the discharge valve from opening if the liquid activity level exceeds that which can be safely discharged.

Liquids in the holdup tanks not suitable for discharge are processed through the Liquid Radwaste Processing System skid.

Sampling of the condenser inlet water and discharge water system is done continuously.

Hudson River water samples are collected continuously from the intake structure (control location) and the discharge canal (indicator location), both of which are located on site. The sampling apparatus draws water from the intake structure and from the discharge canal and pumps it into respective containers. Each container has a volume that is approximately five gallons. One sample of inlet water and one sample of discharge water are taken, at a frequency specified by the Radiological Effluent Control Program, from the containers. Each of these samples is approximately four liters (one gallon). These samples are composited for monthly gamma spectroscopy analysis (GSA) and for quarterly tritium analysis.

Gas Processing

During plant operations, gaseous wastes originate from:

a) Degasing reactor coolant and purging the volume control tank.
b) Displacement of cover gases as liquid accumulates in various tanks.
c) Equipment purging.
d) Sampling operations and automatic gas analysis for hydrogen and oxygen in cover gases.
e) Venting of actuating nitrogen for pressure control valves.

During normal operation, the Waste Disposal System supplies hydrogen from cylinders to primary plant components. Two headers are provided, one for operation, one for backup. The pressure regulator in the operating header is set for 100 psig and that in the backup header at 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 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 100 psig and the backup pressure at 90 psig.

During normal operation, the Waste Disposal System also supplies primary plant components with nitrogen for various process functions. This system, identified as Nitrogen to Nuclear

IPEC00036188

Equipment (NNE) is shown on Plant Drawing 9321-F-27233 [Formerly Figure 11.1-2B]. These process functions include cover gas, calibration gas, purge gas, and gas required for operation of level instrumentation. The only safely-related function of the NNE is providing high pressure charging gas for operation of the Safety Injection Accumulators and Power Operated Relief Valves.

However, administrative controls and Technical Specifications ensure that these components maintain a minimum self-contained supply of gas at all times such that their accident mitigation functions can be implemented at anytime without reliance on the main nitrogen supply system. The NNE also has the capability to cross connect to the weld Channel and Containment Penetration Pressurization System (WCCPPS) and the Isolation Valve Seal Water System (IVSWS) for the purpose of providing an alternative nitrogen supply to those systems when those systems' respective nitrogen supplies are depleted. Again, those activities are strictly controlled by administrative procedures. The NNE may be used in conjunction with the WCCPPS and/or IVSWS for post-accident recovery operations if available. The main nitrogen supply for the NNE is derived either from standard cylinders consisting of two banks of 18 cylinders each or from a nitrogen supply trailer via a truck fill connection. Either supply is directed through a common manifold and then either through redundant, backup regulators, which reduces pressure for low pressure gas services, or through a redundant bypass for high pressure gas services.

The use of either supply source for nitrogen is acceptable and controlled by administrative procedures. Plant Drawing 9321-F-27233 [Formerly Figure 11.1-2B] depicts the flow path when configured from the nitrogen supply trailer, but only to illustrate that when the nitrogen supply trailer is utilized, the isolation valves to the cylinders must be closed to ensure that the cylinders do not deplete with the trailer gas supply and thus be unavailable as a backup gas source when the trailer supply expires. When the cylinders are in use, the nitrogen supply is divided into two independent headers/cylinder banks, one for operation and one for backup. The pressure regulator in the operating header is set for approximately 100 psig discharge, and that in the backup at approximately 90 psig.

When the operating header is exhausted, the discharge pressure will fall below 100 psig and an alarm will alert the operator. The second header/cylinder bank will come into service automatically at approximately 90 psig to ensure a continuous supply of gas. After the exhausted cylinder bank has been replenished, the operator manually sets the operating pressure back to approximately 100 psig and the back up pressure at approximately 90 psig. This redundancy is not considered necessary for the trailer gas supply due to its much greater volume and ease of replacement.

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 (0.5 psig minimum to 4.0 psig maximum) to prevent in-leakage. On the other hand, out-leakage from the system is minimized by using diaphragm valves, bellows seals, self-contained pressure regulators and soft-seated packless valves throughout the radioactive portions of the system.

IPEC00036189

Gases vented to the vent header flow to the waste gas compressor suction header. To remove liquid waste buildup from the header, two valves permit draining into individual drain tanks. Any moisture present in the header will drain by gravity to these tanks. The drain valves on the tanks drain to the floor drain, which directs the flow to the Liquid Waste Disposal System. One of the two compressors is in continuous operation when required to be in service 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 110 psig, a pressure transmitter automatically opens the inlet valve to the backup tank, closes the inlet valves 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. Maximum decay time is allowed before releasing gas to the environment. However, the header arrangement at each tank inlet gives the operator freedom to fill, reuse or discharge gas to the environment without restricting operation of other tanks.

Six additional small gas decay tanks are supplied for use during degasing 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. With this arrangement assuming 1% defective fuel rods the activity inventory in any one tank will be less than 2.0×10^4 curies of equivalent Xe-133.

The total radioactivity content of any given gas decay tank is limited by the technical specifications to 50,000 Ci (Xe-133 dose equivalent). This specification ensures that following a postulated gas decay tank rupture, the radiation exposure at the site boundary would not exceed 500 mrem. To preclude exceeding the specification limit, the Offsite Dose Calculation Manual (ODCM) establishes a radioactivity concentration set point in the feed line to the waste gas compressors. A radiation monitor on the feed line monitors the concentration and would alarm if the ODCM set point is exceeded. This, in turn, would alert the operators for action to ensure that the total accumulated tank radioactivity does not exceed the specification limit.

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 considerable 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% by volume of oxygen. This allows him time to isolate the tank before the combustible limit is reached. Another tank is placed in service while the operator locates

IPEC00036190

and eliminates the source of oxygen. Discharge 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.

When the reactor is in cold shutdown, the RCS Venting System discharges near the suction of the purge system. Vent connections are removed and the RCS venting points are capped off before the reactor is brought to hot shutdown. Liquid drains are routed to the liquid Waste Disposal System.

A gas and particulate monitor is attached to the plant vent stack to analyze the amount of radiation contained in the gas effluent (see Section 11.2).

Solids Processing

All radioactive wastes will be processed, packaged and shipped to a licensed burial facility in accordance with NRC, DOT and State regulations and burial site criteria. Overall system performance is in accordance with an established Process Control Program.

Mechanical filter cartridges are placed in high integrity containers and dewatered.

Spent resins are stored in the Spent Resin Storage Tank for a period of time to allow for decay of short-lived radionuclides. Resin is removed from the storage tanks first by bubbling nitrogen through the tank to agitate the resin and then pumping water through the tank at a controlled rate to sluice the slurry to either the Containment Access Facility (CAF) annex building truck bay or to the fuel storage building cask wash pit. There it is received in a shielded shipping cask fitted with a high integrity container of about 100 cu. ft. The slurry will enter the cask and be dewatered by an internal screen designed to retain the resin. Sluice water returns to the waste holdup tank. The basis for all dose rate calculations is one cycle of operation with one percent defective fuel.

Properly processed and contained spent resins may be stored in the Resin Storage Area of the Interim Radwaste Facility.

Miscellaneous solid wastes, such as paper, rags, and glassware can be compressed into 55-gallon drums by a hydraulically operated baler located in the drumming room. Filled drums can be stored in a shielded area in the drumming room, if necessary. These wastes, as well as air filters and small equipment that cannot be successfully decontaminated, may also be stored within 55-gallon drums in the Dry Activated Waste (DAW) Storage Area of the Interim Radwaste Storage Facility.

Components

Codes applying to components of the Waste Disposal System are shown in Table 11.1-2. Components summary data are shown in Table 11.1-3. Waste Disposal System components are located in the Primary Auxiliary Building except for the reactor coolant drain tank that is in the Containment, and the waste holdup tank that is in the liquid holdup tank vault.

The seismic classifications of Waste Disposal System components are included in Chapter 16.

Regenerant Tank

IPEC00036191

The regenerant tank is austenitic stainless steel and provides facility to batch the caustic solution used to regenerate anion exchange resins.

Chemical Drain Tank

The chemical drain tank is a vertical cylinder of austenitic stainless steel and collects drainage from the hot section of the chemistry laboratory. After analysis, the tank contents are pumped to the waste holdup tanks or to the waste condensate tanks.

Reactor Coolant Drain Tank

The reactor coolant drain tank (RCDT) is a horizontal cylinder with spherically dished heads. The tank is all welded austenitic stainless steel. This tank serves as a drain surge for the Reactor Coolant System and other equipment located inside the reactor containment. This tank can either drain directly into the containment sump or its contents can be pumped to the CVCS holdup tanks.

Waste Holdup Tanks

The waste holdup tanks are the central collection point for radioactive liquid waste. The tanks are stainless steel of welded construction. A pumped recirculation/sparging system is included for Waste Holdup Tanks No. 32 and No. 33 to prevent acid buildup in the tanks. Each tank can be isolated, without affecting the operation of the others.

Sump Tank and 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. All 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.

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 a period of time to allow for decay of short-lived isotopes, and then the tank is emptied. However, the contents can be removed at any time if sufficient shielded 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 decaying fission products. Resin is removed from the tank by first backflushing with nitrogen to loosen the resin bed and then flushing the resin out with water entering the bottom of the tank. The tank is all welded austenitic stainless steel.

Gas Decay Tanks

Four large and six small welded carbon steel tanks are provided to contain compressed waste gases (hydrogen, nitrogen, and fission gases). After a period for radioactive decay, these gases may be released at a controlled rate to the atmosphere through the plant vent. All discharges to the atmosphere are monitored.

Compressors

IPEC00036192

Two compressors are provided for removal of gases from equipment discharging to the vent header. These compressors are of the water-sealed centrifugal displacement type. Operation of the second compressor could be automatically controlled by radioactive waste gas vent header pressure or manually. Construction is carbon steel. A mechanical seal is provided to maintain outleakage of compressor seal water at a negligible level.

Baler

A hydraulically operated baler can be used to pack compressible solid wastes into 55-gallon drums. The baler is operated manually from a local station and is supplied with a dust shroud to prevent escape of radioactive particulate matter. The shroud vents to the exhaust system.

Nitrogen Manifold

A Nitrogen manifold is installed as one method used to provide a cover gas in the vapor space of various components. It is comprised of two manifolds discharging to a common header, each manifold consisting of a bank of standard cylinders and a pressure regulator. When one manifold depletes to a preset value, the nitrogen supply is automatically switched to the other manifold and an alarm sounds to alert operators to replenish the depleted cylinders. This is one method provided to ensure a continuous supply of gas.

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 manifold where a pressure control valve maintains a constant supply pressure. A manual bypass flowpath is provided.

Gas Analyzer

An automatic gas analyzer with a nominal one-hour recycle time is provided to monitor the concentrations of the 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.

Pumps

The wetted surfaces of pumps are stainless steel.

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.

Valves

All valves, except for diaphragm valves, exposed to gases are carbon steel. All other valves are stainless steel. All valves have stem leakage control. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage.

IPEC00036193

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 tank might be overpressurized by improper operation or component malfunction. Tanks containing wastes that contain oxygen and are normally of low activity concentrations are vented into the Primary Auxiliary Building exhaust system.

11.1.3 Design Evaluation

Operating experiences demonstrate that the Waste Disposal System for the facility provides for suitable control of radioactive materials to the environment. A description of Indian Point 3 releases is submitted periodically to the NRC in the Radioactive Effluent Release Report, as described in the Technical Specifications, in accordance with the requirements of US NRC Regulatory Guide 1.21. The Indian Point 3 releases, as evidenced by the aforementioned reports, are well within the limits of 10 CFR 20.

Liquid Wastes

Liquid Wastes are generated by plant maintenance and service operations, and consequently, the quantities and activity concentrations of influents to the Waste Disposal System were, at the time of design, expected values. System loads have been greater than anticipated due to weather leaks and rainwater seepage.

The tritium concentration in a composite sample taken from every batch discharged to the river is determined periodically and used to establish the quantity of tritium released during that period.

As required by 10 CFR Part 20, every reasonable effort was made in the design of the Indian Point 3 Waste Disposal System to maintain radiation exposures and releases of radioactive materials to unrestricted areas as far below the limits specified in 10 CFR 20 as practicable.

In order to ensure that the design objectives were realized, several provisions were made for the radioactive waste processing systems. Specific design features were included in the design of the reciprocating charging pumps to collect leakage from these pumps and return it to the CVCS. The pressurizer spray valves, which are modulating in the RCS, have a live loaded packing configuration installed to mitigate the potential for valve stem leakage. These two specific features were intended to reduce the amount of primary coolant leakage, the processing load, and consequently, the amount of activity being released.

Consideration was also given to continued plant operation with the existence of primary to secondary leakage. Technical Specifications limit primary to secondary leak rate to 0.3 gpm per steam generator.

A manually operated intertie was provided from the Indian Point 3 steam generator blowdown to the Indian Point 1 Secondary Boiler Blowdown Purification System (SBBPS). Processing the Indian Point 3 blowdown through the Indian Point 1 SBBPS reduces releases by at least a factor of 10.

The requirements of 10 CFR 20 were satisfied in the design of the Indian Point Unit No. 3 Liquid Treatment System. Actual releases are reported semi-annually.

IPEC00036194

Gaseous Wastes

Gaseous Wastes consist primarily of hydrogen stripped from coolant discharged to the CVCS holdup tanks during dilution, nitrogen and hydrogen gases purged from the CVCS volume control when degasing the reactor coolant and nitrogen from the closed gas blanketing system. The gas decay capacity permits 45 days of decay for waste gas before discharge.

In the event of a pipe or tank rupture, the maximum anticipated quantity of waste gas that could be released from any one tank in the system is less than 50,000 curies of equivalent Xe-133, which would result in a dose of less than 0.5 rem beyond the site exclusion boundary.

Gaseous activity release to the plant vent on the Primary Auxiliary Building (PAB) derives from reactor coolant leakage from various system components and from periodic discharges from the gas decay tanks in the Waste Disposal System.

As part of the 10 CFR 20 compliance analysis at the time of initial license application reactor coolant leakage into the PAB was assumed to be 20 gallons per day at ambient temperature. The iodine release due to reactor coolant leakage into the PAB assumed a partition factor of 10^3 and an iodine removal efficiency of 99% for the charcoal filters in the Primary Auxiliary Building Ventilation System.

Gaseous activity releases from the Turbine Building were calculated for concurrent fuel defects and steam generator tube leakage. The turbine building gaseous releases were based on plant operation with an equivalent fuel defect percentage of 0.2% coincident with a steam generator to tube leakage of 20 gpd.

Nobel gas activities are released from the Turbine Building, primarily through the main condenser air ejector. Gaseous iodine is released from the main condenser air ejector. Gaseous iodine activity is also released from the Turbine Building as a result of steam and liquid leakage from various secondary system components into the building and exhaust from the gland seal condenser.

A system measuring the total effluent flow from the steam jet ejectors was installed in agreement with Regulatory Guide 1.97 in order to quantify the amount of radiation released through this path. The system consists of a sensor probe, mounted in the common exhaust from the after-condensers, and a remotely located electronic transmitter. The flow, ranging from 0 to 100 SCFM, may be monitored at the Critical Function Monitoring System (CFMS) upon demand. (The CFMS is described in Section 7.5)

Release from the main condenser air ejector were based on a maximum discharge rate of 60 SCFM and an iodine decontamination factor of 100 in both the steam generator and the main condenser. Releases due to steam and liquid leakage in the secondary system were based on leakages of 6 gpm of (cold equivalent condensed) steam and 12 gpm of (cold, condensed) liquid. An iodine decontamination factor of 100 in the steam generator was taken into account for both types of leakages and in addition a decontamination factor 3×10^3 for iodine was used for the liquid leakage. Releases from the gland seal condenser were based on an exhaust rate of 2.6 gal/min and an iodine decontamination factor of 100 in both the steam generator and the gland seal condenser. Actual releases were reported semi-annually.

IPEC00036195

Charcoal adsorbers were installed in the containment plant vent, the Primary Auxiliary Building, and the Fuel Handling Building ventilation systems.

Solid Wastes

Solid wastes consist of spent resins, spent filter cartridges, and miscellaneous contaminated materials such as paper, rag, and glassware. All solid radioactive wastes are packaged for removal to a licensed low-level waste burial facility in accordance with applicable regulations and burial site criteria. Waste volume and activities shipped offsite are reported semi-annually.

The Interim Radwaste Storage Facility (IRSF) may be utilized for temporary onsite storage of solid radioactive wastes and other non-liquid radioactive material. The facility design includes adequate shielding so that for up to and including a fully loaded facility, the doses to personnel outside the IRSF structure but within the IRSF protection fence shall be limited to less than 500 mrem/year and the offsite dose at the site boundary to less than 5 mrem/year. Two area radiation monitors with local annunciators are located in the facility.

All waste containers to be stored in this facility will be designed with materials compatible with the solid waste forms to prevent significant container corrosion. They are also designed to reduce the occurrence of uncontrolled releases of radioactive materials due to handling, transporting or storage.

Only solid radioactive waste will be stored in the facility. Floor drains are provided to collect any non-radioactive spilled liquid and are routed to a concrete sump tank located outside the facility. Before the tank is emptied, it will be sampled to ensure that the fluid is non-radioactive.

Fire protection is accomplished through the use of non-combustible construction materials, local fire extinguishers, and availability to an 8-inch fire main. A fire detection system with local annunciators will also be provided. Since the facility employs the use of non-combustible construction materials and storage containers, a fire suppression is not required. In the highly unlikely event of contaminated materials causing a fire, the exhaust louvres will be closed automatically.

11.1.4 Minimum Operating Conditions

Minimum operating conditions for the Waste Disposal System are dictated by the Radiological Effluent Controls, the Process Control Program (PCP), and the TRM.

IPEC00036196

TABLE 11.1-1

TYPICAL DATA

EFFLUENT AND WASTE DISPOSAL SEMI-ANNUAL REPORT (1990)
LIQUID EFFLUENTS-SUMMATION OF ALL RELEASES

	Units	Quarter 3rd	Quarter 4th	Est. Total Error %
A. Fission and activation products				
1. Total release (not including tritium, gases, alpha)	Ci	7.39E-02	1.40E-01	2.50E+01
2. Average diluted concentration during period	uCi/ml	1.50E-10	8.08E-10	
B. Tritium				
1. Total release	Ci	1.03E+02	1.83E+01	2.50E+01
2. Average diluted concentration during period	uCi/ml	2.10E-07	1.06E-07	
C. Dissolved and entrained gases				
1. Total release	Ci	4.11E-00	1.38E-02	2.50E+01
2. Average diluted concentration during period	uCi/ml	8.34E-09	7.94E-11	
D. Gross Alpha radioactivity				
1. Total release	Ci	<9.37E-05	<6.73E-05	2.50E+01
E. Volume of waste released (prior to dilution)	liters	2.34E+06	1.66E+06	1.00E+01
F. Volume of dilution water used during period	liters	4.93E+11	1.73E+11	1.00E+01
G. Percent of liquid effluent limit	%	5.69E-01	6.54E-01	2.50E+01

IPEC00036197

TABLE 11.1-1
(Cont.)

TYPICAL DATA

EFFLUENT AND WASTE DISPOSAL SEMI-ANNUAL REPORT (1990)
LIQUID EFFLUENTS-SUMMATION OF ALL RELEASES

	Units	Quarter 3rd	Quarter 4th	Est. Total Error %
A. Fission and Activation Gases				
1. Total release	Curies	3.50E+02	1.53E 00	2.50E+01
2. Average release rate for period	uCi/sec	4.40E+01	1.93E-01	
3. Percent of technical spec. limit	%	3.77E+00	2.45E-02	
B. Iodines				
1. Total Iodine - 131	Ci	7.61E-05	9.07E-06	2.50E+01
2. Average release rate for period	uCi/sec	9.58E-06	1.14E-06	
C. Particulates				
1. Particulates with half-lives >8 days	Ci	2.91E-06	2.04E-05	2.50E+01
2. Average release rate for period	uCi/sec	3.66E-07	2.56E-06	
3. Gross alpha radioactivity	Ci	<3.73E-07	<3.58E-07	
D. Tritium				
1. Total release	Ci	3.29E-01	4.58E-01	2.50E+01
2. Average release rate for period	uCi/sec	4.14E-02	5.76E-02	
E. Percent of Tech Spec Limit Iodines, Particulate, & Tritium	%	1.67E-02	4.80E-03	2.50E+01

IPEC00036198

TABLE 11.1-1
(Cont.)

TYPICAL DATA

EFFLUENT AND WASTE DISPOSAL SEMI-ANNUAL REPORT (1990)
SOLID WASTE AND IRRADIATED FUEL SHIPMENTS

JULY 1 – DECEMBER 31, 1990

A. Solid Waste Shipped Offsite for Burial or Disposal (Not irradiated fuel)

1. Type of Waste	Unit	6 Month Period			Est. total
		Class A	Class B	Class C	Error %
a. Spent resins, filter sludges, etc.	m^3 Ci	1.34E+1 3.51E+1	8.32E+0 6.39E+1	0 0	25
b. Dry compressible, contam. equipment for burial	m^3 Ci	3.07E+1 5.99E+0	0 0	0 0	25
c. Irradiated Components	m^3 Ci	0 0	0 0	0 0	N/A
d. Other: Dry compressible, contaminated equip. for volume reduction at offsite facility	m^3 Ci	6.14E+1 1.92E+0	0 0	0 0	25

2. Estimate of major nuclide composition (by type of waste)

NUCLIDE	UNIT	a. Resin CLASS A	a. Resin CLASS B	b. Dry Waste CLASS A	d. Vol. Red CLASS A
Cr-51	%	1.5	0.6	0	0
Mn-54	%	1.4	0.6	0	0
Fe-55	%	26	16	59	59
Co-58	%	14	4	5	5
Co-60	%	11	28	28	28
Ni-63	%	5.9	11	5	5
Cs-134	%	20	21.8	0	0
Cs-137	%	18	18	2	2

Percentage of nuclides and total activities are based on a combination of direct measurements and scaling for non-gamma emitting nuclides.

IPEC00036199

TABLE 11.1-1
(Cont.)

TYPICAL DATA

EFFLUENT AND WASTE DISPOSAL SEMI-ANNUAL REPORT (1990)
SOLID WASTE AND IRRADIATED FUEL SHIPMENT

JULY 1 – DECEMBER 31, 1990

3. Solid Waste Disposition

Number of Shipments	Mode of Transport	Destination
7	Truck	Barnwell, SC
3	Truck	SEG, Oak Ridge TN: for volume reduction.

B. Irradiated Fuel Shipments (Disposition)

Number of Shipments	Mode of Transport	Destination
None		

Source of Data: "Semi-Annual Report of Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents for Indian Point 3," for the period July 1, 1990 through December 31, 1990, transmitted to the NRC by letter from J. E. Russell to T. Martin, dated February 15, 1991 (IP3-91-017).

IPEC00036200

TABLE 11.1-2

WASTE DISPOSAL 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 31	No code	
Waste Holdup Tanks 32 and 33	ASME III, (2)	Div. 2
Regenerant Tank	No code	
Waste Filter*	No code	
Piping and Valves	USAS-B31.1(3)	Section 1

NOTES:

(1) ASME III – American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section IV, Nuclear Vessels

(2) ASME-III Section VIII

(3) USAS-B31.1 (1955) – Code for pressure piping US American Standards Associations and special nuclear cases where applicable.

* Not used.

IPEC00036201

TABLE 11.1-3

COMPONENT SUMMARY DATA

Tanks	Quantity	Type	Volume	Design Pressure	Design Temperature	Material
Reactor Coolant Drain	1	Horizontal	350 gal	25 psig	267 F	ss
Regenerant Tank	1	Vertical	400 gal	Atm	180 F	ss
Chemical Drain	1	Vertical	375 gal	Atm	180 F	ss
Sump Tank	1	Vertical	375 gal	Atm	150 F	ss
Waste Holdup Tank No. 31	1	Horizontal	3300 ft^3	Atm	150 F	ss
Waste Holdup Tank No. 32 and 33	2	Horizontal	62,000 gal	Atm	150 F	ss
Spent Resin Storage	1	Vertical	300 ft^3	100 psig	150 F	ss
Gas Decay (large)	4	Vertical	525 ft^3	150 psig	150 F	cs
Gas Decay (small)	6	Vertical	40 ft^3	150 psig	150 F	cs

IPEC00036202

TABLE 11.1-3
(Cont.)

COMPONENT SUMMARY DATA

Pumps	Quantity	Type	Flow (gpm)	Head (ft)	Design Pressure	Design Temperature	Material[1]
Reactor Coolant Drain (32)	1	Horizontal Centrifugal[2]	135	175	225 psig	500 F	ss
Reactor Coolant Drain (31)	1	Horizontal Centrifugal[2]	75	175	225 psig	500 F	ss
Chemical Drain	1	Horizontal Centrifugal[2]	20	100	100 psig	180 F	ss
Regenerant	1	Horizontal Centrifugal[2]	20	100	100 psig	180 F	ss
Sump Tank	2	Horizontal Centrifugal	20	100	100 psig	180 F	ss

NOTE:
(1) Wetted surfaces only
(2) Mechanical seal provided

Miscellaneous	Quantity	Capacity	Type
Waste Evaporator	1	2 gpm	-

NOTE:
(1) Wetted surfaces only
(2) Mechanical seal provided

IPEC00036203

11.2 RADIATION PROTECTION

11.2.1 Design Bases

The General Design Criteria presented and discussed in this section are those which were in effect at the time when Indian Point 3 was designed and constructed. These general design criteria, which formed the bases for the Indian Point 3 design, were published by the Atomic Energy Commission in the Federal Register of July 11, 1967, and subsequently made a part of 10 CFR 50.

The Authority has completed a study of compliance with 10 CFR Parts 20 and 50 in accordance with some of the provisions of the Commission's evaluations of compliance of Indian Point 3 with the General Design Criteria presently established by the Nuclear Regulatory Commission (NCR) in 10 CFR 50 Appendix A, were submitted to NRC on August 11, 1980, and approved by the Commission on January 19, 1982. These results are presented in Section 1.13

The NRC has concluded that the current IP3 leakage detection system capability is adequate to continue to support the technical bases cited in the NRC's March 10, 1986, SE approving Leak Before Break (LBB) for the IP3 Primary Coolant Loop piping. This position was further clarified in the IP3 Supplement to Safety Evaluation re: Leakage Detection Systems (TAC No. MB3328).

Monitoring Radioactivity Releases

Criteria: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released form normal conditions, 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 of 7/11/67).

The containment atmosphere, the plant vent, the administration building vent, the containment fan-cooler's service water discharge, the Waste Disposal System gas and liquid effluent, the condenser air ejectors, the component cooling loop liquid, the component cooling water heat exchanger Service Water discharge, the discharges from the condensate polisher waste collection tanks and the steam generator blowdown are monitored for radioactivity released during normal operations, from anticipated transients, and from accident conditions. The fuel Storage Building and waste areas have no functional air monitoring, however, the HVAC Systems for these two areas are routed to the plant vent, which is monitored.

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. All accidental spills in the auxiliary building are collected in a drain tank. Any Waste Disposal System liquid effluent discharged to the condenser circulating water canal is monitored. Any accidental spills from the Liquid Radwaste Processing System skid are collected in the Fuel Storage Building Cask Washdown area which drains to a sump and is pumped to the Waste Disposal System.

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 Health Physics office area provides adequate monitoring of accident releases. The details of the procedures and equipment to be used in the event of an accident are given in the Indian Point Energy Center Emergency Plan.

IPEC00036204

The discharges from the 20 code safety valves and the 4 power relief valves in the Steam and Power Conversion System are not monitored by the radiation monitoring system, but the activity can be estimated from plant sampling, as the mass of the steam discharged can be determined and the activity concentration in the secondary side is known from periodic sampling.

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 (GCDC 18 of 7/11/67).

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 waste release operation. The permanent record of activity releases I provided by radiochemical analysis of know quantities of waste.

There is a controlled ventilation system for the fuel storage and waste treatment areas of the auxiliary building which discharges to the atmosphere via the plant vent. Radiation monitors are in continuous service in these areas to actuate a high-activity alarm on the control board annunciator, as described in Section 11.2.3.

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 of 6/11/67).

Adequate shielding for radiation protection is ensured during reactor refueling by conducting all spent fuel transfer and storage operations under water. This permits visual control of the operation at all times while maintaining low radiation levels for periodic occupancy of the area by operating personnel. The average exposure with 0.2% failed fuel that personnel could receive from the refueling water during fuel handling operations is 0.5mr/hr. The exposure to the crane operator moving an average fuel assembly is 3.4mr/hr. These dose rates are based on the expected activity during normal refueling operations. 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 annunciated in the Control Room.

Protection against Radioactivity Release from Spent Fuel and Waste Storage

Criterion: Provisions shall be made in the design of the fuel and waste storage facilities such that no undue risk to the health and safety of the public could results from an accidental release of radioactivity (GDC 69 of 7/11/67).

All fuel and waste handling and storage facilities are contained, and their related equipment were designed so that accidental releases directly to the atmosphere are monitored and do not

IPEC00036205

exceed the limits of 10 CFR 100; refer to Sections 11.1.2, 14.2.2, and 14.2.3. The components of the Waste Disposal System are not subjected to any high pressure (Table 11.1-3) or stresses and are of Class I seismic design.

In addition, the tanks have a design pressure greater than atmospheric pressure, and the piping and valves of the system were designed to the codes given in Table 11.1-2. Hence, the probability of rupture or failure of the system is low.

The reactor cavity, refueling canal and present fuel storage pit are reinforced concrete structures with a steam-welded stainless steel plate liner. These structures were designed to withstand the anticipated earthquake loadings as seismic Class 1 structures so that the liner prevents leakage even in the event that the reinforced concrete develops cracks.

11.2.2 Shielding

Design Basis

Radiation shielding was designed for operation at maximum rated 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% fuel element defects.

The shielding provided was designed to ensure that in the event of a hypothetical accident, the integrated offsite exposure due to the continued activity will be below the limits established in 10 CFR 100.

A design review of Indian Point 3 was conducted in accordance with NUREG-0578, to identify areas, components and access paths which may require occupancy during post-accident recovery operation. The results of the review have been reported to NRC and remedial actions are being taken to ensure that all vital areas and equipment requiring access under post accident conditions meet the following criteria:

1) Continuous Occupancy – less than or equal to 15 mr/hr
2) Infrequent Access – less than or equal to 5 rem whole body dose, considering the required occupancy for the duration of the accident

Typical Zone 0 areas are the turbine building and turbine plant service areas and the Central Control Room. Typical Zone I areas are the offices, auxiliary building work stations and corridors, and the outer surfaces of the containment and auxiliary building. Zone II areas would include the surface of the refueling water at refueling and the operating deck of the Containment during reactor shutdown. Areas designated Zone III include the sampling room, reactor cavity area after shutdown, and reactor containment penetration areas, including ventilation, steam line and electrical penetrations.

Typical Zone IV areas include areas within the auxiliary building such as charging pump areas, evaporation area, heat exchanger areas, and valve operator areas. Typical Zone V areas are within the regions adjacent to the Reactor Coolant System at power operation and the demineralizer and volume control tank spaces.

All high radiation areas are appropriately marked and isolated in accordance with 10CFR20 and other applicable applications.

IPEC00036206

The shielding is divided into five categories according to function. These functions include the primary shielding, the secondary shielding, the accident shielding, the fuel handling shielding and the auxiliary shielding.

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 transition temperature

2) Attenuate the neutron flux sufficiently to prevent excessive 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.

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 mc/cc maximum), which is produced by neutron activation of oxygen during passage of the coolant through the core. The secondary shield was designed to limit the full power dose rate outside the Containment Building to less than 0.75 mR/hr.

Accident Shield

The main purpose of the accident shield is to ensure safe radiation levels outside the Containment Building following a maximum credible accident.

Fuel Handling Shield

The fuel handling shield was designed to facilitate the removal and transfer of present fuel assemblies and control rod clusters from the reactor vessel to the spent fuel pit. It was designed to attenuate radiation from spent fuel, control clusters, and reactor vessel internals, and together with exclusion gates, to reduce exposures to less than 2.0 mR/hr at the refueling cavity water surface and less than 0.75 mR/hr in areas adjacent to the spent fuel pit.

Auxiliary Shielding

The function of the 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 and the Sampling System.

IPEC00036207

The shielding provided for the auxiliary building was designed to limit the dose rate to less than 0.75 mR/hr in normally occupied areas, and at or below 2.0 mR/hr in intermittently occupied areas.

Shielding Design

Primary Shield

The primary shield consists of the core baffle, water annuli, core barrel (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 feet. The lower portion of the shield is a minimum thickness of 6 feet of regular concrete ($p = 2.3$ 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 feet thick, except in the area adjacent to fuel handling, where the thickness is increased to 6 feet.

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 out-of-core nuclear instrumentation. Cooling for the primary shield concrete and the nuclear instrumentation is provided by 12,000 cfm cooling air.

The primary shield calculated neutron fluxes and design parameters are listed in Table 11.2-2.

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 cylindrical portion of the reactor containment and a 3 feet concrete annular crane support wall surrounding the reactor coolant loops.

The secondary shield was designed to attenuate the radiation levels in the primary loop compartment from a value of 25 rem/hr to a level of less than 0.75 mr/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.

Accident Shield

The accident shield consists of the 4 feet -6 inches reinforced concrete cylinder capped by a hemispherical reinforced concrete dome of a 3 feet -6 inches thickness. This shielding includes supplemental shields in front of the containment penetrations.

IPEC00036208

The equipment access hatch is shielded by a 3 feet - 6 inches thick concrete shadow shield and a 1 foot 6 inches 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.

Fuel Handling Shield

The refueling cavity, flooded to elevation 93.7 feet during refueling operations, provides a temporary water shield above the components being withdrawn from the reactor vessel. The water height during refueling is approximately 24.5 feet above the reactor vessel flange. This height ensures that a minimum of 10 feet of water will be above the active fuel of a withdrawn fuel assembly. Under these conditions, the dose rate is less than 2.5 mr/hr at the water surface (Reference: NSE 00-3-039 SFPC). This presumes a minimum pool level elevation of 93.2 feet. The spent fuel pit has a nominal level of 93.7 feet, which is half-way between the minimum and maximum water level alarm setpoints.

The refueling canal is a passageway connected to the reactor cavity and extending to the inside surface of the Reactor Containment. The canal is formed by two concrete walls each 6 feet 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 feet thick, shields the spent fuel transfer tube. This shielding was designed to protect personnel from radiation during the time a spent fuel assemble 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 the concrete walls of the fuel transfer pit. An equivalent of 6 feet of regular concrete is provided to ensure a calculated maximum dose value of 0.75 mr/hr in the areas adjacent to the spent fuel pit. Exclusion gates are also provided in the fuel transfer tube.

Spent fuel is stored in the spent fuel pit which is located adjacent to the Containment Building. Shielding for the spent fuel storage pit is provided by 6 feet thick concrete walls and the pit is flooded to a level such that the water height is grater than 13 feet above the spent fuel assemblies.

The refueling shield design parameters are listed in Table 11.2-5.

Auxiliary Shielding

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 the compartments may be entered without having to shut down and, possibly, to decontaminate the adjacent system.

The shield material provided throughout the auxiliary building is regular concrete ($p=2.3$ g/cm^3). The principal auxiliary shielding design parameters are tabulated in table 11.2-6.

IPEC00036209

The design basis used for shield design to allow access to manual backup items (e.g. valves) was that the integrated dose to an operator, immediately after the accident will be less than 3 Rem. Shielding platforms with integrated dose to an operator, immediately after the accident will be less than 3 Rem. Shielding platforms with reach rods to such valves have bee provided. The shielding will result in dose rates which are not significantly greater than the background dose from the containment (approximately 500 mr for one month following the accident). Doses in the vicinity of equipment located within the Primary Auxiliary Building would be much less due to the shielding afforded by the concrete walls of the Primary Auxiliary Building.

Shielding for the residual heat removal pumps is designed to limit the 8-hour integrated does to 3 Rems during maintenance of one residual pump with the adjacent pump circulating containment sump water. This was accomplished by the provision of shield walls around the pumps and associated piping and reach rods on the valves which must be manually operated.

11.2.3 Radiation Monitoring System

The radiation Monitoring System provides radiation detection equipment to ensure safe operation of the plant.

The system was designed to perform three basic functions:

1) Warn operating personnel of any radiation health hazard which develop.
2) Give early warning of a plant malfunction which might lead to a health hazard or plant damage.
3) Prevent inadvertent release of radioactivity to the environment.

Instruments are located at selected points in and around the plant to detect, indicate and record the radiation levels. If the radiation level should rise above the setpoint established for that channel, an alarm is initiated. The Radiation Monitoring System operates in conjunction with regular and special surveys and with chemical and radiochemical 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.

The only components of this system which are located in the Containment, are the detectors for certain area monitoring channels. Some of these would not be expected to operate following a major Loss-of-Coolant Accident and were not designed for this purpose. Components of all other area and process monitoring channels were designed for post-accident, as required.

The components of the original Radiation Monitoring System were designed according to the following environmental conditions:

1) Temperature – an ambient temperature range of 40 to 120°

2) Humidity – 0 to 95%*

3) Pressure – Components in the Primary Auxiliary Building and the Central Control Room were designed for normal pressure. Area monitoring system components inside the Containment were designed to withstand increased pressure.

IPEC00036210

4) Radiation – Process monitors are of a non-saturating design so that they "peg" full scale if exposed to radiation levels up to 100 times full-scale indication. Such process monitors are located in areas where the normal and post-accident background radiation levels will not affect their usefulness.

5) Process Monitors R20, R-62 A, B, C, D and R-63 A, B do not have this non-saturating design since they utilize a Geiger-Mueller tube. The range of these monitors is listed in Table 11.2-7, and these ranges are sufficient for these monitors to perform their functions.

*NOTE: Equipment located in the control room area or other areas in the plant with controlled environments may be specified for narrower temperature and humidity ranges because of the controlled environment provided by the heating and ventilating system.

Some monitors of the Radiation Monitoring System are required to meet the requirements of Regulatory Guide 1.97. These monitors are identified in subsections 11.2-3.1 and 11.2.3.2, and meet or exceed the design conditions stated above.

The Radiation Monitoring System is divided into the following subsystems:

1) The Process Radiation Monitoring System monitors various fluid steams for indication of increasing radiation levels.
2) The Area Monitoring System monitors area radiation in various parts of the plant.
3) The Environmental Radiation Monitoring Program monitors radioactivity in the area surrounding the plant. This program is outlined in the Off-site Dose Calculation Manual (ODCM).

In the Radiation Monitoring System, some monitors are located to detect radioactivity in several sample streams fed to a common header. These monitors read gross activity of the streams. Should a monitor detect a high gross activity, the lines into the common header may be isolated using valves located upstream of the header, and each stream read individually.

In order to assure that the sampling lines into the header do not become plugged, they are periodically inspected and tested. On certain lines of high importance (e.g., the steam generator blowdown line) a flow meter indicates any variation in flow rate that would be caused by a stoppage in one of the lines.

11.2.3.1 Process Radiation Monitoring System

This system consists of channels which monitor various fluid streams for indication of increasing radiation levels. The channels and the type of radioactivity monitored are listed in Table 11.2-7A and the measurement ranges are given in Table 11.2-7. The monitors are described below and are designed to detect the minimum concentrations of the isotopes of interest and, in monitoring gross activity, are designed to generate an alarm under abnormal conditions. Isotopic identification and concentrations are determined by grab sample analysis.

The individual channels of the Process Radiation Monitoring System are detailed below:

Containment – Air Particulate Monitor (R-11)

IPEC00036211

This monitor measures air particulate beta radioactivity in the containment and ensures that the release rate through the containment vent during purging is maintained below specified limits. Two radiation sensitive instruments provide the capability for detection of leakage from the Reactor Coolant System. The containment air particulate monitor is quite sensitive to low leak rates. The containment radiogas monitor is much less sensitive but can be used as a backup to the air particulate monitor.

High radiation level for the channel initiate closure of the containment purge supply and exhaust duct valves and pressure relief line valves.

This channel takes a continuous air sample from the containment atmosphere. The sample is drawn outside the containment in a closed a system monitored by a scintillation counter-filter paper detector assembly. The filter paper collects all particulate matter greater than 1 micron in size, on its constantly moving surface, and is viewed by a photomultiplier-plastic scintillator combination. The sample is returned to the containment, after it passes through the series connected (R-12) gas monitor.

The detector assembly is in a completely enclosed housing. A preamplifier transmits the detector pulse signal to a microprocessor which converts the signal to digital and analog outputs for display and communicated with the Radiation Monitoring System cabinets in the Control Room. The filter paper has a 25-day minimum supply at normal speed. Lead shielding is provided to reduce the background level to where it does not interfere with the detector's sensitivity. The filter paper mechanism, an electromechanical assembly which control the filter paper movement, is provided as an integral part of the detector unit.

Containment Radioactive Gas Monitor (R-12)

The monitor is provided to measure gaseous beta radioactivity in the containment to ensure that the radioactivity release rate during purging is maintained below specified limits. High gas radiation level initiates closure of the containment purge supply and exhaust duct valves and pressure line relief valves.

This channel takes a continuous air sample from the containment atmosphere, after it passes through the air particulate monitor (R-11), and draws the sample through a closed system to the gas monitor assemble. The sample is constantly circulated in the shielded, fixed, volume, where it is viewed by a plastic scintillator coupled to a heated photomultiplier tube. The sample is then returned to the containment.

The detector assembly is in a completely enclosed building. Lead shielding is provided to reduce the background level to a point where it does not interfere with the detector sensitivity. A preamplifier is mounted at the detector skid. Its output is transmitted to a microprocessor which converts the detector signal and analog outputs for display and communicates with the Radiation Monitoring System cabinet in the Central Control Room.

Plant Vent Gas Monitor (R-14)

The Plant Vent Gas Monitor detects radiation passing through the plant vent to the atmosphere. R-14 also acts as backup to R-27 as it can provide the automatic control functions to actuate diversion of the PAB exhaust through charcoal filters. It consists of a signal scintillator type detector that transmit a pulse signal to the control room.

IPEC00036212

Remote indication and annunciation are also provided on the Waste Disposal System control board. On high radiation level alarm the gas release valve in the Waste Disposal System is automatically closed, this assuring that gaseous releases from the Waste Disposal System are within the specified limits.

Condenser Air Ejector Gas Monitor (R-15)

This monitor meets the requirements of Regulatory Guide 1.97. The channel monitors the discharge from the air ejector exhaust header of the condensers for gaseous radiation which is indicative of a primary to secondary system leak. The normal gas discharge is routed to the turbine roof vent. On high radiation level alarm, the condenser exhaust gases are diverted to the Containment through a blower.

The steam jet ejectors and the primary ejectors normally exhaust to the atmosphere through a common vent stack outside the Turbine Hall. Radiation monitor channel R-15 is used to continuously monitor for high radiation in the steam jet vent line, thereby indicating a leak into the steam generator secondary water from the Reactor Coolant System.

An annunciator is provided to warn the operator of a high radiation condition. In case of a high radiation signal the following sequence of events will occur:

1) The normally closed containment isolation valves in the line to the containment building open and the control valves in the seal air line close. A selector switch and open-close lights are available for manual operation of the isolation valves.

2) The air ejector blower starts, and a three-way control valve in the air ejector effluent line diverts the effluent to the Containment Building after the blower has start.

3) A control valve to isolate the steam supply to the condenser priming ejectors is closed to prevent their operation. it should be noted that the control valve is reset locally after the high radiation signal is cleared.

The containment ventilation system provides means to manually limit, under normal conditions, containment pressure to 1 psig. However, 1 psig is not an operational limit.

If high pressure occurs in the blower suction, a pressure switch trips the blower and redirects the air ejector effluent back to the turbine hall vent.

A pressure controller and control valve are located in the steam supply to the steam jet ejectors. A solenoid valve is used to close the control valve in case of low flow through the steam jet air ejector condensers. An additional pressure control valve is located downstream of the first control valve to act as an overpressure shutoff. it is operated from a pilot valve which is set to close the valve if the pressure exceeds 175 psi.

A gamma sensitive Sodium Iodide (NaI) crystal scintillator, photomultiplier tube is used to monitor the gaseous radiation level. The radiation monitor consists of a 3" pipe section ubn series with the steam jet air ejector exhaust line, a thin walled sealed well (perpendicular to and penetrating the 3" pipe) which houses the Na/PM assembly, and employ lead shielding to reduce background radiation interference to an acceptable level.

Containment Fan Cooling Water Monitors (R-16A and R-16B)

IPEC00036213

The R-16A and R-16B channels monitor the containment fan cooling water for radiation indicative of a leak from the containment atmosphere into the cooling water. A small bypass flow form each of the heat exchangers is mixed in a common header and monitored by two adjacent-to-line scintillation detectors. Upon indication of a high radiation level each heat exchanger is individually sampled to determine which unit is leaking. This sampling sequence is achieved by manually selecting the desired unit to be monitored and allotting sufficient time for sample equilibrium to be established (approximately 15 to 20 minutes). Note that for a fan cooler unit (FCU) cooling coil failure, assumed to occur concurrently with a large break LOCA, radiological accessibility to identify and isolate the failed FCU will be possible prior to initiation of external recirculation.

Channels R-16A and R-16B use a photomultiplier tube-scintillation crystal (NaI) combination, mounted adjacent to line. Lead shielding is provided to reduce the background radiation level so it does not interfere with the detector's sensitivity. Indication and alarm are provided in the Central Control Room.

There is a 2" isolation valve and a 1/2" tap off line #12. Also, there is a 1/2" tap off line #11. These valves and taps will facilitate isolation, sampling, calibration, and urge functions. When lines #11 and #12 are isolated on either side of the radiation monitors R-16A and R-16B, using temporary hose or tubing and a portable sample pump, the radiation monitors can be calibrated then purged. These taps can also be used for local sampling in case of monitor failure.

In the event that the area of the detection assemblies for the R16-A and R16-B monitors is inaccessible (E.g., due to tornado impact on the west wall of the Vacco Filter Room, Flooding, etc.), then sampling may be achieved at the flow transmitters on the service water discharge of the fan cooler units or obtained upstream of the affected area per chemistry procedures.

The detector output signals are transmitted to a microprocessor which converts the detector signals to digital and analog outputs for display and communicates with the Radiation Monitoring Cabinet in the control room.

Component Cooling Liquid Monitors (R-17A and R-17B)

These channels continuously monitor the component cooling loop of the Auxiliary Coolant System for radiation indicative of a leak of reactor coolant from the Reactor Coolant System and/or the residual heat removal loop in the Auxiliary Coolant System. Each scintillation counter is located in an in-line well.

Waste Disposal System Liquid Effluent Monitor (R-18)

This detector monitors all Waste Disposal System liquid releases from the plant. Automatic valve closure action is initiated by this monitor to prevent further release when a high radiation level is indicated and alarmed. Remote indication and annunciation are also provided on the Waste Disposal System control board.

Channel R-18 uses a photomultiplier tube-scintillation crystal (NaI) combination, mounted in a sealed wall in an in-line fixed volume sample chamber unit for liquid effluent radiation detection. lead shielding is provided to reduce the background radiation level so it does not interfere with the detector's sensitivity. Indication and alarm are provided in the Control Room.

IPEC00036214

The sample chamber is positioned in the piping system to allow monitoring of the waste liquid during recirculation and discharge. Isolation, drain and sample valves are provided to allow purging to allow purging of the sample chamber with a clean water supply and calibration of the monitor.

The detector output signal is transmitted to a microprocessor which converts the detector signal to digital and analog outputs for display and communicates with the Radiation Monitoring Cabinet in the control room.

Steam Generator Liquid Sample Monitor (R-19)

This monitor meets the requirements of Regulatory Guide 1.97. The channel monitors the liquid phase of the secondary side of the steam generator for radiation, which would indicate a primary-to-secondary system leak, providing backup information to that of the condenser air removal gas monitor. Samples from the bottom of each of the four steam generators are mixed in a common header and the common sample is continuously monitored by one of two separate scintillation detectors. Upon indication of a high radiation level, sample and blowdown isolation valves and the blowdown tank spray valve close. Each steam generation is individually sampled in order to determine the source. This sampling sequence is achieved by manually selecting the desired unit to be monitored and allotting sufficient time for sample equilibrium to be established (approximately one minute).

The monitor is an open frame skid assembly which contains two (2) NaI(T1) Am-241 stabilized scintillation crystal photomultiplier tube detector assemblies. Each detector is housed in its own lead shielded sample chamber. The two detectors, one low range 10^{-6} to μCi/cc and one high range 10^{-3} to 10^{+2} μCi/cc are provided to meet the extended range requirements of Regulatory Guide 1.97. The monitor assembly also contains a pump assembly, sample heat exchanger, valves to direct the sample either to the low or high range detector assemblies, valves to allow purging of the sample chambers with clean water, calibration ports, and instrumentation to monitor sample flow, temperature and pressure.

The detector outputs are transmitted to a remotely mounted microprocessor which converts the detector outputs to digital and analog signals for display, generates alarms and communicates with the Central Control Room Radiation Monitoring Cabinet.

Waste Disposal System Gas Analyzer Monitor (R-20

This channel monitors low-pressure radioactive gases in the suction line to the waste gas compressor. In effect, it measure the rate at which radioactivity is being introduced (via a common header) into a gas decay tank (large or small), and provides a means of ensuring that the accumulated radioactivity in the tank being filled does not exceed the technical specification limit. When the tank inventory limit is approached another tank is placed in service.

The monitor consists of a gamma sensitive Geiger Muller tube mounted adjacent to line. Lead shielding is provided to reduce the background radiation interference. The detector output is transmitted to a remotely located microprocessor which converts the detector output to digital and analog signals for display, generates alarms and communicates with the Control Room Radiation Monitoring Cabinet.

Radiation level indication and high radiation alarm are also provided at the Waste Disposal Panel.

IPEC00036215

Service Water from the Component Cooling Water Heat Exchanger Radiation Monitor (R-23)

The R-23 channel monitors the Service Water common return line from the Component Cooling Water Heat Exchanger for radiation indicative of a leak of Component Cooling Water into the Service Water discharge header. Upon detection of a high radiation level an alarm is actuated in the Control to alert the operators.

Channel R-23 uses a photomultiplier tube-scintillation crystal (NaI) combination detector, mounted adjacent to the common Service Water return line from the CCW Heat Exchanger. Lead shielding is provided to reduce the background radiation level so it does not interfere with the detector's sensitivity. Indication and alarm are provided in the Central Control Room.

Wide Range Plant Vent Gas Monitor (R-27)

This monitor meets the requirements of Regulatory Guide 1.I97. The detector monitors noble gas releases passing through the plant vent to the atmosphere. A wide range gas monitor is installed for this purpose. This system provides 4 channels of varying sensitivity. The lower range channel consists of an isokinetic sampling head connected by heat traced tubing to a sample conditioning module containing particulate and iodine filters. The sample then passes to the sample detection module which included a 2 cmf pump and a plastic scintillator radiation detector. The intermediate and high range detectors have a separate sampling system sized for isoknetic sampling at 0.6 cfm, including heat traced lines and shielded iodine and particulate filters. The detectors used for this portion of the system are CdTe (Cs) directly coupled to a 30 cm3 and 0.03 cm3 gas volume for the intermediate and high range detectors respectively. Both isolinetic sampling heads are located in the plant vent at elevation 164' and heat tracing maintains the temperature of the sample air streams between 80°F and 110°F depending on outside air temperature. A microprocessor controls the sample flow rate and which filter and detector channel are used as well as computing and displaying release information.

There are three ranges of indication with a minimum of one decade overlap between ranges. On high radiation alarm, gas release valve RCV-014, the containment purge supply, purge exhaust, and pressure relief isolation valves are automatically closed and PAB ventilation is diverted through charcoal filters.

Indication is given by recorders installed in the control room Radiation Monitoring System Cabinet. The RM-23A Read Out/Control Module, also located in the Radiation Monitoring System Cabinet, gives additional control/indication of system parameters. A RM-80 micro-processor is located at elevation of 36' in the control building. it has the ability of storing past activity rates and provides automatic control of the system. There is a flow transmitter and RTD in the plant vent at elevation 164', which monitor parameters necessary for operation of the M-80. The sample conditioner and detection skids are located in the purge valve enclosure at elevation 79'.

Control Room Noble Gas Monitor (R-33)

This monitor measure gaseous beta radioactivity in the Control Room environs. The R-33 sample skid, RM-80 microprocessor and Customer Interface Junction Box (CIJB) are located in the Control Building 33 elevation. The monitoring system consists of the inlet and exhaust samples lines, sample skid, RM-80 CIJB, communications isolation junction boxes, Recorder RR- 1/33, and a RM-2A Readout/Control module.

IPEC00036216

A skid mounted diaphragm pump draws a continuous air sample from the sample probe located in the overhead above the control room operators desk and exhausts back into control room overhead. The sample is constantly circulated through the shielded, fixed volume where it is viewed by photomultiplier tube – scintillation crystal (NaI) combination. A preamplifier transmits the detector pulse signal to the RM-80 microprocessor which converts the signal to digital and analog outputs. The RM-80 also provides rate meter indication and sample skid control. The RM-80 microprocessor and adjoining CIJB provide communications between the gas sample skid and the CCR RMS Cabinet. The RM-23A Readout/Control module in the RMS Cabinet in the CCR provides remote control and indication. A central computer in the Control Room RMS Cabinet communicates with the RM-80 microprocessor and displays various parameters on a CRT located in the RMS Cabinet. A four pen (two spare) digital strip chart Radiation Recorder RR-1/33 provides continuous trending and indication of the Control Room activity levels. The R-33 high radiation alarm actuates locally at the sample skid and on the Radiation Monitor Cabinet Annunciator Panel in the Control Room.

Auxiliary Condensate Return Activity Monitor (R-37)

This is a scintillation type detector, which monitors the auxiliary condensate radioactivity. The readout is on the 65' PAB WDS Panel and the control room receives an alarm.

Former Technical Support Center (TSC) Center Monitor (R-41, R-42, R-43)

These detectors monitor airborne activity inside the former TSC. All three are scintillation detectors located in the former TSC Communications Room. The readouts are located in the former TSC Communications and the Panel in the communication room. R-41 monitors the particulate activity, R-42 monitors the gaseous activity and R-43 monitors the Iodine activity.

Administration Building Exhaust Monitor (R-46)

This detector monitors airborne radioactivity content of the Administration Building exhaust air. The monitor is a scintillation detector and the readout is located on the panel on the fourth floor of the Administration Building and it will alarm in the Control Room. R-46 meets the requirements of Regulatory Guide 1.97 and monitors the gaseous activity.

Sewage Pipe Line Monitors (R-56A, R-56B, R56C)

Three (3) adjacent to line type detectors are utilized to monitor the sanitary waste effluent discharges coming from Indian Point Units 1, 2 and 3. The detectors are photomultiplier scintillation type.

The output of the three detectors is continuously monitored by a microprocessor which provides indication and alarms. A high radiation alarm is provided in the Control Room on the Radiation Monitoring System Cabinet. On detection of high high radiation levels a diverter valve is positioned to transfer discharge flow to waste holding tanks.

Radioactive Machine Shoe (PAMs) Monitor (R-59)

The monitor is an open frame skid assembly. The detector is a 2 inch x 0.01 inch beta sensitive phosphor and a PM tube. Included on the skid are a rotometer flowmeter and a vacuum indicator. Air flow of 2 scfm is obtained by means of a diaphragm pump. The monitor has a

IPEC00036217

microprocessor with a local control unit. readouts are provided in the Control Room and the 55' PAB. R-59 meets the requirements of Regulatory Guide 1.97.

Condensate Polisher Overboard Monitor (R-61)

This channel monitors liquid radioactivity of discharges from the LTDS or HTDS Waste Collection. Automatic valve closure is initiated by this monitor to prevent further release after a high radiation level is indicated and alarmed. This liquid monitor is part of a skid mounted, microcomputer-controlled offline sampling system containing a microprocessor, gamma sensitive scintillation detector, valves, control station and a flow switch. The detector output is transmitted to the microprocessor which converts the detector signal into digital and analog outputs for display, generates alarms and communicates with the Control Room Radiation Monitoring Cabinet. Alarms are provided in the Control Room and locally in the Condensate Polisher. The alarm trip setpoint for this process radiation monitor is established in accordance with the Indian Point 3 Offsite Dose Calculation Manual. The trip setpoint ensures that the offsite radioactive releases are kept within 10 CFR 20 limits. Manual operation of a reset switch is required to reopen the discharge valves.

Main Steam Monitors (R-62 A-D)

Four radiation detectors are externally mounted next to the main steam lines outside the containment and upstream of the safety valves. These channels monitor the noble gases released through the main steam line safety valves and atmospheric dump valves during normal and accident plant operation. Local indications/alarms are in the upper cable tunnel penetration areas as well as the control room.

The detection channels for the R-62 radiation monitor are designed to meet the range requirements of NUREG-0737. The range of these channels ($7.66E^{-03}$ to $7.66E^{+02}$ μCi/cc of ODCM instantaneous release mix) complies with a NUREG-0737 required range of $1.00E^{-01}$ to 1.00^{+0} μCi/cc of Xe-133 dose equivalent radioactivity in that the Xe-133 equivalent range for monitor R-62 is $6.04E^{-02}$ to $6.04E^{+03}$ μCi/cc.

The R-62 channels meet the intent of the range requirement imposed by Regulatory Guide 1.97 (i.e. 10^1 μCi/cc to 10^3 μCi/cc) in that they provide accurate monitoring of any radioactive releases through the main steam lines for the maximum steam line activity concentrations following a postulated design basis steam generator tube rupture accident. The actual detection range of the monitor has a low limit that is below the low limit of the range requirement imposed by Regulatory Guide 1.97 and a high limit that is above the maximum concentration of noble gases expected in the main steam lines on a design basis steam generator tube rupture accident. This range ($7.66E^{-03}$ to $7.66E^{+02}$ μCi/cc of ODCM instantaneous release mix) is displayed on the RM-23L digital display at the RM-80 microprocessor and on the RM-23A controller for the radiation monitor. The scales for the analog output from the monitor to the analog alarm and indication assemblies, the recorders and the QSPDS are $1.00E^{-03}$ to $1.00E^{+03}$ μCi/cc which bound the actual detection range.

Each of the Geiger-Mueller tube detectors is mounted in a lead shield to minimize the effect of background radiation. Each detector transmits its output signal to a common microprocessor which converts the detector outputs to digital and analog signals for display locally and communicates with a radiation monitor controller located in the control room. This controller has

IPEC00036218

a digital display of radiation levels for the operator which provides output signals for strip chart recorders and the Qualified Safety Parameter Display System (QSPDS).

Gross Failed Fuel Detector (R-63A, R-63B)

The Gross Failed Fuel Detector (GFFD) is based on the principle of measuring gamma radiation from fission products in the primary coolant after having allowed decay of the seven second half-life N-16.

Delay time is obtained by the length of tubing from the core to the detector. Piping to the detector is connected to the hot leg of the reactor coolant loop (Figure 11.2-6). The fluid passes a sample cooler before it reaches the two redundant detectors. The fluid passes through a flow meter and flow controller before draining into the volume control tank. The proper delay time (about 60 seconds) to the detector can be adjusted by regulating the rate of water flow. Figure 11.2-7 shows the block diagram of the GFFD.

No reactor limitations are imposed based on operability of this detector. The recommended operator action in conjunction with the use of the gross failed fuel detector are as follows:

1) Log the gross failed fuel detector reading once per shift and report any unusual count rate increase to the shift manager.

2) Have chemistry samples taken if the concentration exceed 5 μCi/cc. This change is indicative of some possible fuel element failures occurring.

Operational requirements relating to the GFFD are included in the Technical Specifications. These monitors meet the requirements of Regulatory 1.97.

Whenever both Gross Failed Fuel Detector Monitors are inoperable, grab sampling frequency shall be increased to twice per day, five days per week. The maximum time between analyses shall be sixteen hours for the two samples taken on a given day and three days between daily analysis. This accelerated sampling frequency need only be performed until one Gross Failed Fuel Detector Monitor is declared operable.

Design Containment Equilibrium Activities

During normal plant operations, Radiation Monitoring Systems Channels R-11 and R-12 provide continuous indications of the containment atmosphere gross air particulate activity and gross gaseous activity, respectively. Backup monitoring during purging is provided by Radiation Monitoring system Channels, R-14, plant vent gas monitor and R-27, plant vent wide range gas monitor. Prior to either containment purge or pressure relieving operations, containment air samples are obtained and analyzed for both particulate and gaseous activities. Table 11.2-8 lists the anticipated design equilibrium containment activities following a 16-hour operation of the containment recirculation filtration system at an iodine removal efficiency of 99%. The operating basis reactor coolant leakage into the containment of 14.4 gal/day and reactor operation with 0.2% equivalent fuel defects are assumed. Table 11.2-9 shows calculated containment activities after recirculation filtration for 16 hours at a conservative iodine removal efficiency of 90% and assuming 50 lb/day reactor coolant leak rate into the containment and 1% fuel defects.

IPEC00036219

The tritium level in the reactor coolant is monitored weekly, not to exceed 10 days between analyses. Measures are taken to ensure that during refueling, tritium activity in the refueling water is less than 1 μCi/cc. With containment purge at an assumed rate of 10,000 cfm, the maximum concentration of tritium in the containment air was calculated to be less than 1/5 of DAC.

The basis for this concentration was determined from the assumption that the refueling water evaporation rate is 100 lb/hr, the containment is purged for 2 hours at an assumed rate of 10,000 cfm prior to access, and the purge continues during the refueling operation at an assumed rate of 10,000 cfm. The containment purge isolation valves will be shut prior to going above cold shutdown to ensure closing against accident conditions.

During normal plant operation, grab samples from the auxiliary building areas are analyzed for tritium as required in the Radiological Effluent Controls section of the ODCM.

During normal operation, grab samples from the containment building are analyzed for tritium as required by 10 CFR 20 for personnel protection.

Monitoring of Radioactivity Discharges

During normal plant operation all liquids discharged from the nuclear steam supply systems of the plant are released via the Waste Disposal System. Prior to discharging from the plant, samples are taken from the monitor tanks for isotopic analysis. In addition, all liquids discharged from the Waste Disposal System, are monitored by the Waste Disposal System Liquid Effluent Monitor R-18. This monitor provides automatic closure of flow control valve RCV-019 to assure discharges of less than 10 CFR 20 limits.

Proper operation of the monitor is assured by utilization of its check source and by comparison of the monitor reading to the monitor tank sample analysis. This sample analysis is taken to establish activity in the liquid to be discharged prior to its release from the plant.

Monitoring for the occurrence of primary to secondary leakage is provided by both the Condenser Air Ejector Monitor R-15 and the Steam Generator Blowdown Sample Monitor R-19. Upon indication of leakage by either of these monitors, means have been provided to manually divert the blowdown from Indian Point 3 to the Indian Point 1 Secondary Boiler Blowdown Purification System (SBBPS). From the standpoint of rapid determination of the occurrence of primary to secondary leakage, the two monitors (R-15 and R-19) provide redundancy for this function.

Proper operation of R-19 is assured by utilization of its check source and by comparison of the monitor reading to a blowdown liquid sample analysis. During those periods of operation with primary to secondary leakage and utilization of the Indian Point 1 SBBPS, the blowdown liquid is also monitored by the radiation monitor provided for the Indian Point 1 SBBPS before release to the environment.

During those periods of plant operation with primary to secondary leakage, monitoring for the subsequent occurrence of radioactivity from such leakage in the Condensate Polishing Facility waste effluent is provided by radiation detector R-61. Automatic valve closure is initiated by this monitor to prevent further release after a high radiation level is indicated and alarmed. Readout and alarm are in the Control Room and a local alarm is provided in the Condensate Polisher.

IPEC00036220

The release rate of radioactive liquid effluents from the site must be such that the concentration of radionuclides from the circulating water discharge does not exceed the limits specified in 10 CFR 20, Appendix B, for unrestricted area.

Waste Disposal Processes

The Waste Disposal System for Indian Point 3 is described in Section 11.1. Performance data are given in Table 11.1-1.

The Indian Point 3 liquid releases include discharges from the Waste Disposal System, steam generator blowdown, and Steam and Power Conversion System liquid leakage.

A manually operated intertie is provided from the Indian Point 3 steam generator blowdown to the Indian Point 1 Secondary Boiler Blowdown Purification System (SBBPS).

The radio iodine releases from the blowdown tank vent line are estimated using partition factors from Regulatory Guide 1.42. The radio iodine release is assumed to be 5% of the radioiodine activity released from the Steam Generator Blowdown when directed to the Blowdown Flash Tank.

The Indian Point 3 gaseous releases include pressure relief operations, reactor coolant leakage in the Primary Auxiliary Building, discharges from the Waste Disposal System, steam generator blowdown, and secondary system releases from the main condenser air ejector, the gland seal condenser and Steam and Power Conversion System steam and liquid leakage. Offsite doses from gaseous tritium releases are negligible.

Plant equipment is used in conjunction with developed operating procedure to maintain surveillance of radioactive gaseous and liquid effluents produced during normal reactor operations and expected operational occurrences in an effort to maintain radioactive releases to unrestricted areas as low as practicable.

The release rate of radioactive liquid effluents from the site must be such that the concentration of radionuclides in the circulating water discharge does not exceed 10 times the limits specified in 10 CFR 20, Appendix B, for unrestricted areas. Prior to release of effluents from the radwaste system of either Indian Point 3 or Indian Point 1, a sample is taken and analyzed to provide the data necessary to assure compliance with these limits.

The release rate of gaseous effluents is limited by the Technical Specifications. The contents of the gas holdup tanks are sampled and analyzed prior to release to provide the necessary data to assure compliance with this limit. During release of gaseous effluent to the plant, the conditions stated in the Technical Specifications must be met. The inventory of noble gases in any gas tank are also limited by the Technical Specifications.

During power operation the air ejector discharge monitor may be inoperable for 48 hours. when the monitor is inoperable, samples are taken from the air ejector discharge and analyzed for gross activity on a daily basis, except that when there is indication of primary to secondary leakage, the sample is taken and analyzed for gross activity once per shift.

During the first indication of primary to secondary leakage, the partition factor for the blowdown tank, as established by the Indian Point 3 "Offsite Dose Calculation Manual", is used. Whenever there is indication of primary to secondary leakage and any steam generator is being

IPEC00036221

blow down, the blowdown line monitor must be operable. It may be inoperable. It may be inoperable for 48 hours, provided samples are taken once per shift of the blowdown effluent and analyzed for gross activity.

The discharge rate of noble gases to the plant vent from gas decay tanks are controlled by an adjustable control valve and a pressure reducing valve.

Gaseous releases from the plant vent are monitored by means of radiogas detectors. Containment atmosphere is separately monitored. On high activity in the plant vent, the monitor initiates an isolation of the containment atmosphere, and no discharge to the plant vent from this source can occur.

Basis for Monitor Trip Points

Alarm trip points for Process Radiation System monitors are established in accordance with the Indian Point 3 "Offsite Dose Calculation Manual". These trip points ensure that offsite radioactive releases are kept within regulatory limits.

Radio Nuclides in Steam Generator Blowdown

The non-gaseous isotopic radioactive concentration in the steam generator blowdown liquid is conservatively calculated using the following set of equations:

$$S_p \text{ (uc/gm)} = (L)\,(F)\,(A_p)\,(1-e^{-(\lambda+B/M)t}) \,/\, M\lambda + B/M)$$

$$S_d \text{ (uc/gm)} = S_p + (L)\,(F)\,(A_d)\,(1-e^{-(\lambda+B/M)t}) \,/\, M\lambda + B/M)$$

where:

S = Radioactive isotopic concentration in blowdown liquid – uc/gm (NOTE: Subscript p refers to parent isotopes, subscript d refers to daughter isotopes)

L = Primary to secondary leak rate – gm/sec

F = Ratio of actual percent fuel rod defects to the design defect level of 1% - dimensionless

A = Radioactive isotopic concentration in the reactor coolant (see Chapter 9) – uc / gm

λ = Isotope decay constant – sec^{-1}

B = Blowdown Rate (Total 4 steam generators) – gm/sec

M = Mass of secondary water in steam generators – gm

The noble gas fission product activity released from the secondary plant during operation with primary to secondary leakage is conservatively assumed to be released via the condenser air ejector. The noble gas release rate is calculated as follows:

$$Q = \text{(us/sec)} = (L)\,(F)\,(A)$$

where:

Q = Noble gas activity release rate – uc/sec

IPEC00036222

L = Primary to secondary leak rate – gm/sec

F = Ratio of actual percent fuel rod defects to the design defect level of 1% - dimensionless

A = Radioactive noble gas isotopic concentration in the reactor coolant (See Chapter 9) – uc/gm

Tables 11.2-10 and 11.2-11 provide the isotopic activity in the blowdown liquid and the noble gas activity emission rate from the air ejector as a function of primary to secondary leak rate. Table 11.2-10 is based on operation with 0.2% equivalent fuel rod defects and Table 11.2-11 is based on operation with 1% equivalent fuel rod defects.

Pertinent assumptions to be used in the calculations include:

1) Total mass of secondary water in steam generators (M) – 1.46×10^6 gms
2) Continuous blowdown rate (total 4 steam generators) (B) = 3.16×10^3 gm/sec

Tables Table 11.2-12 and 11.2-13 provide the noble gas isotopic concentration in the condenser air ejector discharge as a function of primary to secondary leak rate. Table 11.2-12 is based on expected operation with 0.2% equivalent fuel rod defects while Table 11.2-13 is based on design defect level of 1% equivalent fuel rod defects.

The noble gas isotopic concentrations in the condenser air ejector discharge were based on the air ejector's maximum discharge rate of 60 SCFM. In actual operation, the air ejector discharge rate will be less than 60 SCFM and the radiation monitor response time will be shorter.

Radiation monitoring channel R-15 (condenser air ejector gas monitor) has been provided to ensure that the noble gas radioactive releases from secondary plant are less than the 10 CFR 20 offsite discharge limits. Radiation monitoring channel R-19 (Steam Generator Secondary Side Liquid Monitor) has been provided to ensure the radioactive blowdown liquid releases from the secondary plant are less than 10 times the 10 CFR 20 "Effluent Concentrations". Tables 11.2-14 and 11.2-15 provide the radiation monitor responses corresponding to the radioactivity concentration listed in Tables 11.2-10 and through Table 11.2-13.

11.2.3.2 Area Radiation Monitoring System

This system consists of channels which monitor radiation levels in various areas of the plant. These areas are listed in Table 11.27B and the measurement ranges are given in Table 11.2-7.

Control Room Area Radiation Monitor (R-1)

This monitor measure the area radiation in the Control Room and satisfies the requirements of Reg. Guide 1.97. The monitor consists of a detector, RM-80 microprocessor and Customer Interface Junction Box (box located in the Control Building 33' elevation) RM-80 CIJB, Communications Isolation Junction Boxes, recorder RR-1/33, and a RM-23A Readout Control module.

The detector is a fixed position gamma sensitive G-M tube located on the north wall on the Control room (Control Building, 53' elevation). A preamplifier transmits the detector pulse signal to the RM-80 microprocessor which converts the signal to digital and analog outputs and also provides local rate meter indication. The RM-80 microprocessor and adjoining CIJB

IPEC00036223

communicate with the Control Room RMS Cabinet. An RM-23A Readout/Control module in the RMS Cabinet in the Control Room provides remote control and indication.

A central computer in the RMS Cabinet in the control room communicates with the RM-80 microprocessor and displays various parameters on a CRT located in the RMS Cabinet. A two channel Strip Chart Radiation Recorder (RR-1/33) located on the RMS Cabinet provides continuous trending and indication of CCR area radiation levels. The CCR high radiation alarm actuates locally at the RM-80/CIJB and on the Radiation Monitoring Cabinet Annunciator located on the RMS Cabinet in the CCR. The high radiation alarm also automatically transfers the CCR HVAC system into the 10% Incident Mode of Operation.

Area Monitors (R-2, R-4, R-6, R-7, R-8)

Each channel consists of a fixed gamma sensitive GM tube. The detector output is amplified and the log count rate determined by the integral amplifier at the detector. The level is indicated locally at the detector and at the Radiation Monitoring System cabinets. High radiation alarms are displayed on the main annunciator the Radiation Monitoring System cabinets, and at the detector location. 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. Monitors R-4, R-6, R-7 and R-8 meet the requirements of Regulatory Guide 1.l97

Fuel Storage Building Area Radiation Monitor (R-5)

This is an extended range area monitor used to measure the area radiation fields of the Fuel Storage Building as required by Reg. Guide 1.97. It uses a GM tube detector for low range and an ionization chamber detector for high range. On a high radiation signal the bypass dampers around the charcoal filter must be manually closed, if open, the Fuel Storage Building rolling door closes, the supply fans will trip, if running, and the exhaust fan is started. The inlet dampers to the charcoal filter will open. The rolling door and personnel doors' inflatable seals will inflate, but this action is not required for R-5 operability.

Channel R-5 consists of 2 detectors, local indicator, annunciator, and microprocessor. A central computer in the Radiation Monitoring Cabinet in the Control Room communicates with the microprocessor and displays various parameters on a CRT.

Vapor Containment (VC) High Radiation Area Monitors (R-25, R-26)

These redundant monitors meet the requirements of Regulatory Guide 1.97 and are used to measure the area radiation fields in the VC. They can be used to follow the course of an accident by indicating the extent of gaseous and vapor fission products released from the primary system. These monitors consist of ion chamber detectors, local indicators, annunciator, and microprocessor. A central computer in the Radiation Monitoring Cabinet in the Control Room communicates with each microprocessor and displays various parameters on a CRT.

CVCS Tank Area Radiation Monitors (R-34A, R34B, R-34C)

These are ionization chamber type detectors which monitor the tank area radiation levels for CVCS Tank #31, 32 and 33, respectively. The readout of these detectors is in the Control Room.

IPEC00036224

Waste Holdup Tank (WHUT) Area Radiation Monitors (R-38A, R-38B, R-38C)

These are ionization type detectors which monitor the WHUT area radiation levels for WHUT #31, 32 and 33 respectively. The readout of these detectors is in the Control Room.

WHUT Pump Room Area Radiation Monitor (R-38D)

This is an ionization type detector which monitors the area radiation level in the WHUT Pump Room. The readout is in Rack D11 of the Control Room.

Former TSC Area Radiation Monitors (R-44, R-44B, R-44C, R-44D)

These are all G-M Type detectors. R-44A is the former TSC HVAC area radiation monitor. The detector is located in the former TSC HVAC vent duct and the readout is located in the former TSC HVAC room and former TSC Communication Room. This detector will swap the former TSC HVAC damper to the emergency mode on a high radiation signal.

R-44B is the former TSC outside area radiation monitor. The detector is located outside the north wall and the readout in the I&C Supervisor's Office. This detector will swap the former TSC HVAC dampers to the emergency mode on a high radiation signal. R-44C and R-44D are former TSC inside area radiation monitors. Their detectors are located in the TSX hallway opposite the Health Physics cabinet and in the former TSC hallway hear the director and documents office respectively. They both readout in the former TSC hallway and the former TSC Communications Room. Their function is to monitor the radiation level in that particular area.

Administration Building Area Radiation Monitors (R-48 A-G, R-49, R-51)

These are all GM type detectors which readout locally and on the Victoreen Panel on the fourth floor of the Administration Building. They monitor the radiation levels in their particular areas. R-48D, R-48E, R-48F, R-49 and R-51 have been removed from service.

Radioactive Machine Shop (RAMS) Area Radiation Monitors (R-53 A-C, R-54, R-55 A-B)

These are all GM type detectors which read out locally and on the Victoreen Panel on the fourth floor of the Administration Building. They monitor the radiation levels in these particular areas. R-53A, R-53B, R-54A, R-54C and R-55A have been removed from service.

Area Monitors (R-64, R-65, R-66, R-67, R-68, R-69, R-70)

These are extended range area monitors used to measure the area radiation fields of the PAB, Fan House and Pipe Penetration Areas as required by Regulatory Guide 1.97. They utilize a GM tube detector for low range and an ionization chamber detector for high range. The monitors also have a local indicator, annunciator, and a microprocessor. A central computer in the Radiation Monitoring racks communicates with each microprocessor and displays various parameters on a CRT.

Operating Conditions

IPEC00036225

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.

Calibration

A primary calibration was performed on a one time basis in the vendor's "Design Verification Tests", which utilizes typical isotopes of interest to determine proper detector response. Further primary calibrations are not required as the geometry cannot be significantly altered within the sampler. Calibration of samplers is then performed based on a known correlation between the detector responses and a secondary standard.

Maximum Offsite Concentrations During Venting

The design basis maximum concentrations of activity at the site boundary resulting from venting of the gas decay tanks correspond to 20% of MPC based on annual average meteorology and a ground level release. This site boundary concentration is based on venting at a rate which will alarm the radiation monitor in the vent line and automatically close the vent valve thereby terminating the venting process. However, during the venting process, the average site boundary concentrations is much less than this. Based on the maximum release rate and 1% defective fuel, venting of the gas decay tanks occurs less than 30% of the time in one year. However, based on the expected level of fuel defects corresponding to 0.2%, the gas decay tanks would only be vented 5% of the time throughout the year.

The Containment was expected to be purged four times per year; three purges during hot shutdown conditions and the other during the refueling shutdown. Presently, Containment purging at Indian Point 3 occurs only during cold shutdown. During the refueling cold shutdown, the major portion of the activity release is expected to occur in the first 2.5 hours. The offsite concentrations of radioactivity as a result of purging the Indian Point 3 containment is less than the effluent release limit in the Technical Specifications. The Containment Radioactive Gas Monitor (R-12) and Containment Air Particulate Monitor (R-11) can initiate automatic closure of the containment purge lines in order to assure that this limit not be exceeded. The containment purge valves will be shut prior to going above cold shutdown to ensure closure against accident pressure conditions. The circuit arrangement is such that the purge and pressure relief valves close upon a high radiation signal.

As all venting concentrations at the site boundary are below 10 CFR 20 MPC values, no limitations on releases need to be imposed by meteorological considerations.

Purge and Vent During Normal Operation

During normal reactor operations a "closed containment" is maintained. Containment purging normally occurs only during cold shutdown conditions.

It may be necessary, however, to provide containment pressure relief during normal operation. The flow rate and time period associated with the pressure relief are much less than that associated with the normal purging operation. Review of plant operating data for Indian Point 3

IPEC00036226

indicates that venting of the containment is necessary once every two days for approximately one and one-half hours.

Prior to either containment purge or pressure relieving operations, containment air is sampled and analyzed for both particulate and gaseous activities.

A high radiation signal from either the Containment Air Particulate Monitor or the Containment Radioactive Gas Monitor initiates automatic closure of the containment supply and exhaust duct valves and pressure relief line valves. Both these monitors would be in operation during containment purging and venting operations. The monitors are located a few feet from the containment wall in the fan house at an elevation of 54'-9".

The Containment Radioactive Gas Monitor and the Plant Vent Gas Monitor would both detect the radiation levels that would result from a fuel handling accident inside the Containment. High radiation level for the Containment Radioactive Gas Monitor initiates automatic closure of the containment purge supply and exhaust duct valves and pressure relief line valves.

Refer to the Technical Specifications and the Radiological Effluent Controls Program for applicable requirements relating to operability and periodic testing of these monitors plus related limitations placed on containment venting operations.

11.2.4 Health Physics Program

The Indian Point health physics program, medical emergency program and emergency plan are described in the "Indian Point Energy Center Emergency Preparedness Program" and the Indian Point 3 "Radiation Protection Plan."

11.2.5 Liquid Waste Release

All liquid waste releases are assayed for radioactivity prior to release to assure compliance with the limits established in the Technical Specifications.

11.2.6 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%, 50% and 100%, at rated full power. Survey data were reviewed for conformance to design levels before increasing to the next power range.

The Off-Site Dose Calculation Manual (ODCM) specifies surveillance requirements for Technical Specification required radiation monitors. The Technical Specification required effluent monitors are tested with calibrated sources at the designated calibration frequency and are tested daily using a remotely operated check source to verify the instrument response.

11.2.7 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 11.2.7.A.2 for testing of sealed sources that are stored and not being used).

IPEC00036227

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 11.2.7.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 microcurie of radioactive material on the test sample.

D. If the leakage test reveals the presence of 0.005 microcurie 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.

IPEC00036228

TABLE 11.2-1

PLANT ZONE CLASSIFICATIONS

Zone	Condition of Occupancy	Maximum Dose Rate (1% failed fuel) m Rem/hr
0	Unrestricted Area	Less than 0.5
I	Restricted Area	0.5-2.0
II	Low Radiation Area	2.0-5.0
III	Radiation Area	5.0-100
IV	High Radiation Area	Greater than 100
V	Exclusion Area*	Greater than 1000

*NOTE: Access to Zone V areas must be cleared with the reactor operators in the Control Room, or is controlled by watch HP.

IPEC00036229

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	7.4×10^8	3.9×10^2
5.53 Kev < E ≤ 1 Mev	1.3×10^{10}	8.9×10^2
0.625 ev ≤ E ≤ 5.53 Kev	7.4×10^9	1.6×10^3
E < 0.625 ev	1.9×10^9	1.3×10^5

Design Parameters

Core thermal power	3216 MW(t)
Active core height	144 in
Effective core diameter	132.7 in
Baffle wall thickness	1.125 in
Barrel wall thickness	2.285 in
Thermal shield wall thickness	2.80 in
Reactor vessel I.D.	173.0 in
Reactor vessel wall thickness	8.625 in
Reactor coolant cold leg temperature	542 F
Reactor coolant hot leg temperature	601 F
Maximum thermal neutron flux exiting primary concrete	< 10^6 n/cm^2 sec
Reactor shutdown dose exiting primary concrete	<15 mr/hr

IPEC00036230

TABLE 11.2-3

SECONDARY SHIELD DESIGN PARAMETERS

Core power density	98.5 watt/cm^3
Reactor coolant liquid volume	12,600 ft^3
Reactor coolant transit times:	
Core	0.817 sec
Core exit to steam generator inlet	2.001 sec
Steam generator inlet channel	0.592 sec
Steam generator tubes	3.220 sec
Steam generator tubes to vessel inlet	2.758 sec
Vessel inlet to core	2.167 sec
Total out of core	10.738 sec
Full power dose rate outside secondary shield	<0.75 mr/hr

IPEC00036231

TABLE 11.2-4

ACCIDENT SHIELD DESIGN PARAMETERS

Core thermal power	3216 Mw(t)
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
Clean-up rate following accident	0
Maximum integrated direct dose (one week exposure) in the control room	<1.5 rem
Maximum integrated direct dose (one week 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 mr/hr
Maximum dose rate at water surface	2.0 mr/hr

IPEC00036232

TABLE 11.2-6

PRINCIPAL AUXILIARY SHIELDING

Component	Concrete Shield Thickness. Ft-In
Demineralizers	4 – 0
Charging pumps	2 – 6
Liquid waste holdup tanks	2 – 6
Volume control tank	3 – 6
Reactor Coolant filter	3 – 6
Gas decay tanks	3 – 6
Gas Compressor	2 – 0
Design parameters for the auxiliary shielding include:	
Core thermal power	3216 MW(t)
Fraction of fuel rods containing small clad defects	0.01
Reactor coolant liquid volume	12,600 ft^3
Letdown flow (normal purification)	75 pgm
Effective cesium purification flow	7 gpm
Cut-in concentration deborating demineralizer	150 gpm
Dose rate outside auxiliary building	0.75 mr/hr
Dose rate in the building outside shield walls	0.75 mr/hr

IPEC00036233

TABLE 11.2-7

RADIATION MONITORING SYSTEM CHANNEL RANGES

Channel	Range*	Units	Nuclides Detected
R-1	0.1 - 1E+4	mR/hr	NG
R-2	0.1 - 1E+4	mR/hr	NG, FP, CP
R-4	0.1 - 1E+4	mR/hr	CP
R-5	1E-4 - 1E+4	R/hr	FP, CP
R-6	0.1 - 1E+4	mR/hr	FP, CP
R-7	0.1 - 1E+4	mR/hr	NG, FP, CP
R-8	0.1 - 1E+4	mR/hr	FP, CP
R-11	1E-11 – 1E-5	μCi/cc	Rb-88, FP CP
R-12	1E-7 – 1E-1	μCi/cc	NG
R-14	1E-6 to 1E-1	μCi/cc	NG
R-15	!e-6 – 1E0	μCi/cc	NG
R-16A, B	1E-7 –1E-1	μCi/ml	NG, FP, CP
R-17A, B	1E-6 to 1E-1	μCi/cc	NG, FP, CP
R-18	1E-7 – 1E-1	μCi/ml	FP, CP
R-19	1E-6 – 1E+2	μCi/ml	NG, FP, CP
R-20	1E-2 – 1E+3	μCi/cc	NG
R-23	1E-7 – 1E-1	μCi/cc	NG, FP, CP
R-25, 26	1 – 1E+8	R/hr	NG
R-27	10 – 1E+13	μCi/sec	NG
R-33	10 – 1E+8	cpm	NG
R-34A, B, C	0.1 – 1E+7	mR/hr	FP, CP
R-37	10 – 1E+6	cpm	FP, CP
R-38A, B, C, D	0.1 – 1E+7	mR/hr	FP, CP
R-41	10 – 1E+6	cpm	FP, CP
R-42	10 – 1E +6	cpm	NG

NG = Noble Gases, e.g., Xe-133, Xe-135, Kr-87, Kr-88
FP = Fission Products, e.g., Cs-137, Cs-134
CP = Corrosion Products, e.g., Co-60, Co-58, Mn-54, Cr-51
*Range when stated in units of activity is a function of detection system counting rate range and the count rate to activity conversion factors associated with the expected radio nuclide mix present in the sampled medium.

IPEC00036234

TABLE 11.2-7
(Cont.)

RADIATION MONITORING SYSTEM CHANNEL RANGES

Channel	Range*	Units	Nuclides Detected
R-43	10 - 1E+6	cpm	Iodines
R-44Am B, C, D	0.01 - 1E+3	mR/hr	NG
R-46	10 - 1E+6	cpm	NG
R-48A – C, G	0.01 - 1E+3	mR/hr	FP, CP
R-53C	0.01 - 1E+3	mR/hr	FP, CP
R-54B	0.01 - 1E+3	mR/hr	FP, CP
R-55B	0.01 - 1E+3	mR/hr	FP, CP
R-56A, B, C	1E-7 – 1E-1	μCi/cc	FP, CP
R-59	1E-6 – 1E+2	μCi/cc	NG
R-61	1E-7 - 1E-1	μCi/cc	NG, FP, CP
R-62A – D	7.66E-03 to 7.66E+02	μCi/cc	NG, ODCM Mix (digital range)
	1.00E-03 to 1.00E+03	μCi/cc	NG, IDCM Mix (analog range)
R-63A	1-2E+4	μCi/cc	NG
R-63B	1-2E+4	μCi/ml	NG
R-64	0.1-1E+7	mR/hr	CP, FP, NG
R-65	0.1-1E+7	mR/hr	CP, FR, NG
R-66	0.1-1E+7	mR/hr	CP, FR, NG
R-67	0.1-1E+7	mR/hr	CP, FR, NG
R-68	0.1– 1E+7	mR/hr	CP, FR, NG
R-69	0.1– 1E+7	mR/hr	CP, FR, NG
R-70	0.1 – 1E+7	mR/hr	CP, FR, NG

NG = Noble Gases, e.g., Xe-133, Xe-135, Kr-87, Kr-88
FP = Fission Products, e.g., Cs-137, Cs-134
CP = Corrosion Products, e.g., Co-60, Co-58, Mn-54, Cr-51
Iodines, e.g., I-131, 1-133, 1-135
*Range when stated in units of activity is a function of detection system counting rate range and the count rate to activity conversion factors associated with the expected radio nuclide mix present in the sampled medium.

IPEC00036235

TABLE 11.2-7A

PROCESS RADIATION MONITORING SYSTEM

I. Gaseous Radiation Monitoring

Channel	Monitor Location
R-12	Fan House - 54'-9'
R-14	Plant Vent -124'
R-15	Turbine Bldg - 53'
R-20	Primary Auxiliary Bldg - 55'
R-27	Purge Valve - 80'
R-33	Control Bldg - 33' (Cable Spreading Room)
R-42	Former Technical Support Center – Comm. Room
R-46	Administration Bldg – 4th floor
R-59	RAMS - 55'
R-62A	ABFB
R-62B	ABFB
R62-C	ABFB
R62-D	ABFB

II. Particulate Radiation Monitoring

Channel	Monitor Location
R-11	Fan House - 54'-9'
R-13	Pipe Pen -67' (RETIRED)
R-41	Former Technical Support Center – Comm. Room

III. Iodine Monitoring

Channel	Monitor Location
R-43	Former Technical Support Center – Comm. Room

IPEC00036236

TABLE 11.2-7A
(Cont.)

PROCESS RADIATION MONITORING SYSTEM

IV. Radiation Monitoring

Channel	Monitor Location
R-16A	Primary Auxiliary Bldg - 15'
R-16B	Primary Auxiliary Bldg - 15'
R-17A	Primary Auxiliary Bldg - 41' (CCW Heat Exchanger Discharge)
R-17B	Primary Auxiliary Bldg - 41' (CCW Heat Exchanger Discharge)
R-18	Primary Auxiliary Bldg - 41'
R-19	Service Water Access - 43'
R-23	Primary Auxiliary Bldg - 41'
R-37	Auxiliary Condensate Return
R-56A	Sewage Lift Station – Lower Parking Lot
R-56B	Sewage Lift Station – Lower Parking Lot
R-56C	Sewage Life Station – Middle Parking Lot
R-61	CPF – 1st Fl. mezz.
R-63A	Pipe Pen - 67'
R-63B	Pipe Pen - 67'

IPEC00036237

TABLE 11.2-7B

Area Radiation Monitoring System

Channel	Detector Location
R-1	Control Room – 33"
R-2	Vapor Containment - 80'
R-4	Charging Pump Room
R-5	Fuel Storage Building - 95'
R-6	Chemistry Sampling Room
R-7	In-Core Instrumentation Room
R-8	Drumming Station
R-25	Vapor Containment - 95' West
R-26	Vapor Containment - 95' East
R-34A	31 CVCS Tank Area
R-34B	32 CVCS Tanks Area
R-34C	33 CVCS Tank Area
R-38A	31 Waste Holdup Tank Area
R-38B	32 Waste Holdup Tank Area
R-38C	33 Waste Holdup Tank Area
R-38D	Waste Holdup Tank Pump Room
R-44A	Former Technical Support Center HVAC Area
R-44B	Former Technical Support Center Outside Area
R-44C	Former Technical Support Center Inside Area
R-44D	Former Technical Support Center Inside Area
R-48A	Radiochemistry Lab – 4th Floor Admin Bldg
R-48B	Radiochemistry Lab – 4th Floor Admin Bldg
R-48C	Chemistry Counting Room – 4th Floor Admin Bldg
R-48D	Respiratory Maintenance Room – REMOVED FROM SERVICE
R-48E	HVAC Room – 4th Floor Admin Bldg – REMOVED FROM SERVICE
R-48F	Controlled Passage – 4th Floor Admin Bldg – REMOVED FROM SERVICE
R-48G	Source Vault – 4th Floor Admin Bldg
R-49	Liquid Waste Disposal Area - 47' Admin Bldg – REMOVED FROM SERVICE
R-51	Laundry Room - 47' Admin Bldg – REMOVED FROM SERVICE
R-53	RAMS Sump Stairwell – REMOVED FROM SERVICE
R-53B	RAMS Outside Filter Area - 41' – REMOVED FROM SERVICE
R-53C	RAMS Radiation Area - 41'
R-54A	RAMS Decon Room - 54' – REMOVED FROM SERVICE
R-54B	RAMS Disassembly Area - 54'
R-54C	RAMS Storage Room - 54' – REMOVED FROM SERVICE
R-55A	RAMS Radiation Area - 73' Near Fence – REMOVED FROM SERVICE
R-55B	RAMS Radiation Area - 73' Near Tool Room
R-64	Primary Auxiliary Bldg - 55'
R-65	Primary Auxiliary Bldg - 73'
R-66	Primary Auxiliary Bldg - 34'
R-67	Primary Auxiliary Bldg - 41'
R-68	Primary Auxiliary Bldg - 15'
R-69	Pipe Pen - 54'
R-70	Fan House - 80'

IPEC00036238

TABLE 11.2-8

EQUILIBRIUM CONAINTMENT AIR ACTIVITIES FOLLOWING RECIRCULATION FILTRATION AT FULL POWER OPERATION

(14.4 gal/day Reactor Coolant Leak, 0.2% Equivalent Fuel Rod Defects)

Isotope	Equilibrium Containment Activity Curies
Kr-85M	0.006
Kr-85 (Peak)	6.77
Kr-87	1×10^{-3}
Kr-88	0.006
Xe-133M	0.106
Ke-133	22.0
Xe-135M	$<10^{-3}$
Xe-135	0.036
I-131	0.0036
I-132	0.0006
I-133	0.0043
I-134	0.0002
I-135	0.0020

IPEC00036239

TABLE 11.2-9

EQUILIBRIUM CONAINTMENT AIR ACTIVITIES FOLLOWING RECIRCULATION FILTRATION AT FULL POWER OPERATION

(59 lb/day Reactor Coolant Leak, 1% Equivalent Fuel Rod Defects)

Isotope	Equilibrium Containment Activity Curies
Kr-85M	0.012
Kr-85 (Peak)	14.1
Kr-87	$2x\ 10^{-3}$
Kr-88	0.013
Xe-133M	0.22
Xe-133	45.9
Xe-135M	$<10^{-3}$
Xe-135	0.075
I-131	0.00925
I-132	0.0013
I-133	0.01
I-134	$<10^{-3}$
I-135	0.0045

IPEC00036240

TABLE 11.2-10

ACTIVITY DISTRIBUTION IN THE SECONDARY PLANT
AS A FUNCTION OF PRIMARY TO SECONDARY LEAK RATE

(Expected Operation With 0.2% Equivalent Fuel Rod Defects)

Secondary Plant Noble Gas Release - μCi/sec

Primary to Secondary Leak Rate

Isotope	0.014 gpm	0.1 gpm	0.5 gpm	1.0 gpm	5.0 gpm
Kr-85	1.18	8.43	42.14	84.29	421.43
Kr-85M	0.34	2.43	12.14	24.29	121.43
Kr-87	0.20	1.43	7.14	14.29	71.43
Kr-88	0.60	4.29	21.43	43.86	214.29
Xe-133	46.1	329.29	1646.43	3292.86	16464.29
Xe-133M	0.51	3.64	18.21	36.43	182.14
Xe-135	1.02	7.29	36.43	72.86	364.29
X3-135M	0.03	0.21	1.07	2.14	10.71

Steam Generator Blowdown Liquid Concentration - μCi/gm

Primary to Secondary Leak Rate

Isotope	0.014 gpm	0.1 gpm	0.5 gpm	1.0 gpm	5.0 gpm
Mo-99	2.44×10^{-4}	1.62×10^{-3}	8.13×10^{-3}	1.62×10^{-2}	8.12×10^{-2}
I-131	1.19×10^{-4}	7.93×10^{-4}	3.97×10^{-3}	7.93×10^{-3}	3.97×10^{-2}
I-132	9.46×10^{-6}	6.42×10^{-5}	3.15×10^{-4}	6.31×10^{-4}	3.15×10^{-3}
I-133	1.42×10^{-4}	9.47×10^{-4}	4.73×10^{-3}	9.47×10^{-3}	4.73×10^{-2}
I-134	2.57×10^{-6}	1.71×10^{-5}	8.57×10^{-5}	1.71×10^{-4}	8.57×10^{-4}
I-135	4.70×10^{-5}	3.13×10^{-4}	1.57×10^{-3}	3.13×10^{-3}	1.57×10^{-2}
Cs-134	1.48×10^{-5}	9.87×10^{-5}	4.93×10^{-4}	9.87×10^{-4}	4.93×10^{-3}
Cs-137	7.34×10^{-5}	4.89×10^{-4}	2.45×10^{-3}	4.89×10^{-3}	2.45×10^{-3}

IPEC00036241

TABLE 11.2-11

ACTIVITY DISTRIBUTION IN THE SECONDARY PLANT
AS A FUNCTION OF PRIMARY TO SECONDARY LEAK RATE

(Expected Operation With 1.0% Equivalent Fuel Rod Defects)

Secondary Plant Noble Gas Release - μCi/sec

Primary to Secondary Leak Rate

Isotope	0.014 gpm	0.1 gpm	0.5 gpm	1.0 gpm	5.0 gpm
Kr-85	5.90	42.14	210.70	421.40	2107.00
Kr-85M	1.70	12.14	60.70	121.40	607.00
Kr-87	1.00	7.14	35.70	71.40	357.00
Kr-88	3.00	21.43	107.15	214.30	1071.50
Xe-133	230.5	1646.43	8232.15	16464.30	82321.50
Xe-133M	2.55	18.21	91.05	182.10	910.50
Xe-135	5.10	36.43	182.15	364.30	1821.50
X3-135M	0.15	1.07	5.35	10.70	53.50

Steam Generator Blowdown Liquid Concentration - μCi/gm

Primary to Secondary Leak Rate

Isotope	0.014 gpm	0.1 gpm	0.5 gpm	1.0 gpm	5.0 gpm
Mo-99	1.22×10^{-3}	8.13×10^{-3}	4.07×10^{-2}	8.13×10^{-2}	4.07×10^{-1}
I-131	5.95×10^{-4}	3.97×10^{-3}	1.99×10^{-2}	3.97×10^{-2}	1.99×10^{-1}
I-132	4.73×10^{-4}	3.15×10^{-3}	1.58×10^{-2}	3.15×10^{-2}	1.58×10^{-1}
I-133	7.10×10^{-4}	4.73×10^{-3}	2.37×10^{-2}	4.73×10^{-2}	2.37×10^{-1}
I-134	1.29×10^{-6}	8.57×10^{-6}	8.29×10^{-5}	8.57×10^{-5}	4.29×10^{-4}
I-135	2.35×10^{-4}	1.57×10^{-3}	7.85×10^{-3}	1.57×10^{-2}	7.85×10^{-2}
Cs-134	7.40×10^{-5}	4.93×10^{-4}	2.47×10^{-3}	4.93×10^{-3}	2.47×10^{-2}
Cs-137	3.67×10^{-4}	2.45×10^{-3}	1.23×10^{-2}	2.45×10^{-2}	1.23×10^{-1}

IPEC00036242

TABLE 11.2-12

NOBLE GAS ACTIVITY CONCENTRATIONS IN THE CONDENSER
AIR EJECTOR AS A FUNCTION OF PRIMARY TO SECONDARY LEAK RATE

(Operation With Expected 0.2% Equivalent Fuel Rod Defects)

Air Ejector Discharge Concentration - μ Ci/sec

Primary to Secondary Leak Rate

Isotope	0.014 gpm	0.1 gpm	0.5 gpm	1.0 gpm	5.0 gpm
Kr-85	4.17×10^{-5}	2.98×10^{-4}	1.49×10^{-3}	2.98×10^{-3}	1.49×10^{-2}
Kr-85M	1.20×10^{-5}	8.58×10^{-5}	4.29×10^{-4}	8.58×10^{-4}	4.29×10^{-3}
Kr-87	7.06×10^{-6}	5.05×10^{-5}	2.52×10^{-5}	5.05×10^{-4}	2.52×10^{-3}
K-88	2.12×10^{-5}	1.51×10^{-4}	7.57×10^{-4}	1.51×10^{-3}	7.57×10^{-3}
Xe-133	1.63×10^{-3}	1.16×10^{-2}	5.81×10^{-2}	1.16×10^{-1}	5.81×10^{-1}
Xe-133M	1.80×10^{-5}	1.29×10^{-4}	6.43×10^{-4}	1.29×10^{-3}	6.43×10^{-3}
Xe-135	3.60×10^{-5}	2.57×10^{-4}	1.29×10^{-3}	2.57×10^{-3}	1.29×10^{-2}
X3-135M	1.06×10^{-6}	7.42×10^{-6}	3.78×10^{-5}	7.42×10^{-5}	3.78×10^{-4}

IPEC00036243

TABLE 11.2-13

NOBLE GAS ACTIVITY CONCENTRATIONS IN THE CONDENSER
AIR EJECTOR AS A FUNCTION OF PRIMARY TO SECONDARY LEAK RATE

(Operation With Expected 0.2% Equivalent Fuel Rod Defects)

Air Ejector Discharge Concentration - μ Ci/sec

Primary to Secondary Leak Rate

Isotope	0.014 gpm	0.1 gpm	0.5 gpm	1.0 gpm	5.0 gpm
Kr-85	2.08×10^{-4}	1.49×10^{-3}	7.44×10^{-3}	1.49×10^{-2}	7.44×10^{-2}
Kr-85M	6.00×10^{-5}	4.29×10^{-4}	2.14×10^{-3}	4.29×10^{-3}	2.14×10^{-2}
Kr-87	3.53×10^{-5}	2.52×10^{-4}	1.26×10^{-3}	2.52×10^{-3}	1.26×10^{-2}
K-88	1.06×10^{-4}	7.57×10^{-4}	3.78×10^{-3}	5.57×10^{-3}	3.78×10^{-2}
Xe-133	8.14×10^{-3}	5.81×10^{-2}	2.91×10^{-1}	5.81×10^{-1}	2.91×10^{-0}
Xe-133M	9.00×10^{-5}	6.43×10^{-4}	3.22×10^{-3}	6.43×10^{-3}	3.22×10^{-2}
Xe-135	1.80×10^{-4}	1.29×10^{-3}	6.43×10^{-3}	1.29×10^{-2}	6.43×10^{-2}
X3-135M	5.30×10^{-6}	3.78×10^{-5}	1.89×10^{-4}	3.78×10^{-4}	1.89×10^{-3}

TABLE 11.2-14

RADIATION MONITORING SYSTEM CHANNEL R-15 (CONDENSER AIR EJECTOR)
AND CHANNEL R-19 (STEAM GENERATOR SECONDARY LIQUID) RESPONSE
FOR EXPECTED PLANT OPERATION WITH 0.2% EQUIVALENT FUEL ROD DEFECTS

Primary to Secondary Leak Rate

RMS Channel	0.014 gpm	0.1 gpm	0.5 gpm	1.0 gpm	5.0 gpm
#15 Output-CPM	3.4×10^{4}	2.2×10^{5}	9.7×10^{5}	1.0×10^{6}	1.0×10^{6}
#15 Output-μci/cc	1.7×10^{-3}	1.2×10^{-2}	7.0×10^{-2}	1.2×10^{-1}	7.0×10^{-1}
#19 Output-μci/cc	7.3×10^{-4}	5.2×10^{-3}	2.6×10^{-2}	5.2×10^{-2}	2.6×10^{-1}

IPEC00036244

TABLE 11.2-15

RADIATION MONITORING SYSTEM CHANNEL R-15 (CONDENSER AIR EJECTOR) AND CHANNEL R-19 (STEAM GENERATOR SECONDARY LIQUID) RESPONSE FOR OPERATION WITH 1% EQUIVALENT FUEL ROD DEFECTS

Primary to Secondary Leak Rate

RMS Channel	0.014 gpm	0.1 gpm	0.5 gpm	1.0 gpm	5.0 gpm
#15 Output-CPM	1.7×10^{5}	9.3×10^{5}	1.0×10^{6}	1.0×10^{6}	1.0×10^{6}
#15 Output-μci/cc	8.5×10^{-3}	6.0×10^{-2}	3.0×10^{-1}	6.0×10^{-1}	3.0×10^{-0}
#19 Output-μci/cc	3.6×10^{-3}	2.6×10^{-2}	1.3×10^{-1}	2.6×10^{-1}	1.3×10^{-0}

TABLE 11.2-16
DELETED

IPEC00036245

TABLE 11.2-17

TIME-INTEGRATED ACTIVITY CONCENTRATION OUTSIDE CONTROL ROOM
DUE TO CONTAINMENT LEAKAGE (μci/C.C.) - HR

Isotope	0-2 hr	2-8 hr	8-24 hr	1-4 days	4-30 days
Kr-85m	1.63-3	1.33-3	7.72-4	1.53-5	0
Kr-85	9.26-5	1.39-4	3.70-4	3.97-4	3.42-3
Kr-87	2.24-3	5.65-4	2.23-5	0	0
Kr-88	4.08-3	2.43-3	7.02-4	0	0
Xe-133m	2.43-3	3.48-3	8.14-3	5.24-3	3.56-3
Xe-133	9.77-3	1.45-2	3.77-2	3.45-2	7.56-2
Xe-135m	1.42-3	1.89-3	2.86-3	3.05-4	0
Xe-135	2.74-3	4.40-3	9.51-3	1.79-3	1.53-5
I-131	1.08-4	3.10-5	1.53-5	1.53-7	0
I-132	1.42-4	1.44-5	9.58-7	0	0
I-133	2.38-4	6.10-5	2.39-5	1.53-7	0
I-134	2.04-4	5.11-6	0	0	0
I-135	2.09-4	4.12-5	9.58-6	0	0

IPEC00036246

TABLE 11.2-18

TIME-INTEGRATED ACTIVITY CONCENTRATION OUTSIDE CONTROL ROOM
DUE TO ESF LEAKAGE (μci/C.C.) - HR

Isotope	30 min - 2 hr	2-8 hr	8-24 hr	24 hr – 4 day	4-30 days
I-131	6.25-6.08-4	1.23-5	3.16-5	5.84-5	1.77-4
I-132	6.62-6	4.91-6	9.81-7	4.08-9	----
I-133	1.35-5	2.39-5	4.46-5	2.78-5	2.82-6
I-134	6.47-6	1.41-6	1.23-6	----	----
I-135	1.12-5	1.55-5	1.48-5	1.72-6	1.11-9

TABLE 11.2-19

TIME-INTEGRATED ACTIVITY CONCENTRATION INSIDE CONTROL ROOM
DUE TO CONTAINMENT LEAKAGE (μci/C.C.) - HR

Isotope	0-2 hr	2-8 hr	8-24 hr	1-4 days	4-30 days
Kr-85m	1.63-3	1.33-3	7.72-4	1.53-5	0
Kr-85	9.26-5	1.39-4	3.70-4	3.97-4	3.42-3
Kr-87	2.24-3	5.65-4	2.23-5	0	0
Kr-88	4.08-3	2.43-3	7.02-4	0	0
Xe-133m	2.43-3	3.48-3	8.14-3	5.24-3	3.56-3
Xe-133	9.77-3	1.45-2	3.77-2	3.45-2	7.56-2
Xe-135m	1.42-3	1.89-3	2.86-3	3.05-4	0
Xe-135	2.74-3	4.40-3	9.51-3	1.79-3	1.53-5
I-131	2.39-6	6.85-7	3.38-7	3.38-9	0
I-132	3.14-6	3.18-7	2.12-8	0	0
I-133	5.26-6	1.35-6	5.28-7	3.38-9	0
I-134	4.51-6	1.13-7	0	0	0
I-135	4.62-6	9.11-7	2.12-7	0	0

IPEC00036247

TABLE 11.2-20

TIME-INTEGRATED ACTIVITY CONCENTRATION OUTSIDE CONTROL ROOM
DUE TO ESF LEAKAGE (µci/C.C.) - HR

	30 min - 2 hr	2-8 hr	8-24 hr	24 hr – 4 day	4-30 days
I-131	2.38-7	4.69-7	1.20-6	2.23-6	6.74-6
I-132	2.53-7	1.87-7	3.74-8	1.56-10	----
I-133	5.14-7	9.11-7	1.70-6	1.06-6	1.08-7
I-134	2.47-7	5.37-8	4.69-10	----	----
I-135	4.28-7	5.92-7	5.66-7	6.57-8	4.25-11

IPEC00036248

TABLE 11.2-21

CONTAINMENT AIR SOURCE STRENGTH AT
VARIOUS TIMES FOLLOWING A LOCA (TID-14844 RELEASE FRACTION)

SOURCE STRENGTH (Ci)

ISOTOPE	0	2 HRS.	8 HRS.	24 HRS.	4 DAYS	30 DAYS
Kr-85M	3.57+7	2.6-+7	1.00+7	7.85+5	8.37	0
KR-85	1.74+6	1.74+6	1.74+6	1.74+6	1.73+6	1.70+6
Kr-87	6.85+7	2.36+7	9.63+5	1.90+2	0	0
Kr-88	9.74+7	5.91+7	1.32+7	2.41+5	4.67-3	0
Xe-133m	4.63+7	4.52+7	4.20+7	3.46+7	1.41+7	5.39+3
Xe-133	1.83+8	1.83+8	1.81+8	1.73+8	1.28+8	4.55+6
Xe-135m	2.71+7	2.62+7	2.08+7	7.48+6	1.43+4	0
Xe-135	4.94+7	5.35_7	5.50+7	3.23+7	3.20_5	0
I-131	2.02+7	7.26+5	2.09+5	1.39+4	7.19-2	0
I-132	3.07+7	6.14+5	3.04+4	1.84+1	0	0
I-133	4.53+7	1.54+6	3.71+5	1.54+4	9.48-3	0
I-134	5.29+7	3.94+5	1.00+3	2.21-4	0	0
I-135	4.10+7	1.21+6	1.93+5	2.67+3	1.15-5	0

IPEC00036249

TABLE 11.2-22

CONTAINMENT SUMP AND RECIRCULATION PIPINGS OUTSIDE CONTAINMENT SOURCE STRENGTHS AT VARIOUS TIMES FOLLOWING A MAXIMUM CREDIBLE ACCIDENT (TID-14844 RELEASE FRACTION)

SOURCE STRENGTH (MeV/cc-sec)

Er. MeV	0	0.5 HR.	2.0 HRS.	8.0 HRS.	1 DAY	7 DAYS	30 DAYS
0.2-0.4	3.12+09	1.09+09	8.76+08	7.59+08	5.65+08	2.34+08	2.92+07
0.4-0.9	1.17+10	7.79+09	4.28+09	1.64+09	7.98+08	1.50_08	7.01+07
0.9-1.35	7.01+09	3.31+09	1.95+09	8.57+08	1.95+08	8.76+06	2.34+06
1.35-1.8	6.82+-0	3.31+09	1.73+-0	6.04+08	1.48+08	4.48+07	1.29+07
1.8-2.2	2.92+09	1.69+09	9.93+08	2.34+08	1.25_07	1.79+06	7.20+05
2.2-2.6	3.31+09	2.14+09	1.19+09	2.53+08	1.31+07	2.73+06	7.79+05
2.6-3.0	1.58+09	2.53+08	1.17+08	1.67+07	3.70+05	4.67+04	1.34+04
3.0-4.0	1.11+09	1.44+08	4.87+-7	7.01+06	1.48+05	1.83+04	5.26+03
4.0-5.0	8.18+08	6.23+06	5.-6+06	0	0	0	0
5.0-6.0	3.60+06	4.67+04	0	0	0	0	0

IPEC00036250

TABLE 11.2-23

RADIATION DOSES IN THE CONTROL ROOM INTEGRATED OVER 30 DAYS AFTER LOCA

Control Room	Dose Guidelines per S.R.P. 6-4	Containment Air	Containment Sump Water	Activity Inside Rm. From Makeup Air Intake	Activity Outside Rm. Thru Plume Release	Activity Inside Rm. From Makeup Air Intake	Activity Outside Rm. Thru Plume Release	Activity Radiation From Recirc. Pipes	TOTAL
a. Whole body gamma	5 Rem	$1x10^{-3}$ Rem	$1.5x10^{-3}$ Rem	1.75 Rem	$1.4x10^{-2}$ Rem	NIL	NIL	$2.1x10^{-3}$ Rem	1.8 Rem
b. Thyroid	30 Rem	-	-	19.2 Rem	-	9.6 Rem	-	-	28.8 Rem
c. Beta Skin	30 Rem	-	-	28.2 Rem	-	NIL	-	-	28.2 Rem

IPEC00036251

CHAPTER 12

CONDUCT OF OPERATIONS

12.1 ORGANIZATIONAL STRUCTURE AND RESPONSIBILITIES

12.1.1 Management and Technical Support Organization

Entergy as the sole owner and operator of Indian Point 3 has assumed full responsibility for its operation and engineering technical support. Prior to March 10, 1978, this responsibility was contracted to the Consolidated Edison Company as agent for the Authority. Although not directing the operation and maintenance during this period, the Authority maintained technical cognizance by residence at the plant, attendance at the Con Edison's Station Nuclear Safety Committee meetings, membership on the Con Edison's Nuclear Facilities Safety Committee, providing engineering support and design review, selection of equipment, and involvement in licensing efforts related to Indian Point 3. This overview function was maintained in order to provide self-assurance of safe and efficient operation in conformance with NRC regulatory requirements and the facility licensing commitments. On November 21, 2000, Entergy became the sole owner and operator of Indian Point 3.

12.1.1.1 Organizational Arrangement

Figure 12.1-2 depicts the corporate structure for the management and technical support of the operation of Indian Point 3. The Nuclear organization headed by the Chief Operating Officer (COO) provides the management and technical support for the operation of Indian Point 3. Independent oversight activities are conducted through the Quality Assurance / Oversight Organization.

The Chief Executive Officer (CEO), President, and Chief Operating Officer (COO) have overall responsibility for the entire administration of the Entergy Nuclear Operations Inc. (ENO) including financial, public relations and legal aspects. The Chief Operating Officer reports directly to the President on matters relating to operations, engineering, construction, quality assurance and security.

Upon activation of the Indian Point Energy Center Emergency Plan, the Chief Operating Officer also reports directly to the President on financial and public information matters.

12.1.1.2 Maintenance Program

Indian Point 3 is maintained in accordance with approved written procedures as described in the Entergy Nuclear Northeast nuclear management manuals or the plant's administrative procedures. Anticipated work procedures to maintain the plant in a safe and operable condition are prepared and approved, prior to the time they are required, in accordance with administrative procedures. Non-routine or emergency maintenance is accomplished in accordance with maintenance procedures. Maintenance requests are in writing or submitted electronically using properly approved forms provided for that purpose. Work does not commence until the equipment is placed in such condition as to safely protect personnel, equipment and other plant components from harm or damage. Administrative procedures define the mechanics of protective controls.

IPEC00036252

A preventive maintenance program is conducted on equipment for which experience has demonstrated a need for periodic servicing. Testing is regularly scheduled on equipment and systems in order to detect degradation from original operating parameters. Historical records of maintenance activities on all principal equipment are preserved.

12.1.1.3 Technical Support

Entergy maintains a high degree of technical expertise in the Plant Staff. Technical support of the various activities associated with overall plant operation is provided by Entergy's headquarters and site personnel.

Entergy Nuclear Northeast (ENNE) has prime responsibility for all planned and systematic activities necessary to assure the safe, reliable and efficient operation of the ENNE nuclear power facilities. The expertise in this unit includes nuclear, mechanical, electrical and civil/structural engineering disciplines as well as operations, maintenance, training, core physics and fuel management. The original plant designer, the NSSS vendor and other qualified consultants are utilized as necessary (see Section 1.6.2).

ENNE also provides technical expertise in the areas of thermo-hydraulic and transient analysis, metallurgy, process control, piping, materials, chemistry, nuclear and environmental matters.

12.1.1.3.1 Entergy Nuclear Operations (ENO) Organization

Chief Operating Officer (COO)

The COO is responsible for the overall safe, efficient, and reliable operation of the plant and reports directly to the President. The COO is the "corporate officer" specified in Technical Specification 5.2, "Organization". The COO is also responsible for the development and implementation of the Business Plan to assure that the necessary programs and resources are provided to Entergy's nuclear generating facilities. The management structure for the nuclear generation organization is shown in Figure 12.1-2.

Vice President – Indian Point Energy Center (VP-IPEC)

The VP-IPEC reports to the COO and is responsible for the combined operation of Indian Point 2 and Indian Point 3 as a single site. This position also has responsibility for overall safe and efficient operation of Indian Point 3 as directed by the COO.

Vice President – Engineering

The VP-E reports to the COO and has responsibilities in the areas of:

- nuclear engineering and
- nuclear project control.

Additionally, the VP-E is designated as the Recovery Manager in charge of the headquarters response effort to a declared emergency at the plant. As Recovery Manager, the VP-E is authorized to expend Entergy funds, utilize manpower and equipment as necessary to mitigate or terminate the emergency situation, and implement the recovery operation. The engineering management structure is shown in Figure 12.1-3.

IPEC00036253

General Manager - Engineering

The General Manager-Engineering at IPEC reports to VP - E and is responsible to perform, support and/or manage the following activities at Indian Point 3: [This can be through an intermediate level manager(s)]

- design authority for changes to the design basis (except for nuclear fuel and core design);
- plant modifications;
- project management;
- maintaining design and licensing basis documentations;
- establishing engineering standards;
- drafting and drawing revisions;
- monitoring and improving plant system performance;
- managing engineering design, analysis, and control activities for the mechanical, civil, structural, electrical, and instrumentation and controls engineering disciplines;
- management of project engineering management activities;
- management of modification planning;
- managing design drawing and drafting and drafting activities;
- managing procurement engineering;
- managing the equipment database;
- managing field engineering service activities;
- monitoring system performance;
- formulating recommendations for system improvements;
- performing field engineering with respect to plant maintenance and modifications;
- evaluating and processing requests for engineering services to coordinate engineering tasks between engineering groups;
- completing engineering design for material substitutions and some small modifications;
- operational management of the reactor core (this includes physics testing, thermal hydraulics, economics of fuel management, reactor core safety analysis, analysis of anomalies and special nuclear material accountability);
- maintaining fuel records in accordance with NRC requirements;
- monitoring component performance;
- formulating recommendations for plant and component improvements; and
- maintains overall responsibility for the surveillance test program.

Corporate Engineering

The Corporate Engineering Organization consists of Nuclear Engineering Analysis, Engineering Programs and Engineering Support. Each of these groups is headed by an Engineering Manager. Corporate Engineering is responsible for the following activities:

- design authority for nuclear fuel and core design;
- responsible for fuel fabrication contracts and fuel reliability program;
- provides analysis support to each site Reactor Engineering group;
- develops and maintains common analysis tools for risk, safety and fuel analysis;
- directs ASME programs that include welding, Inservice Inspection and Testing, pressure testing, containment inspection and non-destructive inspection;

IPEC00036254

- provides chemistry and metallurgy support to the sites as necessary;
- maintains programs for steam generators;
- provides support to site engineering groups in the area of design configuration management and computer-aided design;
- facilitates the development of common Engineering procedures, standards and guidelines;
- facilitates the activities of peer groups and working groups in assigned areas; and
- tracks and coordinates budget development for the Engineering organization.

Director – Oversight

The Director – Oversight reports to the COO through the Vice President – Operations Support (VP-OS). The Director Oversight is responsible for:

- establishing, maintaining and ensuring that the Quality Assurance Program (described in the Entergy Quality Assurance Program Manual) is implemented in accordance with Appendix B to 10 CFR 50 and verifying that other organizations, both internal and external, are implementing the portions of the program which they have been delegated. This organizational arrangement provides the necessary independence between personnel performing quality related activities from those personnel checking, auditing, or inspecting such quality related activities;
- providing oversight and direction of activities in the area of Procurement Quality, Audits and Assessments, and Quality Engineering; and
- performing independent objective oversight activities and providing timely feedback to Nuclear Generation.

Director – Nuclear Safety Assurance (D-NSA)

The Director – Nuclear Safety Assurance is responsible to the VP-IPEC. The position of D-NSA encompasses responsibilities in the following areas:

- Nuclear Licensing,
- Radioactive Waste Management Activities,
- Environmental Support, and
- Implementing the Nuclear Safety Speakout Program.

The D-NSA is responsible for regulatory compliance functions involving Federal and state agencies, including the NRC. The D-NSA functions as the primary interface with the NRC. The D-NSA is also responsible for the development and implementation of licensing policies and cost beneficial licensing actions.

The D-NSA provides support for implementing environmental regulations effectively and economically.

The D-NSA assures that the radioactive waste management programs at the nuclear plants benefit from regulatory and industry actions and that volumes are reduced and cost savings are achieved through application of new technology, best industry practices, and lessons learned.

IPEC00036255

The D-NSA is the point of contact for industry organizations such as the Nuclear Energy Institute (NEI), the Institute for Nuclear Power Operations (INPO), and other commercial nuclear power industry organizations. The D-NSA coordinates Entergy Nuclear Northeast participation in these groups and other inter-utility activities.

The D-NSA is responsible for the oversight of Entergy Nuclear Northeast's Nuclear Safety Speakout Program and for communicating significant employee concern issues to the COO.

12.1.1.3.2 Director – Security

The Director – Security reports to the VP-OS and is responsible for:

- ensuring that the Security Program is in full compliance with applicable regulatory requirements and licensing commitments; and
- maintaining and ensuring full implementation of the Security Program and ensuring that this Program is in accordance with the Facility Operating License.

12.1.1.4 Qualifications

In general, the minimum qualifications with respect to education and experience for those Headquarters and site personnel directly involved with providing technical support for Indian Point 3 are indicated below. With the approval of the President / CEO / CNO, or responsible section head, exceptions may be made on a case-by-case basis if education and experience are equivalent.

Chief Operating Officer

Education: Baccalaureate degree in engineering or related sciences.

Experience: Ten years experience of responsible power plant supervision of which five shall be nuclear.

Vice President – Indian Point Energy Center

Education: Baccalaureate degree in engineering or related sciences.

Experience: Ten years experience of responsible power plant supervision of which five shall be nuclear.

Vice President – Engineering

Education: Baccalaureate degree in engineering, physical or biological sciences.

Experience: Six years of professional level experience in nuclear services, nuclear plant operations, or nuclear engineering, and the necessary overall nuclear background to determine when additional support is needed for dealing with complex problems beyond the scope of Entergy's expertise.

Director – Security

Education: Formal training in a field related to the area of responsibility.

IPEC00036256

Experience: Three years in activities related to specific responsibilities, two years of which shall be directly related to nuclear facilities.

Directors / Managers of functional areas with responsibilities for nuclear power plant activities.

Education: Baccalaureate degree in engineering or related sciences.

Experience: Three years in design, operation or other related activities of nuclear power plants.

Staff Engineers

Education: Baccalaureate degree in engineering or related science.

Experience: Years of experience commensurate with assignment.

The resumes of persons who provide the primary or specialized headquarters support are available at the headquarters office for NRC inspection.

12.1.2 Operating Organization

12.1.2.1 Plant Staff Organization

The General Manager – Plant Operations reports to the VP-IPEC and has complete responsibility for the safe and efficient operation of the plant. The GM-PO administers an organization of Entergy supervisory employees skilled in the various disciplines of nuclear plant operation. Supervisory employees in turn direct the actions and supervise the performance of physical forces at the plant, some of which may be contracted personnel. Plant personnel that perform duties described in ANSI / ANS 3.1-1978 meet or exceed the minimum qualifications of Section 12.1.3, or justifications will be provided to the NRC prior to an individual's filling one of these positions.

12.1.2.2 Plant Personnel Responsibility and Authority

General Manager – Plant Operations (GM-PO)

The GM-PO reports to the VP-IPEC. The GM-PO is the "plant manager" specified in Technical Specification 5.2, "Organization". The responsibilities of the GM-PO include:

- implementing all Entergy policies in conformance with applicable regulatory requirements with regard to the facility; and
- directing and coordinating all plant functions, including selection and training of personnel and implementation of plant security and fire protection, through the subordinate managers to safely maximize electrical generation.

Site Manager of Operations (SM-O)

The M-O is responsible to the GM-PO, and the responsibilities of this position include:

- functional operation of the plant;

IPEC00036257

- assuring that the plant operates in an efficient, safe manner within the bounds of the Technical Specifications and other regulatory requirements;
- management of (through an intermediate level of manager(s)) the operations, planning, scheduling / outage, maintenance, instrumentation and control, health physics and chemistry functions;
- preparations in support of routine site work activities, including non-outage corrective maintenance, preventive maintenance, and surveillance tests;
- planning / preparation for and coordination of plant outages, including forced outages and refueling outages;
- directing and coordinating the maintenance function in support of the operation of the plant;
- ensuring that personnel safety programs are developed, maintained, and implemented in accordance with applicable regulatory requirements;
- maintain all mechanical and electrical equipment;
- coordinate all maintenance activities during extensive overhauls and inservice inspection;
- the repair, calibration and analysis of system control malfunctions and test work associated with fixed and portable instruments and controls;
- enhance all departmental efforts in the interest of integrated plant reliability; and
- acting on behalf of the GM-PO, in his absence.

Quality Assurance Manager

The Quality Assurance (QA) Manager is located at the plant but reports directly to the Director - Oversight in the headquarters office. The QA Manager is responsible for:

- implementing the Quality Assurance Program at the plant
- directing a staff of supervisors, inspectors, auditors and engineers in the implementation of the QA Program.

The QA Manager communicates quality assurance activities and results to the VP-O. The QA manager indirectly reports to the Director of Nuclear Safety Assurance at the site.

Operations Manager

The Operations Manager is responsible to the Site Operation Manager and the responsibilities of this position include:

- assuring that the plant is operated in accordance with approved procedures by qualified personnel;
- assuring that maintenance requests are properly transmitted, thus assuring that plant equipment is in a state of high reliability and readiness;
- providing the liaison between the shift and plant staff organizations;
- assuring that plant operation is conducted in full compliance with the Technical Specifications and all other regulatory requirements, and
- serving as a voting member of the On-Site Safety Review Committee (OSRC).

Either the Operations Manager or the Assistant Operations Manager holds a Senior Reactor Operator License (SRO).

Assistant Operations Manager

IPEC00036258

The Assistant Operations Manager is responsible to the Operations Manager, and the responsibilities of this position include:

- direction of the functional conduct of shift operations; and
- assurance that plant operation is conducted in full compliance with the Technical Specifications and all other regulatory requirements.

Either the Assistant Operations Manager or the Operations Manager is required to hold a current NRC Senior Reactor Operator License.

Manager-Operations Support

The Manager-Operations Support is responsible to the Operations Manager. Responsibilities of this position include providing technical and administrative support to the operations department. Activities include:

- ensuring that operations department documentation is maintained in accordance with procedures,
- ensuring that routine audits and evaluations of department programs are performed, and
- establishing the shift schedule for operating crews in accordance with Technical Specification staffing requirements.

The Manager – Operations Support meets the qualification requirements of ANSI / ANS 3.1-1978.

The Shift Technical Advisor (STA) reports to the Manager-Operations Support and is responsible for providing engineering expertise and advice to the Shift Manager and Control Room Supervisor on matters involving operational and nuclear safety.

Shift Manager

The Shift Manager is responsible for the operation of the plant on his shift. On off-shifts, weekends, and holidays, the Shift Manager represents plant management unless the Assistant Operations Manager, Operations Manager, any General Manager / Director, or the VP-O is onsite. The Shift Manager is responsible for:

- operation of the plant, in accordance with requirements of the NRC and other regulatory agencies;
- assurance that all operations on his shift are performed in accordance with approved procedures and are in compliance with the limits of the Technical Specifications;
- originating maintenance requests, as problems may arise;
- administrative implementation of plant security on off-shifts;
- maintaining an NRC Senior Reactor Operator License;
- performing the review and analysis of plant transients;
- determining the circumstance, analyzing the cause, and determining that operation can proceed safely before the reactor is returned to power after a trip or an unscheduled or unexplained power reduction; and
- providing direction for returning the reactor to power following a trip or an unscheduled or unexplained power reduction.

IPEC00036259

In case of radiation or any other hazard which, in the opinion of the Shift Manager, requires plant shutdown, the Shift Manager can order the plant shut down.

Field Support Supervisor (FSS)

The FSS reports to the Shift Manager and is manned at the discretion of the Operations Manager. The FSS is required to maintain a current SRO license and is responsible to the Shift Manager for supervision and coordination of operational activities outside the Control Room according to Administrative Procedures. The FSS may serve as the SRO assigned to supervise fuel handling operations and may assume the role of STA, if qualified. The FSS has the signature authority as a designee of the Shift Manager unless specifically prohibited by the applicable procedure governing the activity.

Fire Brigade Leader

The Fire Brigade Leader is responsible to the Shift Manager during a response to a plant fire and is responsible for the conduct of fire fighting activities. The Fire Brigade Leader must hold or have held an operating license at either unit at IPEC within the past 3 years and attend training on the opposite unit's safe shutdown strategy (opposite to where the Fire Brigade Leader holds or has held an operating license) as well as meet the minimum qualification requirements of a Fire Brigade Leader as defined in the Fire Protection Program. When assigned, the Fire Brigade Leader will not concurrently fill a shift position which is manned to meet the minimum shift crew composition as defined in the Technical Specifications or a position assigned other essential functions during a fire emergency.

Control Room Supervisor (CRS)

The Control Room Supervisor (CRS) is responsible to the Shift Manager and is responsible for:

- assisting the Shift Manager in providing supervision, direction, oversight, and command and control of station activities during the shift; and
- directing the Reactor Operators and Nuclear Plant Operations from the control room.

The Control Room Supervisor must hold an active NRC Senior Reactor Operator license and is second in command of IP3 activities on shift. The Control Room Supervisor has direct authority to shut down the plant if, in his opinion, it is required because of radiation or any other hazard.

Reactor Operator

The Reactor Operator (RO) is directed in his activities, which are mainly in the control room, by the Control Room Supervisor and Shift Manager. The RO has the responsibility to:

- assist the CRS in the direction of Nuclear Plant Operators; and
- maintain an NRC Reactor Operator License.

Nuclear Plant Operators

The Nuclear Plant Operators take direction from the Control Room Supervisor, Reactor Operator, and Shift Manager. The Nuclear Plant Operators are responsible for:

IPEC00036260

- operation of all auxiliary equipment throughout the plant;
- providing clearance operations prior to maintenance;
- restoring equipment to service following maintenance; and
- knowledge of radiation control and protection requirements.

Director – Nuclear Safety Assurance (D- NSA)

The D-NSA is directly responsible (through an intermediate level of manager(s)) to the SVP-IPEC for:

- directing and coordinating support services associated with the operation of the plant by overseeing the plant licensing and the corrective action functions and activities;
- coordinating and implementing licensing activities at the site;
- keeping the VP-O apprised of licensing activities;
- developing operating policy as it applies to nuclear regulations and licensing matters;
- examining and evaluating plant operation characteristics and industry operational experience;
- developing detailed recommendations to improve plant safety and reliability; and
- tracking NRC action items and commitments.

The D-NSA has the QA Manager indirectly reporting to him at the site. See Section 12.1.2.2 for QA Manager direct reporting.

Technical Support Manager (M-TS)

The M-TS is directly responsible (through an intermediate level of managers) to the VP-IPEC for:

- Chemistry activities, and
- Radiation Protection activities.

Radiation Protection Manager

The Radiation Protection Manager is responsible to the Technical Support Manager for compliance with approved procedures for the radiological control and protection of personnel and the general public from radiological hazards. In this capacity, the Radiation Protection Manager has overall responsibility for:

- custodianship of source material used for equipment and responsibility for radiological aspects of nuclear shipments leaving the plant
- Radiation Protection Plan
- radiation protection areas; and
- monitoring the environmental program and all other functions having to do with the radiological and ecological effects of the plant.

If, in the opinion of the Radiation Protection Manager, radiological conditions threaten a radiation hazard to plant personnel or the general public, the Manager may recommend cessation of work or that the plant be shut down. If necessary, the Manager has recourse to the VP-O onsite or the COO.

IPEC00036261

Security Manager

The manager of the security function reports to the Director Security, WPO, and is responsible for:

- implementing the security plan by insuring the security implementing procedures are carried out by exercising control over the plant's guard force;
- maintaining a liaison with local law enforcement agencies, while receiving advice from the Headquarter's Director of Security for policy matters with regard to the security of the plant;
- assuring that intrusion alarms are tested and in good working order, while initiating work requests as necessary to correct deficiencies; and
- ensuring that personnel safety programs are developed, maintained and implemented in accordance with applicable regulatory requirements.

The Security Manager indirectly reports to the Director of Nuclear Safety Assurance at the site.

Emergency Planning Manager

The Emergency Planning Manager is responsible to the Director – Emergency Programs in the corporate office, and indirectly to the Director – Nuclear Safety Assurance onsite, and is responsible for:

- developing, maintaining, and implementing the Indian Point Energy Center Emergency Plan;
- assuring overall onsite and corporate emergency preparedness;
- assuring site compliance with federal regulations and plant standards; and
- coordinating Emergency Preparedness activities with state and local government and the Federal Emergency Management Agency.

The Emergency Planning Manager indirectly reports to the Director of Nuclear Safety Assurance at the site.

Training Manager

The Training Manager reports to the VP-T and is responsible for:

- the formulation and implementation of all training programs, with the exception of those related to quality assurance, and fire brigade activities, for all classifications of personnel within the plant (to accomplish this task, the Training Manager may schedule other managers for training in their specialty or accomplish it himself);
- formulating and implementing replacement training and retraining of NRC licensed operators, and maintaining records of training and retraining activities pursuant to NRC requirements; and
- scheduling and tracking for fire brigade training programs.

12.1.2.3 Lines of Communication

IPEC00036262

Major communications on plant operation, availability, scheduling and maintenance generally will be between the VP-IPEC and the COO. However, should consultation on performance, anomalies or modifications be required, the VP-IPEC has at his disposal, for direct communications, the entire headquarters staff. Likewise, any of the supervisors at the plant having specific responsibilities may have direct communication with the engineer at headquarters assigned to that discipline or who is most cognizant of the area of concern.

Should the VP-IPEC be unavailable, the GM-PO will assume his responsibilities or the VP-IPEC may delegate this responsibility to other qualified supervisory personnel.

Department Managers within the plant organization are responsible for the performance of specific duties. The GM-PO is responsible to the VP-IPEC for the functional performance of the plant. A Shift Manager, competent to supervise all shift operations, is on duty at all times, and has the authority to control all operating, maintenance and testing on his shift. At all times, the Shift Manager or Control Room Supervisor on duty has direct authority to shut down the plant if, in his opinion, it is required because of radiation or any other hazard.

Administrative procedures originate from the VP-IPEC or his authorized representative. Safety related procedures are reviewed and approved in accordance with UFSAR requirements.

12.1.2.4 Operating Shift Crews

The minimum requirements for shift crew composition, established in 10 CFR 50.54 (m)(2) and Section 5.2.2 of the Technical Specifications, are implemented by administrative procedures.

12.1.3 Qualification of Nuclear Plant Personnel

12.1.3.1 Qualification Requirements

The minimum qualifications with regard to educational background and experience for plant staff positions will meet or exceed the minimum qualifications of ANSI / ANS 3.1 - 1978 for comparable positions except for: (1) the Radiation Protection Manager who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975, and (2) the Shift Technical Advisor who shall have 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; and (3) the Operation Manager who shall meet or exceed the minimum qualifications of ANSI / ANS 3.1-1978 except for the Senior Reactor Operator License requirement which shall be in accordance with the plant Technical Specifications.

12.2 TRAINING

The Training Programs at Indian Point 3 Nuclear Power Plant are established, implemented and maintained using a systems approach to training. The following training programs are accredited by the National Academy for Nuclear Training:

1) Licensed Operator/Senior Operator Initial Training

2) Licensed Operator Requalification Training

3) Nuclear Plant Operator Training

IPEC00036263

4) Shift Manager Training

5) Shift Technical Advisor Training

6) Instrument and Control Technician Training

7) Radiological, Environmental and Health Physics Technician Training

8) Chemistry Technician Training

9) Electrical Maintenance Training

10) Mechanical Maintenance Training and Technical Supervisor

11) Engineering Support Personnel Training

These training programs incorporate the instructional requirements necessary to provide personnel to operate and maintain the facility in a safe manner in all modes of operation.

12.3 WRITTEN PROCEDURES

The Plant, Administrative and Entergy Nuclear Northeast (ENN) Procedures govern the operation and maintenance of the facility in a safe and efficient manner. Those activities which are controlled by procedures are listed in Table 12.3-1.

Written procedures, with their appropriate check-off lists and instructions, are prepared using the review and approval mechanism dictated by the Quality Assurance Program described in the Entergy Quality Assurance Program Manual.

The approved procedures are maintained at key operating locations within the facility and their distribution is controlled.

IPEC00036264

TABLE 12.3-1

LIST OF ACTIVITIES CONTROLLED BY PROCEDURES

Title
Plant Staff Organization
On-site Safety Review Committee
Review and Acceptance of Vendor-Written Procedures
Procedure Use and Adherence
Plant Security
Protection of Unclassified Safeguards Information
Obtaining / Maintaining Access for and Terminating Contractor Personnel
Summary of the IP3 Emergency Planning Program
Radiation Protection Plan
Radioactive Waste Reduction Program
Respiratory Protection Program
Correction Action Process
CR Operability and Reportability Review
Determining operability of SSC's
Corrective Action Review Board
Work Control
Conduct of Planning and Scheduling
Outage Risk Assessment
Start-up Management
Outage Management
Protective Tagging
Radioactive Effluents Control Program
Temporary Alterations
Lead Shielding Control
Training
Conduct of Training
Control of Temporary Equipment
Quality Assurance Program
Calibration of Measuring and Test Equipment
Records Management Program
Control of Vendor Equipment Technical Information
Distribution of Controlled Documents
Control of Changes to Technical Specifications and Licensing Requirements
Engineering Request Process
Commitment Management
Surveillance Test Program
Infrequently Performed Tests or Evolutions
10CFR50 Appendix J Option B Program
Special Nuclear Materials Accounting and Handling
Conduct of Operations
Post Trip/Transient Evaluation
Limiting Condition for Operation Tracking
Conduct of Maintenance

IPEC00036265

TABLE 12.3-1
(Cont.)

LIST OF ACTIVITIES CONTROLLED BYPROCEDURES

Title

Emergency Diesel Generator Inspection and Maintenance Schedule
Conduct of Instrument and Control
Instrument and Control Procedure Controls
Conduct of Radiological and Environmental Services
Petroleum Bulk Storage Program
Asbestos Management Program
Conduct of System Engineering
Nuclear Safety Evaluations, Environmental Impact Evaluations, and Classification of Structures, Systems, Components, and Subcomponents
Preparation of Justification of Continued Operation (JCO) and Reasonable Assurance of Safety (RAS)
Procurement
Conduct of Finance
Housekeeping and Cleanliness of Fluid System
Non-Radiological Medical Emergency
Con Edison / Power Authority Memorandums of Understanding
Resolution of Procurement Nonconformance Reports
Welding Program – Control of Special Processes
Integrity of Systems Outside Containment
Overtime Restrictions
Operating Experience Program
Action and Commitment Tracking System
IP3 Performance Enhancement Program
Environmental Qualification
IP3 ASME Section XI Repair / Replacement Program
Meteorological Monitoring System
Equipment Database Program
Inservice Inspection Program
Conduct of Materials Management
Material Control
Control of Field Issued Material
Reactivity Control and Management
Control of Maintenance Activities Under Limiting Conditions for Operation
Preventive Maintenance Program
Conduct of Construction Services
IP3 SWS Corrosion Monitoring Program
Control of Vendor / Contractor Activities
Chemical Material Control and Waste Management
Maintenance Rule
Conduct of Programs and Component Engineering
IPEC Fire Protection Program
Motor Operated Valve Program

IPEC00036266

12.4 RECORDS

Records retention requirements are addressed in the Entergy Quality Assurance Program Manual (QAPM). Plant Administrative Procedures define the responsibility for, and provide a method for the collection, filing, indexing, storing, maintenance and disposition of those records subject to the provisions of US NRC Regulatory Guide 1.88, Revision 2, and American National Standards Institute (ANSI) N45.2.9-1974 and National Fire Protection Association Standard 232-1975. The procedures define records as those documents which furnish evidence of the quality of items and/or activities affecting quality, excluding correspondence, and list the records, their retention period, their source, and the organization responsible for storage.

In addition, the QAPM specifies NQA-1, 1983; "Quality Assurance Program Requirements for Nuclear Facilities." NQA-1 includes requirements for the long term storage facility used for the storage of quality records.

12.5 REVIEW AND AUDIT OF OPERATIONS AND OPERATING EXPERIENCE

Three separate groups provide for the review and audit of plant operations and Operating Experience. Two of these, the Plant Operating Review Committee and the Corrective Action / Assessment Department, are onsite groups. The other independent review and audit group is the Safety Review Committee as further described in this section.

12.5.1 On-Site Safety Review Committee (OSRC)

The OSRC Committee's function is to advise the VP-IPEC on all matters related to nuclear safety and all matters which could adversely change the plant's environmental impact. The membership, meeting frequency, responsibilities, records and charter of the OSRC are addressed in the Entergy Quality Assurance Program Manual.

The following actions shall be taken for Reportable Events:

1) The Commission shall be notified and a report submitted pursuant to the requirements of Section 50.73 to 10 CFR Part 50 and
2) Each Reportable Event shall be reviewed by the OSRC and a report submitted by the Vice President – IPEC, to the Chief Operating Officer, Director- Licensing and the Chairman of the SRC.

12.5.2 Corrective Action / Assessment Department (CA&A)

CA&A serves to examine INPO event reports and industry experience generated data which could indicate useful areas for improving plant safety and/or reliability.

All operating experience information will be reviewed by this group or an appropriate technical group to ensure that an identical enactment of the event cannot occur at the Indian Point Three plant. Where useful improvements can be achieved, the group will develop and present detailed recommendations for revised procedures, equipment modifications or other improvements. Recommendations will be formally reviewed by the Manager of Corrective Action / Assessment or other responsible managers. Approved recommendations will be tracked by the group and implemented through normal plant procedures.

IPEC00036267

12.5.3 Safety Review Committee (SRC)

The safety related activities at the plant are reviewed by a separate off-site knowledgeable group, the Safety Review Committee (SRC). This committee performs the function of the independent review body.

Entergy maintains the Safety Review Committee to provide timely and continuing independent review and audit of Entergy's nuclear power plant safety related activities and environmental matters. The Committee provides senior management with a reasonable assurance that the plant is being operated in a safe manner and in conformance with the Facility Operating License, Technical Specifications, and approved procedures. The Committee reports to the COO. The SRC advises the COO on matters regarding nuclear safety and provides the COO with reports of SRC review and audit activities.

The SRC shall function to provide the competence required to review the areas of:

1) Nuclear Power Plant Operations

2) Nuclear Engineering

3) Chemistry and Radiochemistry

4) Metallurgy

5) Nuclear Licensing

6) Instrumentation and Control

7) Radiological Safety

8) Mechanical Engineering

9) Electrical Engineering

10) Administrative Controls and Quality Assurance Practices

11) Civil / Structural Engineering

12) Environmental

13) Emergency Planning

14) Other appropriate fields associated with the unique characteristic of a nuclear power plant (i.e., training, operational analysis, NDE methods, Title 10 CFR, fire protection and security).

In addition, the Chairman of the SRC may call upon additional Entergy personnel or outside technical experts when such expertise is desirable to investigate any safety concern.

IPEC00036268

The membership requirements, meeting frequency, responsibilities, records and charter of the Safety Review Committee are addressed in the Entergy Quality Assurance Program Manual.

The identification of specific SRC members is made in the written charter which delineates SRC activities. This charter, and any revisions made to it, must be approved by the COO.

Facility activities are audited in accordance with the requirements of the Entergy Quality Assurance Program Manual and under Safety Review Committee cognizance.

12.6 CONTINGENCY PLANS

The provisions relating to the Contingency Plans are described in a document entitled "Indian Point Energy Center Emergency Plan and Procedures."

12.7 SITE SECURITY AND ACCESS CONTROL

The provisions relating to Security are described in documents entitled "Indian Point 3, Security Plan," with revisions submitted through January 1, 2000; "Indian Point 3, Security Contingency Plan," with revisions submitted through January 1, 2000; and "Indian Point 3, Security Force Training and Qualification Plan," with revisions submitted through August 1, 1999.

IPEC00036269

CHAPTER 13

INITIAL TESTS AND OPERATIONS

13.1 TESTS PRIOR TO REACTOR INITIAL FUELING [Historical Information]

A comprehensive testing program ensured that equipment and systems performed in accordance with the 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 check-off lists. Initial operating test procedures were prepared and written by WEDCO or Westinghouse, using, as a basis, the test objectives stated in Table 13.1-1, the proposed Technical Specifications, the Plant Manual, and manufacturers' technical manuals. The procedures were written to simulate, as closely as possible, actual plant operating conditions, based on the above documents and on the engineer's experience in the startup and operation of other similar nuclear power plants.

After a procedure was written, it was distributed within WEDCO and Westinghouse for review and comment by cognizant and knowledgeable personnel. When this review was completed and all comments were resolved, the procedure was submitted to Con Edison (the Joint Test Group support group) for review and comment. When the Con Edison support group completed its review, an informal meeting was held between WEDCO and Con Edison to resolve Con Edison's comments. Comments that were resolved were incorporated in the procedure. Unresolved comments were forwarded to the Joint Test Group in writing for final resolution. The Joint Test Group resolved all previously unresolved comments and incorporated them in the procedure, if appropriate. After all comments were resolved, the Joint Test Group approved the procedure for performance.

The Joint Test Group provided the final resolution to any unresolved comments and approval of the procedure for performance.

The initial operating procedures were developed in accordance with the Technical Specifications (see Section 12.3). They were available for on-site NRC Staff review approximately three months prior to core loading.

Field and engineering analyses of the test results were made to verify that systems and components performed satisfactorily and recommended corrective actions, when necessary. If during performance of an operational test procedure, it was found that the system or equipment tested failed to meet the design and/or performance criteria, the cognizant WEDCO engineer and/or Con Edison Supervisor evaluated the deficiency and recommended a system or equipment modification or a change in the operational procedure. In either event, an evaluation of this recommendation was made by responsible personnel and a decision made as to the resolution of the deficiency. System or equipment modifications required the approval of the cognizant WEDCO or Westinghouse NES engineering group. Procedural changes required the approval of the Joint Test Group.

In all cases of system or equipment modification, or of procedural changes, the original test criteria were met.

The program included tests, adjustments, calibrations, and system operations necessary to assure that initial fuel loading and subsequent power operation could be safety undertaken. In general, the types of tests were classified as flush, hydrostatic, functional, and operational.

IPEC00036270

Functional tests verified that the system or equipment was capable of performing the function for which it was designed. Operational tests involved actual operation of the system and equipment under design or simulated design conditions.

Whenever possible, tests were performed under the same conditions as experienced under subsequent station operations. During system tests for which unit parameters were not available and could not be simulated, the systems were operationally tested as far as possible without these parameters. The remainder of the tests were performed when the parameters became available. Abnormal unit conditions were simulated during testing when such conditions did not endanger personnel or equipment, or contaminated clean systems.

A listing of test objectives to be satisfied prior to initial reactor fueling is contained in Table 13.1-1. Additional information on pre-operational testing of specific components and systems is contained in Inspection and Tests sections of Chapters 3 through 11. Acceptance criteria for pre-operational tests were given in the procedure covering the specific test. In the case of pre-operational testing of safety related equipment, the acceptance criteria conformed to the basic safety requirements of the FSAR.

The Indian Point 3 preoperational testing program was reviewed and approved by NRC as stated in the Safety Evaluation Report (9/21/73). In supplements 2 and 3 to the safety evaluation, NRC stated that a recommendation had been issued by the Office of Inspection and Enforcement to the effect that preoperational and startup testing of Indian Point 3 had been satisfactorily completed. Records of test results are maintained at the plant site (see Section 12.4).

During preoperational testing, Consolidated Edison Company of New York was the operator for Indian Point 3. Thus, the test program discussed in this Chapter was performed by Consolidated Edison with the technical assistance of WEDCO (see Section 1.6) and was witnessed by personnel from the Authority. For a discussion on the relationship between the Authority and Consolidated Edison, and for a history of the license transfer activities, refer to Section 1.1 and 1.6.

IPEC00036271

TABLE 13.1-1

OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tests	Test Objective
1. Electrical System.	To ensure continuity, circuit integrity, and the correct and reliable functioning of electrical apparatus. Electrical tests are performed on transformers, switchgear, turbine-generators, motors, cables, control circuits, excitation switchgear, d-c systems, annunciator systems, lighting distribution switchboards, communication systems and miscellaneous equipment. Special attention is directed to the following tests. (a) High voltage switchgear breaker interlock test. (b) Station loss of voltage auto-transfer test. (c) Emergency power transfer test. (d) Tests of protective devices. (e) Equipment automatic start tests. (f) Exciter check for proper voltage build up. (g) Insulation tests.
2. Voice Communication System	To verify proper communication between all local stations, and to balance and adjust amplifiers and speakers.
3. Service Water System	To verify, prior to critical operations, that the system supplies adequate flow through all heat exchangers, and meets the specified requirements when operated in the safeguards mode.
4. Fire Protection System	To verify proper operation of the deluge system.

IPEC00036272

TABLE 13.1-1
(Cont.)

OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tests	Test Objective
5. Compressed Air System	To verify leak tightness of the system, proper operation of all compressors, the manual and automatic operation of controls at design set-points, design air dryer cycle time and moisture content of discharge air, and adequate air pressure to each controller served by the system.
6. 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.
7. Cold Hydrostatic Tests	To verify the integrity and leak tightness of the Reactor Coolant System and auxiliary primary systems with the performance of a hydrostatic test at the specified test pressure.
8. Ventilation Systems	To verify proper operability of fans, controls, and other components of the Containment Ventilation System, the Control Building and auxiliary building ventilation systems.
9. Condensate and Feedwater System	To verify valve and control operability and set-points. Functional testing of feedwater system is performed when the Main Steam System is available. Flushing and hydrostatic tests are performed where applicable.
10. Auxiliary Coolant Systems	To verify component cooling flow to all components, and to verify proper operation of instrumentation, controllers, and alarms. Specifically, each of three systems; i.e., Component Cooling System, Residual Heat Removal System and Spent Fuel Pit Cooling System, is tested to ensure:

IPEC00036273

TABLE 13.1-1
(Cont.)

OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tests	Test Objective
	(a) All manual and remote operated valves are operable manually and/or remotely. (b) All pumps perform their design functions satisfactorily. (c) All temperature, flow, level, and pressure controllers function to control at the required set-point when supplied with appropriate signals. (d) All temperature, flow level, and pressure alarms provide alarms at the required locations when the alarm set-point is reached and cleared when the reset point is reached. (e) Adequate flow rates are established through the principal heat exchangers.
11. Boron Recycle System	To verify valve and control operability and set-points, flushing and hydrostatic testing as applicable. Functional testing is performed when a steam supply and heat tracing is available.
12. Chemical and Volume Control System	To verify the following: (a) All manual and remotely operated valves are operable manually and/or remotely. (b) All pumps perform satisfactorily during various plant conditions. (c) All temperature, flow, level and pressure controllers function properly during various plant conditions.

IPEC00036274

TABLE 13.1-1
(Cont.)

OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tests	Test Objective
	(d) All temperature, flow, level and pressure alarms provide alarms at the required locations when the alarm set-point is reached and clear when the reset point is reached.
	(e) The reactor makeup control regulates blending, dilution, and boration as designed.
	(f) The design seal water flow rates are attainable at each reactor coolant pump.
	(g) Chemical Addition Subsystem functions properly.
13. Safety Injection System	To verify prior to critical operation, system response to control signals and sequencing of the pumps, valves, and controllers as specified in the system description and the manufacturers' technical manuals; and to check the time required to actuate the system after a safety injection signal is received. More specifically that:
	(a) All manuals and remotely operated valves are operable manually and/or remotely.
	(b) Each pair of values installed for redundant flow paths operates as designed.
	(c) All pumps perform their design functions satisfactorily.
	(d) The proper sequencing of valves and pumps occurs on initiation of a safety injection signal.

IPEC00036275

TABLE 13.1-1
(Cont.)

OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tests	Test Objective
	(e) The fail position on loss of power for remotely operated solenoid valves is as specified.
	(f) Valves requiring initiation signals to operate do so when supplied with these signals.
	(g) All level and pressure instruments are properly calibrated and provide alarm and indication at the required location(s).
	(h) The time required to actuate the system is within the design specifications.
14. Containment Spray System	To verify, prior to critical operation, system response to control signals and sequencing of the pumps, valves, eductor and controllers as specified in the system description and the manufacturers' technical manuals; and to check the time required to actuate the system after a containment high-high pressure signal is received. More specifically, see the test objective listing for the Safety Injection System.
15. Fuel Handling System*	To show that the system is capable of providing a safe and effective means of transporting and handling fuel from the time it reaches the station until it leaves the station. In particular, the tests are designed to verify that:
	(a) The major structures required for refueling, such as the reactor cavity, refueling canal, new fuel and spent fuel storage, and

*NOTE: Tests conducted with a dummy fuel element.

IPEC00036276

TABLE 13.1-1
(Cont.)

OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tests	Test Objective
	decontamination facilities, are in accordance with the design intent. (b) The major equipment required for refueling such as the manipulator crane, fuel handling tools, spent fuel transfer system, operates in accordance with the design specifications. (c) Auxiliary equipment and instrumentation function properly.
16. Radiation Monitoring Systems	To verify the calibration, operability, and alarm set-points of all area radiation monitors, air particulate monitors, gas monitors and liquid monitors which are included in the process Radiation Monitor System and the Area Radiation Monitor System.
17. Reactor Control and Protection System	To verify calibration, operability, and alarm settings of the Reactor Control and Protection System; to test its operability in conjunction with other systems. For example, attention is directed to the following tests. (a) Reliable functioning of protection system logic and instrumentation (b) Reliable functioning of annunciator circuits (c) Setpoints (d) System operating parameters (e) Inservice testing features

IPEC00036277

TABLE 13.1-1
(Cont.)

OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tests	Test Objective
18. 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 are designed to verify that: (a) All system equipment, cabling, and interconnections are properly installed. (b) The source range detector and associated instrumentation 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 operate properly. (c) The intermediate range instrumentation operates properly, the reactor protective and control features such as high level reactor trip and high level rod stop signals operate properly, and the permissive signals for blocking source range trip and source range high voltage off operate properly. (d) The power range instrumentation operates properly; the protective features such as the overpower trips, permissive and dropped-rod functions operate with the required redundancy and separation through the associated logic matrices; and the nuclear power signals to other systems are available and operating properly. (e) All auxiliary equipment such as the startup rate channel, recorders, and indicators operate properly.

IPEC00036278

TABLE 13.1-1
(Cont.)

OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tests	Test Objective
	(f) All instruments are properly calibrated and all set-points and alarms are properly adjusted.
19. Radioactive Waste 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 monitors, alarms and controls prior to critical operation. More specifically that:
	(a) All manual and automatic valves are operable.
	(b) All instruments controllers operate to control system at required values.
	(c) All alarms are operable at required locations.
	(d) All pumps perform their design function satisfactorily.
	(e) All pumps indicators and controls are operable at required locations.
	(f) The waste gas compressors operated as specified.
	(g) The gas analyzer operates as specified.
	(h) The waste evaporator operates as specified.
20. Sampling System	To verify that a quantity of representative fluid can be obtained safely from each sampling point. In

IPEC00036279

TABLE 13.1-1
(Cont.)

OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tests	Test Objective
	particular the tests are designed to verify that: (a) All system piping and components are properly installed. (b) All remotely and manually operated valving operates in accordance with the design specifications. (c) All sample containers and quick-disconnect couplings function properly.
21. Emergency Power System	To demonstrate that the system is capable of providing power for operation of vital equipment under power failure conditions. In particular, the tests are designed to verify that: (a) All system components are properly installed. (b) Each emergency diesel (and logic system) functions according to the design intent under emergency conditions. (c) The emergency units are capable of supplying the power to vital equipment as required under emergency conditions. (d) All redundant features of the system function according to the design intent
22. Charcoal Filter Tests	To verify filter efficiency of the installed elements prior to critical operation.
23. Hydrogen Recombiner	Verification of ignition and attainment of normal operating temperatures prior to critical operation.

IPEC00036280