3.0 THE PROPOSED ACTION

3.1 Description of the Proposed Action

The proposed action is to renew the facility operating licenses for IP2 and IP3 for an additional twenty years beyond the expiration of the current operating licenses. For IP2 and IP3 (Facility Operating Licenses DPR-26 and DPR-64), the requested renewals would extend the license expiration dates from midnight September 28, 2013, to midnight September 28, 2033, and December 12, 2015, to midnight December 12, 2035, respectively.

There are no changes related to license renewal with respect to operation of IP2 and IP3 that would significantly affect the environment during the period of extended operation.

3.2 General Plant Information

The principal structures of IP2 and IP3 consist of two pressurized water reactors with containment structures (IP1 is deactivated and is in SAFSTOR), turbine buildings, auxiliary buildings, administrative building, training building, and intake structures [IP2 UFSAR, Section 1.2.2]. Figure 3-1 shows the general features of the facility. Figure 2-3 shows the exclusion zone. No residences are permitted within this exclusion zone.

3.2.1 Reactor and Containment Systems

The site utilizes pressurized water reactors in the nuclear steam supply system and a once-through circulating water system that withdraws cooling water from and discharges to the Hudson River. Westinghouse Electric Corporation supplied the nuclear steam supply system. Power generation during the license renewal term will consist of IP2 and IP3, with pressurized water reactors and turbine generators producing outputs of 3,216 and 3,216 megawatts-thermal (MWt), which are approximately 1,078 and 1,080 megawatts-electrical (MWe), respectively [PowerGEM]. IP2 achieved commercial operation in 1974 and IP3 became commercial in 1976.

Fuel for IP2 and IP3 is made of low-enrichment (< 5% by weight) uranium dioxide pellets stacked in pre-pressurized tubes made from zircaloy or ZIRLO, with welded end plugs that form sealed enclosures. Based on core design values, IP2 and IP3 operate at an individual rod average fuel burnup (burnup averaged over the length of a fuel rod) of no more than 62,000 MWD/MTU, which ensures that peak burnups remain within acceptable limits specified in Appendix B to Subpart A of 10 CFR Part 51 (Table B-1).

The engineered safety features for the plants have sufficient redundancy in component and power sources such that under the conditions of a hypothetical loss-of-coolant accident, the system can, even when operating with partial effectiveness, maintain the integrity of the containment and keep the public's exposure below the limits of 10 CFR 50.67. The containment system incorporates continuously pressurized and monitored penetrations, liner weld channels, and a seal water injection system that provides a highly reliable, essentially leak-tight barrier against the escape of radioactivity that might be released to the containment atmosphere. [IP2 UFSAR, Section 1.2.2.9; IP3 UFSAR, Section 1.2.2] The containment isolation control systems for IP2 and IP3 automatically initiate closure of isolation valves to close off all potential leakage paths for radioactive material to the environs. Upon loss of power, the purge valves fail in the closed position [IP2 UFSAR Section 5.1.4.6; IP3 UFSAR, Section 5.1.4.6]. The containment for IP2 and IP3 is a reinforced concrete structure completely enclosing the reactor vessel.

3.2.2 Cooling and Auxiliary Water Systems

3.2.2.1 Circulating Water System

Hudson River water is used for the condenser circulating water for both IP2 and IP3. The circulating water systems for IP2 and IP3 include shoreline-situated intake structures consisting of seven bays (six for circulating water and one for service water) for each unit. River water flows under the floating debris skimmer wall into six separate screen wells. The water flows through Ristroph traveling 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. A representative scale illustration of the Ristroph screen structure for IP2 is provided in Figure 3-9. The Ristroph screens for IP3 are similar in design and construction. Additionally, the head section of the screen employs five (5) spray wash headers; three (3) low pressure fish 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 screenwell flows to a motor-driven, vertical, mixed flow condenser circulating water pump. [IP2 UFSAR, Section 10.2.4; IP3 UFSAR, Section 10.2.4]

For IP2, each of the six dual-speed condenser circulating water pumps provides 140,000 gpm and 21-ft total dynamic head when operating at 254 rpm and 84,000 gpm and 15-ft total dynamic head when operating at 187 rpm. Each pump is located in an individual pump well, thus tying a section of the condenser to an individual pump [IP2 UFSAR, Section 10.2.4]. For IP3, each of the six variable-speed condenser circulating water pumps provides 140,000 gpm at 29 ft total dynamic head when operating at 360 rpm [IP3 UFSAR, Section 10.2.4].

After moving through the condensers, cooling water from IP2 and IP3 flows downward from the discharge water boxes via six 96-inch diameter down pipes and exits beneath the water surface in a 40-foot wide discharge canal.

The discharge velocity in the canal is approximately 4.5 feet per second (fps) at full flow. Average transit time for cooling water ranges from 5.6 minutes (IP3) to 9.7 minutes (IP2). The cooling water from the canal is released into the Hudson River through an outfall structure located south of IP3, which was designed to enhance mixing of cooling water and river water to minimize thermal impact to the river at a discharge velocity of approximately 10 fps through 12 discharge ports across a length of 252 feet. [IP3 UFSAR, Section 9.6.1]

3.2.2.2 Intake Structures

The location and orientation of the Indian Point intake structures are illustrated in Figures 3-1 and 3-2.

3.2.2.2.1 IP2

The IP2 circulating water intake bays are each approximately 53 feet long and are independent of adjoining bays (see Figure 3-3). The bays are approximately 13.5 feet wide from the back wall to a point approximately 11 feet from the entrance; they then taper outward to a width of almost 15 feet at the entrance. The bottoms of the intakes are located at 27 feet below MSL (Figure 3-4). The equipment decks are at elevation 15 feet above MSL. An ice curtain wall that extends one foot below mean low water (mlw) is located at the entrance to each forebay and prevents floating debris as well as ice from entering the bay. At the time the Ristroph screens were installed, new coarse, bar screens were installed. A debris barrier wall that extends to a depth of four feet below MSL was attached to the face of the bar screen frame to reduce the potential for sticks and other large, floating debris to enter the intakes. [CHGEC, Section IV.B.2.c]

IP2's two-speed circulating water pumps are designed to pump 140,000 gpm when operated at full speed and 84,000 gpm when operated at reduced speed (60% of full speed). When the pumps are operating at full flow, the intake water approach velocity is approximately one (1) fps; at reduced flow it is about 0.6 fps. [CHGEC, Section IV.B.2.c]

The circulating water intake bays at IP2 have modified vertical Ristroph-type traveling water screens (see Figures 3-3, 3-4, 3-5 and 3-9). Design features incorporated into the machines were developed and tested in concert with the Hudson River Fishermen's Association [CHGEC]. Key fish-conserving components of the screens are screen basket lip troughs designed to retain water and minimize vortex stress, a high-pressure spray wash system for debris removal from the front side of the machine, a low-pressure spray wash system for fish removal from the rear side of the machine, and a fish sluice system for collection of the impinged fish for return to the river. The 0.25-by-0.5-inch clear opening slot mesh on the screen basket panels is smooth to minimize fish abrasion across the mesh into the collection sluice. The modified traveling screens consist of a series of panels attached to an endless chain designed to rotate continuously around an upper and lower sprocket shaft system. As baskets rotate out of the intake bay, impinged fish are retained in the water-filled rails and are carried over the headshaft, where they are washed out onto the mesh. A low-pressure wash system facilitates the transfer of fish to the fish collection sluice for return to the Hudson River. [CHGEC, Section IV.B.2.c]

Fish are returned to the estuary through a 12-inch diameter pipe that extends 200 feet into the river on the north side of the IP2 intake structure. The pipe is partially buried in the river bottom, and discharges fish at a depth of 35 feet. The location of the discharge was selected after conducting dye and fish release studies to find a location that would minimize re-impingement. [CHGEC, Section IV.B.2.c]

3.2.2.2.2 IP3

The IP3 intake consists of seven bays: six for circulating water and one for service water (see Figure 3-5). The bays do not extend out to the bar racks, but are served by a common plenum 12 feet wide and 120 feet long. Nine bar racks form its walls: seven for the west wall and one each for the north and south walls. Thus, the opening of each bay is located 12 feet behind the western bar racks. The circulating water bays are approximately 13.5 feet wide over their entire length. The bottoms of the intakes are 27 feet below MSL (see Figure 3-6). The equipment deck and ice curtain wall are as described for IP2. At IP3, modified Ristroph screens are installed at the pump bay entrances from the common plenum. [CHGEC, Section IV.B.2.c.ii]

IP3 has six variable-speed circulating water pumps. Flow rates generated by these pumps range from 140,000 gpm when operated at full speed to 64,000 gpm when operated at the lowest speed (46% of full speed). When the pumps are operating at full flow, the intake water approach velocity is approximately one (1) fps; at reduced flow it is about 0.6 fps. [CHGEC, Section IV.B.2.c.ii]

The circulating water intake bays at IP3 are outfitted with modified vertical (Ristroph-type) traveling water screens. Design features incorporated into the machines were developed and tested in concert with the Hudson River Fishermen's Association [CHGEC, Section IV.B.2.c.i]. Key components of these screens are identical to those installed at IP2. A fish return system discharges at the northwest comer of the station's cooling water discharge canal (See Figure 3-9 for IP2 fish return system which is similar). [CHGEC, Section IV.B.2.c.ii]

3.2.2.2.3 IP2 and IP3 Circulating System Operations

In accordance with the terms of an October 1997 Consent Order, Entergy uses its best reasonable efforts to operate IP2 and IP3's dual/variable speed pumps so as to keep the volume of river water drawn into the plants at the minimum required for efficient operation, with due regard to ambient river water temperature, plant operating status, and the need to meet water quality standards or other permit conditions.

3.2.2.2.4 Service Water

The primary function of the service water system is to provide river water as a cooling medium to those systems or components requiring heat removal for proper functioning during normal plant operation and abnormal plant conditions, such as the maximum credible accident condition. The secondary functions of the service water system are (1) to protect certain equipment from potential contamination from river water by providing cooling to intermediate freshwater systems as required, (2) to provide water for washing the traveling screens, and (3) to provide seal water for the main circulating water pumps [CHGEC, Section IV.B.2.d].

IP2 is fitted with six identical vertical, centrifugal sump type pumps, each having a capacity of at least 5,000 gpm at 220-ft total design head (TDH) [IP2 UFSAR, Section 9.6.1.2]. IP3 has six similar pumps located at its intake structure, each rated at 6,000 gpm and 195-ft TDH. In addition, there are three back-up service water pumps located on a platform over the discharge canal at IP3. [IP3 UFSAR, Section 9.6.1]

Additional service water to the non-essential service water header for IP2 and spray wash water for the Ristroph screens at IP2 is provided through the IP1 river water intake structure. The IP1 intake (Figure 3-2) is outfitted with coarse bar screens at each of the four intake bays, which are arranged in two sets of two bays each. These were designed to provide two channels for screening water drawn in by each of the two circulating water pumps. A single 0.125-in. mesh-outfitted dual-flow screen is located within the service water portion of each of the two intake bay sets. These dual-flow screens filter water drawn in by the single 16,000-gpm river water pump and the two 1500-gpm spray wash pumps in each of the two intake bay sets. The screens are washed automatically when head differentials exceed predetermined settings. Materials removed from the mesh are sluiced to the Hudson River. During normal operation only one of the two river water pumps and two of the spray wash pumps are in operation at any given time. [CHGEC, Section IV.B.2.d]

In IP2 and IP3, the service water intake bays (one service water bay per unit) are centrally located within each of the intake structures. Six service water pumps (5000 gpm/pump at IP2, and 6,000 gpm/pump at IP3) draw water from each of these bays for the operation of heat exchange equipment, such as turbine lubricating oil coolers and systems required for the safe shutdown of each unit. Two 6-ft-wide modified Ristroph screens have been installed within the service water bays at IP2 and IP3, as shown in Figures 3-3 and 3-5. The calculated average approach velocity at the entrance to the service water bays is about 0.2 fps when all six service water pumps are operating. [CHGEC, Section IV.B.2.d]

3.2.2.3 Discharge Structures

The cooling water from the condensers at IP2 and IP3 flows downward from the discharge water boxes via six 96-inch down pipes and exits beneath the surface of the water in the discharge canal (Figure 3-7). The discharge velocity in the 40-ft-wide discharge canal is approximately 4.5 fps at full flow. The average transit time for cooling water traveling from the IP2 intake to the outfall structure (Outfall 001) is 9.7 minutes; from IP3 it is 5.6 minutes. [CHGEC, Section IV.B.2.e]

The outfall or discharge structure for the IP2 and IP3 facility is designed to enhance mixing of cooling water and river water in such a way as to minimize thermal impact in the river. It can accommodate the combined cooling water flow from both IP2 and IP3 (about 1.75 million gpm, including service water). The cooling water from the discharge channel is released to the Hudson River via an outfall structure located south of IP3. The outfall structure, depicted schematically in Figure 3-8, consists of 12 submerged rectangular ports equipped with adjustable gates that are in line and parallel to the river axis. The ports, 4 feet high by 15 feet wide and spaced 21 feet apart (center to center), are submerged to a depth of 12 feet (center to surface) at mlw. The first upstream port is approximately 600 ft from the IP3 intake; the length of the total port section is approximately 252 feet. The discharge port gates can be adjusted mechanically to maintain a minimum hydraulic head differential of 1.75 feet across the outfall structure, which assures a discharge velocity of approximately 10 fps. [CHGEC, Section IV.B.2.e]

3.2.3 Radioactive Waste Treatment Processes (Gaseous, Liquid, and Solid)

The site uses liquid, gaseous, and solid waste processing systems to collect and treat, as needed, radioactive materials that are produced as a by-product of plant operations. Radioactive materials in liquid and gaseous effluents are reduced to levels as low as reasonably achievable. Radionuclides removed from the liquid and gaseous effluents are converted to a solid waste form for eventual disposal with other solid radioactive wastes in a licensed disposal facility.

The site waste processing systems meet the design objectives of 10 CFR Part 50, Appendix I, and control the processing, disposal, and release of radioactive liquid, gaseous, and solid wastes. Radioactive material in the reactor coolant is the source of most gaseous, liquid, and solid radioactive wastes in light water reactors. Radioactive fission products build up within the fuel as a consequence of the fission process. The fission products are contained within the sealed fuel rods; however, small quantities of radioactive materials may be transferred from the fuel elements to the reactor coolant under normal operating conditions. Neutron activation of materials in the primary coolant system also contributes to radionuclides in the coolant.

Radioactive fluids entering the Waste Disposal System (WDS) are collected in tanks until determination of subsequent treatment can be made. The fluids are sampled and analyzed to determine the quantity of radioactivity, with an isotopic breakdown, if necessary. Before any discharge, the fluids are processed as required and then released under controlled conditions. The system design and operation are characteristically directed toward minimizing releases to unrestricted areas. Discharge streams are appropriately monitored and safety features are incorporated to preclude excessive releases. Liquid wastes are processed to remove most of the radioactive materials prior to release. [IP2 UFSAR, Section 11.1.1, IP3 UFSAR, Section 11.1.1]

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. [IP2 UFSAR, Section 1.3.9]

Spent resins from the demineralizers and the filter cartridges are packaged and stored on-site until shipment off-site for disposal. All solid waste is placed in suitable containers and stored onsite until shipped off-site for disposal. [IP2 UFSAR, Section 11.1.1]

Reactor fuel assemblies that have exhausted a certain percentage of their fissile uranium content are referred to as spent fuel. Spent fuel assemblies are removed from the reactor core and replaced by fresh fuel during routine refueling outages, typically every 24 months. The spent fuel assemblies are then stored for a period of time in the spent fuel pool in the fuel storage building and may later be transferred to dry storage at an onsite interim spent fuel storage installation provided necessary regulatory approvals are obtained.

Storage of radioactive materials is regulated by the NRC under the Atomic Energy Act of 1954, and storage of hazardous wastes is regulated by the U.S. Environmental Protection Agency (EPA) under the Resource Conservation and Recovery Act of 1976.

As of 2006, site preparation work for a new Independent Spent Fuel Storage Installation (ISFSI) Facility had begun on the north end of the IPEC Site in an area which was previously undeveloped and outside the existing Protected Area. The ISFSI Facility will contain a 96' x 208' concrete storage pad, which will provide storage locations for 78 Holtec International HI-STORM 100S(B) Casks. The HI STORM Casks will be arranged in a 6 x 13 array with 75 storage locations allocated for the casks. The remaining three storage locations will remain empty.

3.2.3.1 Liquid Waste Processing Systems and Effluent Controls

3.2.3.1.1 IP2

During normal plant operation the WDS processes liquids from the following sources [IP2 UFSAR, Section 11.1.2.1.2].

- equipment drains
- chemical laboratory drains
- decontamination drains
- demineralizer regeneration
- floor drains/sumps
- steam generator blowdown
- excess CVCS effluent

The reactor coolant drain tank collects and transfers liquid drained from the following sources [IP2 UFSAR, Section 11.1.2.1.1].

- reactor coolant loops
- pressurizer relief tank
- reactor coolant pump secondary seals
- excess letdown during startup
- accumulator drains
- valve and reactor vessel flange leakoffs
- refueling canal drain
- containment spray header drain lines

The valve and reactor flange leakoff liquids flow to the reactor coolant drain tank and are discharged directly to the chemical and volume control system holdup tanks by the reactor coolant drain pumps, which are designed to operate automatically by a level controller in the tank. [IP2 UFSAR, Section 11.1.2.1.1]

Since the fluid pumped by the reactor coolant drain pumps is of high quality and can be reused, the discharge of these pumps will normally be routed to the holdup tanks of the chemical and volume control system. If the fluid is considered unsuitable for reuse, it will be sent to the waste holdup tank. The discharge of the reactor coolant drain pumps can also be routed to the refueling water storage tank. This path may be used when pumping down the containment refueling canal during return from refueling operations. In the event the reactor coolant drain pumps are unavailable, the contents of the reactor coolant drain tank or the pressurizer relief tank can be dumped to the containment sump. [IP2 UFSAR, Section 11.1.2.1.1]

The waste holdup tank serves as the collection point for liquid wastes. It collects fluid directly from the following sources [IP2 UFSAR, Section 11.1.2.1.1].

- reactor coolant drain tank pumps
- containment sump pumps

- holdup tank pit sump pump
- sump tank pump (from primary auxiliary building)
- spent regenerant chemicals from demineralizers
- equipment drains
- chemical drain tank pump
- relief valve discharge from the component cooling surge tank and the chemical and volume control system holdup tanks
- waste condensate pumps
- maintenance and operation building floor drains
- primary auxiliary building sump pumps

Where plant layout permits, waste liquids drain to the waste holdup tank by gravity flow. Other waste liquids, including floor drains, drain to the sump tank or to the primary auxiliary building sump. The liquid wastes are pumped to the waste holdup tank. The liquid waste holdup tank is processed by sending its contents to the IP1 waste collection system. [IP2 UFSAR, Section 11.1.2.1.1]

Capability exists to transfer the waste holdup tank contents to the waste condensate tank. If used, sampling indicates that the liquid is suitable for discharge and the waste liquid can be pumped from the waste holdup tank to the waste condensate tanks. There its activity can be determined for recording by isolation sampling and analyzing before it would be discharged through the radiation monitor to the condenser circulating water. [IP2 UFSAR, Section 11.1.2.1.1]

The IP1 waste collection system has four tanks with a capacity of 75,000 gallons each. From there the liquid can also be processed by use of sluiceable demineralizer vessels. [IP2 UFSAR, Section 11.1.2.1.1]

A portable demineralization system is being used in the IP1 Chemical System Building. The system employs a number of in-line ion exchanger resin beds and filters to remove radionuclides and chemicals as required from the waste stream. The demineralization/filtration system processes liquid waste from the IP1 waste collection tanks and discharges the clean water to the distillate storage tanks. [IP2 UFSAR, Section 11.1.2.1.1]

Spent resins from the portable system are sluiced from the vessels into a high integrity container, which is dewatered and then transported to the burial site without solidification. [IP2 UFSAR, Section 11.1.2.1.1]

Spent filters can also be placed in the high integrity container. The distillate produced by the demineralizer water processing is collected in two distillate storage tanks. Each storage tank is vented to the IP1 ventilation system. Normally one tank is filling while the other is sampled and discharged. When a distillate storage tank is ready for discharge, it is isolated and sampled to determine the allowable release rate. If the contents of the tank are not suitable for release, they are returned to waste collection tanks for reprocessing. If analysis confirms that the activity level is suitable for release, the distillate is discharged to the river. A radiation detector and high radiation trip valve are provided in the release line to prevent an inadvertent release of activity at concentrations in excess of the setpoint derived from the technical specifications. In the event of primary-to secondary coolant leakage, the affected steam generator blowdown can be manually diverted to the support facilities secondary boiler blowdown purification system flash tank. [IP2 UFSAR, Section 11.1.2.1.1]

This system cools the blowdown and either stores it in the support facilities waste collection tanks or purifies it. The purification process consists of filtering and demineralizing the blowdown. The filters will remove undissolved material of 25 microns or greater. Mixed bed demineralizers, which utilize cation and anion resin, remove isotopic cations and anions, as well as nonradioactive chemical species. The effluents of the demineralizers are monitored and the specific activity is recorded. [IP2 UFSAR, Section 11.1.2.1.1] IP2's UFSAR Section 10.2.1 provides further discussion of the steam generator blowdown.

Also, in the event of primary-to-secondary leakage, potentially contaminated water that collects in secondary-side drains may be collected and routed to a collection point in the auxiliary boiler feedwater building for eventual processing. The path is an alternative to the normally used path to the drains collection tank. [IP2 UFSAR, Section 11.1.2.1.1]

3.2.3.1.2 IP3

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 (Nos. 32 and 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. [IP3 UFSAR, Section 11.1.2.1]

The liquid radwaste storage facility, which houses waste holdup tanks No. 32 and No. 33, is an underground concrete structure 75' 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 insures that in a seismic event both structures will react independently. [IP3 UFSAR, Section 11.1.2.1]

The building is supported on hard rock. The foundation consists of a rigid 2-inch thick slab which is waterproofed. The waterproof membrane is laid upon a 4-inch concrete base. A 2-inch protection of concrete is placed over the waterproofing. The walls of the building, also waterproofed, consist of reinforced concrete. The 3-inch thick reinforced concrete roof was poured on a steel deck and beam system. [IP3 UFSAR, Section 11.1.2.1]

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. [IP3 UFSAR, Section 11.1.2.1]

During normal plant operation the IP3 WDS processes liquids from the following sources [IP3 UFSAR, Section 11.1.2.1].

- equipment drains and leaks
- radioactive chemical laboratory drains
- decontamination drains
- demineralizer regeneration
- floor drains

The system also collects and transfers liquid drained from the following sources directly to the Chemical and Volume Control System (CVCS) for processing [IP3 UFSAR, Section 11.1.2.1].

- reactor coolant loops
- pressurizer relief tank
- reactor coolant pump secondary seals
- excess letdown during startup
- accumulators
- valve and reactor vessel flange leakoffs

The valve and reactor flange leakoff liquids flow to the reactor coolant drain tank (RCDT). The RCDT water can drain directly to the containment sump or can be discharged directly to the CVCS holdup tanks by the RCDT pumps. These pumps also return water from the refueling canal and cavity to the refueling water storage tank (RWST). 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 RWST. [IP3 UFSAR, Section 11.1.2.1]

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. [IP3 UFSAR, Section 11.1.2.1]

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 CVCS. 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. [IP3 UFSAR, Section 11.1.2.1]

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. [IP3 UFSAR, Section 11.1.2.1]

Liquids in the holdup tanks not suitable for discharge are processed through the liquid radwaste processing system skid. [IP3 UFSAR, Section 11.1.2.1]

3.2.3.1.3 IP2 and IP3 Liquid Effluent Releases

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 which is approximately five gallons. One sample of inlet water and one sample of discharge water are taken, at a frequency specified by the Offsite Dose Calculation Manual (ODCM), 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. [IP3 UFSAR, Section 11.1.2.1]

The liquid waste processing systems for IP2 were discussed in Section 3.2.3.1. Where IP2 plant layout permits, waste liquids drain to the waste holdup tank by gravity flow. Other IP2 waste liquids, including floor drains, drain to the IP2 sump tank or to the primary auxiliary building sump. The IP2 liquid wastes are pumped to the IP2 waste holdup tank. The liquid waste holdup tank is processed by sending its contents to the IP1 waste collection system. [IP2 UFSAR, Section 11.1.2.1]

The IP1 waste collection system has four tanks with a capacity of 75,000 gal each. From there the liquid can also be processed by use of sluiceable demineralizer vessels. A portable demineralization system is being used in the IP1 Chemical System Building. The system employs a number of in-line ion exchanger resin beds and filters to remove radionuclides and chemicals as required from the waste stream. The demineralization/filtration system processes liquid waste from the IP1 waste collection tanks and discharges the clean water to the distillate storage tanks. The distillate produced by the demineralizer water processing is collected in two distillate storage tanks. Each storage tank is vented to the IP1 ventilation system. Normally one tank is filling while the other is sampled and discharged. When a distillate storage tank is ready for discharge, it is isolated and sampled to determine the allowable release rate. If the contents of the tank are not suitable for release, they are returned to waste collection tanks for reprocessing. If analysis confirms that the activity level is suitable for release, the distillate is discharged to the river. [IP2 UFSAR, Section 11.1.2.1.1]

IP3 liquid waste processing systems were also discussed in Section 3.2.3.1. Where IP3 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. 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. [IP3 UFSAR, Section 11.1.2.1].

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. [IP3 UFSAR, Section 11.1.2.1]

Controls for limiting the release of radiological liquid effluents are described in the ODCM. Controls are based on (1) concentrations of radioactive materials in liquid effluents and projected dose or (2) dose commitment to a hypothetical member of the public. Concentrations of radioactive material that may be released in liquid effluents to unrestricted areas are limited to the concentration specified by 10 CFR Part 20 for radionuclides other than dissolved or entrained noble gases. The total concentration of dissolved or entrained noble gases in liquid releases is limited to 2×10^{-4} microcurie/ml [ENN 2007a, Section D 3.1.1; ENN 2007b, Section 2.3.1]. The ODCM dose limits during a calendar quarter are 0.015 mSv (1.5 mrem) to the total body and 0.05 mSv (5 mrem) to any organ [ENN 2007a, Section D 3.1.2; ENN 2007b, Section 2.3.2]. During the calendar year, the ODCM dose limits are 0.03 mSv (3 mrem) to the total body and 0.10 mSv (10 mrem) to any organ [ENN 2007a, Section D 3.1.2; ENN 2007b, Section 2.3.2]. Radioactive liquid wastes are subject to the sampling and analysis program described in the ODCM.

3.2.3.2 Gaseous Waste Processing Systems and Effluent Controls

3.2.3.2.1 IP2

During plant operations, gaseous waste will originate from the following sources [IP2 UFSAR, Section 11.1.2.1.2].

- degassing the reactor coolant and purging the volume control tank
- displacement of cover gases as liquid accumulates in various tanks
- equipment purging
- sampling operations and automatic gas analysis for hydrogen and oxygen in cover gases

During normal operation, the WDS supplies nitrogen and hydrogen to primary plant components. Two headers are provided, one for operation and one for backup. The pressure regulator in the operating header is set for 110 psig discharge and that in the backup header for 90 psig. When the operating header is exhausted, its discharge pressure will fall below 100 psig and an alarm will alert the operator. The second tank will come into service automatically at 90 psig to ensure a continuous supply of gas. After the exhausted header has been replaced, the operator manually sets the operating pressure back to 110 psig and the backup pressure at 90 psig. This operation is identical for both the nitrogen supply and the hydrogen supply. [IP2 UFSAR, Section 11.1.2.1.2]

Most of the gas received by the WDS 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 2.0 psig maximum) to prevent in-leakage. On the other hand, outleakage from the system is minimized by using Saunders patent diaphragm valves, bellows seals, self-contained pressure regulators, and soft-seated packless valves throughout the radioactive portions of the system. [IP2 UFSAR, Section 11.1.2.1.2]

Gases vented to the vent header flow to the waste gas compressor suction header. One of the two compressors is in continuous operation with the second unit instrumented to act as backup for peak load conditions. From the compressors, gas flows to one of the four large gas decay tanks. The control arrangement on the gas decay tank inlet header allows the operator to place one large tank in service and to select a second large tank for backup. When the tank in service becomes pressurized to a predetermined pressure, a pressure transmitter automatically opens the inlet valve to the backup tank, closes the inlet valve to the filled tank, and sounds an alarm to alert the operator of this event so that he may select a new backup tank. Pressure indicators are supplied to aid the operator in selecting the backup tank. Gas held in the decay tanks can either be returned to the chemical and volume control system holdup tanks, or discharged to the atmosphere if the activity concentration is suitable for release. Generally, the last tank to receive gas will be the first tank emptied back to the holdup tanks in order to permit the maximum decay time for the other tanks before releasing gas to the environment. However, the header arrangement at the tank inlet gives the operator freedom to fill, reuse, or discharge gas to the environment simultaneously without restriction by operation of the other tanks. [IP2 UFSAR, Section 11.1.2.1.2]

Six additional small gas decay tanks are supplied for use during degassing of the reactor coolant prior to a cold shutdown. The reactor coolant fission gas activity inventory is distributed equally among the six tanks through a common inlet header. A radiation monitor in the sample line to the gas analyzer checks the gas decay tank activity inventory each time a sample is taken for hydrogen-oxygen analysis. An alarm warns the operator when the inventory limit is approached so that another tank may be placed in service. [IP2 UFSAR, Section 11.1.2.1.2]

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. [IP2 UFSAR, Section 11.1.2.1.2]

During release, a trip valve in the discharge line is closed automatically by a high activity level indication in the plant vent. During operation, gas samples are drawn periodically from tanks discharging to the waste gas vent header, as well as from the particular large gas decay tank being filled at the time, and automatically analyzed to determine their hydrogen and oxygen content. The hydrogen analysis is for surveillance since the concentration range will vary considerably from tank to tank. There should be no significant oxygen content in any of the tanks, and an alarm will warn the operator if any sample shows 2% by volume of oxygen. This allows time to isolate the tank before the combustible limit is reached. Another tank is placed in service while the operator locates and eliminates the source of oxygen. Discharged gases are released from the plant vent and diluted in the atmosphere due to the turbulence in the wake of the containment building in addition to the effects of normal dispersion. [IP2 UFSAR, Section 11.1.2.1.2]

3.2.3.2.2 IP3

During plant operations, gaseous wastes originate from the following sources.

- degassing reactor coolant and purging the volume control tank
- displacement of cover gases as liquid accumulates in various tank
- equipment purging
- sampling operations and automatic gas analysis for hydrogen and oxygen in cover gases
- venting of actuating nitrogen for pressure control valves

During normal operation, the WDS 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. [IP3 UFSAR, Section 11.1.2.1]

During normal operation, the WDS supplies primary plant components with nitrogen for various process functions. This system is identified as nitrogen to nuclear equipment (NNE). These process functions include cover gas, calibration gas, purge gas, and gas required for operation of level instrumentation. The only safety function of the NNE is providing high pressure charging gas for operation of the safety injection accumulators and power operated relief valves. [IP3 UFSAR, Section 11.1.2.1]

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 any time 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 system 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 directly through a common manifold and then either through a redundant backup regulator which reduces pressure for low-pressure gas services or through a redundant bypass for high pressure gas services. [IP3 UFSAR, Section 11.1.2.1]

The use of either supply source for nitrogen is acceptable and controlled by administrative procedures. 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 back-up 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. [IP3 UFSAR, Section 11.1.2.1]

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. [IP3 UFSAR, Section 11.1.2.1]

Most of the gas received by the WDS during normal operation is cover gas displaced from the CVCS 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. [IP3 UFSAR, Section 11.1.2.1]

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 WDS. One of the two compressors is in continuous operation with the second unit instrumented to act as backup for peak load conditions. From the compressors, gas flows to one of the four large gas decay tanks. The control arrangement on the gas decay tank inlet header allows the operator to place one large tank in service and to select a second large tank for backup. When the tank in service becomes pressurized to 110 psig, a pressure transmitter automatically opens the inlet valve to the backup tank, closes the inlet valve to the filled tank, and sounds an alarm to alert the operator of this event so that he may select a new backup tank. Pressure indicators are supplied to aid the operator in selecting the backup tank. [IP3 UFSAR, Section 11.1.2.1]

Gas held in the decay tanks can either be returned to the CVCS 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. [IP3 UFSAR, Section 11.1.2.1]

Six additional small gas decay tanks are supplied for use during degassing of the reactor coolant prior to a cold shutdown. The reactor coolant fission gas activity inventory is distributed equally among the six tanks through a common inlet header. With this arrangement, assuming one percent defective fuel rods, the activity inventory in any one tank will be less than 2.0×10^4 curies of equivalent Xe-133. [IP3 UFSAR, Section 11.1.2.1]

The total radioactivity content of any given gas decay tank is limited by the ODCM 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 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. [IP3 UFSAR, Section 11.1.2.1]

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. [IP3 UFSAR, Section 11.1.2.1]

During operation, gas samples are drawn periodically from tanks discharging to the waste gas vent header, as well as from the particular large gas decay tank being filled at the time, and automatically analyzed to determine their hydrogen and oxygen content. The hydrogen analysis is for surveillance since the concentration range will vary considerably from tank to tank. There should be no significant oxygen content in any of the tanks, and an alarm will warn the operator if any sample shows 2% by volume of oxygen. This allows time to isolate the tank before the combustible limit is reached. Another tank is placed in service while the operator locates and eliminates the source of oxygen. Discharged gases are released from the plant vent and diluted in the atmosphere due to the turbulence in the wake of the containment building in addition to the effects of normal dispersion. [IP3 UFSAR, Section 11.1.2.1]

When the reactor is in cold shutdown, the RCS (reactor coolant system) 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 WDS. [IP3 UFSAR, Section 11.1.2.1]

A gas and particulate monitor is attached to the plant vent stack to analyze the amount of radiation contained in the gas effluent. [IP3 UFSAR, Section 11.1.2.1]

3.2.3.2.3 IP2 and IP3 Gaseous Effluent Releases

The site maintains gaseous releases within ODCM limits. The gaseous radwaste system is used to reduce radioactive materials in gaseous effluents before discharge to meet the dose design objectives in 10 CFR Part 50, Appendix I. In addition, the limits in the ODCM are designed to provide reasonable assurance that radioactive material discharged in gaseous effluents would not result in the exposure of a member of the public in an unrestricted area in excess of the limits specified in 10 CFR Part 20, Appendix B. The quantities of gaseous effluents released from the site are controlled by the administrative limits defined in the ODCM. The controls are specified for dose rate, dose due to noble gases, and dose due to radioiodine and radionuclides in particulate form. For noble gases, the dose rate limit at or beyond the site boundary is 5 mSv/yr (500 mrem/yr) to the total body, and 30 mSv/yr (3,000 mrem/yr) to the skin [ENN 2007a, Section D 3.2; ENN 2007b, Section 2.4.1]. For iodine and particulates with half-lives greater than 8 days, the limit is 15 mSv/yr (1,500 mrem/yr) to an organ [ENN 2007a, Section D 3.2.1; ENN 2007b, Section 2.4.1]. The limit for air dose due to noble gases released in gaseous effluents to areas at or beyond the site boundary during a calendar quarter is 0.05 milligray (5 mrad) for gamma radiation and 0.1 mGy (10 mrad) for beta radiation [ENN 2007a, Section D 3.2.2; ENN 2007b, Section 2.4.2]. For a calendar year, the limit is 0.1 mGy (10 mrad) for gamma radiation and 0.2 mGy (20 mrad) for beta radiation [ENN 2007a, Section D 3.2.2; ENN 2007b, Section 2.4.2]. The radioactive gaseous waste sampling and analysis program specifications provided in the ODCM address the gaseous release type, sampling frequency, minimum analysis frequency, type of activity analysis, and lower limit of detection.

3.2.3.3 Solid Waste Processing

Solid wastes consist of solidified waste liquid concentrates and sludges, spent resins and filters, and miscellaneous materials such as paper and glassware. Resin is normally stored in the spent resin storage tank for decay. Accumulated resin then moves from the storage to a high integrity container, which is dewatered and prepared for transportation in accordance with the process control program. Spent filters can be placed in the high integrity containers.

Miscellaneous solid waste such as paper, rags, and glassware are processed in accordance with the process control program. When possible, solid waste is sent to a licensed incineration and volume reduction center, or to a material recovery center. This process is controlled by the process control program.

3.2.3.3.1 IP2 Facilities

The original steam generator storage facility (OSGSF) for IP2 is designed to contain contaminated materials and facilitate decontamination should such an action become necessary. Waterstops are used at all construction joints to prevent both the intrusion of water into the facility and the escape of contaminated water from the facility. The floor of the facility is sloped to provide adequate drainage to a sump. Protective coatings are applied to the floor slab and lower portion of the walls to ease decontamination, if required. A passive HEPA filter system is provided to allow venting of the OSGSF while containing any airborne contamination.

The OSGSF is a reinforced concrete structure measuring approximately 150 feet by 54 feet (not including the labyrinth entryways) and located on the eastern side of the plant, between Electrical Tower 3 and the Buchanan Service Center access road. This location is within the Owner Controlled Area outside the Protected Area.

This structure is constructed of cast-in-place concrete with a single-ply membrane roofing system. The walls of the OSGSF are 3'-0" thick and the roof tapers from 2'-6" in the center of the building to 2'-0" at the east and west walls. The slab is 3'-0" thick with a thickened perimeter that is 5'-0" thick. Personnel access doors with labyrinth entryways are provided at each end of the building to prevent radiation streaming through the door. The walls of the labyrinth entryway are 3'-0" thick with the roof over the labyrinth entryway tapered from 1'-2" to 1'-0". Two locked steel doors in each entryway provide access to the building after the pre-cast concrete blocks were put in place, one in the exterior wall opening and one in the labyrinth wall. Two locked steel doors secure the building and a security fence is installed around the perimeter of the facility. [IP2 UFSAR, Section 11.1.2.1.3]

IP1 contains radioactive waste processing facilities which provide waste processing services for both IP1 and IP2.

Sandblasters are available to remove fixed radioactivity from non-compressible items such as gas bottles, I-beams, angle irons, steel plates, and various tools and equipment. A very low volume of contaminated sand (grit) is being generated. This sand is used to fill voids in non-compactable waste containers. To further reduce solid waste volumes, a liquid abrasive bead decontamination unit, an ultrasonic unit, and a solvent degreaser unit were installed in 1985 to remove loose and fixed contamination from equipment. This equipment can then be reused in the controlled area or released for uncontrolled use. Also, offsite supercompaction and licensed incineration methods are available and used to reduce total burial volumes. [IP2 UFSAR, Section 11.1.3.3]

3.2.3.3.2 IP3 Facilities

Solid radioactive wastes in the form of dry activated waste (DAW) or solidified (or dewatered) resins may be stored in the IP3 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 of 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. [IP3 UFSAR, Section 11.1.1]

The four steam generators originally installed in IP3 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 IP3 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 IP3 is decommissioned. [IP3 UFSAR, Section 11.1.1]

3.2.4 Transportation of Radioactive Materials

All solid waste is placed in suitable containers and stored on-site until shipped off-site for disposal. Monitoring and alarm instrumentation are provided for fuel and waste storage and handling areas to detect inadequate cooling and excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release operation, but the permanent record of activity releases is provided by radiochemical analysis of known quantities of waste. [IP2 UFSAR, Section 11.2.1.2]

Site radioactive waste shipments are packaged in accordance with NRC and Department of Transportation (DOT) requirements. The type and quantities of solid radioactive waste generated at and shipped from the site vary from year to year, depending on plant activities. The site currently transports radioactive waste to the Studsvic facility in Irwin, Tennessee, the Race facility in Memphis, Tennessee, or the Duratek facility in Oak Ridge, Tennessee, where the wastes are further processed prior to being sent to the Barnwell facility in Barnwell County, South Carolina, or the Envirocare facility in Clive, Utah.

3.2.5 Nonradioactive Waste Systems

Nonradioactive waste is produced from plant maintenance, cleaning and operational processes. The majority of the wastes generated consists of nonhazardous waste oil and oily debris and result from operation and maintenance of oil-filled equipment. Universal wastes, such as spent fluorescent bulbs and batteries common to any industrial facility, comprise a majority of the remaining waste volumes generated. Hazardous wastes routinely make up a small percentage of the total wastes generated, and include and consist of spent and off-specification (e.g., shelf-life expired) chemicals, laboratory chemical wastes, and occasional project specific wastes such as that generated as a result of repair work to a bulk acid storage tank.

Some amount of chemical and biocide wastes are produced from processes used to control the pH in the coolant, to control scale, to control corrosion, to regenerate resins, and to clean and de-foul the condenser. These waste liquids are typically combined with cooling water discharges in accordance with the sites SPDES Permit NY-0004472.

Nonradioactive chemicals, paint, oil, fluorescent lamps, and other items that have either been used or exceeded their useful shelf-life are collected in central collection areas and managed in accordance with Entergy Nuclear fleet procedure EN-EV-106 (Waste Management Program). The materials are received in various forms and are packaged to meet all regulatory requirements prior to final disposition at an offsite facility licensed to receive and mange the material. Typical waste streams tracked by quantities at the facility, as shown in Table 3-1, include waste oil, oily debris, glycol, lighting ballasts containing polychlorinated biphenyls, fluorescent lamps, batteries, and hazardous wastes (i.e., paints, lead abatement waste, broken lamps, off-specification and expired chemicals).

Programs that have been implemented at the facility to reduce waste generation are described in Entergy Nuclear's Waste Minimization Plan. This Plan, which also identifies waste streams (current and potential) generated at the facility, is used in conjunction with nuclear fleet procedures associated with waste minimization (EN-EV-104, Waste Minimization), waste management (EN-EV-106, Waste Management Program), chemical control (EN-EV-112, Chemical Control Program), and other site-specific procedures to minimize waste generation to the maximum extent practicable. [Entergy 2004; Entergy 2006a; Entergy 2006b]

Sanitary wastewater from all plant locations is transferred to the Village of Buchanan publicly owned treatment works (POTW) system where it is managed appropriately, except for a few isolated areas which have their own septic tanks which are pumped out by a septic company, as needed, and taken to an offsite facility for appropriate management. Although the sanitary wastewaters are nonradioactive, a radiation monitoring system is provided to continuously monitor the effluent from the protected area.

Nonradioactive gaseous effluents result primarily from testing of the emergency generators and boiler operations. Discharge of regulated pollutants is minimized by limiting fuel usage and hours of operation in accordance with IP2 and IP3 air quality permits, 3-5522-00011/00026 and 3-5522-00105/00009, respectively.

Table 3-1
Nonradioactive Waste Generation (Typical)

Waste Stream	2003	2004	2005	2006
Waste Oil	449,000	171,174	144,436	110,240
Oily Debris	18,900	13,600	11,000	11,200
Glycol	3,120	8,960	18,840	4,800
PCBs (Lighting Ballasts)	600	200	180	400
Universal Waste Lamps	6,390	5,602	7,001	8,671
Universal Waste Batteries	39,697	14,716	3,335	11,870
IP2 Hazardous Waste	1,283	1,040	778	10,722[1]
IP3 Hazardous Waste	1,787	323	13,072[2]	84

1. Increased generation due to dispositions of expired and off-specification chemicals.
2. Increased generation affected by disposition of sulfuric acid sludge and off-specification sulfuric acid from a tank undergoing repairs.

3.2.6 Maintenance, Inspection and Refueling Activities

Various programs and activities currently at the site maintain, inspect, test, and monitor the performance of plant equipment. These programs and activities include, but are not limited to, those implemented to

- meet the requirements of 10 CFR Part 50, Appendix B (Quality Assurance), Appendix R (Fire Protection), Appendices G and H, Reactor Vessel Materials;
- meet the requirements of 10 CFR 50.55a, American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, In-service Inspection and Testing Requirements;
- meet the requirements of 10 CFR 50.65, the maintenance rule, and
- maintain water chemistry in accordance with EPRI guidelines.

Additional programs include those implemented to meet Technical Specification surveillance requirements, those implemented in response to NRC generic communications, and various periodic maintenance, testing, and inspection procedures necessary to manage the effects of aging on structures and components. Certain program activities are performed during the operation of the units, while others are performed during scheduled refueling outages.

3.2.7 Power Transmission Systems

The Consolidated Edison Company (ConEdison) transmission system provides two basic functions for the site: 1) it provides auxiliary power as needed for startup and normal shutdown and 2) it transmits the output power generated by IP2 and IP3. Each unit has two main transformers that increase turbine generator output from 22-kV to 345-kV. Power is delivered to the ConEdison transmission grid via two double-circuit 345-kV lines that connect the IP2 and IP3 main transformers to the Buchanan substation located across Broadway near the main entrance to the Indian Point facility. The IP2 line is referred to as feeder W95 and the IP3 line as feeder W96. Except for the point where they cross over Broadway, the lines are located within the site boundary, are approximately 2,000 feet in length, and were constructed using tubular-steel transmission poles. In addition to the two double-circuit 345-KV lines, the poles also carry 138-kV transmission lines that supply offsite power from the Buchanan substation into IP2 and IP3 (NRC, page IV-3). These lines are referred to as 95332 and 95331, respectively. The poles also carried the 138-kV output (line 95191) from IP1 before the line was retired in 1973.

The Buchanan Substation has two ring buses designated as North and South. The South ring bus distributes IP3 345-kV output to three 345-kV transmission lines. The Millwood East (W97) and Millwood West (W98) lines both interconnect to the Millwood Substation with ties to Pleasant Valley Substation, which is the interconnection point between ConEdison and Niagara Mohawk and Connecticut Light and Power System. The third line (Y88) crosses the Hudson River to the Ladentown Substation where it interconnects with the Pennsylvania-New Jersey-Maryland (PJM) system. The North ring bus at the Buchanan substation distributes output from IP2 to 345-kV lines that connect to the Ramapo Substation (W94) and Eastview Substation (W93). The North ring bus also supplies power through a step-down transformer to the Buchanan 138-kV system (IP3 UFSAR, Section 8.2.1; IP2 UFSAR, Sections 8.1.2 and 8.2.1).

When IP2 and IP3 (and IP1) were constructed, power was transmitted beyond the Buchanan substation on existing transmission facilities (NRC, page III-3). However, the addition of transmission line segments beyond the Buchanan substation was briefly addressed in the FESs for both units (USAEC, page III-3; NRC, page IV-3). The IP2 FES noted the addition of two new lines within an existing 9.5-mile long right-of-way between the Buchanan and the Millwood substations. The voltage and purpose of the two additional lines were not addressed. Nevertheless, the AEC staff concluded that because these lines were added to existing structures within an existing right-of-way no adverse environmental impact would occur. The IP3 FES stated that power would be transmitted beyond Buchanan on existing transmission facilities, and the staff concluded that no additional impact would occur as a result of IP3 because these transmission lines had existed for several decades.

ConEdison serves electric customers throughout the five boroughs of New York City; Westchester, Orange, and Rockland Counties; and parts of New Jersey and Pennsylvania. ConEdison has bulk-power transmission interconnections with other electric power companies in the New York Power Pool and the PJM system. During the period when IP2 and IP3 were constructed, ConEdison was actively adding new generating sources and expanding the regional transmission network to provide more electric power to the metropolitan New York area. Several new transmission lines were added and the voltage of some existing lines was increased. Both the Buchanan substation and the interconnecting 138-kV and 345-kV transmission lines are part of a regional system that was planned, designed, and constructed independent of their connections with IP2 and IP3 (Con Edison). Con Edison has concluded that other than lines W95 and W96 that connect IP2 and IP3 to the Buchanan substation, no other transmission systems were specifically constructed to connect these units to the transmission grid.

3.3 Refurbishment Activities

10 CFR 51.53(c)(2) requires that a license renewal applicant's environmental report contain a description of the proposed action, including the applicant's plans to modify the facility or its administrative control procedures as described in accordance with Section 54.21 of this chapter. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment.

The objective of the review required by 10 CFR 54.21 is to determine whether the detrimental effects of aging could preclude certain systems, structures, and components from performing in accordance with the current licensing basis, during the additional 20 years of operation requested in the license renewal application.

The evaluation of structures and components as required by 10 CFR 54.21 has been completed and is described in the body of the IP2 and IP3 License Renewal Application. This evaluation did not identify the need for refurbishment of structures or components for purposes of license renewal and there are no such refurbishment activities planned at this time. Although routine plant operational and maintenance activities will be performed during the license renewal period, these activities are not refurbishments as described in Sections 2.4 and 3.1 of the GEIS and will be managed in accordance with appropriate Entergy programs and procedures.

3.4 Programs and Activities for Managing the Effects of Aging

The programs for managing the effects of aging structures and components at the site are described in the body of the license renewal application (see Appendix B of the IP2 and IP3 License Renewal Application). The evaluation of structures and components required by 10 CFR 54.21 identified some new activities necessary to continue operation of the site during the additional 20 years beyond the initial license term. These activities are described in the body of the license renewal application. The additional inspection activities are consistent with normal plant component inspections and therefore are not expected to cause significant environmental impact. The majority of the aging management programs are existing programs, some requiring modest modifications.

3.5 Employment

The non-outage work force at the site consists of approximately 1,255 persons (as of June 2006) (see Table 3-2). During refueling outages there are typically an additional 950 contractor employees on site. Refueling outages occur every 24 months for each unit, which results in an outage each year for one unit or the other. Entergy has no plans to add non-outage employees to support plant operations during the extended license period.

Refueling and maintenance outages typically last approximately 30 days. The number of workers required on-site for normal plant outages during the period of extended operation is expected to be consistent with the number of additional workers used for past outages at the site, which is approximately 950 temporary workers.

Table 3-2
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
Bronx County (New York)	**9**
Bronx	9
Columbia County (New York)	**4**
Copake	1
Copake Falls	1
Elizaville	1
Kinderhook	1

Table 3-2 (Continued)
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
Dutchess County (New York)	**528**
Beacon	58
Chelsea	2
Dover Plains	2
Fishkill	63
Glenham	2
Holmes	1
Hopewell Junction	86
Hughsonville	1
Hyde Park	7
La Grangeville	16
Millbrook	2
New Hamburg	1
Pawling	1
Pine Plains	2
Pleasant Valley	6
Poughkeepsie	92
Poughquag	16
Red Hook	2
Rhinebeck	1
Salt Point	3
Slate Hill	2
Staatsburg	3
Stormville	12
Tivoli	2
Verbank	1

Table 3-2 (Continued)
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
Wappinger Falls	142
Wingdale	2
Greene County (New York)	**1**
Catskill	1
Kings County (New York)	**6**
Brooklyn	6
Monroe County (New York)	**1**
Rochester	1
Nassau County (New York)	**12**
Baldwin	1
Bethpage	1
Garden City	1
Greenvale	1
Hicksville	1
Jericho	1
Lynbrook	1
Massapequa	2
New Hyde Park	2
Port Washington	1
New York County (New York)	**3**
New York	3
Orange County (New York)	**243**
Circleville	2
Cornwall	14
Cornwall on Hudson	4
Ft Montgomery	1

**Table 3-2 (Continued)
Employee Residence Information (June 2006)**

County, State, and City	Employees (Entergy and Baseline Contractors)
Goshen	5
Hamptonburgh	1
Harriman	3
Highland	18
Highland Falls	7
Highland Mills	3
Maybrook	3
Middletown	23
Monroe	12
Montgomery	13
Mountainville	1
New Hampton	2
New Windsor	17
Newburgh	42
Otisville	1
Pine Bush	7
Port Jervis	3
Rock Tavern	1
Salisbury Mills	2
Sparrowbush	1
Thompson Ridge	2
Unionville	2
Walden	20
Walkill	19
Warwick	5
Washingtonville	9

Table 3-2 (Continued)
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
Putnam County (New York)	**78**
Brewster	5
Carmel	13
Cold Spring	11
Garrison	9
Kent Lakes	1
Lake Peekskill	5
Mahopac	15
Nelsonville	1
Patterson	4
Putnam Valley	14
Queens County (New York)	**13**
Bayside	1
Bellerose	1
Flushing	1
Fresh Meadows	1
Jamaica	1
Kew Gardens	2
Queens Village	1
Richmond Hill	1
South Ozone Park	1
Springfield Gardens	1
Sunnyside	1
Whitestone	1
Rockland County (New York)	**28**
Garnerville	1

Table 3-2 (Continued)
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
Montebello	1
Nanuet	1
New City	8
New Hempstead	1
Nyack	2
Palisades	1
Pearl River	2
Spring Valley	1
Stoney Point	5
Suffern	1
Thiells	1
West Haverstraw	2
West Nyack	1
Saratoga County (New York)	**1**
Saratoga Springs	1
Schenectady County (New York)	**1**
Schenectady	1
Steuben County (New York)	**7**
Campbell Hall	5
Greenwood Lake	2
Suffolk County (New York)	**3**
Bayshore	1
Hauppauge	1
Nesconset	1
Sullivan County (New York)	**15**
Bloomingburg	3

Table 3-2 (Continued)
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
Grahamsville	2
Liberty	1
Monticello	1
Mountaindale	1
Roscoe	1
Summitville	1
Tomkins Cove	2
Wurtsboro	3
Ulster County (New York)	**31**
Accord	2
Clintondale	4
Gardiner	3
Kerhonkson	1
Kingston	2
Marlboro	5
Milton	5
New Paltz	4
Port Ewen	1
Saugerties	2
Spring Glen	1
West Hurley	1
Westchester County (New York)	**206**
Baldwin Place	4
Briarcliff Manor	3
Bronxville	1
Buchanan	20

**Table 3-2 (Continued)
Employee Residence Information (June 2006)**

County, State, and City	Employees (Entergy and Baseline Contractors)
Chester	2
Cortlandt Manor	28
Crompond	2
Croton on Hudson	7
Crugers	1
Dobbs Ferry	2
Eastchester	1
Elmsford	1
Goldens Bridge	1
Millwood	1
Mohegan Lake	3
Montrose	6
Mount Vernon	1
New Rochelle	3
Ossining	9
Peekskill	48
Pelham	1
Pleasantville	1
Port Chester	1
Scarsdale	3
Shrub Oak	4
Sleepy Hollow	1
Somers	3
Tarrytown	1
Valhalla	1
Verplanck	17

Table 3-2 (Continued)
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
White Plains	7
Yonkers	9
Yorktown	2
Yorktown Heights	11
Cobb County (Georgia)	**1**
Marrietta	1
Fulton County (Georgia)	**1**
Atlanta	1
Fairfield County (Connecticut)	**11**
Bethel	1
Danbury	4
Greenwich	2
Newtown	1
Norwalk	1
Ridgefield	1
Stanford	1
Hartfield County (Connecticut)	**1**
Windsor Locks	1
Litchfield County (Connecticut)	**1**
New Milford	1
New Haven County (Connecticut)	**1**
Southbury	1
New London County (Connecticut)	**2**
Waterford	2
New Castle County (Delaware)	**1**
New Castle	1

Table 3-2 (Continued)
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
Martin County (Florida)	**1**
Stuart	1
Montgomery County (Maryland)	**1**
Silver Spring	1
Cheshire County (New Hampshire)	**1**
Hinsdale	1
Bergen County (New Jersey)	**17**
Allendale	1
Fort Lee	1
Franklin Lakes	1
Hasbrouck Heights	1
Haworth	1
Ho Ho Kus	1
Lodi	1
Mahwah	2
New Milford	1
North Vale	1
Paramus	1
Park Ridge	1
Teaneck	1
Waldwick	1
Westwood	1
Wyckoff	1
Essex County (New Jersey)	**3**
Cedar Grove	1
Newark	1

Table 3-2 (Continued)
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
Upper Montclair	1
Gloucester County (New Jersey)	**1**
Mantua	1
Hunterdon County (New Jersey)	**1**
Califon	1
Middlesex County (New Jersey)	**3**
East Brunswick	1
Edison	2
Morris County (New Jersey)	**3**
Flanders	1
Lincoln Park	2
Ocean County (New Jersey)	**2**
Forked River	1
Lavallette	1
Passaic County (New Jersey)	**4**
Clifton	2
Ringwood	1
Wayne	1
Sussex County (New Jersey)	**1**
Montague	1
Luzerne County (Pennsylvania)	**1**
Drums	1
Pike County (Pennsylvania)	**2**
Milford	2
Wayne County (Pennsylvania)	**4**
Honesdale	2

Table 3-2 (Continued)
Employee Residence Information (June 2006)

County, State, and City	Employees (Entergy and Baseline Contractors)
Lords Valley	2
Harris County (Texas)	**1**
Houston	1
TOTAL	**1255**

3.6 References

CHGEC (Central Hudson Gas and Electric Corporation) Consolidated Edison Company of New York, Inc., New York Power Authority, and Southern Energy New York, Draft Environmental Impact Statement for State Pollutant Discharge Elimination System Permits for Bowline Point, Indian Point 2 and 3, and Roseton Steam Electric Generating Stations, 1999.

Con Edison. 2007. Letter dated January 19, 2007 from J.McAvoy (Vice President, Con Edison) to F. Dacimo (Vice President, Entergy Nuclear Operations).

ENN (Entergy Nuclear Northeast). 2007a. Indian Point Units 1, 2, Offsite Dose Calculation Manual (ODCM), Rev. 10, January 2007.

ENN (Entergy Nuclear Northeast). 2007b. Indian Point Energy Center, Indian Point 3 Offsite Dose Calculation Manual (ODCM), Revision 18, January 2007.

Entergy. 2004. EN-EV-104, Waste Minimization.

Entergy. 2006a. EN-EV-106, Waste Management Program. August 7, 2006.

Entergy. 2006b. EN-EV-112, Chemical Control Program. November 13, 2006.

IP2 UFSAR. Indian Point Energy Center, Indian Point 2, Updated Final Safety Analysis Report.

IP3 UFSAR. Indian Point Energy Center, Indian Point 3, Updated Final Safety Analysis Report

NRC (U.S. Nuclear Regulatory Commission). 1975. Final Environmental Statement Related to the Operation of Indian Point Unit No. 3, Docket No. 50-286, U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation.

PowerGEM (Power Grid Engineering & Markets). 2004. System Reliability Impact Study: Extended Power Uprate of Indian Point Units 2 and 3.

USAEC (U.S. Atomic Energy Commission). 1972. Final Environmental Statement Related to the Operation of Indian Point Unit No. 2, Docket No. 50-247, United States Atomic Energy Commission, Directorate of Licensing.

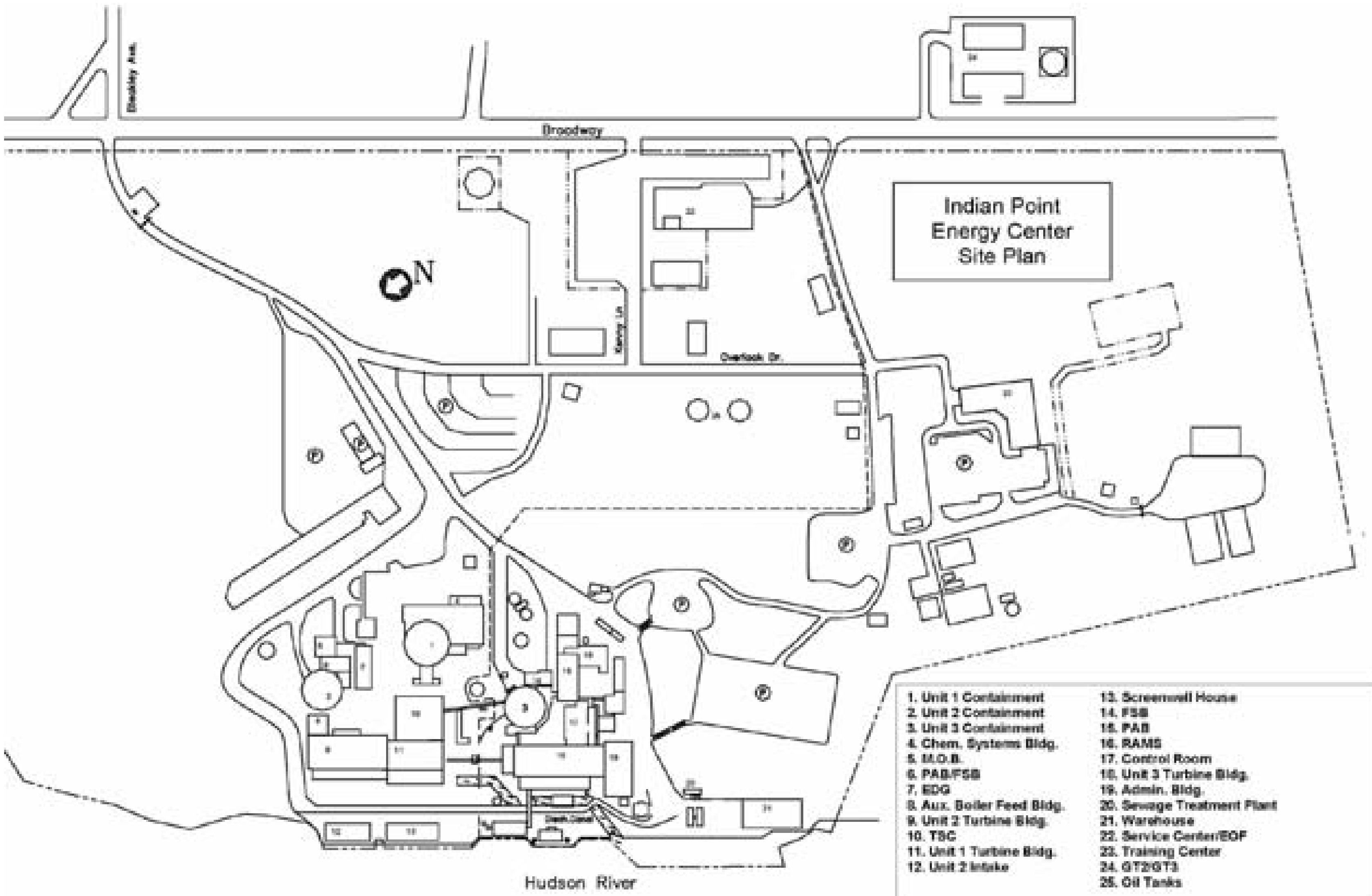


Figure 3-1
Indian Point Facility

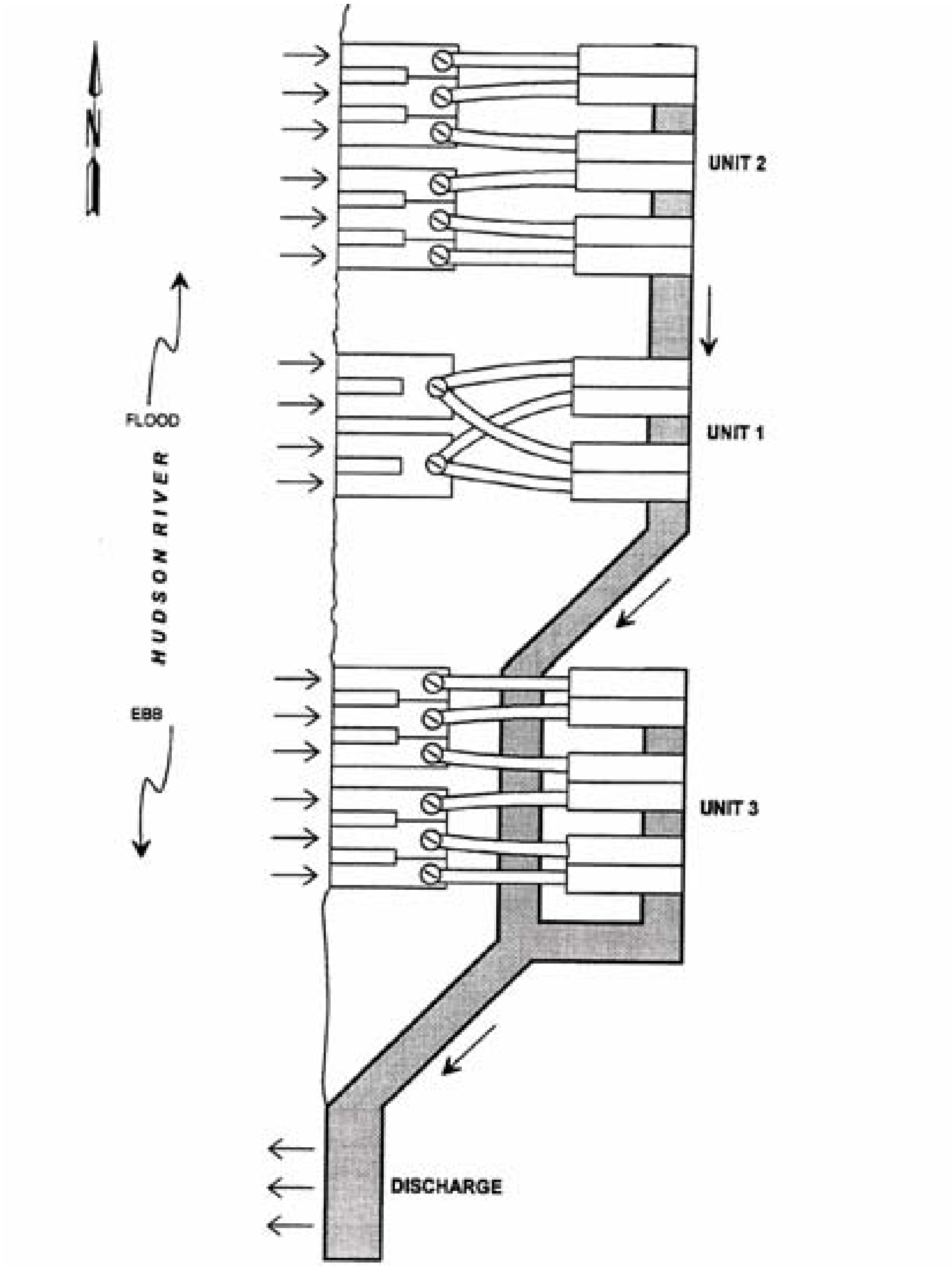
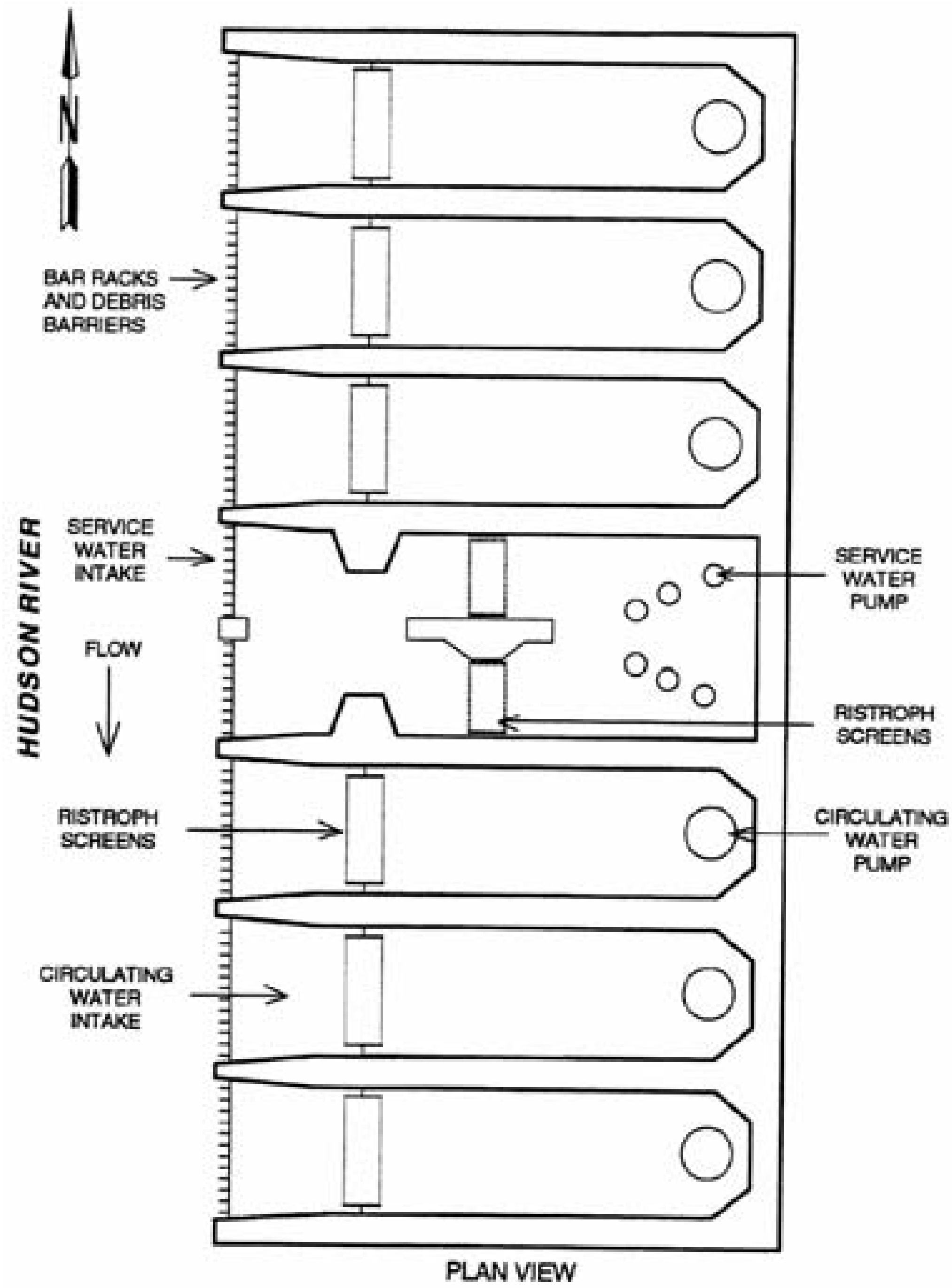


Figure 3-2
Indian Point Intake Structures



Source: CHGEC Section IV.B

Figure 3-3
IP2 Cooling Water System

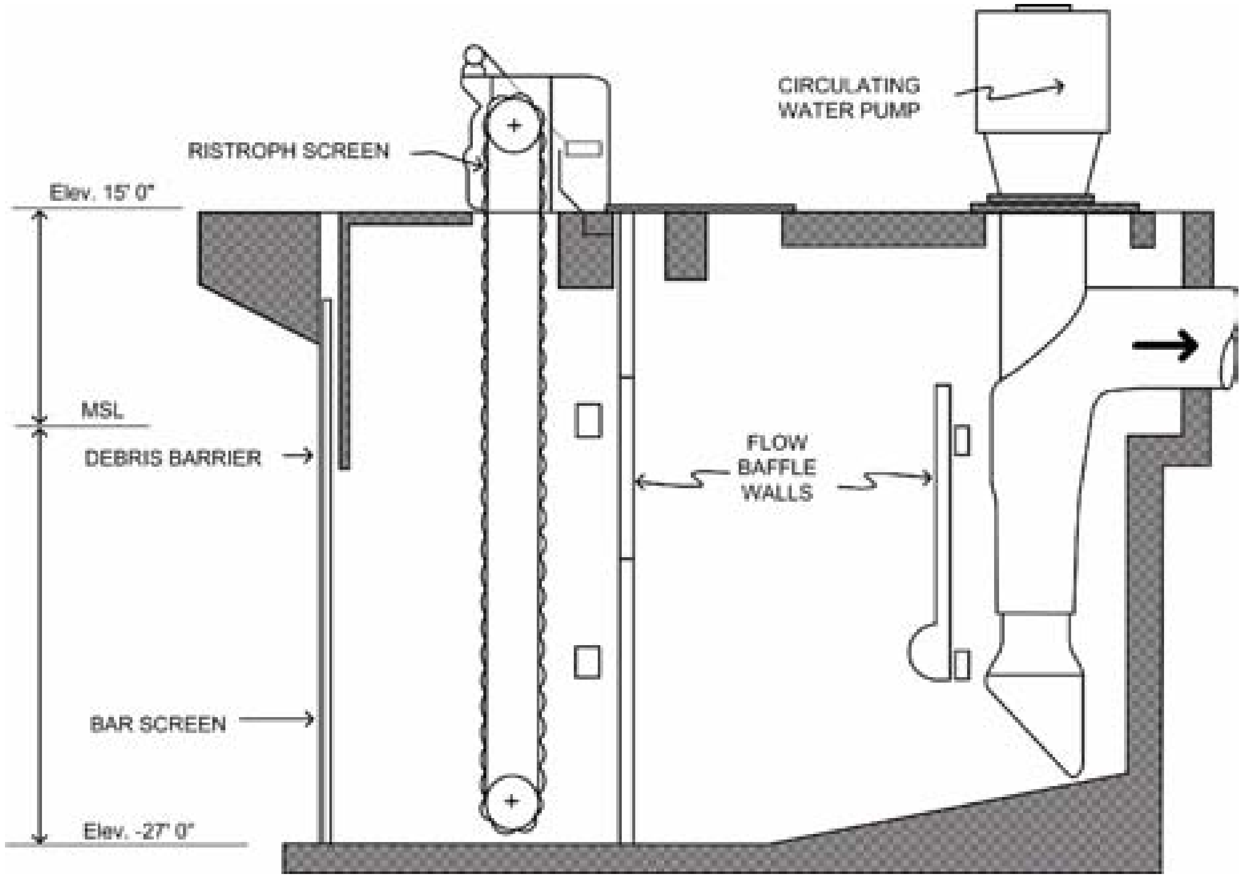
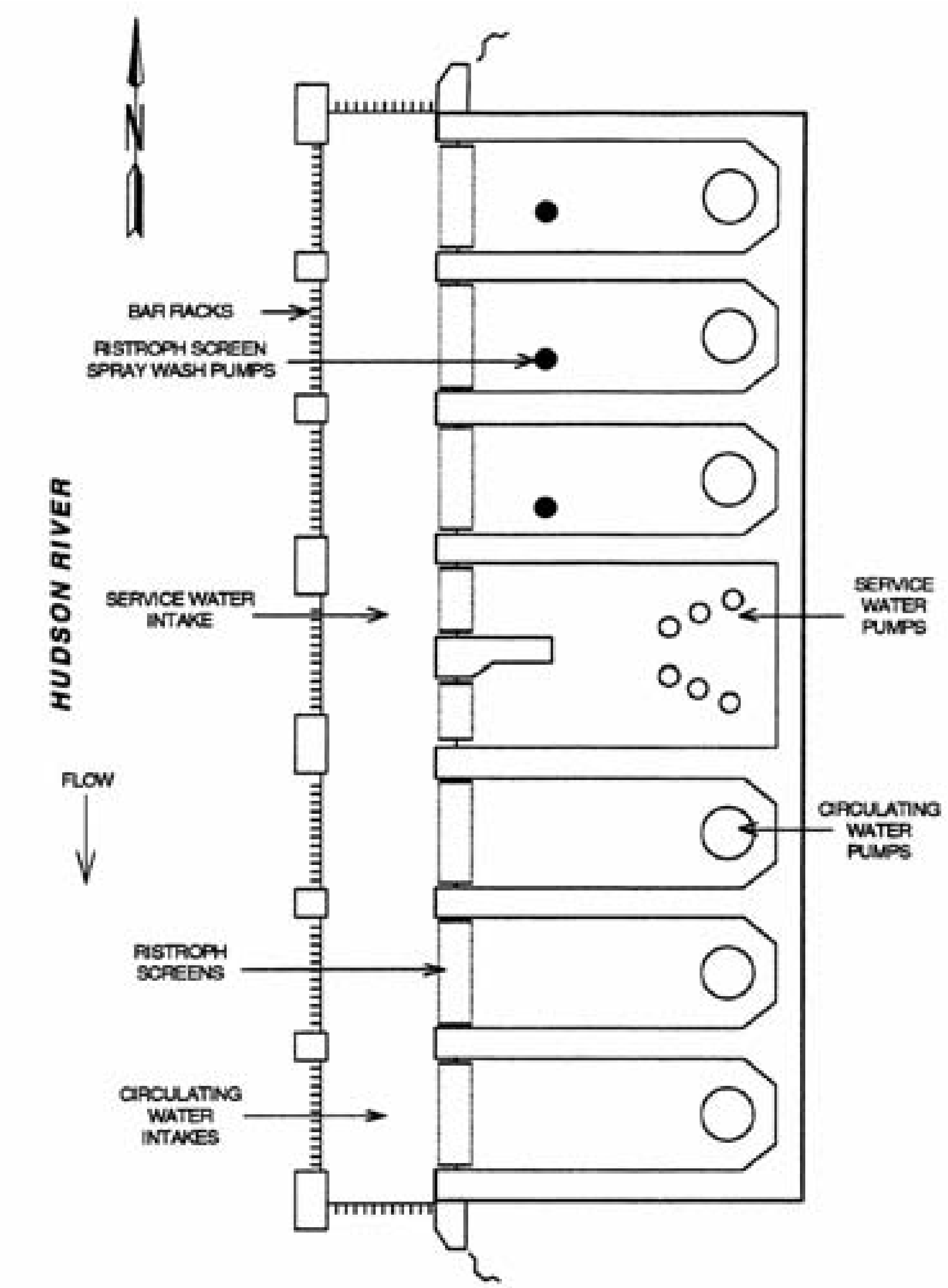


Figure 3-4
IP2 Intake System



Source: CHGEC Section IV.B

Figure 3-5
IP3 Cooling Water System

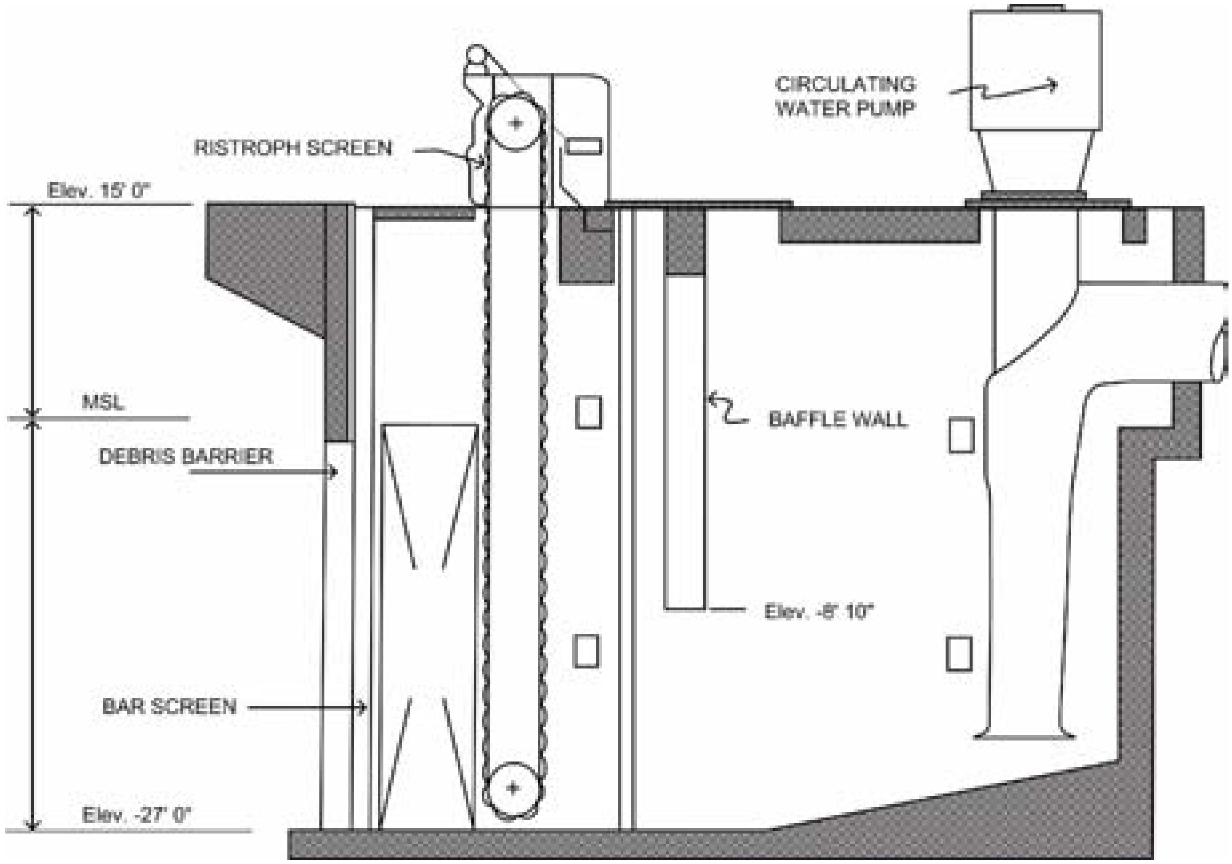


Figure 3-6
IP3 Intake System

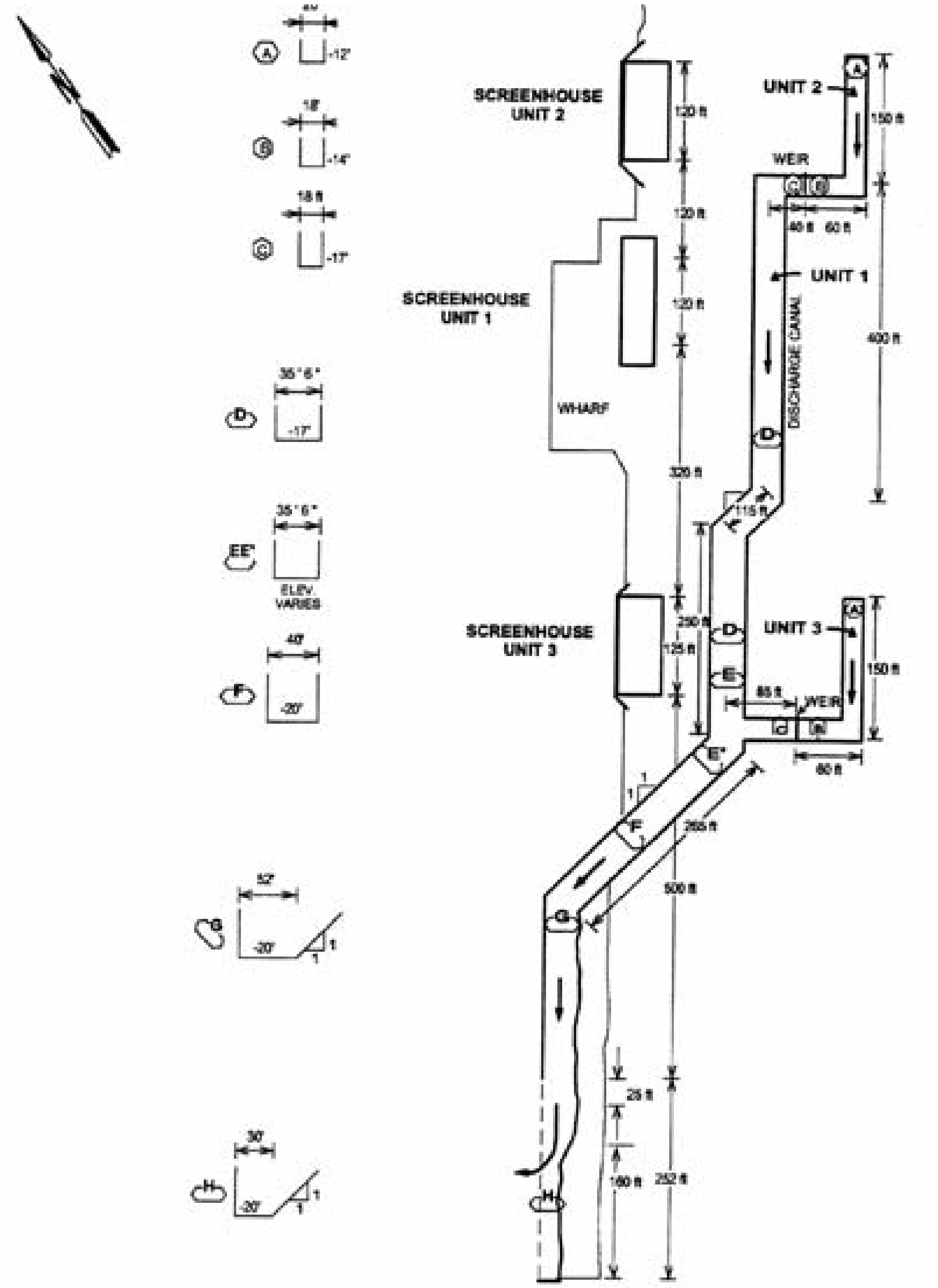
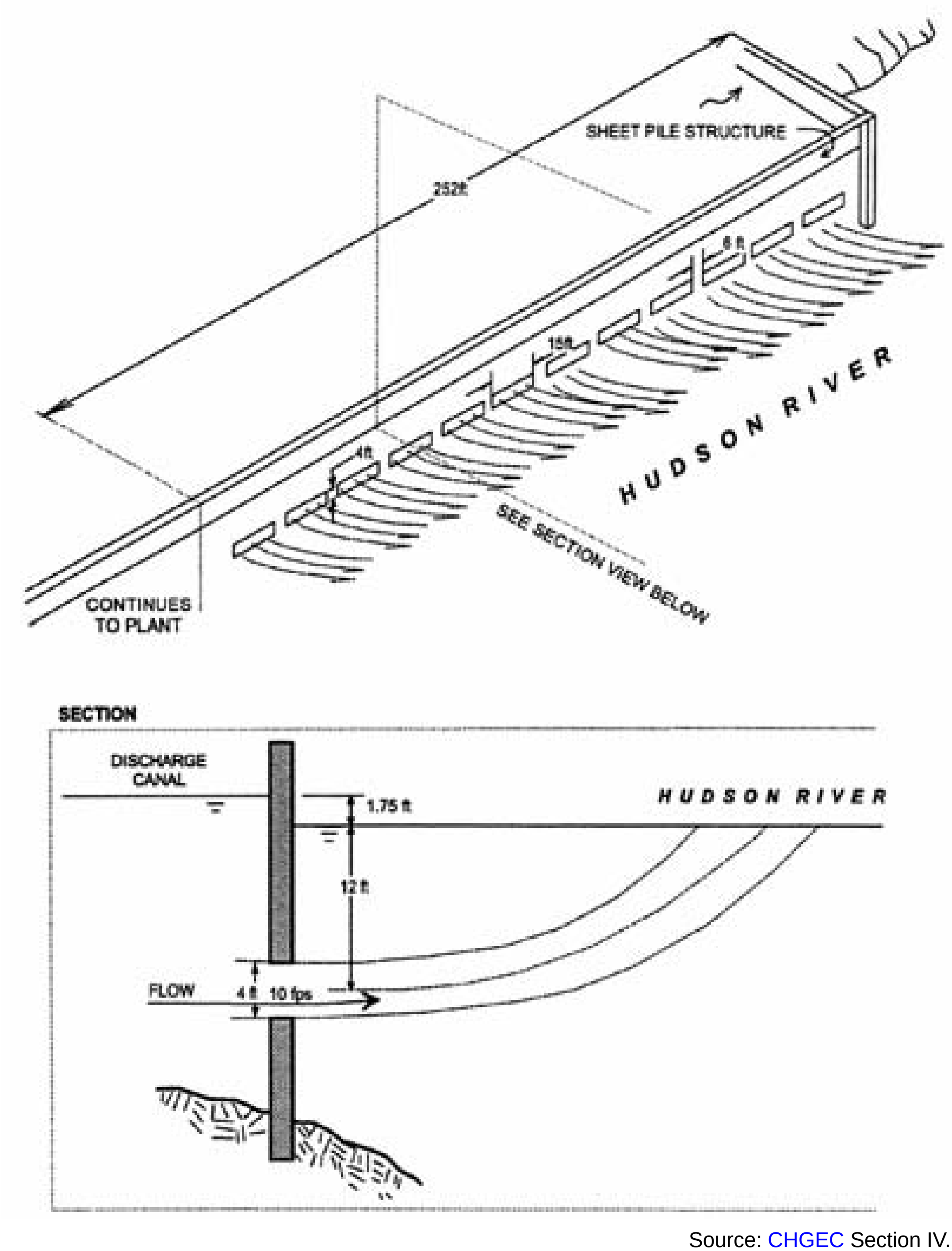


Figure 3-7
Indian Point Discharge Canal System



Source: CHGEC Section IV.B

Figure 3-8
Indian Point Discharge Structure

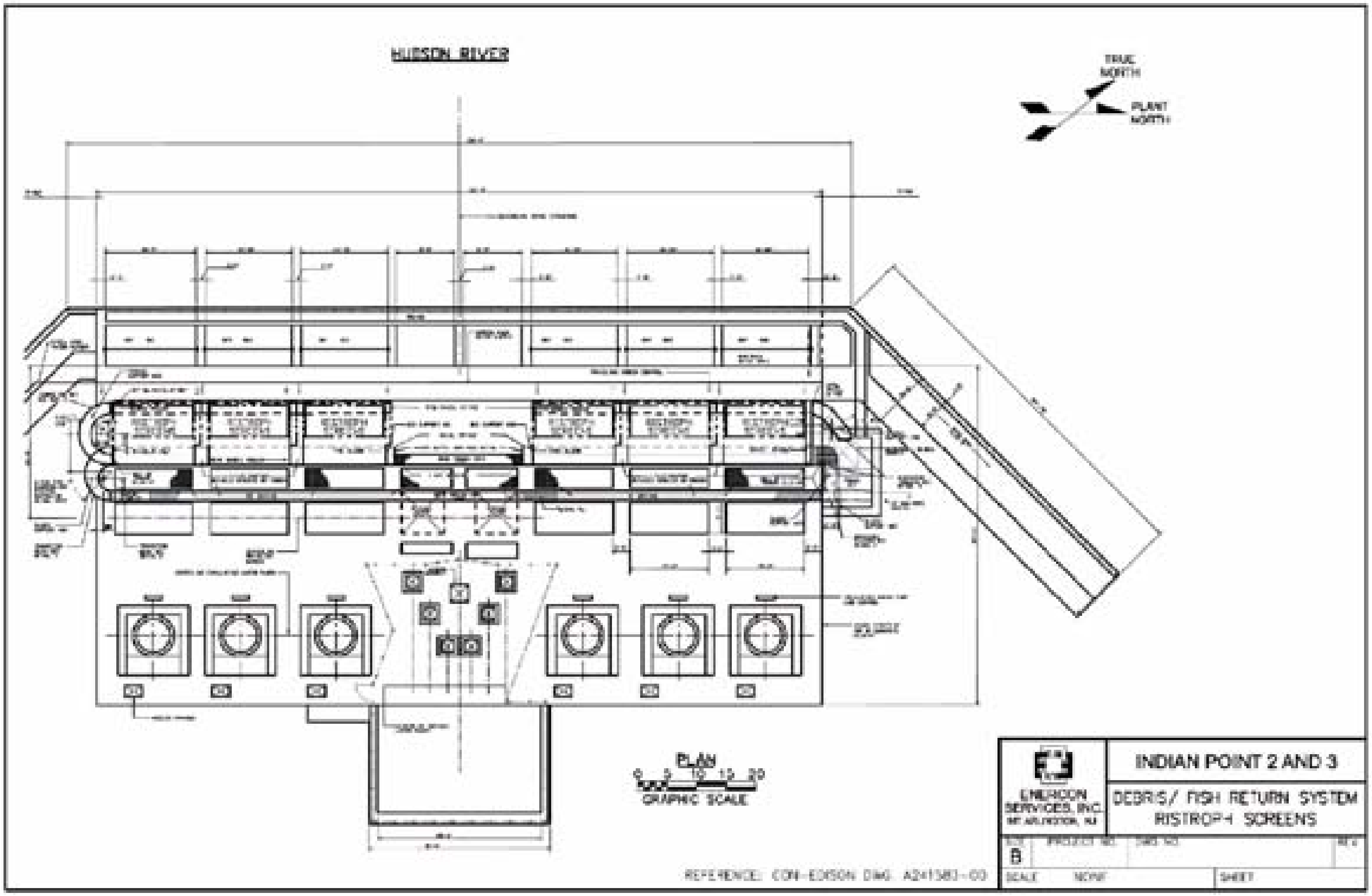


Figure 3-9
IP2 Fish Return System

4.0 ENVIRONMENTAL CONSEQUENCES OF PROPOSED ACTION

Discussion of GEIS Categories for Environmental Issues

The NRC has identified and analyzed 92 environmental issues that it considers to be associated with nuclear power plant license renewal and has designated the issues as Category 1, Category 2, or NA (not applicable). NRC designated an issue as Category 1 if the following criteria were met:

- the environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristic;
- a single significance level (i.e., small, moderate, or large) has been assigned to the impacts that would occur at any plant, regardless of which plant is being evaluated (except for collective offsite radiological impacts from the fuel cycle and from high-level waste and spent-fuel disposal); and
- mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely to be not sufficiently beneficial to warrant implementation.

If the NRC concluded that one or more of the Category 1 criteria could not be met, NRC designated the issue Category 2. NRC requires plant-specific analysis for Category 2 issues. NRC designated two issues as NA, signifying that the categorization and impact definitions do not apply to these issues. NRC rules do not require analyses of Category 1 issues that NRC resolved using generic findings (10 CFR Part 51, Appendix B, Table B-1) as described in the GEIS [NRC 1996]. An applicant may reference the GEIS findings for Category 1 issues.

Category 1 License Renewal Issues

Entergy has determined that, of the 69 Category 1 issues, 19 are not applicable to the site because they apply to design or operational features that do not exist at the facility. In addition, because Entergy does not plan to conduct refurbishment activities, the NRC findings for the 7 Category 1 issues applicable to refurbishment do not apply. Table 4-1 lists these 26 Category 1 issues and provides a brief explanation of why they are not applicable to the site. Table 4-2 lists the 43 Category 1 issues applicable to the site. Entergy reviewed the NRC findings on these 43 issues and identified no new and significant information that would invalidate the findings for the site (see Section 5). Therefore, Entergy adopts by reference the NRC findings for these Category 1 issues.

Table 4-1
Category 1 Issues Not Applicable to IP2 and IP3

Surface Water Quality, Hydrology, and Use (for all plants)	
Impacts of refurbishment on surface water quality	No refurbishment activities planned.
Impacts of refurbishment on surface water use	No refurbishment activities planned.
Altered thermal stratification of lakes	The site is not located on a lake.
Eutrophication	IP2 and IP3 do not discharge to a lake
Discharge of sanitary wastes and minor chemical spills	The site does not discharge sanitary wastes to surface water.
Aquatic Ecology (for all plants)	
Refurbishment	No refurbishment activities planned.
Premature emergence of aquatic insects	Aquatic insects are primarily of concern in freshwater environments
Aquatic Ecology (for plants with cooling tower based heat dissipation systems)	
Entrainment of fish and shellfish in early life stages	The site does not use cooling towers.
Impingement of fish and shellfish	The site does not use cooling towers.
Heat shock	The site does not use cooling towers.
Groundwater Use and Quality	
Impacts of refurbishment on groundwater use and quality	No refurbishment activities planned.
Groundwater quality degradation (Ranney Wells)	The site does not use Ranney wells.
Groundwater quality degradation (saltwater intrusion)	The site does not use or withdraw groundwater.
Groundwater quality degradation (cooling ponds in salt marshes)	The site does not use cooling ponds.
Groundwater use conflicts (potable and service water; plants that use <100 gpm)	The site does not use or withdraw groundwater.
Human Health	
Radiation exposures to the public during refurbishment	No refurbishment activities planned.

Table 4-1
Category 1 Issues Not Applicable to IP2 and IP3
(Continued)

Occupational radiation exposures during refurbishment	No refurbishment activities planned.
Microbiological organisms (occupational health)	The site is not located on a small river.
Terrestrial Resources	
Cooling pond impacts on terrestrial resources	The site does not use cooling ponds.
Cooling tower impacts on crops and ornamental vegetation	The site does not use cooling towers.
Cooling tower impacts on native plants	The site does not use cooling towers.
Bird collisions with cooling towers	The site does not use natural draft towers.
Power line right-of-way management (cutting and herbicide application)	All power lines at the site exist on site property from plant to switchyard.
Floodplains and wetland on power line right-of-way	All power lines at the site exist on site property from plant to switchyard and none cross regulated floodplains or wetlands.
Socioeconomics	
Aesthetic impacts (refurbishment)	No refurbishment activities planned.
Land Use	
Power line right-of-way	All power lines at the site exist on site property from plant to switchyard.

Table 4-2
Category 1 Issues Applicable to IP2 and IP3

Surface Water Quality, Hydrology, and Use (for all plants)
Water use conflicts (plants with once-through cooling systems)
Altered salinity gradients
Altered current patterns at intake and discharge structures
Temperature effects on sediment transport capacity
Scouring caused by discharged cooling water
Discharge of chlorine or other biocides

Table 4-2
Category 1 Issues Applicable to IP2 and IP3
(Continued)

Discharge of other metals in waste water
Aquatic Ecology (for all plants)
Accumulation of contaminants in sediments or biota
Entrainment of phytoplankton and zooplankton
Cold shock
Thermal plume barrier to migrating fish
Distribution of aquatic organisms
Gas supersaturation (gas bubble disease)
Low dissolved oxygen in the discharge
Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses
Stimulation of nuisance organisms (e.g., shipworms)
Terrestrial Resources
Bird collision with power lines
Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)
Air Quality
Air quality effects of transmission lines
Land Use
Land use (license renewal period)
Human Health
Noise
Radiation exposures to public (license renewal term)
Occupational radiation exposures (license renewal term)
Socioeconomics
Public services: public safety, social services, and tourism and recreation
Public services, education (license renewal term)
Aesthetic impacts (license renewal term)
Aesthetic impacts of transmission lines (license renewal term)

**Table 4-2
Category 1 Issues Applicable to IP2 and IP3
(Continued)**

Postulated Accidents
Design basis accidents
Uranium Fuel Cycle and Waste Management
Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)
Offsite radiological impacts (collective effects)
Offsite radiological impacts (spent fuel and high-level waste disposal)
Non-radiological impacts of the uranium fuel cycle
Low-level waste storage and disposal
Mixed waste storage and disposal
On-site spent fuel
Nonradiological waste
Transportation
Decommissioning
Radiation doses
Waste management
Air quality
Water quality
Ecological resources
Socioeconomic impacts

Category 2 License Renewal Issues

NRC designated 21 issues as Category 2. Sections 4.1 through 4.21 address the Category 2 issues, beginning with a statement of the issue. As is the case with Category 1 issues, some Category 2 issues (6) apply to operational features that the site does not have. In addition, some Category 2 issues (4) apply only to refurbishment activities. If the issue does not apply to the site, the section explains the basis.

For the 11 Category 2 issues applicable to the site, the corresponding sections contain the required analyses. These analyses include conclusions regarding the significance of the impacts relative to renewal of the operating license for the site and, when applicable, discuss potential mitigative alternatives to the extent required. Entergy has identified the significance of the impacts associated with each issue as SMALL, MODERATE, or LARGE consistent with the criteria that NRC established in 10 CFR Part 51, Appendix B, Table B-1, Footnote 3 as follows.

- SMALL: Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

- MODERATE: Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attributes of the resource.

- LARGE: Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

In accordance with NEPA practice, Entergy considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are small receive less mitigative consideration than impacts that are large).

"NA" License Renewal Issues

NRC determined that its categorization and impact-finding definitions did not apply to electromagnetic fields (chronic effect) and environmental justice. NRC noted that applicants currently do not need to submit information on chronic effects from electromagnetic fields (10 CFR Part 51, Appendix B, Table B-1, Footnote 5). For environmental justice, NRC does not require information from applicants, but noted that it would be addressed in individual license renewal reviews (10 CFR Part51, Appendix B, Table B-1, Footnote 6). Entergy has included environmental justice demographic information in Section 2.6.2.

Format of Category 2 Issue Review

The review and analysis for the Category 2 issues along with environmental justice and cumulative impacts are found in Sections 4.1 through 4.23. The format for the review of the Category 2 issues, Section 4.1 through 4.21, is described below.

- *Issue*: a brief statement of the issue.

- *Description of Issue:* a brief description of the issue.

- *Findings from Table B-1, Appendix B to Subpart A:* the findings for the issue from Table B-1—Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants, Appendix B to Subpart A.

- *Requirement:* restatement of the requirement from 10 CFR 51.53(c)(3)(ii).

- *Background*: for issues applicable to the site, a background excerpt from the applicable section of the GEIS. The specific section of the GEIS is referenced for the convenience of the reader. In most cases, background information is not provided for issues that are not applicable to the site.

- *Analysis of Environmental Impact*: an analysis of the environmental impact as required by 10 CFR 51.53(c)(3)(ii). The analysis takes into account information provided in the GEIS, Appendix B to Subpart A of 10 CFR Part 51, as well as current specific information.

- *Conclusion*: for issues applicable to the site, the conclusion of the analysis along with the consideration of mitigation alternatives as required by 10 CFR 51.45(c) and 10 CFR 51.53(c)(3)(iii).

4.1 Water Use Conflicts

4.1.1 Description of Issue

Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow).

4.1.2 Findings from Table B-1, Appendix B to Subpart A

SMALL or MODERATE. The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on in-stream and riparian communities near these plants could be of moderate significance in some situations. See 10 CFR 51.53(c)(3)(ii)(A).

4.1.3 Requirement [10 CFR 51.53(c)(3)(ii)(A)]

If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow.

4.1.4 Analysis of Environmental Impact

The site does not utilize cooling towers or cooling ponds. IP2 and IP3 utilize once-through cooling systems. Therefore, this issue is not applicable to the site and further analysis is not required.

4.2 Entrainment of Fish and Shellfish in Early Life Stages

4.2.1 Description of Issue

Entrainment of fish and shellfish in early life stages (for all plants with once-through and cooling pond heat dissipation systems).

4.2.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. The impacts of entrainment are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid. See 10 CFR 51.53(c)(3)(ii)(B).

4.2.3 Requirement [10 CFR 51.53(c)(3)(ii)(B]

If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current CWA 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40 CFR 125, or equivalent state permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

4.2.4 Background

The impacts of fish and shellfish entrainment are small at many plants, but they may be moderate or even large at a few plants with once-through cooling systems. Further, ongoing restoration efforts may increase the numbers of fish susceptible to intake effects during the license renewal period, so that entrainment studies conducted in support of the original license may no longer be valid. [NRC 1996, Section 4.2.2.1.2]

4.2.5 Analysis of Environmental Impact

4.2.5.1 Background

The effects of entrainment on aquatic resources were considered by NRC and EPA, or an EPA-authorized state water quality permitting agency, at the time of original licensing, and are routinely reconsidered by the EPA, or the state, often times in the context of the renewals of National Pollutant Discharge Elimination System (NPDES) permits or updates of in-place 316(b) demonstrations. Further, the vast majority of existing nuclear stations, including those stations undergoing license renewal, currently are or in the future will be undergoing comprehensive 316(b) review as EPA develops final 316(b) regulations for existing facilities in response to the recent remand of that rule.

Entrainment and impingement in the Hudson River, particularly within the sphere of influence of Indian Point and other major Hudson River electric-generating facilities (of which there are several), have been continuously and extensively evaluated, and peer reviewed by leading fisheries biologists, since the original licensing of IP2. These studies, undertaken at an annual cost to the Hudson River facilities of $2.0 million annually (in 1981 dollars), and performed at the direction and under the oversight of NYSDEC, have resulted in what William Sarbello, then of the NYSDEC, referred to in November 2000 as "probably, the best data set on the planet." [USEPA].

The IP2 FES concluded that the issuance of an operating permit for IP2 to former owner Consolidated Edison Company of New York, Inc. (ConEdison), should be subject to the conditions relating to 316(b) considerations: (1) once-through cooling would be permitted only until January 1, 1978; (2) evaluate the economic and environmental impacts of a new closed-cycle cooling system to determine a preferred system to install and submit this evaluation to the USAEC by July 1, 1973; (3) ConEdison should monitor the nature and extent of impingement and entrainment mortality; and (4) ConEdison should submit a plan of action for minimizing detrimental effects on aquatic biota by July 1, 1973 and implement the plan upon approval by the USAEC [USAEC]. These conditions, among others, were inserted by the NRC into the IP2 Operating License as Condition 2.E. A similar license condition was included in the IP3 Operating License issued to NYPA, the former owner of IP3. Consistent with these licensing conditions, ConEdison and NYPA submitted an Environmental Report in 1976 to the NRC in which various alternative closed-cycle cooling systems were evaluated for IP2 and IP3 from an economic and environmental standpoint. The time frame established in the FES and IP2 and IP3 license conditions was extended until May 1, 1982, and then rendered moot by the 1981 execution of the global settlement, known as the Hudson River Settlement Agreement (HRSA), arising out of the parallel United States Environmental Protection Agency (EPA) NPDES permitting process for IP2 and IP3, in which all parties agreed that closed-cycle cooling would not be implemented at that time.

In 1975, contemporaneous with ConEdison and NYPA's review of closed-cycle cooling systems, EPA initiated NPDES permitting proceedings for both stations, producing an initial draft permit (jointly held by IP2 and IP3 because of their shared discharge canal) that echoed the respective NRC licenses for these stations in requiring closed-cycle cooling. (EPA actually required closed-cycle cooling for all of the Hudson River facilities.) NYPA and ConEdison opposed these NPDES permit conditions, initiating a contested proceeding (with substantial collateral litigation). Consolidated adjudicatory hearings commenced in February 1977 before an EPA administrative law judge, and several years were engaged in the station owners' marshalling of evidence and witnesses. In July 1979, EPA's witnesses were called to the stand, and the owners of the various stations began cross-examination. The landmark Hudson River Settlement Agreement (HRSA) occurred at this time, resolving the need for further continued hearings or an EPA decision.

In particular, the ten-year HRSA, dated October 19, 1980, resolved the then-pending EPA permit proceeding relating to IP2 and IP3 and reflects the negotiated resolution among EPA, the NYSDEC, the former owners of the Hudson River facilities, including ConEdison and NYPA, and various environmental groups. As a result of the HRSA, both former owners, ConEdison and NYPA, submitted a license amendment request to the NRC for the removal of license condition 2.E that required the closed-cycle cooling system [HRSA]. License Amendment No. 71 removed Condition 2.E, for both IP2 and IP3, effective May 14, 1981 [NRC 1981]. In place of the cooling tower requirement, the HRSA included various technical, operational and restoration measures relating to the Hudson River facilities, including IP2 and IP3. These measures included, with respect to IP2 and IP3, the installation of dual or variable speed intake pumps, state-of-the-art Ristroph screens and fish-return systems, flow reduction obligations (facilitated by the pump retrofits) designed to minimize water use in a manner consistent with efficient station operation, and appropriate outage scheduling (including through an outage credit point system that rewarded outages taken during potential entrainment periods). In addition, the development of a striped bass fish hatchery was made a joint requirement for all of the power generators party to the HRSA, as were certain other requirements [HRSA].

The new pumping systems were timely installed at IP3 and IP2. Ristroph screens and fish return systems were timely installed at IP3 and IP2 and completed in 1990 and 1991, respectively [IP2 UFSAR, Section 10.2.4; IP3 UFSAR Section 10.2.4]. IP2 has six two-speed circulating water pumps designed to pump 140,000 gpm at full speed and 84,000 gpm at reduced speed. IP3 has six variable-speed circulating water pumps designed to pump 140,000 gpm at full speed and 64,000 gpm at the lowest speed. Each unit has six service water pumps, IP3 rated at 6,000 gpm per each pump and IP2 at 5,000 gpm per each pump. There are three back-up service water pumps located on a platform at IP3 over the discharge channel. After moving through the condensers, cooling water from IP2 and IP3 flows downward from the discharge water boxes by way of six 96-inch down pipes, and exits under the water surface in a 40-foot-wide discharge canal.[CHGEC]

The owners use best reasonable efforts to operate the IP2 and IP3 dual and variable speed circulating pumps to keep the volume of river water drawn into the stations during the relevant entrainment period at the minimum required for efficient operation, considering ambient river water temperature, plant operating status, the need to meet water quality standards and other permit conditions. Flow rates are dependent upon intake water temperature, and typically peak between early May and late October. In addition, outages are scheduled, where reasonably practicable, in a manner sensitive to entrainment considerations, typically during the late spring entrainment period, with the result that only one unit is operating during that outage period each year. Further, extensive entrainment survival studies reflect a very high level of entrainment survival among certain species. [CHGEC, Section V.D]

The first SPDES permit was granted to both units in 1982, with the HRSA annexed as a permit condition for the duration of the HRSA. A SPDES permit renewal was granted in October 1987 by the NYSDEC [Attachment C], again during the lifespan of the HRSA. In 1992, a timely SPDES permit renewal application was submitted to the NYSDEC for both units, as a result of which the 1992 permit continues in effect under New York administrative law until a new permit is issued by NYSDEC. The HRSA, which was annexed to the 1982 SPDES Permit, expired after its 10-year term, but was replaced by four judicially approved consecutive Consent Orders, the first of which was executed in 1992, between the owners of IP2 and IP3, other Hudson River power generators, NYSDEC, and other stakeholders. Each of these Consent Orders effectively continued the HRSA terms and conditions, although without requiring outages at IP2 or IP3, or the continued operation of the striped bass hatchery (owing in part to the striped bass population proliferation over the period in question). The most recent Consent Order expired in 1998 [NYSDEC 1997a]. However, IP2 and IP3 voluntarily have agreed with NYSDEC to continue the activities required in the last Consent Decree. The submission of a timely and complete SPDES renewal application for IP2 and IP3 administratively continued the site's current SPDES permit under the New York State Administrative Procedure Act and the NYSDEC's implementing regulations.

In July 1992, NYSDEC requested that certain of the Hudson River power generators, including IP2 and IP3, submit an Environmental Impact Statement (EIS) under the New York SEQRA on the potential impacts of their requested SPDES permit renewals. In conjunction with the SPDES Permit applications for Indian Point, Roseton, and Bowline Point generation plants, these owners responded by providing a DEIS in 1993, and, after an extensive interim consultation with the NYSDEC, a revised DEIS in 1999 [CHGEC]. The NYSDEC accepted the DEIS as complete as a matter of New York administrative law, and issued its FEIS in 2003. In conjunction with litigation among the parties, NYSDEC subsequently determined that additional public involvement and response was needed before a final SPDES permit would be issued to IP1, IP2, and IP3 or any other of the Hudson River facilities addressed on a cumulative basis in the DEIS and FEIS [NYSDEC 2003b].

NYSDEC also issued a draft SPDES permit for IP1, IP2, and IP3 in 2003 that, among other conditions, requires the design and, if appropriate, the installation of closed-cycle cooling systems for IP2 and IP3 if the site seeks and receives from NRC license renewals for IP2 and IP3, and the NRC, among other regulators, reaches all appropriate feasibility and safety determinations [NYSDEC 2003a]. In particular, the draft SPDES permit fact sheet states: "This permit does not require the construction of cooling towers unless: (1) the applicant seeks to renew its NRC operating licenses, (2) the NRC approves extension of the licenses, and determines that the installation and operation of closed-cycle cooling is feasible and safe, and (3) all other necessary Federal approvals are obtained." [NYSDEC 2003c, Section IV.D.4]. The draft permit also requires that all applicable local approvals must be obtained before cooling towers will be required. The conditions of the draft permit are the subject of a contested adjudicatory proceeding currently pending before a two-judge panel of NYSDEC administrative law judges. As a matter of New York administrative law, the 1992 SPDES permit remains in full effect as administratively continued, pending issuance of the final SPDES permit currently subject to the adjudicatory process. With respect to that contested proceeding, the owners of IP2 and IP3 have taken the position that the mitigation measures currently implemented at IP2 and IP3 as a result of the HRSA and Consent Orders, as supported by ongoing Hudson River monitoring, are adequate in minimizing potential impacts from current operations and operations during the license renewal period. Nonetheless, additional measures may be established as the outcome of the SPDES process and would be incorporated into the SPDES permit for IP2 and IP3 that would be in place during the license renewal period.

In sum, the owners of IP2 and IP3, and the owners of other Hudson River generating stations, have conducted comprehensive Hudson River aquatic studies under the oversight and direction of NYSDEC since the 1970s. The results of these studies were reported in the 1999 DEIS and 2003 FEIS. Based on the reports summarized in the DEIS and FEIS, studies completed in the 1970s included sampling and evaluation of all trophic levels in the Hudson River estuary. Representative species, populations and communities were defined and evaluated. During the 1980s and 1990s, studies focused more closely on key fish species, particularly those adults and larvae that use the estuary as spawning habitat or represent commercial/recreational species, chiefly striped bass. Many of these studies have specifically addressed the potential impacts of cooling water intake structures to the macroinvertebrates, all appropriate fish life stages and fish populations. Entrainment mitigation measures have been implemented in accordance with the

HRSA and the four Consent Orders [NYSDEC 1997a]. Among the other measures discussed above, these mitigation measures have included installation of the dual and multi-speed cooling water intake pumps and minimizing cooling water withdrawal to only that required for efficient plant operation.

4.2.5.2 Entrainment Analysis

IP2 and IP3 are equipped with once-through heat dissipation systems that withdraw cooling water from and discharge to the Hudson River. The details of the IP2 and IP3 cooling systems, intake structures, and discharge systems are provided in Chapter 3 of this ER. IP2 and IP3 each have separate shoreline-situated intake structures consisting of seven bays (six for circulating water and one for service water). Additional service water and screen wash water is provided for IP2 from the IP1 intake structure.

As explained above, the 1999 DEIS submitted to the NYSDEC provides extensive descriptions of more than 23 years of Hudson River fisheries and habitat studies involving trends in representative species abundance, diversity, richness, and mortality rates, and therefore potential impacts from entrainment and impingement at once-through cooling water intakes. Specifically, the DEIS describes estimates of entrainment mortality integrated with estimates of the abundance of fish in certain portions of the River to derive the theoretical proportional reduction of the population of that age class, expressed as the conditional mortality rate (CMR), i.e., the mortality to the fraction of the river population caused by IP2 and IP3 entrainment if there were no other sources of mortality implicated [CHGEC, Section VI.B.1.b]. The estimated average annual CMR due to entrainment for American shad is 0.64%, for Atlantic tomcod is 12.04%, for bay anchovy is 10.38%, for river herring is 1.20%, for striped bass is 7.82%, and for white perch is 4.94% [CHGEC, Section V.D]. CMRs and discussion of models to define the CMRs are presented in the DEIS and its appendixes.

The diversity of species within the fish communities in the Hudson River ecosystem was generally affected by the ecosystem changes that affected water quality (the fish community in the brackish portion of the estuary) and habitat availability (the fish community in the freshwater portion of the estuary). The number of marine species entering the estuary increased when water quality increased in the New York City area. However, the diversity of YOY, yearling, and older fish in the lower portion of the estuary was more strongly affected (decreased) by the increase in the abundance of large striped bass. The number of freshwater species in the upper portion of the estuary decreased when the water chestnut populations recovered and achieved nuisance levels in the late 1970s and early 1980s. [CHGEC, Section V.D.4.c]

Subsequent to submission of the DEIS, the generators submitted to the NYSDEC, among other things, a review by three leading fisheries biologists, Drs. Charles C. Coutant, Lawrence W. Barnthouse, and Webster Van Winkle, of the Hudson River data set, with a trend analysis of the relative abundance and diversity of the fish populations in the River [Barnthouse]. The express purpose of that Report was to provide an even greater level of confidence to NYSDEC regarding the DEIS conclusion that no adverse impacts to fisheries have occurred or are likely to occur as a result of the operation of the cooling water intake structures of the various stations, including IP2 and IP3. In addition, since submission of the DEIS, the generators have continued to provide the annual year-class reports outlining the results of the annual monitoring program for the year in question, as well as all of the raw data collected and an estimate of the abundance (i.e., standing crop) of fish in the River during that period. This information continues to confirm the absence of any adverse impact on fisheries reasonably attributable to IP2 or IP3 [ASA].

4.2.6 Conclusion

More than 30 years of extensive fisheries studies of the Hudson River in the vicinity of IP2 and IP3 support current operations. The results of the studies performed from 1974 to 1997, the period of time covered in the DEIS, are referenced and summarized in the DEIS, and have not shown any negative trend in overall aquatic river species populations attributable to plant operations. Ongoing studies continue to support these conclusions [ASA]. In addition, current mitigation measures implemented through the HRSA and retained in the four Consent Orders, the current agreements with NYSDEC, and the outcome of the draft SPDES Permit proceeding, will ensure that entrainment impacts remain SMALL during the license renewal term. Therefore, withdrawal of water from the Hudson River for the purposes of once-through cooling at the site does not have any demonstrable negative effect on representative Hudson River fish populations, nor does it warrant further mitigation measures.

4.3 Impingement of Fish and Shellfish

4.3.1 Description of Issue

Impingement of fish and shellfish (for all plants with once-through and cooling pond heat dissipation systems).

4.3.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. See 10 CFR 51.53(c)(3)(ii)(B).

4.3.3 Requirement [10 CFR 51.53(c)(3)(ii)(B)]

If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40 CFR Part 125, or equivalent state permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

4.3.4 Background

Aquatic organisms that are drawn into the intake with the cooling water but are too large to pass through the debris screens may be impinged against the screens. Mortality of fish that are impinged is high at many plants because impinged organisms are eventually suffocated by being held against the screen mesh, or are abraded, which can result in fatal infection. Impingement can affect large numbers of fish and invertebrates (crabs, shrimp, jellyfish, etc.). As with entrainment, operational monitoring and mitigative measures have allayed concerns about population-level effects at most plants, but impingement mortality continues to be an issue at others. Consultation with resource agencies revealed that impingement is a frequent concern at plants using once-through cooling, particularly where restoration of anadromous fish (fish that migrate from the sea to spawn in fresh water) may be affected. The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through cooling systems. [NRC 1996, Section 4.2.2.1.3]

4.3.5 Analysis of Environmental Impact

4.3.5.1 Background

The effects of impingement on aquatic resources were considered by NRC and EPA, or an EPA-authorized state water quality permitting agency, at the time of original licensing, and are routinely reconsidered by the EPA, or the state, often times in the context of the renewals of NPDES permits or updates of in-place 316(b) demonstrations. Further, the vast majority of existing nuclear stations, including those stations undergoing license renewal, currently are or in the future will be undergoing comprehensive 316(b) review as EPA develops final 316(b) regulations for existing facilities in response to the recent remand of that rule.

Impingement in the Hudson River, particularly within the sphere of influence of Indian Point and other major Hudson River electric-generating facilities (of which there are several), has been continuously and extensively evaluated, and peer reviewed by leading fisheries biologists, since the original licensing of IP2. These studies, undertaken at an annual cost to the Hudson River facilities of $2.0 million annually (in 1981 dollars), and performed at the direction and under the oversight of NYSDEC, have resulted in what William Sarbello, then of the NYSDEC, referred to in November 2000 as "probably, the best data set on the planet." [USEPA].

The IP2 FES concluded that the issuance of an operating permit for IP2 to former owner ConEdison should be subject to the conditions relating to 316(b) considerations: (1) once-through cooling would be permitted only until January 1, 1978; (2) evaluate the economic and environmental impacts of a new closed-cycle cooling system to determine a preferred system to install and submit this evaluation to the USAEC by July 1, 1973; (3) ConEdison should monitor the nature and extent of impingement and entrainment mortality; and (4) ConEdison should submit a plan of action for minimizing detrimental effects on aquatic biota by July 1, 1973, and implement the plan upon approval by the USAEC [USAEC, Section XI.C]. These conditions, among others, were inserted by the NRC into the IP2 Operating License as Condition 2.E. A similar license condition was included in the IP3 Operating License issued to NYPA, the former owner of IP3. Consistent with these licensing conditions, ConEdison and NYPA submitted an Environmental Report in 1976 to the NRC in which various alternative closed-cycle cooling systems were evaluated for IP2 and IP3 from an economic and environmental standpoint. The time frame established in the FES and IP2 and IP3 license conditions was extended until May 1, 1982, and then rendered moot by the 1981 execution of the global settlement, known as the HRSA, arising out of the parallel EPA NPDES permitting process for IP2 and IP3, in which all parties agreed that closed-cycle cooling would not be implemented at that time.

In 1975, contemporaneous with ConEdison and NYPA's review of closed-cycle cooling systems, EPA initiated NPDES permitting proceedings for both stations, producing an initial draft permit (jointly held by IP2 and IP3 because of their shared discharge canal) that echoed the respective NRC licenses for these stations in requiring closed-cycle cooling (EPA actually required closed-cycle cooling for all of the Hudson River facilities). NYPA and ConEdison opposed these NPDES permit conditions, initiating a contested proceeding (with substantial collateral litigation). Consolidated adjudicatory hearings commenced in February 1977 before an EPA administrative law judge, and several years were engaged in the station owners' marshalling of evidence and witnesses. In July 1979, EPA's witnesses were called to the stand, and the owners of the various stations began cross-examination. The landmark HRSA settlement occurred at this time, resolving the need for further continued hearings or an EPA decision.

In particular, the ten-year HRSA, dated October 19, 1980, resolved the then-pending EPA permit proceeding relating to IP2 and IP3 and reflects the negotiated resolution among EPA, the NYSDEC, the former owners of the Hudson River facilities, including ConEdison and NYPA, and various environmental groups. As a result of the HRSA, both former owners, ConEdison and NYPA, submitted a license amendment request to the NRC for the removal of license condition 2.E that required the closed-cycle cooling system [HRSA]. License Amendment No. 71 removed Condition 2.E, for both IP2 and IP3, effective May 14, 1981 [NRC 1981]. In place of the cooling tower requirement, the HRSA included various technical, operational and restoration measures relating to the Hudson River facilities, including IP2 and IP3. These measures included, with respect to IP2 and IP3, the installation of dual or variable speed intake pumps, state-of-the-art Ristroph screens and fish-return systems, flow reduction obligations (facilitated by the pump retrofits) designed to minimize water use in a manner consistent with efficient station operation, appropriate outage scheduling (including through an outage credit point system that rewarded outages taken during potential entrainment periods). In addition, the development of a striped bass fish hatchery was made a joint requirement for all of the power generators party to the HRSA, as were certain other requirements [HRSA].

The new pumping systems were timely installed at IP3 and IP2. Ristroph screens and fish return systems were timely installed at IP3 and IP2 and completed in 1990 and 1991, respectively. IP2 has six two-speed circulating water pumps designed to pump 140,000 gpm at full speed and 84,000 gpm at reduced speed. IP3 has six variable-speed circulating water pumps designed to pump 140,000 gpm at full speed and 64,000 gpm at the lowest speed. [IP2 UFSAR, Section 10.2.4; IP3 UFSAR Section 10.2.4] Each unit has six service water pumps, IP3 rated at 6,000 gpm for each pump and IP2 at 5,000 gpm for each pump. There are three back-up service water pumps located on a platform at IP3 over the discharge channel. After moving through the condensers, cooling water from IP2 and IP3 flows downward from the discharge water boxes by way of six 96-inch down pipes, and exits under the water surface in a 40-foot wide discharge canal. [CHGEC]

The owners use best reasonable efforts to operate the IP2 and IP3 dual and variable speed circulating pumps so as to keep the volume of River water drawn into the stations at the minimum required for efficient operation, considering ambient river water temperature, plant operating status, the need to meet water quality standards and other permit conditions. Flow rates are dependent upon intake water temperature, and typically peak between early May and late October. [CHGEC, Section VIII.B.2]

The first SPDES permit was granted to both units in 1982, with the HRSA annexed as a permit condition for the duration of the HRSA. A SPDES permit renewal was granted in October 1987 by the NYSDEC [Attachment C], again during the lifespan of the HRSA. In 1992, a timely SPDES permit renewal application was submitted to the NYSDEC for both units, as a result of which the 1992 permit continues in effect under New York administrative law until a new permit is issued by NYSDEC. The HRSA, which was annexed to the 1982 SPDES Permit, expired after its 10-year term, but was replaced by four judicially approved consecutive Consent Orders, the first of which was executed in 1992, between the owners of IP2 and IP3, other Hudson River power generators, NYSDEC, and other stakeholders. Each of these Consent Orders effectively continued the HRSA terms and conditions, although without requiring outages at IP2 or IP3, or the continued operation of the striped bass hatchery (owing in part to the striped bass population proliferation over the period in question). The most recent Consent Order expired in 1998 [NYSDEC 1997a]. However, IP2 and IP3 voluntarily have agreed with NYSDEC to continue the activities required in the last Consent Decree. The submission of a timely and complete SPDES renewal application for IP2 and IP3 administratively continued the site's current SPDES permit under the New York State Administrative Procedure Act and the NYSDEC's implementing regulations.

In July 1992, NYSDEC requested that certain of the Hudson River power generators, including IP2 and IP3, submit an EIS under the New York SEQRA on the potential impacts of their requested SPDES permit renewals. In conjunction with the SPDES Permit applications for Indian Point, Roseton, and Bowline Point generation plants, these owners responded by providing a DEIS in 1993, and, after an extensive interim consultation with the NYSDEC, a revised DEIS in 1999 [CHGEC]. The NYSDEC accepted the DEIS as complete as a matter of New York administrative law and issued its FEIS in 2003, but, in conjunction with litigation among the parties, subsequently determined that additional public involvement and response was needed before a FEIS would be issued to IP2 and IP3 or any other of the Hudson River facilities addressed on a cumulative basis in the DEIS and FEIS [NYSDEC 2003b].

NYSDEC also issued a draft SPDES permit for IP2 and IP3 in 2003 that, among other conditions, requires the design and, if appropriate, the installation of closed-cycle cooling systems for IP2 and IP3 if the site seeks and receives from NRC license renewals for IP2 and IP3, and the NRC, among other regulators, reaches all appropriate feasibility and safety determinations [NYSDEC 2003a]. In particular, the draft SPDES permit fact sheet states: "This permit does not require the construction of cooling towers unless: (1) the applicant seeks to renew its NRC operating licenses, (2) the NRC approves extension of the licenses, and determines that the installation and operation of closed-cycle cooling is feasible and safe, and (3) all other necessary Federal approvals are obtained." [NYSDEC 2003c, Section IV.D.4]. The draft permit also requires that all applicable local approvals must be obtained before cooling towers will be required. The conditions of the draft permit are the subject of a contested adjudicatory proceeding currently pending before a two-judge panel of NYSDEC administrative law judges. As a matter of New York administrative law, the 1992 SPDES permit remains in full effect as administratively continued, pending issuance of the final SPDES permit currently subject to the adjudicatory process. With respect to that contested proceeding, the owners of IP2 and IP3 have taken the position that the mitigation measures currently implemented at IP2 and IP3 as a result of the HRSA and Consent Orders, as supported by ongoing Hudson River monitoring, are adequate in minimizing potential impacts from current operations and operations during the license renewal period. Nonetheless, additional measures may be established as the outcome of the SPDES process and would be incorporated into the SPDES permit for IP2 and IP3 that would be in place during any license renewal period.

In sum, the owners of IP2 and IP3, and the owners of other Hudson River generating stations, have conducted comprehensive Hudson River aquatic studies under the oversight and direction of NYSDEC since the 1970s. The results of these studies were reported in the 1999 DEIS and 2003 FEIS. Based on the reports summarized in the DEIS and FEIS, studies completed in the 1970s included sampling and evaluation of all trophic levels in the Hudson River estuary. Representative species, populations and communities were defined and evaluated. During the 1980s and 1990s, studies focused more closely on key fish species, particularly those adults and larvae that use the estuary as spawning habitat or represent commercial/recreational species, chiefly striped bass. Many of these studies have specifically addressed the potential impacts of cooling water intake structures to the macroinvertebrates, all appropriate fish life stages and fish populations [NYSDEC 1997a]. IP2 and IP3 has installed dual or variable speed intake pumps, state-of-the-art Ristroph screens and fish-return systems, flow reduction obligations (facilitated by the pump retrofits) designed to minimize water use in a manner consistent with efficient station operation.

4.3.5.2 Impingement Analysis

IP2 and IP3 are equipped with once-through heat dissipation systems that withdraw cooling water from and discharges to the Hudson River. The details of the IP2 and IP3 cooling systems, intake structures, and discharge systems are provided in Chapter 3 of this ER. IP2 and IP3 each have shoreline-situated intake structures consisting of seven bays (six for circulating water and one for service water). Additional service water and screen wash water is provided for IP2 from the IP1 intake structure.

As explained above, the 1999 DEIS submitted to the NYSDEC on behalf of SPDES Permit Applications for Indian Point, Roseton, and Bowline Point generation plants provides extensive descriptions of more than 23 years of Hudson River fisheries and habitat studies involving trends in key species abundance, diversity, richness, and mortality rates, and impacts from impingement at once-through cooling water intakes. Specifically, the DEIS describes sampling study results at Indian Point, and identified 88 species of fish in more than 20 years of impingement studies. However, 95% of the catch was composed of eight species, which were selected by the NYSDEC for more analysis. The CMR was used to define quantitative estimates of impingement losses. The CMR uses monthly estimates of numbers of fish lost due to impingement in conjunction with estimates of the river population, during the same time period, to estimate the fraction of the river population lost due to IP2 and IP3 impingement if there were no other sources of mortality implicated. [CHGEC, Appendix VI-2-A]

CMR estimates of the numbers of fish lost to impingement integrated with estimates of the abundance of fish in the river were also presented in the DEIS as a percentage to estimate the proportional reduction of the population [CHGEC, Section VI.B.1.b]. CMRs and discussion of models to define the CMRs are presented in the DEIS and its appendixes [CHGEC, Section VI.2.A and B]. The estimated average annual CMR due to impingement for American shad is 0.0%, for Atlantic tomcod is 0.62%, for bay anchovy is 0.05%, for blueback herring is 0.22%, for alewife is 0.14%, for spottail shiner is 0.10%, for striped bass is 0.20%, and for white perch is 1.70% [CHGEC, Section V.D].

The diversity of species within the fish communities in the Hudson River ecosystem was generally affected by the ecosystem changes that affected water quality (the fish community in the brackish portion of the estuary) and habitat availability (the fish community in the freshwater portion of the estuary). The number of marine species entering the estuary increased when water quality increased in the New York City area. However, the diversity of YOY, yearling, and older fish in the lower portion of the estuary was more strongly affected (decreased) by the increase in the abundance of large striped bass. The number of freshwater species in the upper portion of the estuary decreased when the water chestnut populations recovered and achieved nuisance levels in the late 1970s and early 1980s. [CHGEC, Section V.D.4.c.]

It should be noted that the impingement percentages included data collected from 1981 to 1990, which was prior to installation of the Ristroph screens on the intakes for IP2 and IP3. Therefore, the impingement mortality during current operations and the license renewal period would be significantly less, based on the impingement mortality percentage estimates cited above and anticipating the continued use of the Ristroph screens and fish return systems installed. In the Fact Sheet to the draft permit, NYSDEC noted without objection that "[a]ccording to Entergy, this current design, along with seasonable flow reductions and generation outages…, attains an estimated 77% reduction in impingement mortality." [NYSDEC 2003c]

Subsequent to submission of the DEIS, the generators submitted to the NYSDEC, among other things, a review by three leading fisheries biologists, Drs. Charles C. Coutant, Lawrence W. Barnthouse and Webster Van Winkle, of the Hudson River data set, with a trend analysis of the relative abundance and diversity of the fish populations in the River [Barnthouse]. The express purpose of that Report was to provide an even greater level of confidence to NYSDEC regarding the DEIS conclusion that no adverse impacts to fisheries have occurred or are likely to occur as a result of the operation of the cooling water intake structures of the various stations, including IP2 and IP3. In addition, since submission of the DEIS, the generators have continued to provide the annual year-class reports outlining the results of the annual monitoring program for the year in question, as well as all of the raw data collected and an estimate of the abundance (i.e., standing crop) of fish in the River during that period. This information continues to confirm the absence of any adverse impact on fisheries reasonably attributable to IP2 or IP3 [ASA].

4.3.6 Conclusion

More than 30 years of extensive fisheries studies of the Hudson River in the vicinity of IP2 and IP3 support current operations. The results of the studies performed from 1974 to 1997, the period of time covered in the DEIS, are referenced and summarized in the DEIS, and have not shown any negative trend in overall aquatic river species populations attributable to plant operations. Ongoing studies continue to support these conclusions [ASA]. In addition, current mitigation measures implemented through the HRSA and retained in the four Consent Orders, the current agreements with NYSDEC, and the outcome of the draft SPDES Permit proceeding, will ensure that impingement impacts remain SMALL during the license renewal term. Therefore, withdrawal of water from the Hudson River for the purposes of once-through cooling at the site does not have any demonstrable negative effect on representative Hudson River fish populations, nor does it warrant further mitigation measures.

4.4 Heat Shock

4.4.1 Description of Issue

Heat Shock (for all plants with once through and cooling pond heat dissipation systems)

4.4.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, OR LARGE. Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants. See 10 CFR 51.53(c)(3)(ii)(B).

4.4.3 Requirement [10 CFR 51.53(c)(3)(ii)(B)]

If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40 CFR Part 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock....

4.4.4 Background

Based on the research literature, monitoring reports, and agency consultations, the potential for thermal discharges to cause thermal discharge effect mortalities is considered small for most plants. However, impacts may be moderate or even large at a few plants with once-through cooling systems. For example, thermal discharges at one plant are considered by the agencies to have damaged the benthic invertebrate and seagrass communities in the effluent mixing zone around the discharge canal; as a result, helper cooling towers have been installed to reduce the discharge temperatures. Conversely, at other plants it may become advantageous to increase the temperature of the discharge in order to reduce the volume of water pumped through the plants and thereby reduce entrainment and impingement effects. Because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions, this is a Category 2 issue for plants with once-through cooling systems. [NRC 1996, Section 4.2.2.1.4]

4.4.5 Analysis of Environmental Impact

4.4.5.1 Background

New York State has developed mixing zone criteria and thermal discharge limits for steam-electric power plants. These limits are designed to protect the existence of a balanced indigenous population of shellfish, fish, and wildlife in the receiving water body. If the facility cannot meet the stated water quality standard criteria, the facility must submit data demonstrating that its actual discharge will ensure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife. This demonstration is referred to as a 316(a) demonstration. The NPDES permit required for a power plant typically contains discharge temperature limits that are based on either state standards or 316(a) demonstrations.

The site holds SPDES permit NY-0004472 with effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with Title 8 of Article 17 of the Environmental Conservation Law (ECL) of New York State and the CWA, as amended (33 U.S.C. Section 1251 et seq.). In accordance with permit requirements, the site monitors discharge characteristics and reports the results to the NYSDEC. A copy of the current SPDES Permit is attached [Attachment C].

The site is equipped with a once-through heat dissipation system that withdraws cooling water from and discharges to the Hudson River. The details of the plant cooling systems, intake structures, and discharge systems are provided in Section 3. IP2 and IP3 each have shoreline-situated intake structures consisting of seven bays (six for circulating water and one for service water). Additional service water and screen wash water is provided for IP2 from the IP1 intake structure.

IP2 has six two-speed circulating water pumps designed to pump 140,000 gpm at full speed and 84,000 gpm at reduced speed. IP3 has six variable-speed circulating water pumps designed to pump 140,000 gpm at full speed and 64,000 gpm at the lowest speed. Each unit has six service water pumps, IP3 rated at 6,000 gpm for each pump and IP2 at 5,000 gpm for each pump. There are three back-up service water pumps located on a platform at IP3 over the discharge channel. After moving through the condensers, cooling water from IP2 and IP3 flows downward from the discharge water boxes via six 96-inch downpipes and exits under the water surface in a 40-foot wide discharge canal.

The site uses best reasonable efforts to operate the IP2 and IP3 dual and variable speed circulating pumps so as to keep the volume of river water drawn into the plant at the minimum required for efficient operation, considering ambient river water temperature, plant operating status, and the need to meet thermal water quality standards and other permit conditions. Flow rates are dependent upon intake water temperature and typically peak between early May and late October.

Impacts due to thermal discharge have been studied and evaluated since the original licensing of IP2. The IP2 FES concluded that the issuance of an operating permit for IP2 should be subject to the following specified conditions: (1) once-through cooling would be permitted only until January 1, 1978, with a closed-cycle cooling system thereafter; (2) the site must evaluate the economic and environmental impacts of a new closed-cycle cooling system to determine a preferred system to install and submit this evaluation to the USAEC by July 1, 1973; (3) the required closed-cycle cooling system shall be designed, built, and put into operation no later than January 1, 1978; (4) ConEdison should monitor the nature and extent of impingement and entrainment mortality; (5) ConEdison should monitor concentrations of residual free and combined chlorine during each chlorination period and its effects on biota; (6) ConEdison should monitor dissolved oxygen in the discharge water and thermal plume; (7) ConEdison should monitor the size, shape, and locations of isotherms in the thermal plume; (8) ConEdison should monitor changes in aquatic life in the Hudson River from operation of the once-through cooling system; (9) ConEdison should submit a plan of action for minimizing detrimental effects on aquatic biota by July 1, 1973, and implement the plan upon approval by the USAEC [USAEC, Section XI.C]. These conditions were inserted by the NRC into the IP2 Operating License as Condition 2.E. Similar license conditions were subsequently included in the IP3 Operating License.

Former owners ConEdison and NYPA submitted an Environmental Report in 1976 to the NRC in which various alternative closed-cycle cooling systems were evaluated for IP2 and IP3 from an economic and environmental standpoint. In 1980, litigation concerning the operation of electric generating units on the Hudson River, including IP2 and IP3, resulted in the HRSA, which was negotiated between the NYSDEC, the former owners of the sites, and other parties to the litigation. As a result of the HRSA, both former owners, ConEdison and NYPA, submitted a license amendment request to the NRC for the removal of license condition 2.E that required the closed-cycle cooling system [HRSA]. License Amendment No. 71 removed Condition 2.E, for both IP2 and IP3, effective May 14, 1981 [NRC 1981]. In place of the cooling tower requirement, the HRSA included mitigation measures relating to IP2 and IP3 including seasonal outages, installation of dual or variable speed intake pumps, installation of angled screens to minimize impingement, and the development of a striped bass fish hatchery (this latter was made a joint requirement for all of the power generators party to the HRSA) [HRSA].

The first SPDES permit was granted to both units in 1982, with the HRSA annexed as a permit condition for the duration of the HRSA. An SPDES permit renewal was granted in October 1987 by the NYSDEC [Attachment C], again during the lifespan of the HRSA. In 1992, a timely SPDES permit renewal application was submitted to the NYSDEC for both units, as a result of which the 1992 permit continues in effect under New York administrative law until a new permit is issued by NYSDEC. The HRSA, which was annexed to the 1982 SPDES Permit, expired after its 10-year term, but was replaced by four judicially approved consecutive Consent Orders, the first of which was executed in 1992, between the owners of IP2 and IP3, other Hudson River power generators, NYSDEC, and other stakeholders [NYSDEC 1997a]. Each of these Consent Orders effectively continued the HRSA terms and conditions, although without requiring outages at IP2 or IP3, or the continued operation of the striped bass hatchery (owing in part to the striped bass population proliferation during the period in question). The consent orders did, however, incorporate flow reduction requirements consisting of flow credits. The most recent Consent Order expired in 1998. However, IP2 and IP3 voluntarily have agreed with NYSDEC to continue the activities required in the last Consent Decree. The submission of a timely and complete SPDES renewal application for IP2 and IP3 administratively continued the site's current SPDES permit under the New York State Administrative Procedure Act and the NYSDEC's implementing regulations.

In July 1992, NYSDEC requested that certain of the Hudson River power generators, including IP2 and IP3, submit an EIS under the New York State SEQRA on the potential impacts of their requested SPDES permit renewals. In conjunction with the SPDES Permit applications for Indian Point, Roseton, and Bowline Point generation plants, these owners responded by providing a DEIS in 1993, and, after an extensive interim consultation with the NYSDEC, a revised DEIS in 1999 [CHGEC]. The NYSDEC accepted the DEIS as complete as a matter of New York administrative law, and issued its FEIS in 2003, but, in conjunction with litigation among the parties, subsequently determined that additional public involvement and response was needed before a final SPDES permit would be issued [NYSDEC 2003b] to IP2 and IP3 or any other of the Hudson River facilities addressed on a cumulative basis in the DEIS and FEIS.

NYSDEC also issued a draft SPDES permit for IP2 and IP3 in 2003 that, among other conditions, requires the design and, if appropriate, the installation of closed-cycle cooling systems for IP2 and IP3 if the site seeks and receives from NRC license renewals for IP2 and IP3, and the NRC, among other regulators, reaches all appropriate feasibility and safety determinations [NYSDEC 2003a]. In particular, the draft SPDES fact sheet states, "This permit does not require the construction of cooling towers unless: (1) the applicant seeks to renew its NRC operating licenses, (2) the NRC approves extension of the licenses, and determines that the installation and operation of closed-cycle cooling is feasible and safe, and (3) all other necessary Federal approvals are obtained." [NYSDEC 2003c]. The draft permit also requires that all applicable local approvals must be obtained before cooling towers will be required. The conditions of the draft permit are the subject of a contested adjudicatory proceeding currently pending before a two-judge panel of NYSDEC administrative law judges. As a matter of New York administrative law, the 1992 SPDES permit remains in full effect as administratively continued, pending issuance of the final SPDES permit currently subject to the adjudicatory process. With respect to that contested proceeding, the owners of IP2 and IP3 have taken the position that the mitigation measures currently implemented at IP2 and IP3 as a result of the HRSA and Consent Orders, as supported by ongoing Hudson River monitoring, are adequate in minimizing potential impacts from current operations and operations during the license renewal period. Nonetheless, additional measures may be established as the outcome of the SPDES process and would be incorporated into the SPDES permit for IP2 and IP3 that would be in place during any license renewal period.

The site and the other Hudson River power generating utilities have conducted Hudson River aquatic studies since the 1970s. The results of these studies were reported in the 1999 DEIS and 2003 FEIS. Based on the reports summarized in the DEIS and FEIS, studies completed in the 1970s included sampling and evaluation of all trophic levels in the Hudson River estuary. Key species, populations, and communities were defined. During the 1980s, studies focused more closely on the fish species, particularly those adults and larvae that use the estuary as spawning and nursery habitat. As part of the Hudson River Utilities Monitoring Program, extensive environmental studies were conducted by the Hudson River utilities and the NYSDEC in the Hudson River estuary. Many of these studies have specifically addressed potential impacts to the macroinvertebrates, larval fish, adult fish, and anadromous fish populations. Thermal mitigation measures have been implemented in accordance with the HRSA and subsequent Consent Orders [NYSDEC 1997a]. Among others, these mitigation measures have included installation of the dual- and multi-speed cooling water intake pumps and minimizing cooling water withdrawal to only that required for efficient plant operation.

4.4.5.2 Thermal Discharge Analysis

Conditions established by the NYSDEC related to thermal discharge and included in the site's SPDES Permit NY-0004472 are as follows.

- The discharge temperature is not to exceed 110°F.
- Between April 15 and June 30, daily maximum temperature is not to exceed 93.2°F for more than 10 days a year.
- Between April 15 and June 30, daily average temperature is not to exceed 93.2°F for more than 15 days during the term of the permit.
- Twenty-two (22) inches of head differential is to be maintained between levels in the discharge canal and river height whenever site gross electrical output exceeds 600 MWe or river temperature exceeds 90°F.

These conditions, which the facility is in compliance with, were established by the NYSDEC to ensure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife in the Hudson River.

The DEIS identifies the major potential biothermal effects as mortality from excess temperature, mortality from cold shock, blockage of migration, reduced growth or reproductive success. As discussed in the DEIS and sections above, the sites' discharges were designed, and are operated, to minimize potential adverse impacts. Studies conducted at the time of installation during the 1970s and since provide evidence that heat discharge from the sites' cooling systems does not cause appreciable harm or interfere with the maintenance of a balanced indigenous aquatic population. Conclusions regarding each of the major potential thermal biological effects are summarized in the DEIS [CHGEC, Section VI.B.4.c].

4.4.6 Conclusions

Pursuant to 10 CFR 51.53(c)(3)(ii)(B), cited above, the site holds an NYSDEC SPDES permit (NY-0004472) for discharge of cooling waters from IP2 and IP3 [NYSDEC 1987]. The Station is complying with this permit, including limits and conditions established by the NYSDEC for thermal discharges. As mentioned above, IP2 and IP3 entered into a fourth amended Consent

Order with NYSDEC in 1997 which provided that IP2 and IP3's owners would continue mitigation measures, such as the flow reductions timed to reduce impacts to certain fish species [NYSDEC 1997a]. Entergy and former site owner/operators ConEdison and NYPA have conducted extensive studies of the impacts of IP2 and IP3 operations, and the 30-year-plus dataset supports current IP2 and IP3 operations. Entergy concludes that continued operation in the manner required by the current SPDES permit and the associated agreement to continue implementation of the fourth Consent Decree ensures that thermal impacts will satisfy the requirements of CWA 316(a) and will thus remain SMALL during the license renewal term. Therefore, no further mitigation measures are warranted.

4.5 Groundwater Use Conflicts (Plants Using >100 gpm of Groundwater)

4.5.1 Description of Issue

Groundwater use conflicts (potable and service water and dewatering: plants that use >100 gpm).

4.5.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Plants that use more than 100 gpm may cause groundwater use conflicts with nearby groundwater users. See 10 CFR 51.53(c)(3)(ii)(C).

4.5.3 Requirement [10 CFR 51.53(c)(3)(ii)(C)]

If the applicant's plant uses Ranney wells or pumps more than 100 gallons (total onsite) of groundwater per minute, an assessment of the impact of the proposed action on groundwater use must be provided.

4.5.4 Analysis of Environmental Impact

Potable water is supplied by the Village of Buchanan, which purchases water from the City of Peekskill PWS and the NWJWW, and cooling and service water is taken from the Hudson River. Therefore, this issue is not applicable to the site and analysis is not required.

4.6 Groundwater Use Conflicts (Plants Using Cooling Towers Withdrawing Make-Up Water from a Small River)

4.6.1 Description of Issue

Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river).

4.6.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Water use conflicts may result from surface water withdrawals from small water bodies during low flow conditions which may affect aquifer recharge, especially if other groundwater or upstream surface water users come on line before the time of license renewal. See 10 CFR 51.53(c)(3)(ii)(A).

4.6.3 Requirement [10 CFR 51.53(c)(3)(ii)(A)]

If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on in-stream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow.

4.6.4 Analysis of Environmental Impact

The site, which withdraws water from an estuary of the Hudson River, does not utilize cooling towers or cooling ponds and does not withdraw water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year). Therefore, this issue is not applicable to the site and further analysis is not required.

4.7 Groundwater Use Conflicts (Plants Using Ranney Wells)

4.7.1 Description of Issue

Groundwater use conflicts (plants using Ranney wells).

4.7.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Ranney wells can result in potential groundwater depression beyond the site boundary. Impacts of large groundwater withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal. See 10 CFR 51.53(c)(3)(ii)(C).

4.7.3 Requirement [10 CFR 51.53(c)(3)(ii)(C)]

If the applicant's plant uses Ranney wells or pumps more than 100 gallons (total on-site) of groundwater per minute, an assessment of the impact of the proposed action on groundwater use must be provided.

4.7.4 Analysis of Environmental Impact

The site, which utilizes cooling and service water taken directly from the Hudson River, does not utilize Ranney wells. Therefore, this issue is not applicable to the site and analysis is not required.

4.8 Degradation of Groundwater Quality

4.8.1 Description of Issue

Groundwater quality degradation (cooling ponds at inland sites).

4.8.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Sites with closed-cycle cooling ponds may degrade groundwater quality. For plants located inland, the quality of the groundwater in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses. See 10 CFR 51.53(c)(3)(ii)(D).

4.8.3 Requirement [10 CFR 51.53(c)(3)(ii)(D)]

If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided.

4.8.4 Analysis of Environmental Impact

The site, which is located in a coastal area, uses a once-through cooling system and does not utilize cooling ponds. Therefore, this issue is not applicable to the site and analysis is not required.

4.9 Impacts of Refurbishment on Terrestrial Resources

4.9.1 Description of Issue

Refurbishment impacts - Terrestrial Resources

4.9.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application. See 10 CFR 51.53(c)(3)(ii)(E).

4.9.3 Requirement [10 CFR 51.53(c)(3)(ii)(E)]

All license renewal applicants shall assess the impact of refurbishment and other license renewal related construction activities on important plant and animal habitats.

4.9.4 Analysis of Environmental Impact

As noted in Section 3.3, there are no refurbishment activities required for IP2 and IP3 license renewal. Therefore this issue is not applicable to the site and no further analysis is required.

4.10 Threatened or Endangered Species

4.10.1 Description of Issue

Impacts from refurbishment and continued operations on threatened or endangered species.

4.10.2 Finding from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected. See 10 CFR 51.53(c)(3)(ii)(E).

4.10.3 Requirement of 10 CFR 51.53(c)(3)(ii)(E)

All license renewal applicants shall assess the impact of refurbishment and other license renewal related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act.

4.10.4 Background

The NRC did not reach a conclusion about the significance of potential impacts to threatened and endangered species in the GEIS because (1) the significance of impacts on such species cannot be assessed without site- and project-specific information that will not be available until the time of license renewal and (2) additional species that are threatened with extinction and that may be adversely affected by plant operations may be identified between the present and the time of license renewal. [NRC 1996, Section 3.9]

4.10.5 Analysis of Environmental Impact

Section 2.4 addresses issues related to critical and important habitats, wetlands, and unique natural areas. Section 2.5 discusses threatened or endangered species that could occur within the vicinity of the site.

As discussed in Section 3.3, Entergy has no plans to conduct refurbishment or construction activities at the site during the license renewal term. Therefore, there would be no refurbishment-related impacts to special-status species and no further analysis of refurbishment-related impacts is applicable.

Entergy contacted the USFWS, NMFS, and NYNHP for input on the presence of listed threatened or endangered species in the vicinity of Indian Point, and received input in December 2006 and January 2007. As stated in Section 2.5, there are four federally protected animal species which may occur in the vicinity of the site: Indiana Bat, bog turtle, bald eagle, and shortnose sturgeon. Of the four species, only two, the shortnose sturgeon and the bald eagle, are confirmed as being present in the site area. There have been no sightings or knowledge of local populations of either the Indiana Bat or the bog turtle either on-site or within the vicinity of the site. The USFWS also identified the New England Cottontail as a Candidate Species for listing in Westchester County [USFWS 2007]. NMFS listed the Atlantic sturgeon as a potential species for listing (See Attachment A) [NMFS 2007].

In recent years, the stretch of the Hudson from Kingston to Croton has been an increasingly popular bald eagle area, probably because sections of the river are kept open by discharges from power plants and railroad tracks provide an ample supply of dead animals (carrion) for scavenging eagles. Bald eagles have increased in total number, successful nesting pairs, and number of young produced. Alteration of the landscape required by bald eagles continues to be the biggest single threat to this species. Logging, developments of all kinds, and increasing demands for public use of all kinds (i.e. boating, canoe/kayak trails, personal watercraft, ATVs, hiking trails, etc.) are increasing at a tremendous rate that is not commensurate with protection of the landscape [NYSDEC 2005a]. Future continued bald eagle preservation for future generations will be tied to protection of habitat. There are no plans to alter operations, expand existing facilities, or acquire additional land in support of license renewal, therefore there are no anticipated potential impacts on nesting sites from continued site operations. Entergy has fleet procedural controls in place to ensure that threatened and endangered species are adequately protected if present, during site operations and project planning [Entergy].

The shortnose sturgeon is considered to be amphidromous, since they appear to spend most of their life in their natal river and only occasionally enter nearby coastal water. In the Hudson River, it spawns from April - May. Adult sturgeon migrate upriver from their mid-Hudson over-wintering areas to freshwater spawning sites north of Coxsackie [NMFS 2000].

NMFS indicated a potential for entrainment of Atlantic sturgeon larvae in the region in which Indian Point is located. NMFS noted sturgeon yolk sac larvae (YSL) and PYSL have been documented in the vicinity of Indian Point, but assumes the larvae in the lower river area (RM 48 to 110) are Atlantic sturgeon. As noted in Section 2.5 of this ER, the Atlantic sturgeon is not yet a listed threatened or endangered species, but is a species of concern. NMFS also indicated a potential for impingement of shortnose sturgeon on the IP2 and IP3 intake screens. In its January 2007 letter, NMFS requested additional information from Entergy regarding the impacts of its intake and discharge on sturgeon species. In a March 2007 follow-up letter received from the NMFS as a result of discussions between Entergy and NMFS, the agency clarified its position regarding sturgeon species entrainment and impingement, citing Section 7(a)(2) of the Endangered Species Act (ESA) which requires a Section 7 consultation for a federal action, such as the renewal of an operating license. If it is determined through consultation between the NRC and NMFS that the action is not likely to adversely affect any listed species, then no additional measures are necessary. However, it is determined that the action is likely to adversely affect any listed species, then a formal consultation resulting in the issuance of a Biological Opinion and accompanying Incidental Take Statement would be required. (See Attachment A)

NMFS issued an Environmental Assessment (EA) in 2000 to address the issuance of an Incidental Take Permit pursuant to Section 10 of the Endangered Species Act (ESA) for the incidental take of shortnose sturgeon resulting from the operation of cooling water systems at two existing power plants, the Roseton and Danskammer Point power plants, located on the Hudson River estuary. As part of its permit application, Central Hudson Gas & Electric Corporation (CHGEC) prepared a Conservation Plan that included minimization, monitoring, and adaptive management strategies to ensure that the continued operation of these two plants would not jeopardize the recovery of shortnose sturgeon in the Hudson River [ASA]. In its EA, NMFS evaluated the cumulative impacts of incidental take from all the Hudson River power plants, including Indian Point. [NMFS 2000, Section 1]

In its 2000 EA, NMFS noted the following:

- The population of shortnose sturgeon in the Hudson River estuary appears to have increased over the past few decades and the Estuary presently contains the largest discrete population of shortnose sturgeon reported anywhere. Recent studies have suggested a four-fold increase in population size since the 1970s. Available data appear to indicate that the population of shortnose sturgeon in the Hudson River estuary is healthy and that this species is reproducing and adding young fish to the Hudson population. [NMFS 2000, Section 4.5.3]

- Due to their life-history characteristics, the Hudson River population of shortnose sturgeon has low vulnerability to entrainment effects from operation of any of the six power plants. Shortnose sturgeon spawn in the northern most areas of the Estuary. In addition, shortnose sturgeon eggs are demersal and adhesive and, upon hatching, yolk-sac larvae and larvae seek cover on the bottom. As a result, the eggs and larvae of shortnose sturgeon are located primarily upstream of RM 110, well upriver of any of the six power plant intakes. [NMFS 2000, Section 5.21];

- NMFS noted that of the six Hudson River power plants, only the Bowline Point plant was located near a concentration of shortnose sturgeon. Based on the distribution of shortnose sturgeon concentration areas, juvenile and adult shortnose sturgeon are unlikely to frequent the area of the remaining five power plants and thus appear to have relatively low vulnerability to impingement at any of these power plants. Further, juvenile shortnose sturgeon prefer the deeper waters of channel areas, where they are found on the bottom. This deep benthic orientation, coupled with the fact that the intakes of these power plants are located along the shore, further reduces vulnerability to impingement at any of these five power plants. [NMFS 2000, Section 5.2.2]

- It is important to recognize that many impinged fish survive once returned to the Estuary such that lethal take will be considerably lower. Each of the Hudson River Utilities have conducted impingement viability studies at their respective intakes and have demonstrated that the majority of the species impinged have moderate to high survival rates. Hardier species are likely to exhibit extremely high survival after impingement. Shortnose sturgeon are relatively hardy and resistant to physical stresses similar to those encountered in power plant. During recent intensive trawling of the Estuary to study shortnose sturgeon, the sampling team from Cornell University collected and handled more than 7,000 shortnose sturgeon without a single reported mortality. [NMFS 2000, Section 5.2.2]

- The NMFS estimated impingement at the site to be approximately 0.8 occurrences per year each at IP2 and IP3, or 1.6 fish per year, since the installation of the Ristroph screens at the site in 1990 and 1991. Based on the apparent rate of decay, some of those collected were dead prior to collection. By comparison, Roseton and Danskammer Point were estimated to impinge an average of approximately 1.5 and 4.4 shortnose sturgeon per year, respectively. Based on these data, the NMFS concluded that future impingement rates due to incidental take are unlikely to jeopardize the continued recovery of the Hudson River shortnose sturgeon population [NMFS 2000, Section 5.2.2].

In 1979 the NMFS biological opinion, issued prior to installation of the IP2 and IP3 Ristroph traveling screens and fish return systems, concluded that overall, the intakes and discharges of Hudson River power plants are unlikely to jeopardize the recovery of the Hudson River shortnose sturgeon population [Dadswell]. This opinion was validated by the results of the 2000 EA. Entergy believes that the installation of the Ristroph screens and fish return systems at the site minimizes or eliminates the potential for shortnose sturgeon impingement mortality and concurs with NMFS that the impact to the Hudson River shortnose sturgeon population is small [NMFS 2000].

In the NMFS 2007 response to Entergy's request for comment on listed species, the agency noted status review for the Atlantic sturgeon has been initiated and considers the species a Candidate Species. NMFS notes that a distribution of YSL and PYSL have been identified in the Hudson from RM 48 to RM 110 and assumes the lower river grouping are Atlantic sturgeon. As such, NMFS considers entrainment a significant concern for Atlantic sturgeon in this area of the river. However, the Atlantic sturgeon eggs are large, demersal, and adhesive, and attach within about 20 minutes to rocks, gravel, plants, roots, and other objects [CHGEC, Section V.D.2.h.i]. By the time their yolk sac is absorbed (about 9-10 days post hatch), the larvae clearly exhibit a predominantly benthic behavior, swimming on the bottom or near the bottom with increased scouring activity [CHGEC, Section V.D.2.h.i]. Thus, the potential impact from entrainment or impingement for the Atlantic sturgeon is SMALL and would be similar to that of the shortnose sturgeon discussed above.

During the environmental assessment for license renewal, the NYNHP was contacted for information regarding state listed threatened and endangered species and unique natural areas in the vicinity of the site. The NYNHP provided comment on species potentially occurring within a six-mile radius of the site, but did not identify adverse impacts to state protected animals or plants that would occur (See Attachment A).

Potential threatened and endangered state listed plants and animals which could occur in the vicinity of the site have been identified in Table 2-4. These state listed species are not addressed in this ER as the species are not known to occur on the site.

Entergy is not aware of any potential concerns regarding threatened or endangered species which could occur due to the site operations. Maintenance activities necessary to support license renewal would be limited to previously disturbed areas on-site and no additional land disturbance is anticipated in support of license renewal. In addition there are no plans to alter plant operations during the license renewal term which would effect threatened and endangered species.

During the environmental assessment for license renewal, the NYNHP was contacted for information regarding state listed threatened and endangered species and unique natural areas in the vicinity of the site. The NYNHP provided comment on species potentially occurring within a six-mile radius of the site, but did not identify adverse impacts to state protected animals or plants that would occur (See Attachment A).

In addition, based on consultation with state and federal fish and wildlife agencies (see Attachment A), no critical habitats have been designated on the site and no impacts are anticipated to threatened and endangered species during the license renewal period.

4.10.6 Conclusion

The continued operation of the site will not adversely impact any federally listed species which may exist on or pass through the site. Any maintenance activities necessary to support continued plant operations during the license renewal period would be limited to previously disturbed areas on-site and no additional land disturbance is anticipated in support of license renewal and there are no plans to alter plant operations which would affect the aquatic ecology. In addition, Entergy has fleet procedural controls in place to ensure that threatened and endangered terrestrial species are adequately protected, if present, during site operations and project planning [Entergy].

If it is determined through consultation between the NRC and NMFS that the action is likely to adversely affect listed sturgeon species, then a formal consultation resulting in the issuance of a Biological Opinion and accompanying Incidental Take Statement may be required. Beyond the potential for the Incidental Take Statement, and a potential for a Habitat Conservation Plan for sturgeon species, Entergy anticipates any future Biological Opinion would conclude that the Hudson River intake and discharge at IP2 and IP3 will not jeopardize the recovery of the Hudson River sturgeon populations, and therefore the impact on these species is also SMALL.

Therefore, Entergy concludes that impacts to threatened or endangered species from license renewal would be SMALL and does not warrant additional mitigation measures.

4.11 Air Quality During Refurbishment (Nonattainment and Maintenance Areas)

4.11.1 Description of Issue

Air quality during refurbishment (nonattainment and maintenance areas).

4.11.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the number of workers expected to be employed during the outage. See 10 CFR 51.53(c)(3)(ii)(F).

4.11.3 Requirement [10 CFR 51.53(c)(3)(ii)(F)]

If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended.

4.11.4 Analysis of Environmental Impact

The site is located within the New Jersey-New York-Connecticut Interstate Air Quality Control Region (40 CFR 81.13). As discussed in Section 2.11, this area has been designated as a nonattainment area (40 CFR 81.333) for the 8-hour ozone standard (40 CFR 50.10) and the $PM_{2.5}$ (40 CFR 50.7) standard, both promulgated by EPA in 1997.

Although emissions regulated under state air quality regulations would be protective of air quality standards, Entergy has no plans for refurbishment related to license renewal at IP2 and IP3 as discussed in Section 3.3 of this ER. Therefore, this issue is not applicable to the site and analysis is not required.

4.12 Impact on Public Health of Microbiological Organisms

4.12.1 Description of Issue

Microbiological organisms (public health) (plants using lakes or canals, or cooling towers, or cooling ponds that discharge to a small river).

4.12.2 Finding from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically. See 10 CFR 51.53(c)(3)(ii)(G).

4.12.3 Requirement [10 CFR 51.53(c)(3)(ii)(G)]

If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow rate of less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided.

4.12.4 Background

Public health questions require additional consideration for the 25 plants using cooling ponds, lakes, canals, or small rivers because the operation of these plants may significantly enhance the presence of thermophilic organisms. The data for these sites are not now at hand and it is impossible to predict the level of thermophilic organism enhancement at a given site with current knowledge. Thus, the impacts are not known and are site-specific. Therefore, the magnitude of the potential public health impacts associated with thermal enhancement of *N. fowleri* cannot be determined generically [NRC 1996, Section 4.3.6].

4.12.5 Analysis of Environmental Impact

Although Indian Point is technically located on an estuary, and not a river, the net downstream flows due to surface runoff have been reported to be in excess of 11,700,000 gpm 20 percent of the time, 6,800,000 gpm 40 percent of the time, 4,710,000 gpm per minute 60 percent of the time, 3,100,000 gpm 80 percent of the time, and 1,800,000 gpm 98 percent of the time [IP2 UFSAR, Section 2.5]. Flow at Troy, New York, is gauged at the USGS station at Green Island and was reported in the DEIS. Based on calculations from Table V-7 of the DEIS, the average monthly freshwater flow at Green Island is approximately 12,643.5 cubic feet per second (cfs), or 3.99×10^{11} cubic feet per year (cfy) [CHGEC, Section V.B.3].

The flow of the Hudson River is controlled more by tides than by surface water runoff from the surrounding watershed. Tidal flow past the site is approximately 80 million gpm about 80 percent of the time, and the estimated flow 500 feet off the shore line is about nine million gpm in a 500-600 foot wide section [IP2 UFSAR, Section 2.5].

The site does not utilize a cooling pond, lake, or a canal. The 80 million gpm of tidal flow past the site is equivalent to 5.62×10^{12} cfy, which does not qualify as a small river. Therefore, this issue is not applicable to the site and further analysis is not required.

4.13 <u>Electromagnetic Fields - Acute Effects</u>

4.13.1 Description of Issue

Electromagnetic fields, acute effects (electric shock)

4.13.2 Findings from Table B-1, Subpart A, Appendix A

SMALL, MODERATE, or LARGE. Electric shock resulting from direct access to energized conductors or from induced charges in metallic structures has not been a problem at most operating plants and generally is not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electrical shock potential at the site. See 10 CFR 51.53(c)(3)(ii)(H).

4.13.3 Requirements [10 CFR 51.53(c)3)(ii)(H)]

If the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents, an assessment of the impact of the proposed action on the potential shock hazard from the transmission lines must be provided.

4.13.4 Background

The transmission line of concern is that between the plant switchyard and the intertie to the transmission system. With respect to shock safety issues and license renewal, three points must be made. First, in the licensing process for the earlier licensed nuclear plants, the issue of electrical shock safety was not addressed. Second, some plants that received operating licenses with a stated transmission line voltage may have chosen to upgrade the line voltage for reasons of efficiency, possibly without reanalysis of induction effects. Third, since the initial NEPA review for those utilities that evaluated potential shock situations under the provision of the NESC, land use may have changed, resulting in the need for reevaluation of this issue.

The electrical shock issue, which is generic to all types of electrical generating stations, including nuclear power plants, is of small significance for transmission lines that are operated in adherence with NESC. Without review of each nuclear plant's transmission line conformance with NESC criteria, it is not possible to determine the significance of the electrical shock potential. [NRC 1996, Sections 4.5.4 and 4.5.4.1]

4.13.5 Analysis of Environmental Impact

Objects near transmission lines can become electrically charged due to their immersion in the lines' electric field. This charge results in a current that flows through the object to the ground. The current is called "induced" because there is no direct connection between the line and the object. The induced current can also flow to the ground through the body of a person who touches the object. An object that is insulated from the ground can actually store an electrical charge, becoming what is called "capacitively charged." A person standing on the ground and touching a vehicle or a fence receives an electrical shock due to the discharge of the capacitive charge through the person's body to the ground. After the initial discharge, a steady-state current can develop, the magnitude of which depends on several factors, including the following:

- strength of the electric field which, in turn, depends on the voltage of the transmission line as well as its height and geometry;
- size of the object on the ground; and
- extent to which the object is grounded.

In 1977, the NESC adopted a provision that describes an additional criterion to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98-kV alternating current to ground. The clearance must limit the steady-state induced current to 5 milliamperes if the largest anticipated truck, vehicle, or equipment were short-circuited to ground. By way of comparison, the setting of ground fault circuit interrupters used in residential wiring (special breakers for outside circuits or those with outlets around water pipes) is 4 to 6 milliamperes.

As discussed in Section 3.2.7 of this ER, the transmission lines that connect IP2 and IP3 to the transmission system are the lines that extend from the plant to the Buchanan Substation located across Broadway from the site. These lines include the 345-kV lines that transmit power from IP2 and IP3 and the 138-kV lines that provide offsite power from the Buchanan Substation to the stations. At the time IP2 and IP3 were acquired by Entergy, the 138-kV and 345-kV transmission lines between the plant and the Buchanan Substation met all applicable NESC vertical clearance requirements. Using methods described by EPRI, it was also demonstrated that these lines meet the more restrictive induced shock hazard limit of 4.5 mA required by New York Public Service Commission (NYPSC) [Con Edison].

No changes in the configuration or operation of these transmission lines have occurred since the ownership of these lines was transferred to Entergy. In addition, no significant changes have occurred in land use along the transmission line corridor between the plant and the Buchanan Substation. Therefore, these lines do not have the capacity to induce as much as 5 mA in a vehicle parked beneath the lines, which conforms to the NESC provisions for preventing electric shock from induced current.

Lines that connect IP2 and IP3 to the transmission grid at the Buchanan Substation meet the applicable vertical clearance requirements specified by the NESC for limiting the steady-state current due to electrostatic effects since these lines already meet the more restrictive induced shock hazard limit of 4.5 mA required by the NYPSC. Therefore, impacts due to the electrical shock potential for these lines is of SMALL significance and does not warrant further assessment or mitigation measures.

4.13.6 Conclusion

Lines that connect IP2 and IP3 to the transmission grid at the Buchanan substation meet the applicable vertical clearance requirements specified by NESC, and the clearance limits the steady-state current due to electrostatic effects to no more than 4.5 mA. Therefore, Entergy concludes that the electrical shock potential for these lines is of SMALL significance and does not warrant further assessment or mitigation measures.

4.14 Housing Impacts

4.14.1 Description of Issue

Housing Impacts.

4.14.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or in areas with growth control measures that limit housing development. See 10 CFR 51.53(c)(3)(ii)(I).

4.14.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on housing availability...(impacts from refurbishment activities only) within the vicinity of the plant must be provided.

4.14.4 Background

The impacts on housing are considered to be of small significance when a small and not easily discernible change in housing availability occurs, generally as a result of a very small demand increase or a very large housing market. Increases in rental rates or housing values in these areas would be expected to equal or slightly exceed the statewide inflation rate. No extraordinary construction or conversion of housing would occur where small impacts are foreseen.

The impacts on housing are considered to be of moderate significance when there is a discernible, but short-lived reduction in available housing units because of project-induced in-migration. The impacts on housing are considered to be of large significance when project-related demand for housing units would result in very limited housing availability and would increase rental rates and housing values well above normal inflationary increases in the state.

Moderate and large impacts are possible at sites located in rural and remote areas, at sites located in areas that have experienced extremely slow population growth (and thus slow or no growth in housing), or where growth control measures that limit housing development are in existence or have been recently lifted. [NRC 1996, Section 3.7.2]

4.14.5 Analysis of Environmental Impact

Supplement 1 to Regulatory Guide 4.2, provides the following guidance.

Section 4.14.1 states, "If there will be no refurbishment or if refurbishment involves no additional workers then there will be no impact on housing and no further analysis is required."

Section 4.14.2 states, "If additional workers are not anticipated there will be no impact on housing and no further analysis is required."

As of June 2006 the site had approximately 1,255 full time workers (Entergy employees and baseline contractors) during normal plant operations. The majority of these employees live within a five-county area surrounding the plant. As discussed in Section 2.9, steady growth in the housing market has occurred in the five county area near the site since 1990. In addition, vacancy rates have reduced, while the total number of new housing units has increased. This increase has kept pace with the low-to-moderate growth in the area population.

As noted in Section 3.3, there are no refurbishment activities required for the site license renewal. Additionally, Entergy does not anticipate a need for additional full time workers during the license renewal period.

4.14.6 Conclusion

Although the State of New York has growth control measures in place under New York's Open Space Conservation Plan, which is enforced by the Quality Communities Task Force, Entergy concludes that the impact on housing from the continued operation of the site will be SMALL and further mitigation is not warranted. This conclusion is based on the following:

- IP2 and IP3 are located in a high population area (see Section 2.6.2).
- There are no refurbishment activities required for license renewal at the site (see Section 3.3).
- Entergy does not anticipate an increase in employment during the license renewal period (see Section 3.5).
- Vacancy rates and new housing units have kept pace with low to moderate growth in the area's population (see Section 2.9).
- The number of the site employees will continue to be a very small percentage of the population in the adjacent counties during the period of the renewed license (see Sections 2.6.1 and 3.5).

4.15 Public Utilities; Public Water Supply Availability

4.15.1 Description of Issue

Public Services (public utilities).

4.15.2 Findings from Table B-1, Appendix B to Subpart A

SMALL or MODERATE. An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability. See 10 CFR 51.53(c)(3)(ii)(I).

4.15.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

The applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.

4.15.4 Background

Impacts on public utility services are considered small if little or no change occurs in the utility's ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as the quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services.

In general, small to moderate impacts to public utilities were observed as a result of the original construction of the case study plants. While most locales experienced an increase in the level of demand for services, they were able to accommodate this demand without significant disruption. Water service seems to have been the most affected public utility.

Public utility impacts at the case study sites during refurbishment are projected to range from small to moderate. The potentially small to moderate impact at Diablo Canyon is related to water availability (not processing capacity) and would occur only if a water shortage occurs at refurbishment time.

Because the case studies indicate that some public utilities may be overtaxed during peak periods, the impacts to public utilities would be moderate in some cases, although most sites would experience only small impacts [NRC 1996, Section 3.7.4.5].

4.15.5 Analysis of Environmental Impact

As noted in Section 3.3, there are no refurbishment activities required for the renewal of the IP2 and IP3 site Operating Licenses. In addition, Entergy does not anticipate a need for additional workers during the license renewal period. Therefore, there will be no impact to public utilities from refurbishment activities or additional plant workers.

Table 2-12 provides details on the major community water suppliers in the area surrounding the plant site. For all systems, the current system capacities are above the average daily demand on the respective water systems.

Plant operations during the license renewal period are not projected to cause a noticeable effect on the local water supply. The Village of Buchanan, which provides potable water to the site, purchases water from the City of Peekskill and Northern Westchester Joint Water Works (NWJWW) public water supply systems.

As discussed in Section 2.10.1 of this ER, the site purchases approximately 2,326,200 cubic feet (ft3) or 17,400,000 gallons per month of potable and process water from the Village of Buchanan water system. The Village of Buchanan purchases water from the City of Peekskill PWS and the NWJWW.

The City of Peekskill has two sources of water, both of which are surface waters. The City of Peekskill's year round major water source originates in the Town of Putnam Valley. The second water source is an emergency source from a neighboring community, via the Catskill Aqueduct, which is a major source for the New York City water system. The City of Peekskill's system uses the Catskill Aqueduct and NWJWW as alternative sources of water supply to meet peek summer loads. The NWJWW has assumed ownership of the Amawalk treatment plant, which has been upgraded to a 7,000,000 gpd capacity. A new NWJWW 7,000,000 gpd plant (Catskill water treatment plant) has been in operation since 2000. The City of Peekskill PWS supplies 4,000,000 gpd of reliable high-quality potable water to residential and industrial customers in the area, via water that is pumped to the Camp Field reservoir, where it is then filtered and treated.

In addition, a 1,500,000 gallon water storage tank is maintained on-site to add reliability to the site's makeup water system. Therefore, the City of Peekskill water system, which is the source of water for the Village of Buchanan, should be able to meet the site's water demand in the foreseeable future.

4.15.6 Conclusion

License renewal operations will not cause appreciable or a noticeable increased demand on the public water supply system. As noted in Section 3.3, there are no refurbishment activities required for the site's license renewal. Entergy also does not anticipate a need for additional workers during the license renewal period and, as a result, the levels of water usage at the plant site should remain consistent with the current pattern of water usage. In addition, the Village of Buchanan, via the City of Peekskill and NWJWW water systems, has water sources that can meet the demand of residential and industrial customers in the area (see Table 2-12). Therefore, impacts to public water supplies will continue to be SMALL during the IP2 and IP3 Operating License renewal period. Further consideration of mitigation measures is not warranted.

4.16 <u>Education Impacts from Refurbishment</u>

4.16.1 Description of Issue

Public Services (effects of refurbishment activities upon local educational system).

4.16.2 Findings from Table B-1, Appendix B to Subpart A

SMALL or MODERATE. Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors. See 10 CFR 51.53(c)(3)(ii)(I).

4.16.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on … public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided.

4.16.4 Analysis of Environmental Impact

As noted in Section 3.3, there are no refurbishment activities required for IP2 and IP3 license renewal. Therefore this issue is not applicable to the site and no further analysis is required.

4.17 Offsite Land Use—Refurbishment

4.17.1 Description of Issue

Offsite Land Use (effects of refurbishment activities).

4.17.2 Findings from Table B-1, Appendix B to Subpart A

SMALL or MODERATE. Impacts may be of moderate significance at plants in low population areas. See 10 CFR 51.53(c)(3)(ii)(I).

4.17.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on… land-use…(impacts from refurbishment activities only) within the vicinity of the plant must be provided.

4.17.4 Analysis of Environmental Impact

As noted in Section 3.3, there are no refurbishment activities required for IP2 and IP3 license renewal. Therefore, there will be no impacts from refurbishment activities and no further analysis is required.

4.18 Offsite Land Use—License Renewal Term

4.18.1 Description of Issue

Offsite Land Use (effects of license renewal).

4.18.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Significant changes in land-use may be associated with population and tax revenue changes resulting from license renewal. See 10 CFR 51.53(c)(3)(ii)(I).

4.18.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on …land-use…(impacts from refurbishment activities only) within the vicinity of the plant must be provided.

4.18.4 Background

During the license renewal term, new land use impacts could result from plant-related population growth or from the use of tax payments from the plant by local government to provide public services that encourage development.

However, as noted in Regulatory Guide 4.2, Section 4.17.2, Table B-1 of 10 CFR Part 51 partially misstates the conclusion reached in Section 4.7.4.2 of NUREG-1437. NUREG-1437, Section 4.7.4.2 concludes that "population-driven land use changes during the license renewal term at all nuclear plants will be small." Regulatory Guide 4.2 further states that "Until Table B-1 is changed, applicants only need cite NUREG-1437 to address population-induced land-use change during the license renewal term."

The assessment of new tax-driven land use impacts in the GEIS considered the following:

(1) the size of the plant's tax payments relative to the community's total revenues,

(2) the nature of the community's existing land use pattern, and

(3) the extent to which the community already has public services in place to support and guide development.

In general, if the plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land use changes during the plant's license renewal term would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development. If the plant's tax payments were projected to be medium to large relative to the community's total revenue, new tax-driven land use changes would be moderate.

This is most likely to be true where the community has no pre-established patterns of development (i.e., land use plans or controls) or has not provided adequate public services to support and guide development in the past, especially infrastructure that would allow industrial development. If the plant's tax payments are projected to be a dominant source of the community's total revenue, new tax-driven land use changes would be large. This would be especially true where the community has no pre-established pattern of development or has not provided adequate public services to support and guide development in the past.

Based on predictions for the case study plants, it is projected that all new population-driven land use changes during the license renewal term at all nuclear plants will be small because population growth caused by license renewal will represent a much smaller percentage of the local area's total population than has operations-related growth. In addition, any conflicts between offsite land use and nuclear plant operations are expected to be small. In contrast, it is projected that new tax-driven land use changes may be moderate at a number of sites and large at some others. Because land use changes may be perceived by some community members as adverse and by others as beneficial, the staff is unable to assess generically the potential significance of site-specific off-site land use impacts [NRC 1996, Section 4.7.4.2].

4.18.5 Analysis of Environmental Impact

The environmental impacts from this issue are from population-driven land use changes and from tax-driven land use changes.

4.18.5.1 Population-Driven Land Use Changes

Entergy agrees with the GEIS conclusion that new population-driven land use changes at the site during the license renewal term will be SMALL [NRC 1996, Section 4.7.4.2]. Entergy does not anticipate that additional workers will be employed at the site during the license renewal period. Therefore, there will be no adverse impact resulting from population driven land use changes associated with license renewal.

4.18.5.2 Tax-Driven Land Use Changes

All payments paid to local governments lie within Westchester County. Because there are no refurbishment activities and no new construction as a result of license renewal, no new sources of plant-related tax payments are expected that could significantly influence land use in Westchester County. During the license renewal term, however, new land-use impacts could result from the use by local governments of the tax revenue paid by Entergy for the assessed value of the site. As discussed in Section 2.7, Entergy paid the Village of Buchanan, which is located within Westchester County, a total of approximately $1.9 million in property taxes in 2005. In addition, the facility paid $19.2 million in PILOT, property taxes, and other taxes to the Town of Cortlandt, Verplanck Fire District, Westchester County, and the Hendrick Hudson Central School District, and Lakeland School District.

Westchester County has experienced relatively low population growth (see Table 2-6) and limited land-use changes since 1992 (See Section 2.8). Although recent population growth is not directly related to the presence of the site, continued growth could be affected by the economic benefit of the plant on local schools, roads, and community services. Tax receipts from the site are a significant portion of revenue to local government. This revenue likely provides for a higher level of public infrastructure and services than would otherwise be possible. This enhances the county's attractiveness as a place to live and could contribute to overall growth of the area and the conversion of open space and woodlands to residential and commercial uses.

Although the taxes paid by the site represents a significant portion of local tax revenues, the impacts from tax driven off-site land use changes is expected to be small because the area around the site has

- pre-established land-use patterns of development that are anticipated to continue during the license renewal term and
- public services and regulatory controls are in place to support and guide land use and development.

4.18.6 Conclusion

Entergy agrees with the GEIS conclusion that new population-driven land use changes at the site during the license renewal term will be SMALL. Entergy does not anticipate that additional workers will be employed at the site during the license renewal period Therefore, there will be no adverse impact to the offsite land use from additional plant workers and mitigation measures are not warranted.

In addition, the impact to tax-driven land use changes from the continued payment of PILOT and property taxes from IP2 and IP3 is expected to be SMALL due to pre-established land use patterns and controls to guide land use development. Therefore, mitigation measures are not warranted.

4.19 Transportation

4.19.1 Description of Issue

Public services, Transportation

4.19.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Transportation impacts (level of service) of highway traffic generated during the term of the renewed license are generally expected to be of small significance. See 10 CFR 51.53(c)(3)(ii)(J).

4.19.3 Requirement [10 CFR 51.53(c)(3)(ii)(J)]

All applicants shall assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license.

4.19.4 Background

Transportation impacts would continue to be of small significance at all sites during operations and would be of small or moderate significance during scheduled refueling and maintenance outages. Because impacts are determined primarily by road conditions existing at the time of the project and cannot be easily forecasted, a site specific review will be necessary to determine whether impacts are likely to be small or moderate and whether mitigation measures may be warranted [NRC 1996, Section 4.7.3.2].

4.19.5 Analysis of Environmental Impact

As there are no refurbishment activities required for the license renewal period and no expected increase in total number of employees that will be on-site at IP2 and IP3 during the same period, impacts to transportation during the license renewal term would be similar to those experienced during current operations and would be dictated by the workers currently involved in plant operations. As of June 2006, the site employed 1,255 workers during normal operations (see Section 3.5). An additional 950 workers may be present at the facility during refueling outages.

Traffic volumes for the area were obtained from the Westchester County Public Works Department, Division of Traffic Engineering. A 2002 traffic count [WCPWD] provided traffic data along Broadway from Kings Ferry Road to Buchanan Village. Peak counts both northbound and southbound occurred at 8:00 a.m., 11:00 a.m., and 5:00 p.m. during the count period with traffic counts ranging between 102 to 151 vehicles per hour during these time periods. Review of those counts on Broadway outside the plant entrances during the week of September 16, 2002, indicates traffic begins to increase at 6:00 a.m., is relatively stable throughout the day with the peaks cited above, before beginning to taper off after 8:00 p.m.

Traffic volume was slightly higher in the southbound direction than for the northbound direction. A daily average total of 1,746 vehicles per day use Broadway outside the plant for the northbound direction. This compares to an average of 1,837 vehicle counts per day in the southbound lane [WCPWD].

This count did not include temporary traffic increases due to annual outages at the site. The site generally schedules its outages in the spring, and may have an average of approximately 950 temporary workers on-site for the duration of the outage. Peak traffic during outages would be expected to be leaving and entering the site from 5:30 to 7:00 a.m. and from 6:30 to 8:00 p.m. Compensating measures, such as staggered shift starting and quitting times, have been taken by the site to account for the increased traffic flow during outages to maintain a reasonable level of service.

Traffic performance is generally defined in the qualitative term of level of service (LOS), which describes operational traffic conditions as perceived by motorists. New York performs LOS determinations for major highways, but does not perform such determinations for smaller state routes or local roads. Available traffic count information, as provided in Table 2-13 of this ER, shows generally increasing traffic volumes on Route 9 and 9A, but is unrelated to traffic from Indian Point. License renewal activities are not expected to increase the volume of traffic or affect the current highway LOS around the site, including Bleakley Avenue, Broadway, and US Highway 9. Therefore, traffic patterns around the site are not anticipated to be affected by plant operations during the license renewal period.

4.19.6 Conclusion

As noted in Section 3.3, there are no refurbishment activities required for IP2 and IP3 license renewal and no expected increases in the total number of employees that will be on-site during the license renewal period. Compensating measures, such as staggered shift starting and ending times, have been taken by the site to account for the increased traffic flow during outages to maintain a reasonable level of service. Therefore, impacts on local traffic will be SMALL and further mitigation measures are not warranted.

4.20 Historic and Archaeological Properties

4.20.1 Description of Issue

Historic and Archaeological Resources

4.20.2 Finding from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Generally plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the federal agency to consult with the State Historic Preservation Officer (SHPO) to determine whether there are properties present that require protection. See 10 CFR 51.53 (c)(3)(ii)(K).

4.20.3 Requirement [10 CFR 51.53(c)(3)(ii)(K)]

All applicants shall assess whether any historic or archaeological properties will be affected by the proposed project.

4.20.4 Background

It is unlikely that moderate or large impacts to historic resources would occur at any site unless new facilities or service roads are constructed or new transmission lines are established.

The identification of historic resources and determination of possible impacts to them must be done on a site-specific basis through consultation with the SHPO. The site-specific nature of historic resources and the mandatory National Historic Preservation Act consultation process mean that the significance of impacts to historic resources and the appropriate mitigation measures to address those impacts cannot be determined generically [NRC 1996, Section 3.7.7].

4.20.5 Analysis of Environmental Impact

As discussed in Section 3.3, there are no refurbishment activities required for the IP2 and IP3 license renewal. Therefore, no further analysis is required with respect to refurbishment activities.

No aboveground prehistoric or historic archaeological sites eligible for listing or listed on the NRHP or NYRHP are located on the site. In addition, Entergy has no plans to alter its operations on the site, expand existing facilities, or disturb additional land in support of license renewal. Therefore, renewal of the license would result in no adverse impacts to any archaeological sites.

Seventy percent of the land within a 6-mile radius of the site is classified as archaeologically sensitive, which means that NRHP-eligible and listed archaeological sites (prehistoric and historic) are present. Because these archaeological sites and their artifact contents are buried beneath soil, adverse impacts would occur only as a result of soil intrusive activities. Entergy has no plans to conduct such soil intrusive activities at any location outside of the site boundaries or outside its transmission line corridors under a renewed license (transmission lines extend only to the Buchanan Substation located due east across Broadway). Therefore, renewal of the license would result in no adverse impacts to archaeological sites located outside of the site.

No aboveground historic sites eligible for listing or listed on the NRHP or NYRHP are located within the current operational areas of the site. In addition, Entergy has no plans to alter its operations on the site, expand existing facilities, or disturb additional land in support of license renewal. Also the Phase 1A Survey discussed in Section 2.12 of this ER identified that the site had been previously heavily surface mined and that no cultural resources are expected to remain. Therefore, renewal of the license would result in no adverse impacts to such aboveground historical sites on the site or in its transmission line corridors.

Hundreds of eligible and listed aboveground historic sites are present in the vicinity (6-mile radius) of the site. Such historic properties are susceptible to any substantial force that could degrade their physical or historical integrity. Physical integrity refers to the structural condition (or soundness) of a historic property such as a house. The physical integrity of a historic site can be affected by the nearby operation of heavy equipment or by vibrations from the detonation of explosives. Historical integrity is the ability of a property to convey its significance to the public by virtue of its location, design, setting, materials, workmanship, feeling, and association (36 CFR 60.4). The historical integrity of a site can be adversely impacted by factors such as noise. It can also be degraded when an original and historically enhancing visual setting is intruded upon by more recent structures that detract from this setting and the historical feel of the property.

The Indian Point site was for many years a commercial amusement area operated by the Hudson River Day Line prior its acquisition by the original owners of Indian Point for construction of IP1. As discussed in Section 2.12, construction activity at the site revealed no evidence of items having archaeological value. The IP2 Final Environmental Statement (FES) stated that most of the sites at Indian Point spared by construction or other modern activities have been heavily molested by relic collectors over a very long period and relatively few have received attention from competent archaeologists [USAEC, Section II.D]. No other indication of important archaeological activity in the general area has been located. Thus, the Indian Point site probably contains no valuable prehistoric archaeological deposits.

IP2 and IP3 plant operations and associated transmission lines produce no intense vibrations or other substantial physical forces that would adversely impact historic properties located outside of the site property and transmission line corridors. In addition, IP2 and IP3 and the associated facilities produce little noise. Although it is highly visible on the Hudson River side, the site blends with developed areas to the west of the plant. The nearest historic property is located more than 1 mile from the site [NYSHPO]. As a result of the site's distance from historic properties and its location adjacent to a developed area, impacts on the physical and historical integrity of such sites would be expected to be small.

Although not anticipated, in the event that any excavation is required to be performed at the site, the ground disturbing activity would be reviewed in accordance with Entergy Nuclear fleet procedures EN-IS-112 (Trenching, Excavation and Ground Penetrating Activities) and EN-EV-121 (Cultural Resources Protection Plan). These procedures ensure that investigations and consultations are conducted as needed, and that existing or potentially existing cultural resources are adequately protected in order to assist Entergy in meeting state and federal expectations.

4.20.6 Conclusion

No refurbishment activities are required for license renewal at IP2 and IP3. There are also no plans to alter operations, expand existing facilities, or disturb additional land in support of license renewal. In addition as discussed in Section 4.20.5 above, no historic properties such as NRHP-eligible or listed archaeological sites or aboveground historical sites would be affected by operation of the plant during the license renewal period. Therefore, under a renewed license, the potential impacts on historic properties from continued operation of IP2 and IP3 would be SMALL and further mitigation measures are not warranted.

4.21 Severe Accident Mitigation Alternatives

4.21.1 Description of Issue

Severe accidents

4.21.2 Finding from Table B-1, Appendix B to Subpart A

SMALL. The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives. See 10 CFR 51.53(c)(3)(ii)(L).

4.21.3 Requirement [10 CFR 51.53(c)(3)(ii)(L)]

If the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environmental assessment, a consideration of alternatives to mitigate severe accidents must be provided.

4.21.4 Background

The staff concluded that the generic analysis summarized in the GEIS applies to all plants and that the probability-weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts of severe accidents are of small significance for all plants. However, not all plants have performed a site-specific analysis of measures that could mitigate severe accidents. Consequently, severe accidents are a Category 2 issue for plants that have not performed a site-specific consideration of severe accident mitigation and submitted that analysis for Commission review [NRC 1996, Section 5.5.2.5].

4.21.5 Analysis of Environmental Impact

The method used to perform the SAMA analysis was based on the handbook used by the NRC to analyze benefits and costs of its regulatory activities [NRC 1997].

Environmental impact statements and environmental reports are prepared using a sliding scale in which impacts of greater concern and mitigation measures of greater potential value receive more detailed analysis than impacts of less concern and mitigation measures of less potential value. Accordingly, Entergy used less detailed feasibility investigation and cost estimation techniques for SAMA candidates having disproportionately high costs and low benefits and more detailed evaluations for the most viable candidates.

The following is a brief outline of the approach taken in the SAMA analysis.

(1) <u>Establish the Baseline Impacts of a Severe Accident</u>

Severe accident impacts were evaluated in four areas:

- Off-site exposure costs: Monetary value of consequences (dose) to off-site population.

  The Probabilistic Safety Assessment (PSA) model was used to determine total accident frequency (core damage frequency (CDF) and containment release frequency). The Melcor Accident Consequences Code System 2 (MACCS2) was used to convert release input to public dose. Dose was converted to present worth dollars (based on a valuation of $2,000 per person-rem [NRC 1997] and a present worth discount rate of 7 percent).

- Off-site economic costs: Monetary value of damage to off-site property.

  The PSA model was used to determine total accident frequency (CDF and containment release frequency). MACCS2 was used to convert release input to off-site property damage. Off-site property damage was converted to present worth dollars based on a discount rate of 7 percent.

- On-site exposure costs: Monetary value of dose to workers.

  Best estimate occupational dose values were used for immediate and long-term dose. Dose was converted to present worth dollars (based on a valuation of $2,000 per person-rem and a present worth discount rate of 7 percent).

- On-site economic costs: Monetary value of damage to on-site property.

  Best estimate cleanup and decontamination costs were used. On-site property damage estimates were converted to present worth dollars based on a discount rate of 7%. It was assumed that, subsequent to a severe accident, the plant would be decommissioned rather than restored. Therefore replacement/refurbishment costs were not included in on-site costs. Replacement power costs were considered.

(2) Identify SAMA Candidates

Potential SAMA candidates were identified from the following sources (see Attachments E.1 and E.3 for reference details):

- Severe Accident Mitigation Design Alternative (SAMDA) analyses submitted in support of original licensing activities for other operating nuclear power plants and advanced light water reactor plants, including the evolutionary Westinghouse Advanced Pressurized Water Reactor (AP 600 and AP 1000) designs;
- SAMA analyses for other PWR plants;
- NRC and industry documentation discussing potential plant improvements;
- IP2 and IP3 Individual Plant Examination (IPE) of internal and external event reports and their updates. In these reports, several enhancements related to severe accident insights were recommended and implemented; and
- IP2 and IP3 PSA model risk significant contributors.

(3) Phase I: Preliminary Screening

Potential SAMA candidates for each unit were screened out if they modified features not applicable to the unit, if they had already been implemented at the unit, or if they were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate.

(4) Phase II: Final Screening and Cost Benefit Evaluation

The remaining SAMA candidates were evaluated individually to determine the benefits and costs of implementation, as follows.

- The total benefit of implementing a SAMA candidate was estimated in terms of averted consequences (benefits estimate).
    - ➢ The baseline PSA model was modified to reflect the maximum benefit of the improvement. Generally, the maximum benefit of a SAMA candidate was determined with a bounding modeling assumption. For example, if the objective of the SAMA candidate was to reduce the likelihood of a certain failure mode, then eliminating the failure mode from the PSA would bound the benefit, even though the SAMA candidate would not be expected to be 100% effective in eliminating the failure. The modified model was then used to produce a revised accident frequency.
    - ➢ Using the revised accident frequency, the method previously described for the four baseline severe accident impact areas was used to estimate the cost

associated with each impact area following implementation of the SAMA candidate.

- ➢ The benefit in terms of averted consequences for each SAMA candidate was then estimated by calculating the arithmetic difference between the total estimated cost associated with all four impact areas for the baseline plant design and the revised plant design following implementation of the SAMA candidate.

- The cost of implementing a SAMA was estimated by one of the following methods (cost estimate).

  - ➢ An estimate for a similar modification considered in a previously performed SAMA analysis was used. These estimates were developed in the past and no credit was taken for inflation when applying them to IP2 and IP3.

  - ➢ Engineering judgment on the cost associated with procedural changes, engineering analysis, testing, training and hardware modification was applied to formulate a conclusion regarding the economic viability of the SAMA candidate.

The detail of the cost estimate was commensurate with the benefit. If the benefit was low, it was not necessary to perform a detailed cost estimate to determine if the SAMA was cost beneficial.

(5) Sensitivity Analyses

Three sensitivity analyses were conducted to gauge the impact of key assumptions upon the analysis. The first sensitivity analysis was to investigate the sensitivity of assuming a 26-year period for remaining plant life for IP2 (i.e., six years on the original plant license plus the 20-year license renewal period), and a 28-year period for remaining plant life for IP3 (i.e., eight years on the original plant license plus the 20-year license renewal period). The second sensitivity analysis was to investigate the sensitivity of each analysis case to the discount rate of 3 percent. The third sensitivity analysis was to investigate impacts resulting from economic losses due to tourism and business, which were not included in the base case.

The SAMA analysis for IP2 and IP3 is presented in the following sections. Attachments E.1, E.2, E.3, and E.4 provide a more detailed discussion of the process presented above.

4.21.5.1 Establish the Baseline Impacts of a Severe Accident

A baseline for each unit was established to enable estimation of the risk reductions attributable to implementation of potential SAMA candidates. These severe accident risks were estimated using the IP2 and IP3 PSA models and the MACCS2 consequence analysis software code. The PSA models used for the SAMA analysis (IP2 PSA Revision 1, April 2007, and IP3 PSA Revision 2, April 2007) are internal events risk models.

4.21.5.1.1 The PSA Internal Events Model: Level 1 and Level 2 Analysis

The PSA models (Level 1 and Level 2) used for the SAMA analysis were the most recent internal events risk models for IP2 and IP3.

The IP2 PSA model is a complete updated version of the model used in the 1992 IPE and reflects the IP2 configuration and design as of December 2005. It uses component failure and unavailability data as of December 2005, and resolves all findings and observations from the industry peer reviews conducted in May 2002 and July 2005.

The IP3 PSA model is a complete updated version of the model used in the 1994 IPE and reflects the IP3 configuration and design as of December 2005. It uses component failure and unavailability data as of December 2005, and resolves all findings and observations from the industry peer review of the model conducted in January 2001.

Both the IP2 and IP3 PSA models adopt the small event tree / large fault tree approach and use the CAFTA code for quantifying CDF.

An uncertainty analysis associated with internal events CDF was performed. The ratio of the CDF at the 95th percent confidence level to the mean CDF is a factor of 2.10 for IP2 and 1.40 for IP3. This analysis is presented in Sections E.1.1 and E.3.1 of Attachment E.

The IP2 and IP3 Level 2 analysis uses a Containment Event Tree (CET) to analyze all core damage sequences identified in the Level 1 analysis. The CET evaluates systems, operator actions, and severe accident phenomena in order to characterize the magnitude and timing of radionuclide release. The result of the Level 2 analysis is a list of sequences involving radionuclide release, along with the frequency and magnitude/timing of release for each sequence.

4.21.5.1.2 The PSA External Events Model: Individual Plant Examination of External Events (IPEEE) Model

The IP2 and IP3 IPEEE models were reviewed and used for SAMA analysis. The seismic portion of the IPEEE was completed in conjunction with the Seismic Qualification Utility Group (SQUG) program. Both IP2 and IP3 performed a seismic Probabilistic Risk Assessment (PRA) following the guidance of NUREG-1407, *Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities*, June 1991. A number of plant improvements were identified and, as described in NUREG-1742, *Perspectives Gained from the IPEEE Program*, Final Report, April 2002, these improvements were implemented.

The IP2 fire analysis was performed using the conservative EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology for initial screening of fire zones. Unscreened fire zones were then analyzed in more detail using a fire PRA approach. The end result of IP2 IPEEE fire analysis identified the CDF for significant fire areas. A number of administrative procedures were revised to improve combustible and flammable material control.

The IP3 fire analysis was performed using the EPRI PRA Implementation Guide for quantitative screening of fire areas and for fire analysis of areas that did not screen. The fire analysis utilized the PSA internal event models to address fire induced initiators and equipment failure modes. A number of plant improvements were identified and are described in NUREG-1742, *Perspectives Gained from the IPEEE Program,* Final Report, April 2002. These improvements have been implemented. In addition, a number of administrative procedures were revised to improve combustible and flammable material control.

The IP2 and IP3 IPEEE submittals, in addition to the internal fires and seismic events, examined a number of other external hazards.

- High Winds and /Tornadoes
- External Flooding
- Ice, Hazardous Chemical, Transportation and Nearby Facility Incidents

In consequence of this external hazards evaluation, a number of plant modifications have been implemented at IP2, as identified in Table 4.1 of NUREG-1742, *Perspectives Gained from the IPEEE Program*, Final Report, April 2002. One high winds, floods and other external events related plant modification at IP3 has been proposed for Phase II evaluation (Phase II SAMA 053).

4.21.5.1.3 MACCS2 Model: Level 3 Analysis

A "Level 3" model was developed using the MACCS2 consequence analysis software code to estimate the hypothetical impacts of severe accidents on the surrounding environment and members of the public. The principal phenomena analyzed were atmospheric transport of radionuclides; mitigation actions (i.e., evacuation, condemnation of contaminated crops and milk) based on dose projection; dose accumulation by a number of pathways, including food and water ingestion; and economic costs. Input for the Level 3 analysis included the core radionuclide inventory, source terms from the IP2 and IP3 PSA models, site meteorological data, projected population distribution (within 50-mile radius) for the year 2034, emergency response evacuation modeling, and economic data. The MACCS2 input data are described in Sections E.1.5 and E.3.5 of Attachments E.1 and E.3.

4.21.5.1.4 Evaluation of Baseline Severe Accident Impacts Using the Regulatory Analysis Technical Evaluation Handbook Method

This section describes the method used for calculating the cost associated with each of the four impact areas for the baseline case (i.e., without SAMA implementation). This following analysis was used to establish the maximum benefit that a SAMA could achieve if it eliminated all risk due to IP2 or IP3 at-power internal events.

Off-site Exposure Costs

The Level 3 baseline analysis resulted in an annual off-site exposure risk of 22 person-rem for IP2 and 24.5 person-rem for IP3. This value was converted to its monetary equivalent (dollars) via application of the $2,000 per person-rem conversion factor from the Regulatory Analysis Technical Evaluation Handbook [NRC 1997]. This monetary equivalent was then discounted to present value using the formula from the same source:

$$APE = \left(F_S D_{P_S} - F_A D_{P_A}\right) R \frac{1 - e^{-rt_f}}{r}$$

where,

APE = monetary value of accident risk avoided from population doses, after discounting;

R = monetary equivalent of unit dose, ($/person-rem);

F = accident frequency (events/year);

D_P = population dose factor (person-rem/event);

S = status quo (current conditions);

A = after implementation of proposed action;

r = discount rate (%); and

t_f = license renewal period (years).

IP2

Using a 20-year license renewal period, a 7% discount rate, assuming F_A is zero, and the baseline CDF of 1.79E-05/ry resulted in the monetary equivalent value of $473,568. This value is presented in Table 4-3.

IP3

Using a 20-year license renewal period, a 7% discount rate, assuming F_A is zero, and the baseline CDF of 1.15E-05/ry resulted in the monetary equivalent value of $527,382. This value is presented in Table 4-3.

Off-site Economic Costs

The Level 3 baseline analysis resulted in an annual off-site economic risk monetary equivalent of $44,900 for IP2 and $52,800 for IP3. This value was discounted in the same manner as the public health risks in accordance with the following equation:

$$AOC = \left(F_S P_{D_S} - F_A P_{D_A}\right)\frac{1 - e^{-rt_f}}{r}$$

where

AOC = monetary value of risk avoided from off-site property damage, after discounting;

P_D = off-site property loss factor ($/event);

F = accident frequency (events/year);

S = status quo (current conditions);

A = after implementation of proposed action;

r = discount rate (%); and

t_f = license renewal period (years).

Using previously defined values; the resulting monetary equivalent is $483,254 for IP2 and $568,281 for IP3. This value is presented in Table 4-3.

On-site Exposure Costs

The values for occupational exposure associated with severe accidents were not derived from the PSA model, but from information in the *Regulatory Analysis Technical Evaluation Handbook* [NRC 1997]. The values for occupational exposure consist of "immediate dose" and "long-term dose." The best estimate value provided for immediate occupational dose is 3,300 person-rem, and long-term occupational dose is 20,000 person-rem (over a 10 year clean-up period). The following equations were used to estimate monetary equivalents.

Immediate Dose

$$W_{IO} = \left(F_S D_{IO_S} - F_A D_{IO_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where

W_{IO}= monetary value of accident risk avoided from immediate doses, after discounting;

IO = immediate occupational dose;

R = monetary equivalent of unit dose, ($/person-rem);

F = accident frequency (events/year);

D_{IO}= immediate occupational dose (person-rem/event);

S = status quo (current conditions);

A = after implementation of proposed action;

r = discount rate (%); and

t_f = license renewal period (years).

The values used in the analysis were:

R = $2,000/person-rem;

r = 0.07;

D_{IO} = 3,300 person-rem /accident; and

t_f = 20 years.

For the basis discount rate, assuming FA is zero, the bounding monetary value of the immediate dose associated with accident risk is:

$$W_{IO} = \left(F_S D_{IO_S}\right) R \frac{1 - e^{-rt_f}}{r}$$

$$W_{IO} = 3300 \cdot F_S \cdot \$2000 \cdot \frac{1 - e^{-(0.07 \cdot 20)}}{0.07}$$

$$W_{IO} = (\$7.10 \times 10^7)F_S$$

IP2

For the baseline CDF, $1.79X10^{-5}$/ry,

W_{IO} = $1,272

IP3

For the baseline CDF, $1.15X10^{-5}$/ry,

W_{IO} = $817

Long Term Dose

$$W_{LTO} = \left(F_S D_{LTO_S} - F_A D_{LTO_A}\right) R \cdot \frac{1 - e^{-rt_f}}{r} \cdot \frac{1 - e^{-rm}}{rm} \qquad (2)$$

where

W_{LTO}= monetary value of accident risk avoided long term doses, after discounting ($);

LTO = long-term occupational dose;

m = years over which long-term doses accrue;

R = monetary equivalent of unit dose ($/person-rem);

F = accident frequency (events/year);

D_{LTO}= long-term occupational dose (person-rem/event);

S = status quo (current conditions);

A = after implementation of proposed action;

r = discount rate (%); and

t_f = license renewal period (years).

The values used in the analysis were

R = \$2,000/person-rem;

r = 0.07;

D_{LTO} = 20,000 person-rem /accident;

m = 10 years; and

t_f = 20 years.

For the basis discount rate, assuming F_A is zero, the bounding monetary value of the long term dose associated with accident risk is:

$$W_{LTO} = \left(F_S D_{LTO_S}\right) R \cdot \frac{1 - e^{-rt_f}}{r} \cdot \frac{1 - e^{-rm}}{rm}$$

$$W_{LTO} = (F_S \times 20{,}000)\$2000 \cdot \frac{1 - e^{-0.07 \cdot 20}}{0.07} \cdot \frac{1 - e^{-0.07 \cdot 10}}{0.07 \cdot 10}$$

$$W_{LTO} = (\$3.10 \times 10^8)F_S$$

IP2

For the baseline CDF, $1.79X10^{-5}$/ry,

$$W_{LTO} = \$5{,}542$$

IP3

For the baseline CDF, $1.15X10^{-5}$/ry,

$$W_{LTO} = \$3{,}560$$

Total Occupational Exposures

Combining equations (1) and (2) above, using delta (Δ) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the long-term accident related on-site (occupational) exposure avoided is:

$$AOE = \Delta W_{IO} + \Delta W_{LTO} \quad (\$)$$

where

AOE = on-site exposure avoided.

The bounding value for occupational exposure (AOE_B) is

IP2

$$AOE_B = W_{IO} + W_{LTO} = \$1{,}272 + \$5{,}542 = \$6{,}814.$$

IP3

$$AOE_B = W_{IO} + W_{LTO} = \$817 + \$3{,}560 = \$4{,}377.$$

The resulting monetary equivalent of $6,814 for IP2 and $4,377 for IP3 is presented in Table 4-3.

On-site Economic Costs

Clean up/Decontamination

The total cost of clean up/decontamination of a power reactor facility subsequent to a severe accident is estimated in the *Regulatory Analysis Technical Evaluation Handbook* [NRC 1997] to be $\$1.5 \times 10^9$; this same value was adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

$$PV_{CD} = \left(\frac{C_{CD}}{m}\right)\left(\frac{1 - e^{-rm}}{r}\right)$$

where

PV_{CD} = present value of the cost of cleanup/decontamination;

CD = clean-up/decontamination;

C_{CD} = total cost of the cleanup/decontamination effort, ($);

m = cleanup period (years); and

r = discount rate (%).

Based upon the values previously assumed,

$$PV_{CD} = \left(\frac{\$1.5E+9}{10}\right)\left(\frac{1-e^{-0.07 \cdot 10}}{0.07}\right)$$

$$PV_{CD} = \$1.08E+9$$

This cost is integrated over the term of the proposed license renewal as follows:

$$U_{CD} = PV_{CD}\frac{1-e^{-rt_f}}{r}$$

where,

U_{CD} = total cost of clean up/decontamination over the life of the plant.

Based upon the values previously assumed,

$$U_{CD} = \$1.16E+10$$

Replacement Power Costs

Replacement power costs were estimated in accordance with the *Regulatory Analysis Technical Evaluation Handbook* [NRC 1997]. Since replacement power will be needed for the time period following a severe accident for the remainder of the expected generating plant life, long-term power replacement calculations have been used. The present value of replacement power was estimated as follows:

$$PV_{RP} = \left(\frac{\$1.2 \times 10^8}{r}\right)\left(1-e^{-rt_f}\right)^2$$

where

PV_{RP} = present value of the cost of replacement power for a single event;

t_f = license renewal period (years); and

r = discount rate (%).

The \$1.2 x 10^8 value has no intrinsic meaning, but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event. This equation was developed in the *Regulatory Analysis Technical Evaluation Handbook* [NRC 1997] for discount rates between 5% and 10% only.

Based upon the values previously assumed:

$$PV_{RP} = \left(\frac{\$1.2 \times 10^8}{r}\right)\left(1 - e^{-rt_f}\right)^2 = \left(\frac{\$1.2 \times 10^8}{0.07}\right)\left(1 - e^{-(0.07)20}\right)^2 = \$9.73 \times 10^8$$

To account for the entire lifetime of the facility, U_{RP} was then calculated from PV_{RP}, as follows:

$$U_{RP} = \frac{PV_{RP}}{r}\left(1 - e^{-rt_f}\right)^2$$

where

U_{RP} = present value of the cost of replacement power over the remaining life;

t_f = license renewal period (years); and

r = discount rate (%).

Based upon the values previously assumed,

$$U_{RP} = \frac{PV_{RP}}{r}\left(1 - e^{-rt_f}\right)^2 = \frac{\$9.73 \times 10^8}{0.07}\left(1 - e^{(-0.07)(20)}\right)^2 = \$7.89 \times 10^9$$

Since net generation can be based on plant demands, a power level of 1071 MWe, which reflects typical gross generation levels, was used to conservatively bound the net generated power that would need to be replaced at either IP2 or IP3. After applying a correction factor to account for the difference in typical gross generation levels between IP2/IP3 and the generic reactor described in the *Regulatory Analysis Technical Evaluation Handbook* [NRC 1997] (i.e., 1071 MWe/910 MWe), the value of U_{RP} becomes 9.29 x 10^9.

Total On-site Property Damage Costs

Combining the cleanup/decontamination and replacement power costs, using delta (ΔF) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the best-estimate value of averted occupational exposure can be expressed as:

$$AOSC = \Delta F(U_{CD} + U_{RP}) = \Delta F(\$1.16 \times 10^{10} + \$9.29 \times 10^{9}) = \Delta F(\$2.09 \times 10^{10})$$

where

ΔF = difference in annual accident frequency resulting from the proposed action

<u>IP2</u>

For the baseline CDF, 1.79×10^{-5}/ry,

$$AOSC = \$374{,}303$$

<u>IP3</u>

For the baseline CDF, 1.15×10^{-5}/ry,

$$AOSC = \$240,475$$

The resulting monetary equivalent of \$374,303 for IP2 and \$240,475 for IP3 is presented in Table 4-3.

Table 4-3
Estimated Present Dollar Value Equivalent of Internal Events CDF at IP2 and IP3

Parameter	IP2 Present Dollar Value ($)	IP3 Present Dollar Value ($)
Off-site population dose	$473,568	$527,382
Off-site economic costs	$483,254	$568,281
On-site dose	$6,814	$4,377
On-site economic costs	$374,303	$240,475
Total	$1,337,939	$1,340,515

4.21.5.2 Identify SAMA Candidates

Based on a review of industry documents, an initial list of SAMA candidates was identified. Since IP2 and IP3 are typical pressurized water nuclear power reactors, considerable attention was paid to the SAMA candidates from SAMA analyses for other pressurized water plants. Attachments E.2 and E.4 list the specific documents from which SAMA candidates were initially gathered.

In addition to SAMA candidates identified from the review of industry documents, additional SAMA candidates were obtained from plant-specific sources, such as the IP2 and IP3 IPE and IPEEE. Several enhancements from the IP2 and IP3 IPE and IPEEE related to severe accident insights were recommended and implemented. These enhancements were included in the comprehensive list of SAMA candidates for IP2 and IP3 and were verified to have been implemented during preliminary screening.

In addition, the IP2 and IP3 updated PSA models were used to identify plant-specific modifications for inclusion in the comprehensive lists of SAMA candidates. The risk significant terms from the PSA level 1 and level 2 models were reviewed for similar failure modes and effects that could be addressed through a potential enhancement to the plant. The correlation between candidate SAMAs and the risk significant terms are listed in Tables E.1-2 and E.1-5 of Attachment E.1 for IP2, and Tables E.3-2 and E.3-5 of Attachment E.3 for IP3. The comprehensive lists contained a total of 231 SAMA candidates for IP2 and 237 SAMA candidates for IP3. The first step in the analysis of these candidates was to eliminate the non-viable SAMA candidates through preliminary screening.

4.21.5.3 Preliminary Screening (Phase I)

For each of the units, the purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at the unit. Potential SAMA candidates were screened out if they modified features not applicable to the unit or if they had already been implemented at the unit. In addition, where it was determined those SAMA candidates were potentially viable, but were similar in nature, they were combined to develop a more comprehensive or plant-specific SAMA candidate.

During this process, 163 of the 231 initial SAMA candidates were eliminated, leaving 68 SAMA candidates for IP2, and 175 of the 237 initial SAMA candidates were eliminated, leaving 62 SAMA candidates for IP3 for further analysis. The lists of original SAMA candidates and applicable screening criterion are available in on-site documentation.

4.21.5.4 Final Screening and Cost/Benefit Evaluation (Phase II)

A cost/benefit analysis was performed on the remaining SAMA candidates. The method for determining if a SAMA candidate was cost beneficial consisted of determining whether the benefit provided by implementation of the SAMA candidate exceeded the expected cost of enhancement (COE). The benefit was defined as the sum of the reduction in dollar equivalents for each severe accident impact area (off-site exposure, off-site economic costs, occupational exposure, and on-site economic costs). If the expected implementation cost exceeded the estimated benefit, the SAMA was not considered cost beneficial.

The result of implementation of each SAMA candidate would be a change in the severe accident risk (i.e., a change in frequency or consequence of severe accidents). The method of calculating the magnitude of these changes is straightforward. First, the severe accident risk after implementation of each SAMA candidate was estimated using the same method as for the baseline. The results of the Level 2 model were combined with the Level 3 model to calculate these post-SAMA risks. The results of the benefit analyses for the SAMA candidates are presented in Table E.2-2 of Attachment E.2 for IP2 and Table E.4-2 of Attachment E.4 for IP3.

Each SAMA evaluation was performed in a bounding fashion. Bounding evaluations were performed to address the generic nature of the initial SAMA concepts. Such bounding calculations overestimate the benefit and thus are conservative calculations. For example, one SAMA candidate suggested installing a digital feedwater upgrade system. The bounding calculation estimated the benefit of this improvement by total elimination of risk due to loss of feedwater event (see analysis in phase II SAMA 41 of Table E.2-2 for IP2, and phase II SAMA 39 of Table E.4-2 for IP3). Such a calculation obviously overestimated the benefit, but if the inflated benefit indicated that the SAMA is not cost beneficial, then the purpose of the analysis was satisfied.

As described above for the baseline, values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the *Regulatory Analysis Technical Evaluation Handbook* [NRC 1997] conversion factor of $2,000 per person-rem and discounted to present value. Values for avoided off-site economic costs were also discounted to present value. The formula for calculating net value for each SAMA was

$$\text{Net value} = (APE + AOC + AOE + AOSC) - COE$$

where,

APE = value of averted public exposure ($);

AOC = value of averted off-site costs ($);

AOE = value of averted occupational exposure ($);

AOSC = value of averted on-site costs ($); and

COE = cost of enhancement ($).

If the net value of a SAMA was negative, the cost of the enhancement was greater than the benefit and the SAMA was not cost beneficial.

The SAMA analysis considered that external events (including fires, seismic, and other external events) could lead to potentially significant risk contributions. To account for the risk contribution from external events, the cost of SAMA implementation was compared with a benefit value estimated by applying a multiplier to the internal events estimated benefit. This value is defined as the "baseline benefit." To account for uncertainties associated with the internal events CDF calculations, the cost of SAMA implementation was also compared with a benefit value estimated by applying an uncertainty multiplier to the internal events estimated benefit. This value is defined as the "baseline benefit with uncertainty." Development of the multipliers for IP2 and IP3 is described in the following paragraphs.

IP2

A multiplier of 3.8 was applied to the internal events estimated benefit to account for the impact from external events. The IPEEE analyses provided quantitative, but conservative, results. Therefore, the results were combined as described below to represent the total external events risk.

The IP2 Individual Plant Examination of External Events (IPEEE) concluded for external floods and other external events that no undue risks are present that might contribute to CDF with a predicted frequency in excess of 1.0E-06/yr. As these events are not dominant contributors to external event risk and quantitative analysis of these events is not practical, they are considered negligible in estimation of the external events multiplier.

A high wind analysis was performed for the IP2 IPEEE. Conservative assumptions in the high wind PSA analysis included the following.

- Offsite power was assumed to be lost for all high wind events.
- Building frame failures were assumed to cause failure of all equipment within the building.
- Missile (high wind projectile) impact on a structure was assumed to cause failure of all equipment within that structure.

- Likelihood of missile (high wind projectile) strikes was assumed to be independent of the intensity of the hazard.

- Both onsite and offsite alternate power sources (gas turbines) were assumed to fail given failure of a more robust structure.

The core damage frequency contribution associated with high wind events was estimated to be 3.03×10^{-5} per year. As described above, this is a conservative value. In addition, plant changes, improved equipment performance data, and modeling improvements since the issuance of the IP2 IPEEE have demonstrated that the response of plant systems as modeled at that time was conservative. This can be seen from the reduction in internal events CDF from 2.85×10^{-5} per year at the time the IPEEE was developed to the present value of 1.79×10^{-5} per year. Although conservative, the wind risk contribution of 3.03×10^{-5} per year was used to determine the external event multiplier.

A seismic PSA analysis was performed for the seismic portion of the IP2 IPEEE. The seismic PSA analysis was a conservative analysis. Therefore, its results should not be compared directly with the best-estimate internal events results. Conservative assumptions in the seismic PSA analysis included the following.

- Sequences in the seismic PSA involving loss of off-site power were assumed to be unrecoverable. If off-site power was recovered following a seismic event, there would be many more systems available to maintain core cooling and containment integrity than were credited for those sequences.

- A single, conservative, surrogate element whose failure leads directly to core damage was used in the seismic risk quantification to model the most seismically rugged components.

- Seismic-induced ATWS was considered in the analysis, but no credit was included for manual scram or mitigation of ATWS using the boration system. This conservatively resulted in most seismic-induced ATWS events leading to consequential core damage.

- Redundant components were conservatively assumed to be completely correlated by treating them as if they were one component for the purpose of determining the probability of seismic induced failures.

- Several systems were assumed to be unavailable during a seismic event, including:

  a. the city water system, which can be used to supply backup cooling to the charging pumps if CCW is lost, as an alternate source of suction to the AFW pumps and to provide alternate cooling to the RHR and SI pumps;

b. the primary water system, which can also be used as a backup to CCW to supply cooling to the RHR and SI pumps; and

c. the onsite and offsite gas turbine generators, which can provide alternate station power.

- No credit was taken for recovery of power through the alternate safe shutdown system (ASSS).
- Lawrence Livermore National Laboratory (LLNL) seismic hazard data was used. Use of EPRI seismic hazard data would result in a 10% reduction in overall seismic CDF.

The seismic CDF in the IPEEE was originally estimated to be 1.46×10^{-5} per year. As a result of an IPEEE recommendation, the CCW surge tank hold-down bolts were upgraded, reducing the seismic CDF to 1.06×10^{-5} per year. Although it remains conservative, the seismic risk contribution of 1.06×10^{-5} per year was used to determine the external event multiplier.

The conservative EPRI FIVE methodology was used for initial screening of fire zones in the IP2 IPEEE fire analysis. Unscreened fire zones were then analyzed in more detail using a fire PRA approach.

The sum of the resulting fire zone CDF values (Table E.1-11) is approximately 1.84×10^{-5} per year.

Conservative assumptions in the IP2 IPEEE fire analysis include the following.

- The frequency and severity of fires were generally conservatively overestimated in the generic IPEEE fire analysis methods. A revised NRC fire events database indicates a trend toward lower frequency and less severe fires. This trend reflects improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at utilities.
- Cable failure due to fire damage was assumed to arise from open circuits, hot short circuits, and short circuits to ground. In damaging a cable, the analysis addressed the ability of the fire to induce the conductor failure mode of concern. Hot shorts were conservatively assigned a probability of 0.1, which was applied to all single phase, AC control circuit or DC power and control circuit cases regardless of whether the wires were in the same multi-conductor.
- A plant trip was assumed for all fires, including those for which immediate operator actions are not specified in emergency response procedures.
- PORV block valves were assumed to be in the more limiting position (open or closed) to maximize the impact of the fire.

- The main feedwater and condensate systems were assumed to be unavailable in all scenarios, even when their power source was not impacted by the fire scenario. Use of these systems for recovery, following a failure of AFW, is addressed in current plant procedures.

- All sequences involving induced RCP seal LOCAs were assumed to lead to complete seal failure. Although casualty cables exist for powering ECCS pumps from the ASSS power source, the ASSS was assumed to be ineffective in mitigating induced LOCAs. The currently accepted RCP seal LOCA methodology is more detailed and provides sequences with varying leakage rates. Under that current methodology, a majority of seal LOCAs remain within the capability of a charging pump (which has hardwired ASSS transfer capability) to provide makeup.

As noted previously, plant changes, improved equipment performance data and modeling improvements since the issuance of the IP2 IPEEE have demonstrated that the response of plant systems as modeled at that time was conservative. This can be seen from the reduction in internal events CDF from 2.85 X 10^{-5} per year at the time the IPEEE was developed to the present value of 1.79 X 10^{-5} per year, a reduction factor of 1.6. Factoring in the additional conservatisms in the fire analysis noted above, an overall reduction factor of 2 is reasonable. The IPEEE fire CDF value, reduced by a factor of two, is 9.20 x 10^{-6} per year.

The combination of the reduced high wind, seismic and fire CDF values results in an external events risk estimate of 5.01 x 10^{-5} per year, which is 2.80 times higher than the internal events CDF (1.79 x 10^{-5} per year). Since the external events contribution must be added to the internal events contribution, this justifies use of a multiplier of 3.80 on the averted cost estimates (for internal events) to represent the total SAMA benefits, accounting for both internal and external events. "Baseline benefit" values are estimated using this multiplier on the benefit estimates for internal events.

CDF uncertainty estimates resulted in a factor of 2.10 (Table E.1-3). Since 3.80 x 2.10 = 7.98, a multiplier of 8 provides a conservative upper bound estimate, accounting for both internal and external event impacts, with uncertainty. Therefore, "baseline benefit with uncertainty" values are estimated using this multiplier on the benefit estimates for internal events.

<u>IP3</u>

A multiplier of 5.52 was applied to the internal events estimated benefit to account for the impact from external events. The IPEEE analyses provided quantitative, but conservative results. Therefore, the results were combined as described below to represent the total external events risk.

The IP3 Individual Plant Examination of External Events (IPEEE) concluded for high winds, floods, and other external events that no undue risks are present that might contribute to CDF with a predicted frequency in excess of 1.0E-06/yr. As these events are not dominant contributors to external event risk and quantitative analysis of these events is not practical, they are considered negligible in estimation of the external events multiplier.

The IPEEE analyses using the fire PRA and seismic PSA provided quantitative, but conservative, results. Therefore, the results were combined as described below to represent the total external events risk.

A seismic PSA analysis was performed for the seismic portion of the IP3 IPEEE. The seismic PSA analysis is a conservative analysis. Therefore, its results should not be compared directly with the best-estimate internal events results. Conservative assumptions in the seismic PSA analysis included the following.

- Each of the sequences in the seismic PSA assumes unrecoverable loss of off-site power. If off-site power was maintained, or recovered, following a seismic event, there would be many more systems available to maintain core cooling and containment integrity than were credited in the analysis.

- Seismic events were assumed to induce a small loss of coolant accident (LOCA) in addition to a loss of offsite power.

- A single, conservative, surrogate element whose failure leads directly to core damage was used in the seismic risk quantification to model the most seismically rugged components.

- Redundant components were conservatively assumed to be completely correlated by treating them as if they were one component for the purpose of determining the probability of seismic induced failures.

- The ATWS event tree was conservatively simplified so that all conditions which lead to a failure to trip result in core damage, without the benefit of emergency boration or other mitigating systems.

- Because there is little industry experience with crew actions following seismic events, human actions were conservatively characterized.

The seismic CDF in the IPEEE was conservatively estimated to be 4.40×10^{-5} per year. As described above, this is a conservative value. The seismic PRA CDF has been re-evaluated to reflect updated random component failure probabilities and to model recovery of onsite power and local operation of the turbine-driven AFW pump. The updated seismic CDF is 2.65×10^{-5} per year. Although it remains conservative, the seismic risk contribution of 2.65×10^{-5} per year was used to determine the external event multiplier.

The EPRI Fire PRA Implementation Guide was followed for the IP3 IPEEE fire analysis. The EPRI Fire Induced Vulnerability Evaluation (FIVE) method was used for the initial screening, for treatment of transient combustibles, and as the source of fire frequency data. The sum of the resulting fire zone CDF values (Table E.3-11) is approximately 5.58 x 10^{-5} per year.

Conservatisms in the IP3 IPEEE fire analysis include the following.

- The frequency and severity of fires were generally conservatively overestimated. A revised NRC fire events database indicates a trend toward lower frequency and less severe fires. This trend reflects improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at utilities.

- There is little industry experience with crew actions following fires. This led to conservative characterization of crew actions in the IPEEE fire analysis. Because CDF is strongly correlated with crew actions, this conservatism has a profound effect on fire results.

- Hot gas layer temperature timing calculations were based on simplified analyses (versus more detailed calculations such as GOTHIC or even COMPBURN) which are believed to result in more severe timing (i.e., shorter time to equipment failure).

- Heat and combustion products from a fire within a zone were assumed to be confined within the zone. Heat loss through separating zones was not considered; nor was heat loss through open equipment hatches, ladder ways, open doorways, or unsealed penetrations.

- Cable failure due to fire damage was assumed to arise from open circuits, hot shorts circuits, and short circuits to ground. In damaging a cable, the fire was always assumed to induce the conductor failure mode of concern.

- A plant trip was assumed for all fires, including those for which immediate operator actions are not specified in emergency response procedures.

- For several fire zones, a minimum heat requirement for target damage was estimated.

- Propagation of fires in cable spreading room trays and electrical tunnels was modeled using a maximum heat release rate. This results in a shorter time to damage than the five-minute delay using heat release rate scaling factors as a function of distance recommended in the EPRI fire PRA implementation guide.

Implementation of the IP3 IPEEE recommendations reduced the fire risk. The fire suppression system in the 480V switchgear room (fire zone 14) was restored to automatic actuation, and realignment and rerouting of the power feeds to the EDG exhaust fans and engine auxiliaries in emergency diesel generator room 31 (fire zone 10), emergency diesel generator room 32 (fire zone 10A) and emergency diesel generator room 33 (fire zone 102A) significantly reduce the respective fire zone's CDF. In addition, restoration of the 480V switchgear room fire suppression system to automatic actuation results in a similar reduction in the fire zone 14/37A multiple compartment fire CDF. Consequently, the IPEEE fire CDF value was reduced from 5.58 x 10^{-5} to 2.55 x 10^{-5} per year. Although it remains conservative, the fire risk contribution of 2.55 x 10^{-5} per year was used to determine the external event multiplier.

Combining the reduced seismic and fire CDF values results in an external events risk estimate of 5.20 x 10^{-5} per year, which is 4.52 times higher than the internal events CDF (1.15 x 10^{-5} per year). Since the external events contribution must be added to the internal events contribution, this justifies use of a multiplier of 5.52 on the averted cost estimates (for internal events) to represent the total SAMA benefits for both internal and external events. "Baseline benefit" values are estimated using this multiplier on the benefit estimates for internal events.

CDF uncertainty estimates resulted in a factor of 1.40 (Table E.3-3). Since 5.52 x 1.40 = 7.73, a multiplier of 8 provides a conservative upper bound estimate, accounting for both internal and external event impacts, with uncertainty. Therefore, "baseline benefit with uncertainty" values are estimated using this multiplier on benefit estimates for internal events.

Cost of Enhancements

The expected COE of each SAMA was established from existing estimates of similar modifications combined with engineering judgment. Most of the cost estimates were developed from similar modifications considered in previous performed SAMA analyses. In particular, these cost-estimates were derived from the following major sources.

- ANO-2 SAMA Analysis
- Calvert Cliffs SAMA Analysis
- Donald C. Cook SAMA Analysis
- Fort Calhoun Unit 1 SAMA Analysis
- Joseph M. Farley SAMA Analysis
- McGuire SAMA Analysis

A number of additional conservatisms associated with implementation were included in the cost benefit analysis. The cost estimates for implementing the SAMAs did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation and were not adjusted to present-day dollars.

Detailed cost estimates were often not required to make informed decisions regarding the economic viability of a potential plant enhancement when compared to attainable benefit. Implementation costs for several of the SAMA candidates were clearly in excess of the attainable benefit estimated from a particular analysis case. For less clear cases, engineering judgment was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. Plant-specific cost estimates were compared, where possible, to estimates developed and used at plants of similar design and vintage. Nonetheless, the cost of each candidate was conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately gauged. The cost benefit comparison and disposition of each of the Phase II SAMA candidates is presented in Table E.2-2 of Attachment E.2 for IP2 and Table E.4-2 of Attachment E.4 for IP3.

4.21.5.5 Sensitivity Analyses

Three sensitivity analyses were conducted to gauge the impact of key assumptions upon the analysis. The fist two considered varied extended plant life and discount rate, which are the main factors affecting present worth. The third evaluates impacts resulting from economic losses due to tourism and business, which were not included in the base case. A description of each follows.

Sensitivity Case 1: Years Remaining until End of Plant Life

The purpose of this sensitivity case was to investigate the sensitivity of assuming a 26-year period for remaining plant life for IP2 (i.e., six years on the original plant license plus the 20-year license renewal period), and a 28-year period for remaining plant life for IP3 (i.e., eight years on the original plant license plus the 20-year license renewal period). The 20-year license renewal period was used in the base case. The resultant monetary equivalent for internal event was calculated by using 26 and 28 years remaining until end of facility life to investigate the impact on each analysis case for IP2 and IP3, respectively.

Sensitivity Case 2: Conservative Discount Rate

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the discount rate. The discount rate of 7% used in the base case analyses is conservative relative to corporate practices; nonetheless, a lower discount rate of 3% was assumed in this case to investigate the impact on each analysis case.

Sensitivity Case 3: Inclusion of Economic Losses due to Tourism and Business

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the inclusion of economic losses due to tourism and business. The MACCS2 economic model used for the base case analysis did not consider such losses. While the base case assumed a loss of $163,631/person in the affected region following a postulated severe accident, this sensitivity case assumed a loss of $208,838/person. This increased the calculated offsite economic cost risk for the base case and for each SAMA under consideration. Since the benefit for each SAMA is estimated as the difference between the base case and the SAMA, the sensitivity case 3 benefit values (see table listed below) are the same or only slightly higher than the baseline benefit values.

The benefits estimated for each of these sensitivities are presented in Table E.2-3 of Attachment E.2 for IP2 and Table E.4-3 of Attachment E.4 for IP3.

4.21.6 Conclusion

IP2

This analysis addressed 231 SAMA candidates for mitigating severe accident impacts. Phase I screening eliminated 163 SAMA candidates from further consideration, based on either inapplicability to IP2 design, or features that had already been incorporated into current design, procedures and programs. During the Phase II cost/benefit evaluation of the remaining 68 SAMA candidates, an additional 61 SAMA candidates were eliminated because their cost was expected to exceed their benefit.

Seven Phase II SAMA candidates (i.e., 28, 44, 54, 56, 60, 61, and 65) presented in Table 4-4 were found to be potentially cost beneficial for mitigating the consequences of a severe accident for IP2.

- A plant modification was recommended to provide a portable diesel-driven battery charger to improve DC power reliability.

- A plant modification was recommended to allow use of fire water as backup for steam generator inventory to increase the availability of steam generator water supply.

- A plant modification was recommended to install a flood alarm in the 480V AC switchgear room to mitigate the occurrence of internal floods inside the 480V AC switchgear room.

- A procedure modification was recommended to keep RHR heat exchanger discharge valves, MOVs 746 and 747, normally open. This procedure change would reduce the core damage frequency contribution from transients and LOCAs.

- A plant modification was recommended to provide added protection against flood propagation from stairwell 4 into the 480V AC switchgear room to reduce the core damage frequency contribution from flood sources within stairwell 4 adjacent to the 480V AC switchgear room.

- A plant modification was recommended to provide added protection against flood propagation from the deluge room into the 480V AC switchgear room to reduce the core damage frequency contribution from flood sources within the deluge room adjacent to the 480V AC switchgear room.

- A plant modification was recommended to upgrade the alternate safe shutdown system to allow timely restoration of reactor coolant pump seal injection and cooling from events that cause loss of power from the 480V AC vital buses.

IP3

This analysis addressed 237 SAMA candidates for mitigating severe accident impacts. Phase I screening eliminated 175 SAMA candidates from further consideration, based on either inapplicability to IP3 design, or features that had already been incorporated into current design, procedures and programs. During the Phase II cost benefit evaluation of the remaining 62 SAMA candidates, an additional 57 SAMA candidates were eliminated because their cost was expected to exceed their benefit.

Five Phase II SAMA candidates (i.e., 30, 52, 55, 61 and 62) presented in Table 4-5 were found to be potentially cost beneficial for mitigating the consequences of a severe accident for IP3.

- A plant modification was recommended to provide a portable diesel-driven battery charger to improve DC power reliability.
- An engineering analysis was recommended to evaluate and proceduralize opening the city water supply valve for alternative AFW system pump suction to enhance the availability of AFW System.
- A plant modification was recommended to provide the capability of powering one safety injection pump or RHR pump using the Appendix R diesel (MCC 312A) to enhance RCS injection capability during events that cause loss of power from the 480V AC vital buses.
- A plant modification was recommended to upgrade the alternate safe shutdown system to allow timely restoration of reactor coolant pump seal injection and cooling from events that cause loss of power from the 480V AC vital buses.
- A plant modification was recommended to install a flood alarm in the 480V AC switchgear room to mitigate the occurrence of internal floods inside the 480V AC switchgear room.

The above SAMA candidates for IP2 and IP3 do not relate to adequately managing the effects of aging during the license renewal period. In addition, since the SAMA analysis is conservative and is not a complete engineering project cost-benefit analysis, it does not estimate all the benefits or all of the costs of a SAMA. For instance, it does not consider increases or decreases in maintenance or operation costs following SAMA implementation. Also, it does not consider the possible adverse consequences of the changes. Although not related to adequately managing the effects of aging during the period of extended operation, the above, potentially cost-beneficial SAMAs have been submitted for detailed engineering project cost-benefit analysis.

The IP2 and IP3 sensitivity studies indicated that the results of the analysis would not change for the conditions analyzed.

Table 4-4
IP2 Final SAMAs

Phase II SAMA ID	SAMA title	Result of potential enhancement	CDF Reduction	Off-site Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost
028	Provide a portable diesel-driven battery charger	SAMA would improve DC power reliability.	4.79%	10.00%	9.13%	$420,459	$885,176	$494,000
	Basis for Conclusion: The CDF contribution due to local operation of the turbine-driven AFW pump during SBO scenarios was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was specifically estimated for IP2.							
044	Use fire water system as backup for steam generator inventory	This SAMA would increase the availability of steam generator water supply.	33.00%	14.55%	13.36%	$984,503	$2,072,638	$1,656,000
	Basis for Conclusion: The CDF contribution due to failure of the turbine-driven AFW pump and local operation of AFW during SBO were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was specifically estimated for IP2.							
054	Install flood alarm in the 480VAC switchgear room	This SAMA would reduce core damage frequency following switchgear room flooding.	19.97%	40.45%	38.31%	$1,722,733	$3,626,807	$200,000
	Basis for Conclusion: The CDF contribution from reducing control building flooding initiator frequency by a factor of 3 was estimated to asses the potential impact of this SAMA. The cost of implementing this SAMA was specifically estimated for IP2.							

Table 4-4
IP2 Final SAMAs

Phase II SAMA ID	SAMA title	Result of potential enhancement	CDF Reduction	Off-site Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost
056	Keep RHR heat exchanger discharge MOVs 746 and 747 normally open	This SAMA would reduce the core damage frequency contribution from transients and LOCAs.	1.84%	0.45%	0.22%	$44,633	$93,964	$82,000
	Basis for Conclusion: The probability of the RHR heat exchanger discharge MOVs 746 and 747 failing to open was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was specifically estimated for IP2.							
060	Provide added protection against flood propagation from stairwell 4 into the 480VAC switchgear room	This SAMA would reduce the core damage frequency contribution from flood sources within stairwell 4 adjacent to the 480VAC switchgear room	4.52%	9.09%	8.69%	$387,828	$816,481	$216,000
	Basis for Conclusion: The CDF contribution due to an internal flood initiated from a break in fire protection piping in stairwell 4 was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was specifically estimated for IP2.							

Table 4-4
IP2 Final SAMAs

Phase II SAMA ID	SAMA title	Result of potential enhancement	CDF Reduction	Off-site Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost
061	Provide added protection against flood propagation from the deluge room into the 480VAC switchgear room	This SAMA would reduce the core damage frequency contribution from flood sources within the deluge room adjacent to the 480VAC switchgear room	9.84%	20.00%	18.93%	$853,187	$1,796,183	$192,000
	Basis for Conclusion: The CDF contribution due to an internal flood initiated from a break in 10-in fire protection piping in elevation 15-ft deluge room, adjacent to the 480VAC switchgear room was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was specifically estimated for IP2.							
065	Upgrade the ASSS to allow timely restoration of seal injection and cooling.	This SAMA would reduce the core damage frequency contribution from internal and external events that cause loss of power from the 480V vital buses (SBO, control building floods and fires)	19.97%	40.45%	38.31%	$1,722,733	$3,626,807	$560,000
	Basis for Conclusion: The CDF contribution due to control building flooding initiators was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was specifically estimated for IP2.							

Table 4-5
IP3 Final SAMAs

Phase II SAMA ID	SAMA title	Result of potential Enhancement	CDF Reduction	Off-site Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost
030	Provide a portable diesel-driven battery charger	SAMA would improve DC power reliability.	8.73%	6.94%	6.06%	$509,643	$738,613	$494,000
	Basis for Conclusion: The time available to recover offsite power before local operation of AFW is required was changed from 2 hours to 24 hours during SBO scenarios to conservatively assess the benefit of this SAMA. In addition, internal floods that occur in the switchgear room were reduced (by 5 percent) to account for local operation of the turbine-driven AFW pump. The cost of implementing this SAMA was specifically estimated for IP3.							
052	Open city water supply valve for alternative AFW pump suction	This SAMA would enhance the availability of AFW.	0.89%	0.82%	0.95%	$65,223	$94,526	$50,000
	Basis for Conclusion: The CDF contribution from the loss of normal suction path to the AFW system was eliminated to conservatively asses the potential impact of this SAMA. The cost of implementing this SAMA was specifically estimated for IP3.							
055	Provide the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A)	This SAMA would reduce the core damage frequency contribution from internal flooding scenarios.	16.48%	18.37%	16.48%	$1,274,884	$1,847,657	$1,288,000
	Basis for Conclusion: The CDF contribution due to failure to align MCC 312A given loss of power from vital 480VAC buses due to control building floods was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was specifically estimated for IP3.							

Table 4-5
IP3 Final SAMAs

Phase II SAMA ID	SAMA title	Result of potential Enhancement	CDF Reduction	Off-site Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost
061	Upgrade the ASSS to allow timely restoration of seal injection and cooling.	This SAMA would reduce the core damage frequency contribution from internal and external events that cause loss of power from the 480V vital buses (SBO, control building floods and fires)	17.43%	19.59%	17.80%	$1,365,046	$1,978,328	$560,000
	Basis for Conclusion: The CDF contribution due to control building flooding initiators was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was specifically estimated for IP3.							
062	Install flood alarm in the 480VAC switchgear room	This SAMA would reduce the core damage frequency contribution from flood sources in the 480VAC switchgear room	17.43%	19.59%	17.80%	$1,365,046	$1,978,328	$196,800
	Basis for Conclusion: The CDF contribution due to control building flooding initiators was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was specifically estimated for IP3.							

4.22 Environmental Justice

4.22.1 Description of Issue

Environmental Justice

4.22.2 Finding from Table B-1, Appendix B to Subpart A

The need for and the content of an analysis of environmental justice will be addressed in plant-specific reviews.

4.22.3 Requirement

Other than the above referenced finding, there is no requirement concerning environmental justice in 10 CFR Part 51.

4.22.4 Background

The following background information is from Regulatory Guide 4.2.

Environmental justice was not reviewed in NUREG-1437. Executive Order 12898, "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations," issued on February 11, 1994, is designed to focus the attention of Federal agencies on the human health and environmental conditions in minority and low-income communities. The NRC Office of Nuclear Reactor Regulation is guided in its consideration of environmental justice by Appendix D, Environmental Justice and Flow Chart, to NRR Instruction No. LIC-203, Revision 1, Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues," May 24, 2004. LIC-203 is revised periodically. The environmental justice review involves identifying off-site environmental impacts, their geographic locations, minority and low-income populations that may be affected, the significance of such effects, and whether they are disproportionately high and adverse compared to the population at large within the geographic area, and if so, what mitigative measures are available, and which will be implemented. The NRC staff will perform the environmental justice review to determine whether there will be disproportionately high human heath and environmental effects on minority and low-income populations and report the review in its SEIS. The staff's review will be based on information provided in the ER and developed during the staff's site-specific scoping process.

The NRC's Office of Nuclear Reactor Regulation Office Instruction No. LIC-203 [NRC 2004] contains a procedure for incorporating environmental justice into the licensing process. Entergy used this process in conducting the review and analysis of this issue.

4.22.5 Analysis

The consideration of environmental justice is required to assure that federal programs and activities will not have "disproportionately high and adverse human health or environmental effects…on minority populations and low income populations…" Entergy's analyses of the Category 2 issues defined in 10 CFR 51.53(c)(3)(ii) determined that there were no adverse impacts from the renewal of the IP2 and IP3 operating licenses. Thus, no disproportionate impact on minority or low-income populations would occur from the proposed action. Based on the review of these issues, no review for environmental justice is necessary. However, Entergy presents environmental justice demographic information in Section 2.6.2 to assist the NRC in its review.

4.22.6 Conclusion

As part of its environmental assessment of this proposed action, Entergy has determined that no significant off-site environmental impacts will be created by the renewal of the IP2 and IP3 Operating Licenses. This conclusion is supported by the review performed of the Category 2 issues defined in 10 CFR 51.53(c)(3)(ii) presented in this ER.

As the NRR procedure recognizes, if no significant off-site impacts occur in connection with the proposed action, then no member of the public will be substantially affected. Therefore, there can be no disproportionately high and adverse impacts or effects on members of the public, including minority and low-income populations, resulting from the renewal of the IP2 and IP3 Operating Licenses.

4.23 Cumulative Impacts

Entergy considered potential cumulative impacts in its environmental analysis associated with IP2 and IP3 operations during the license renewal period. For the purposes of this analysis, past actions are those related to the resources at the time of plant licensing and construction, present actions are those related to the resources at the time of current operation of the power plant, and future actions are considered to be those that are reasonably foreseeable through the end of plant operation, which would include the 20-year license renewal term. The geographic area over which past, present and future actions would occur is dependent on the type of action considered and is described below for each impact area.

The impacts of the proposed action are combined with other past, present and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. These combined impacts are defined as "cumulative" in 40 CFR 1508.7 and include individually minor, but collectively significant actions taking place over a period of time. It is possible that an impact that may be SMALL by itself could result in a MODERATE or LARGE impact when considered in combination with the impacts of other actions on the affected resource. Likewise, if a resource is regionally declining or imperiled, even a SMALL individual impact could be important if it contributes to or accelerates the overall resource decline.

4.23.1 Cumulative Impacts on Aquatic Resources

The geographic area considered for the analysis of cumulative impacts on aquatic resources focused on the Hudson-Mohawk River drainage basin, specifically on the portion of the Hudson River basin from the mouth of the Hudson River at the Battery (RM 0) to the Troy Dam (RM 154) at Albany. The Hudson River watershed is a major estuary, covered by the New York State

Coastal Management Program. The Hudson River's cultural and natural history has been studied and described by various individuals, organizations, institutions, and governmental agencies since the beginning of recorded history in America. The portion of the estuary with the greatest potential for cumulative impacts has been intensely studied jointly by the Hudson River Utility Systems and the NYSDEC over the past 30 plus years.

As noted by the NRC, large estuaries are influenced by a variety of factors that alter marine and estuarine food chains, species compositions, or species distributions that are ecologically, commercially, or recreationally important [NRC, 2006]. IP2 and IP3 are one of six electric power generating facilities withdrawing water from and discharging into the Hudson River. An overview of the environmental setting and the impacts of IP2 and IP3 station operations have been described throughout Section 2 and Section 4, respectively. The aquatic ecological setting, described in Section 2.2, discussed cumulative impacts on the lower Hudson from a number of causes.

The DEIS provided a regional environmental setting of the Hudson basin and noted that the Hudson River is used as a source of potable water as well as for waste disposal, transportation, and cooling by industry and municipalities. The Hudson River below Albany is used as a source of potable water by at least five municipalities and receives discharges greater than 50 mgd from 12 facilities. (This number assumes that the structure replacing the World Trade Center will also discharge greater than 50 mgd.) The six electric power generation facilities utilizing the Hudson River for cooling water supply are Bowline Point at RM 37, Lovett at RM 42, Indian Point at RM 43, Danskammer at RM 66, Roseton at RM 67, and Bethlehem at RM 140. Additional intake of Hudson River water may occur at Chelsea Pumping Station, located on the eastern bank of the river across from Roseton Units 1 and 2 Generating Station [CHGEC, Section V.A.9.c.i].

As discussed below, impacts from IP2 and IP3 on aquatic resources have less impact than those associated with damming of the river or its tributaries, long-term land use changes, or other factors induced by climatic changes.

Although not related to IP2 and IP3 operations, both the USFWS and the NYSDEC have identified human activities that have had significant impacts on the Hudson and to its habitat for aquatic organisms and usages. The net effect of dams on most of the tributaries is the removal of a great number of miles of suitable anadromous fish spawning habitat from the system (see Section 2.2) [USFWS 1997]. Shapley and Morris noted the potentially serious impact of dams on tributaries of the Hudson stating, "The roughly 357 dams and other barriers on the 63 tributaries of the Hudson River estuary block what is called the stream continuum." Sections of streams become lake-like, changing the flow of nutrients, sediment, dissolved oxygen—even warmth. Dammed water heats up in the summer. Spilling downstream, it is often hot enough to shock cold-water species such as trout. Dissolved oxygen, which is essential for fish and other aquatic life, is also decreased as it flows downstream over the dam. [Shapley]

Transportation has had a major effect on the Hudson River. Railroad bed construction as early as the 1840s paralleled both banks of the river, crossing all tributaries and isolating many of the tidal marsh complexes. Maintenance and rebuilding of railroads, roads, and bridges along the

Hudson River could adversely impact wetlands, rare plants, fish, and wildlife. Herbicide use along roads and railroads could destroy adjacent rare plant populations. Non-point source pollution in the form of runoff is also seen as a concern. [USFWS 1997]

The entire main stem of the Lower Hudson River (representing 100% of the estuary waters in the basin) is listed as having use (fish consumption) impairments due to toxic/contaminated sediment [NYSDEC 2004, Appendix A]. Increased regulation of wastewater discharges have significantly improved the water quality of the Hudson, while invasive plants and species such as water chestnut and zebra mussels may have reduced the amount of dissolved oxygen and zooplankton, respectively. All of these factors have had impacts on the basin's aquatic ecology but are not associated with the current or future operations of IP2 and IP3. Changes in ecosystem structure and function may be the result of many factors, including the loss of wetland and marsh areas due to dredging or near-river development, and climatic changes that alter predator-prey relationships or species compositions [NRC 2006].

There are activities associated with IP2 and IP3 operations that may potentially produce a localized aquatic affect on the lower Hudson River during the license renewal term such as minimal maintenance dredging associated with the intake structures to facilitate water flow, entrainment of zooplankton and ichthyoplankton, impingement of fish and shellfish, storm water runoff, groundwater discharge, and temperature-related effects due to the cooling water discharge. Similar localized impacts may be associated with other cooling water or potable water intakes or discharges from the other electric power generation plants, as well as industrial or municipal facilities. These activities could produce cumulative impacts on the aquatic ecology within the basin.

The Hudson River Estuary is an important spawning and nursery area for a variety of fish species, including both year-round inhabitants as well as species that move into the estuary solely for the purpose of spawning. The Hudson River Utilities and NYSDEC identified 16 fish and one crab species of concern to describe temporal changes in abundance measures. These included bay anchovy (*Anchoa mitchilli*), weakfish (*Cynoscion regalis*), gizzard shad (*Dorosoma cepedianum*), spottail shiner (*Notropis hudsonius*), white catfish (*Ictalurus catus*), bluefish (*Pomatomus saltatrix*), white perch (*Morone americana*), hogchoker (*Trinectes maculates*), rainbow smelt (*Osmerus mordax*), Atlantic tomcod (*Microgadus tomcod*), alewife (*Alosa pseudoharengus*), blueback herring (*Alosa aestivalis*) striped bass (*Morone saxatilis*), American shad (*Alosa sapidissima*), Atlantic sturgeon (*Acipenser oxyrhynchus*), shortnose sturgeon (*Acipenser brevirostrum*), and blue crab (*Callinectes sapidus*). [CHGEC, Section V.D.2]

During the 24-year monitoring period from 1974 to 1997, species richness and overall abundance of the larval fish community increased in most areas of the estuary. Analysis of the long-term trends in the larval fish community in both the marine brackish regions and the freshwater zone revealed an overall increase in the total number of taxa collected. Increases in overall abundance were due to increases in the abundance of larval striped bass in all areas of the estuary and increases in the abundance of larval bay anchovy in brackish areas. [CHGEC, Section V.D.3.i]

Overall, studies indicate the fish community of the Hudson River estuary has experienced small changes in species richness and diversity, between the regions of the river and fish life stages. These changes are also discussed in Sections 4.2 and 4.3. Ichthyoplankton (fish eggs and larvae) species have increased slightly. The number and diversity of juvenile and older fish have decreased slightly during the river monitoring program. In the brackish region of the Hudson River, the decrease in richness and abundance is indicated to be due to an increase in salinity and consequent reduction in collection of freshwater fish species. [CHGEC, Section V.D.3.ii]

The shortnose sturgeon is listed as a federally endangered species and a discussion of this species is included in Section 2.5. Overall for the six electric power generation plants, the average impingement was 10.2 occurrences per year from 1972 through 1998, but 7.5 occurrences per year from 1989 through 1998. Based on these data, the NMFS concluded that future impingement rates due to incidental take at Roseton and Danskammer Point generating stations, even though higher than at Indian Point, are unlikely to jeopardize the continued recovery of the Hudson River shortnose sturgeon population [NMFS 2000, Section 5.2.2]. NMFS also identified the Atlantic sturgeon as a candidate species. Ristroph traveling screens and fish return systems were installed at the IP2 and IP3 intake structures in the early 1990s that eliminated or minimized the potential impingement mortality of shortnose and Atlantic sturgeon.

Entergy has a program in place to identify onsite spills or releases, evaluate onsite groundwater impacts from current or past station operations, and mitigate the migration of any groundwater contamination in accordance with NRC and NYSDEC regulations. These groundwater monitoring and control efforts will assure minimal effects to offsite aquatic resources and very limited incremental impacts such that future station operations during the license renewal term would not pose a cumulative risk to the Hudson River basin resources.

The Hudson River estuary is controlled by many factors which may produce incremental impacts. However, more than 30 years of extensive fisheries studies of the Hudson River have been conducted in the vicinity of IP2 and IP3. The results of the studies performed from 1974 to 1997 have not shown any negative trend in overall aquatic river species populations attributable to plant operations. Ongoing studies continue to support these conclusions [ASA]. In addition, current mitigation measures implemented through the HRSA and retained in the four Consent Orders, the current agreements with NYSDEC, and the outcome of the draft SPDES Permit proceeding will ensure that aquatic impacts remain SMALL during the license renewal term. Therefore, further mitigation measures are not warranted.

4.23.2 Cumulative Impacts on Terrestrial Resources

Entergy evaluated cumulative impacts of past, current and future activities in the five-county geographic area in which the plant, its transmission corridors, and its employees reside: Westchester, Rockland, Putnam, Dutchess, and Orange counties. Terrestrial resource impacts might include those to upland and river valley habitats, wetlands, and land use. Entergy has evaluated the incremental impacts associated with the proposed action to renew the IP2 and IP3 Operating Licenses.

As stated in Section 4.23.1, the environmental setting is described in Section 2. The description of IP2 and IP3 facilities and operations are described in Section 3, while analyses of impacts to various resources are described in this section of the ER (Section 4). The potential impacts of the various alternatives to the proposed action are discussed in Section 8 of this ER. Again, the cultural and natural history of this area has been studied and described by various individuals, organizations, institutions, and governmental agencies since the beginning of recorded history in America.

Past land use changes include the construction of the IP1, IP2, and IP3 facilities and its associated transmission lines. While significant residential and commercial development changes have occurred in the area since the construction of IP2 and IP3, the five counties in this region all have controls on future development and land use (see Section 2.8). Since 1992, land use and development have been regulated by the Open Space Conservation Plan, which is enforced by the Quality Communities Task Force [NYSL]. Open space is land that is not intensively developed for residential, commercial, industrial, or institutional use [NYSL]. The New York Coastal Zone Management Program also regulates some actions involving terrestrial resources along the Hudson River, as do various other agencies including, but not limited to, the USCOE, the NYSDEC, and the USFWS.

The NYSDEC 1997 Freshwater Wetlands Map indicates no wetlands areas are identified within the site boundary [NYSDEC 1997b]. The nearest state designated wetlands are located 0.45 miles northeast of the site at Lents Cove, east of Broadway. Entergy has procedures in place to

- control potential impacts to any nearby wetlands;
- minimize potential impacts from land disturbance and impacts to potential cultural or historic resources;
- minimize or control spills; and
- ensure permits are in place to minimize impacts from stormwater runoff.

While Entergy does not control the transmission lines beyond the Buchanan Substation directly across Broadway (immediately east of the plant), the transmission line owner and operator (ConEdison) addresses impacts to the transmission line corridors in accordance with its vegetative management plan. None of the management procedures are expected to alter wetland or riverine hydrology or adversely affect vegetation characteristics of these habitats or other habitats.

Although there are no state or federal jurisdictional wetlands on site, the open water of the Hudson River and its emergent wetland habitat supports a number of migrant waterfowl species, including mallard (*Anas platyrhyncos*), Canada goose (*Branta canadensis*), American black duck (*Anas rubripes*), and wood duck (*Aix sponsa*). In addition, several species of woodpeckers, songbirds, herons, and raptors, such as osprey (*Pandion haliaetus*) and bald eagle (*Haliaeetus leucocephalus*), utilize the river areas near the site [NYSDEC 2005b]. Peregrine falcons (*Falco* *peregrinus*) are also found throughout much of the Hudson River Valley, including the vicinity of the site [NYSDEC 2006].

The State and federally listed threatened or endangered terrestrial species and species of concern in Westchester County are cited in Table 2-4. There is no critical habitat designated in Westchester County where IP2 and IP3 are located. Of the listed threatened or endangered species that could potentially be affected by station or transmission line maintenance operations, the only species identified is the bald eagle.

Bald eagles occur throughout virtually the entire area near the site. The bald eagle is known to nest along the Hudson River and has occasionally been seen near the site. In 1997, a nesting pair produced the first eaglet born along the Hudson River in more than 100 years near the Town/ Village of Catskill, NY. In 2005, 12 pairs nested and 18 eaglets were fledged along the river [NYSDEC 2005a]. Bald eagles frequently winter along the Hudson River. Habitat for wintering bald eagles is generally described as large open waters, i.e., large rivers and lakes suitable for foraging. Habitat near the facility could possibly support wintering bald eagles because of the location of the site near the Hudson River. However, none of the management procedures are expected to alter bald eagle habitat or interfere with wintering or nesting. Therefore, IP2 and IP3 are not expected to contribute to adverse cumulative impacts on this species.

Entergy has reviewed its potential incremental contributions to cumulative impacts on terrestrial resources resulting from continued operation of IP2 and IP3 and from the transmission lines that transmit electrical power to the electrical grid. Entergy has concluded that any potential impacts would be SMALL and further mitigation measures are not warranted.

4.23.3 Cumulative Radiological Impacts

The radiological dose limits for protection of the public and workers have been developed by the EPA and the NRC to address the cumulative impact of acute and long-term exposure to radiation and radioactive material. These dose limits are codified in 40 CFR Part 190 and 10 CFR Part 20. For the purpose of this analysis, the area within a 50-mile radius region of interest (ROI) around IP2 and IP3 was included. There are no other nuclear fuel cycle facilities within the 50-mile ROI. The Millstone Nuclear Power Station (Units 2 and 3) is located in Connecticut approximately 92 miles northeast of IP2 and IP3. However, a portion of the population within the IP2 and IP3 ROI is also within the 50-mile ROI for Millstone Power Station. Limerick Nuclear Generating Station is located in Pennsylvania, approximately 112 miles to the southwest of IP2 and IP3, and the Susquehanna Steam Electric Station is located approximately 110 miles west.

The owners of IP2 and IP3 have conducted radiological environmental monitoring programs around the site since 1958. The results of the operational Radiological Environmental Monitoring Program (REMP) are reported to the NRC in the IP2 and IP3 Annual Radiological Environmental Operating Reports. The REMP measures radiation and radioactive materials from all sources, including, but not limited to, IP2 and IP3 radioactive emissions, and thus considers cumulative radiological impacts. On the basis of an evaluation of REMP results, Entergy concludes that impacts of radiation exposure on the public and workers (occupational) from operation of IP2 and IP3 during the renewal term would be SMALL. With respect to the future, the REMP sampling locations identified in the IP2 and IP3 ODCMs have not identified increasing levels or the accumulation of radioactivity in the environment over time. In addition, Entergy is not aware of any plans or proposals for new nuclear facilities in the vicinity of IP2 and IP3 that would potentially contribute to cumulative radiological impacts. The NRC and the State of New York would regulate any future actions in the vicinity of the site that could contribute to cumulative radiological impacts. Therefore, Entergy concludes that future cumulative radiological impacts would be SMALL and therefore mitigation measures are not warranted.

4.23.4 Cumulative Socioeconomics Impacts

The socioeconomic conditions involving housing, local public services, utilities, education, employment, transportation, and personal income were presented for Westchester, Rockland, Putnam, Dutchess, and Orange Counties in New York in Section 2. The impacts of housing, local public services/ utilities, education, and transportation as measures of socioeconomic indicators for these counties were evaluated separately in Sections 4.14, 4.15, 4.16, and 4.19.

As noted in Section 2.7, a report by the Nuclear Energy Institute (NEI) concluded that the site, which is located near the Village of Buchanan, had an economic impact of $763 million in 2002 in Westchester, Rockland, Orange, Putnam, and Dutchess counties [NEI]. Taxes paid by the site have a positive impact on the fiscal condition of Westchester County, especially the Hendrick Hudson and Lakeland school districts. Continued operation of the plant through the license renewal term would provide a significant continuing source of tax revenues to the local community and beneficial economic impact to the surrounding counties and communities.

In addition, the continuance of the 2158 MWe base load electrical power generation capacity provided by IP2 and IP3 provides relatively low cost and environmentally clean power to the lower Hudson River and upper New York City metropolitan area. As discussed in Section 2, the region is in non-attainment for ozone and particulates. As discussed in Section 8, alternative power supplies would create a deficit of base-load electrical power generation capacity that would likely have to be replaced by fossil fuel power generation which would add to adverse air quality impacts, especially for particulates and greenhouse gases. Due to limitations of the current transmission systems, construction of alternative power generation capacity in other areas of the state would be impractical in the near-term and would transfer socioeconomic impacts to other locales.

When combined with the impact of other potential activities, such as likely residential development and population growth in the area surrounding the plant, socioeconomic impacts from IP2 and IP3 license renewal would not produce a noticeable incremental change in any adverse impact measures. Therefore, Entergy concludes that the socioeconomic impact from the renewal of the IP2 and IP3 Operating Licenses, in addition to the impacts of other potential economic activities in the area, would be SMALL compared to other contributors and therefore further mitigation measures are not warranted.

4.23.5 Cumulative Impacts on Groundwater Use and Quality

The area of analysis for cumulative impacts on groundwater would encompass wells primarily within Westchester County. The Hudson River and Rockland, Dutchess, Putnam, and Orange counties are also considered due to IP2 and IP3 employment impacts in these areas.

Groundwater at the IP2 and IP3 site generally flows west toward the Hudson River. As discussed in Section 2.3, the site is situated on the Upper Ordovician, Balmville Limestone formation with some limited areas of glacial till. The Balmville Limestone is a hard, dark gray, metamorphosed dolomitic limestone. Adjacent to the Balmville Limestone are schist and phyllite formations and the igneous intrusive rocks of the Cortland (mafic) Complex. [USAEC, Section II.E.3]

Groundwater is encountered at the site primarily in bedrock fractures and along the jointing or bedding planes of the various rock strata. Thus, groundwater may be encountered at different elevations on the site, dependent upon location, ground surface elevation and the fracture or water-bearing facies encountered.

Groundwater contamination occurrences at the site have involved non-radiological (e.g.,petroleum hydrocarbons) contaminants, and radionuclides. These have been reported to the NRC and NYSDEC, as appropriate, and investigations performed to delineate the area of subsurface impact. As a result of the non-radiological events, corrective actions and monitoring programs were implemented in coordination with the NYSDEC. Based on the results of these programs, NYSDEC has determined that no additional actions are necessary at this time.

Regarding the radiological contamination, the areal extent of groundwater impact remains primarily on the facility property, and various monitoring systems operate under NRC cognizance. The investigation of the radionuclide contamination of the groundwater began in 2005, and although the investigation is on-going, Entergy and the NRC have concluded that although there appears to be some level of contaminated groundwater that discharges to the Hudson River, these levels do not exceed the effluent or radiological dose criteria established by the NRC. Entergy plans to continue to investigate groundwater contamination mitigation methods to determine their feasibility, as deemed appropriate by the NRC. Even if it is determined that no remedial actions are warranted at this time, the contamination at the site will not contribute to offsite regional groundwater impacts.

The site does not utilize groundwater, either for plant operations or for potable water. Surface water from the Hudson River and city water (Village of Buchanan PWS) supply the plant operational and potable water needs. There are no plans to develop groundwater sources at the plant for current operations, nor for operations through the license renewal term since adequate public water supplies are available to support the continued operation of IP2 and IP3, considering the anticipated employment at the site.

Public water supply systems (see Table 2-12) in the vicinity of the site include community and non-community (including non-transient non-community and transient non-community) systems. Community water systems within Westchester, Putnam, Orange, Dutchess, and Rockland counties utilize both groundwater and surface water sources. Compared to regional potable water sources, including groundwater withdrawals for potable water supply and incremental demand from offsite development and population increases in the region, the demand for potable water from the continued operation of IP2 and IP3 is inconsequential.

Based on the fact that there is adequate supply of potable water to meet the current and future demand, the fact that there is no planned increase in the employment at IP2 and IP3, and that there is adequate supply for short-term increases of temporary labor during refueling or any foreseeable construction activities at the site during the license renewal term, Entergy concludes that the cumulative impact on groundwater resources would be SMALL and mitigation measures are not warranted. On the basis of groundwater quality, Entergy also concludes that the cumulative impact on the quality of local groundwater resources would be SMALL and mitigation measures are not warranted.

4.23.6 Conclusion

Entergy considered the potential impacts from IP2 and IP3 operations during the license renewal term and other past, present, and future actions in the vicinity of the site. Entergy's conclusion is that the potential cumulative impacts resulting from IP2 and IP3 operations during the license renewal term would be SMALL. Therefore, further mitigation measures are not warranted.

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5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

"The environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware." [10 CFR 51.53(c)(3)(iv)]

The NRC has resolved most license renewal environmental issues generically and only requires an applicant to analyze those issues the NRC has not resolved generically. While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware. [10 CFR 51.53(c)(3)(iv)]

Entergy performed an analysis to identify the following:

- information that identifies a significant environmental issue not covered in the NRC's GEIS and codified in the regulation, or
- information not covered in the GEIS analyses that lead to an impact finding different from that codified in the regulation.

NRC does not specifically define the term "significant." For its review, Entergy used guidance available in Council on Environmental Quality (CEQ) regulations. The NEPA authorizes CEQ to establish implementing regulations for federal agency use. The NRC requires license renewal applicants to provide the NRC with input, in the form of an environmental report, that the NRC will use to meet NEPA requirements as they apply to license renewal (10 CFR 51.10).

CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), focus on significant environmental issues (40 CFR 1502.1), and eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). Entergy expects that MODERATE or LARGE impacts, as defined by NRC, would be significant. Chapter 4 presents the NRC definitions of SMALL, MODERATE, and LARGE impacts.

Entergy reviewed SEISs and associated environmental Requests for Additional Information (RAIs) with license renewal applications to determine if there were new issues identified for those plants that may be applicable to IP2 and IP3. In addition, state and federal regulatory agencies were consulted regarding new and significant information as it related to license renewal environmental matters. In addition, Entergy has an ongoing assessment process for identifying and evaluating new and significant information that may affect programs at the Entergy nuclear sites, including those related to license renewal matters.

This process is directed in a joint effort by the nuclear corporate support group and environmental focus group members composed of technical personnel from the Entergy Nuclear South and Entergy Nuclear Northeast sites. A summary of this process follows.

- Issues relative to environmental matters are identified as follows:
  - Participation in industry utility groups (i.e., EEI, EPRI, NEI, and USWAG);
  - Participation in non-utility groups (i.e., Institute of Hazardous Materials Management and National Registry of Environmental Professionals);
  - Periodic reviews of proposed regulatory changes;
  - Entergy Nuclear Environmental Focus Group meetings.
- If the issue is applicable to the nuclear sites, it is then further evaluated by the nuclear corporate support group and environmental focus group that consist of technical personnel involved in environmental compliance, environmental monitoring, environmental planning, natural resource management, and health and safety issues. Necessary changes are made to the program and implemented in accordance with site and corporate procedures.

Additional actions incorporated into this assessment process specifically for IP2 and IP3 license renewal include the following.

- Review of documents related to environmental issues at IP2 and IP3.
- Review of current site activities and interview site personnel.
- Review of internal procedures for reporting to the NRC events that could have environmental impacts.
- Credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies.
- Review of environmental issues associated with other license renewal activities.

As a result of this assessment Entergy identified one potential issue that could be classified as new information, but not necessarily significant. This issue is discussed in Section 5.1 below.

5.1 New and Significant Information: Groundwater Contamination

The NRC identified degradation of groundwater quality resulting from closed-cycle cooling ponds as a Category 2 issue. Because Indian Point does not use cooling ponds, this Category 2 issue does not apply to renewal of the IP2 and IP3 Operating Licenses. However, contamination of onsite groundwater due to leaking plant structures, systems, or components could potentially occur and is currently being evaluated as a generic issue to the nuclear industry.

Recent groundwater contamination events at several nuclear power plants have received considerable attention. Although no adverse dose impacts have been identified related to these events, there is concern that under different circumstances than have occurred in cases thus far, undetected leakage could result in areas of groundwater contamination, migration of radioactivity to the unrestricted area, and unevaluated doses to members of the public.

The NRC evaluated impairment of groundwater quality in Section 4.8.2 of the GEIS (NUREG-1437), including impacts due to tritium. As stated in the GEIS, slightly elevated concentrations of tritium have been observed in groundwater adjacent to the Prairie Island plant on the Mississippi River in southern Minnesota. These elevated concentrations have not altered the current use of groundwater near the site. One offsite privately owned well at the Prairie Island plant has reported tritium concentrations ranging between 800 and 1000 pCi/L (dates of measurements are uncertain, but they are no more recent than 1991). By comparison, tritium concentrations in North American streams were about 10 pCi/L prior to the beginning of the nuclear age and about 4000 pCi/L at the end of large-scale atmospheric testing of nuclear weapons in 1963. Radioactive decay of tritium between 1963 and 1992 would produce a concentration of about 715 pCi/L. If tritium concentrations at Prairie Island were as high as 1000 pCi/L in 1992, then perhaps one-third of the tritium contamination found in local groundwater might be attributable to the Prairie Island plant and the balance would be attributable to atmospheric testing. Future radioactive decay of tritium would further reduce its overall concentration in groundwater. Natural decay and tritium release to the environment at Prairie Island might be expected to reach equilibrium eventually at around 300 pCi/L. This compares with a regulatory limit of 20,000 pCi/L in drinking water. [NRC 1996, Section 4.8.2]

In preparing Section 4.8.2 of the GEIS, the NRC reviewed data from appropriate FSARs and FESs pertaining to the operation of nuclear power plants. Sites having a potential impact on groundwater quality were identified; and appropriate state water-use permitting agency representatives and USGS personnel were interviewed by telephone for additional information. The NRC concluded that groundwater quality impacts are considered to be of small significance when the plant does not contribute to changes in groundwater quality that would preclude current and future uses of the groundwater. Hence, the contribution of plant operations (during the license renewal period) to the cumulative impacts of major activities on groundwater quality would be relatively small. [NRC 1996, Section 4.8.2]

The impacts of plant operations and groundwater quality were also reviewed by the NRC in the SEIS for the D.C. Cook Nuclear Plant (NUREG-1437, Supplement 20). Two permitted locations at the Cook Nuclear Plant (CNP) were considered where discharge occurs to groundwater. [NRC 2005, Section 4.7]

Tritium has been detected periodically in groundwater in monitoring wells at the CNP site. Although, the authorization to discharge to groundwater does not contain criteria for tritium, monitoring routine analyses shows that no sample has exceeded the drinking water standard of 20,000 pCi/L. [NRC 2005, Section 4.7]

On the basis of this information, the staff concluded that although the impacts to groundwater quality that would result from continued disposal of wastewater to onsite absorption ponds and sewage lagoons during the license renewal period are considered a new issue, the impacts would be SMALL and, therefore, not significant. Further the NRC determined that mitigation at CNP is not warranted. [NRC 2005, Section 4.7]

Indian Point

At Indian Point, Entergy identified shrinkage cracks in the IP2 spent fuel building wall in August 2005 while excavating in the IP2 Fuel Storage Building (FSB) Loading Bay, adjacent to the south wall of the Spent Fuel Pool (SFP). Cracks in the wall of the SFP exhibited moisture, which upon analysis indicated that the material had the same radiological and chemical characteristics as SFP water. Upon completion of radiological analysis, Entergy determined that the crack exhibited some contamination, and informed the NRC resident inspector of its observation on September 1, 2005.

On September 29, 2005, a sample was taken from MW-111 located in the IP2 transformer yard. Results obtained on October 5, indicated the presence of 211,000 pCi/Liter of tritium. Other [nearby] sampling wells showed no detectable activity. A four-hour report was made as a courtesy notification the NRC and other governmental agencies and followup sampling of nearby wells was initiated. [IPEC]

Entergy has been conducting an assessment since the discovery utilizing a network of monitoring wells to assess and characterize groundwater movement and behavior relative to groundwater contamination at Indian Point. Thirty-six groundwater monitoring wells and test wells have been installed to date in response to the radionuclide releases, to delineate the extent of groundwater impacts, and to define the source(s). Full characterization of the impact to groundwater is continuing. Preliminary results indicate that tritium contaminated groundwater exists at the site. During the course of delineating the sources of tritium, Strontium-90, Cesium-137, and Nickel-63 have been detected in low concentrations in some onsite groundwater monitoring well samples. In addition, the IP1 spent fuel pool was identified as a potential source of the radionuclides in groundwater.

Based on the results of the preliminary hydrogeologic characterization of the site, Entergy has concluded that some contaminated groundwater has likely migrated to the Hudson River. This release pathway is now being monitored and is included in the site effluents offsite dose calculations. A description of the local groundwater conditions were discussed in Section 2.3 of this ER. As discussed in Section 2.3, the site does not utilize groundwater for any of its cooling water, service water, potable water needs, or for any other beneficial uses. As described in Section 2.10.1 of this ER, IP2 and IP3 obtains its cooling and service water supplies from the Hudson River, and potable water supplies from the Village of Buchanan, New York Public Water System. The Village of Buchanan obtains its water from contracts with the City of Peekskill and the Montrose Improvement District (now joined with the NWJWW), which do not utilize groundwater in the vicinity of Indian Point. This is expected to be true during the IP2 and IP3 license renewal term.

Based on samples from the site monitoring wells, survey analyses, annual rainfall recharge to groundwater, information determined from current hydrological assessment, and application of an estimated hydrological gradient to the Hudson River, a total body dose of 1.65E-3 mrem/year is estimated to the maximally exposed individual. This represents 0.055% of the NRC limit of 3 mrem/year for liquid effluent releases [Entergy].

Based on currently available information and the sampling data that have been analyzed and assessed to date, the NRC and Entergy have not found any condition that indicates that occupational or public health and safety have been, or likely will be, affected by the current onsite groundwater contamination. This assessment is based on the fact that there is no drinking water pathway associated with groundwater or the Hudson River in the region surrounding Indian Point, and samples taken in support of the NRC-required Radiological Environmental Monitoring Program (REMP) continue to indicate no detectable plant related radioactivity in groundwater above safe drinking water standards beyond the site boundary. Samples taken include the offsite REMP sampling locations as defined in the IP2 and IP3 ODCMs, the local municipal drinking water reservoirs, and other groundwater monitoring wells located in the immediate vicinity of the plant.

Identified onsite release sources are now being monitored and any contaminated discharges documented as an effluent release in accordance with NRC regulatory requirements. Although the migration of contaminated groundwater to the Hudson River was considered an unmonitored release, it has now been incorporated into the site's effluent monitoring program and is documented in the Annual Radiological Effluents Release Report prepared in accordance with US NRC Regulatory Guide 1.21. While the hydrological site assessment and groundwater analysis allow conservative estimation of such a release to confirm that public health and safety is not adversely affected, efforts have been undertaken by Entergy to find the source(s), repair the condition, and restore the effluent control process as originally designed [NRC 2006]. An extensive hydrogeologic characterization project is currently being conducted at the Indian Point site to delineate discharges to groundwater and to define the measures most protective of the public. To date, results have shown that the IP1 fuel pool as a confirmed source of at least some of the tritium, as well as strontium, cesium, and nickel in the groundwater. Ongoing mitigation activities for this source include treatment of the fuel pool water via a decontamination system installed in August 2006. This source term reduction strategy is expected to reduce contaminants in the groundwater that result from Unit 1 pool leakage. A well near IP1 has shown reductions in concentration and additional trend data will continue to be collected to determine the long-term impact of the ongoing source term reduction. Planned future mitigation actions include continued decontamination of the pool water, as well as the eventual removal of all fuel from the pool to dry casks and the draining of the pool to remove any source of contamination. The long-term monitoring program will be used to determine the need for any additional remediation once groundwater trends are established. If warranted, a pumped treatment technology may be employed as a future mitigation measure.

Although the IP2 spent fuel pool was initially suspected to be the source of the onsite groundwater contamination, no leaks have been identified in the IP2 fuel pool liner and the contamination in that area is not consistent with active leakage. This would indicate that the contamination related to the IP2 fuel pool is the result of historical pool leakage in the 1990s which has since been repaired. Although the results of the ongoing monitoring program do not indicate that any mitigation is warranted at this time, Entergy has installed a pilot recovery well next to the IP2 pool and testing has been conducted to determine the efficacy of this remediation method, should future mitigation become warranted. The on-going long-term groundwater monitoring program will continue to be used to monitor the levels of contamination around the site. The results of this program, along with the final results of the site hydrogeologic characterization, will be used to determine the need for mitigation of this contamination on an ongoing basis.

The NRC has indicated in the CNP SEIS (NUREG-1437, Supplement 20) that the release of radionuclides to the groundwater is considered a new issue. Entergy has reviewed the available data and has concluded that the site conditions do not impact the onsite workforce. The radionuclide release is not anticipated to change environmental considerations, such as water usage, land usage, terrestrial or aquatic ecological conditions, or air quality, and is not expected to affect socioeconomic conditions, as a result of license renewal activities. In addition, no NRC dose limits have been exceeded and EPA drinking water limits are not applicable since no drinking water pathway exists. Although impacts to site groundwater quality have occurred, measures have and are being taken to control releases from the Spent Fuel Pools using waste management equipment and processes. Additional monitoring actions have been developed as part of the site's Groundwater Monitoring Program, and actions added to the existing REMP to monitor potential impacts of site operations throughout the license renewal term and to monitor potential impacts of site operations and waste and effluent management programs. On the basis of current information, Entergy concludes that although the existence of radionuclides in the groundwater during the license renewal period are potentially a new issue, the impacts of those radionuclides would be SMALL and not significant.

5.2 References

Entergy. 2007. Internal Memorandum. Annual Summary of Ground Water Dose Evaluation - 2006.

IPEC Condition Reports and Apparent Cause Evaluation in response to CR-IP2-2005-3986 and CR-IP2-2005-04151. 2005.

NRC (U.S. Nuclear Regulatory Commission). 1996. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), Volumes 1 and 2, NUREG-1437, Washington, DC.

NRC (U.S. Nuclear Regulatory Commission). 2005. Generic Environmental Impact Statement for License Renewal of Nuclear Plants, NUREG-1437, Supplement 20, Regarding D.C. Cook Nuclear Plant, Final Report. Office of Nuclear Reactor Regulation. Washington, DC.

NRC (U.S. Nuclear Regulatory Commission). 2006. Indian Point Nuclear Generating Unit 2 -- Special Inspection Report No. 05000247/2005011.

6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 License Renewal Impacts

Entergy has reviewed the environmental impacts of renewing the IP2 and IP3 Operating Licenses and has concluded that all impacts would be SMALL and further mitigation measures are not warranted. This environmental report documents the basis for Entergy's conclusion. Section 4 incorporates by reference NRC findings for the 43 Category 1 issues that apply to IP2 and IP3 (and for the two "NA" issues for which NRC came to no generic conclusion), all of which have environmental impacts that are SMALL. The remainder of Section 4 analyzes Category 2 issues, all of which are either not applicable or have impacts that would be SMALL. Table 6-1 identifies the environmental impacts that IP2 and IP3 license renewal would have on resources associated with Category 2 issues.

6.2 Mitigation

6.2.1 Requirement [10 CFR 51.45(c)]

The report must contain a consideration of alternatives for reducing adverse impacts, as required by §51.45(c), for all Category 2 license renewal issues in Appendix B to subpart A of this part. No such consideration is required for Category 1 issues in Appendix B to subpart A of this part. [10 CFR 51.53(c)(3)(iii)]

6.2.2 Entergy Response

As discussed in Supplement 1 to Regulatory Guide 4.2, "Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses," when adverse environmental effects are identified, 10 CFR 51.45(c) requires consideration of alternatives available to reduce or avoid these adverse effects. Furthermore, Supplement 1 states, "Mitigation alternatives are to be considered no matter how small the adverse impact; however, the extent of the consideration should be proportional to the significance of the impact" [NRC 2000].

As described in Section 6.1 and shown in Table 6-1, analysis of the Category 2 issues found the impacts to be small for the applicable issues. For these issues, the current permits, practices, and programs (e.g., radiological monitoring and environmental review programs) that mitigate the environmental impacts of plant operations are adequate. Therefore, this ER finds that no additional mitigation measures are sufficiently beneficial as to be warranted.

Table 6-1
Environmental Impacts Related to License Renewal at IP2 and IP3

Issue	Environmental Impact
Surface Water Quality, Hydrology and Use (for all plants)	
Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow) [10 CFR 51.53(c)(3) (ii)(A)]	**NONE.** IP2 and IP3 are equipped with once-through cooling systems that utilize make-up water from an estuary on the Hudson River. IP2 and IP3 do not have or use cooling ponds or cooling towers. Consideration of mitigation is not required.
Aquatic Ecology (for all plants with once-through and cooling pond heat dissipation systems)	
Entrainment of fish and shellfish [10 CFR 51.53(c)(3)(ii)(B)]	**SMALL.** Historic and current studies have shown no negative trend in overall aquatic river species populations related to plant operations. Current mitigation measures implemented through the HRSA and fourth amended Consent Order, and the ongoing SPDES permitting process will ensure impacts remain SMALL. Further consideration of mitigation measures is not warranted.
Impingement of fish and shellfish [10 CFR 51.53(c)(3)(ii)(B)]	**SMALL.** Historic and current studies have shown no negative trend in overall aquatic river species populations related to plant operations. Current mitigation measures implemented through the HRSA and fourth amended Consent Order, and the ongoing SPDES permitting process will ensure impacts remain SMALL. Further consideration of mitigation measures is not warranted.
Heat shock [10 CFR 51.53(c)(3)(ii)(B)]	**SMALL.** Historic and current studies have shown no negative trend in overall aquatic river species populations related to plant operations. Current mitigation measures implemented through the HRSA and fourth amended Consent Order, and the ongoing SPDES permitting process will ensure impacts remain SMALL. Further consideration of mitigation measures is not warranted.
Ground-water Use and Quality	
Groundwater use conflicts (plants using > 100 gpm of groundwater) [10 CFR 51.53(c)(3)(ii)(C)]	**NONE.** There are no pumpable groundwater wells at the IP2 and IP3 site. Potable water is supplied by the Village of Buchanan with cooling and service water taken from the Hudson River estuary. Consideration of mitigation is not required.
Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river) [10 CFR 51.53(c)(3)(ii)(A)]	**NONE.** IP2 and IP3 do not have or use cooling towers. The Station obtains cooling and service water from the Hudson River estuary and potable water from the Village of Buchanan. Consideration of mitigation is not required.
Groundwater use conflicts (Ranney Wells) [10 CFR 51.53(c)(3)(ii)(C)]	**NONE.** IP2 and IP3 do not have or use Ranney wells. Consideration of mitigation is not required.

**Table 6-1 (Continued)
Environmental Impacts Related to License Renewal at IP2 and IP3**

Issue	Environmental Impact
Degradation of groundwater quality [10 CFR 51.53(c)(3)(ii)(D)]	**NONE.** IP2 and IP3 do not have or utilize cooling ponds. IP2 and IP3 are equipped with once-through cooling systems. Consideration of mitigation is not required.
Terrestrial Resources	
Refurbishment impacts on terrestrial resources [10 CFR 51.53(c)(3)(ii)(E)]	**NONE.** No refurbishment activities have been identified. Consideration of mitigation is not required.
Threatened or Endangered Species (for all plants)	
Threatened or endangered species [10 CFR 51.53(c)(3)(ii)(E)]	**SMALL.** No refurbishment activities have been identified. No adverse impacts to threatened or endangered species were expected due to continued operations of IP2 and IP3. Further consideration of mitigation measures is not warranted.
Air Quality	
Air quality during refurbishment [10 CFR 51.53(c)(3)(ii)(F)]	**NONE.** No refurbishment activities have been identified. Consideration of mitigation is not required.
Human Health	
Microbiological (Thermophilic) Organisms [10 CFR 51.53(c)(3)(ii)(G)]	**NONE.** IP2 and IP3 are not located on a small river or small lake, and do not have or use cooling ponds. Further consideration of mitigation measures is not warranted.
Electromagnetic fields – Acute effects [10 CFR 51.53(c)(3)(ii)(H)]	**SMALL.** Transmission lines constructed to connect the plant to the transmission system meet the NESC® recommendations for preventing electric shock from induced currents. Further consideration of mitigation measures is not warranted.
Socioeconomics	
Housing impacts [10 CFR 51.53(c)(3)(ii)(I)]	**SMALL.** No refurbishment activities have been identified. Entergy does not anticipate an increase in employment during the period of extended operation. Therefore, no additional impacts to housing are expected due to continued operations of IP2 and IP3. Further consideration of mitigation measures is not warranted.

Table 6-1 (Continued)
Environmental Impacts Related to License Renewal at IP2 and IP3

Issue	Environmental Impact
Public utilities: public water supply availability [10 CFR 51.53(c)(3)(ii)(I)]	**SMALL.** No refurbishment activities have been identified and no additional workers anticipated during the period of extended operation. PWSs near IP2 and IP3 currently have adequate system capacity to meet demand of residential and industrial customers in the area. Further consideration of mitigation measures is not warranted.
Education impacts from refurbishment [10 CFR 51.53(c)(3)(ii)(I)]	**NONE.** No refurbishment activities have been identified. Consideration of mitigation is not required.
Offsite land use (effects of refurbishment activities) [10 CFR 51.53(c)(3)(ii)(I)]	**NONE.** No refurbishment activities have been identified. Consideration of mitigation is not required.
Offsite land use (effects of license renewal) [10 CFR 51.53(c)(3)(ii)(I)]	**SMALL.** The area around IP2 and IP3 has pre-established land patterns of development and has public services and regulatory controls in place to support and guide development. No additional workers are anticipated during the period of extended operation. Further consideration of mitigation measures is not warranted.
Local transportation impacts 10 CFR 51.53(c)(3)(ii)(J)]	**SMALL.** No refurbishment activities have been identified and no increases in total number of employees during the period of extended operation are expected. Further consideration of mitigation measures is not warranted.
Historic and archaeological properties [10 CFR 51.53(c)(3)(ii)(K)]	**SMALL.** No refurbishment activities have been identified and no archaeologically and historically sensitive areas are present on-site. Further consideration of mitigation measures is not warranted.
Postulated Accidents	
Severe accident mitigation alternatives [10 CFR 51.53(c)(3)(ii)(L)]	**SMALL.** No impact from continued operation. Potentially cost-effective SAMAs are not related to adequately managing the effects of aging during period of extended operation. Further consideration of mitigation measures is not warranted.

6.3 Unavoidable Adverse Impacts

6.3.1 Requirement [10 CFR 51.45(b)(2)]

The applicant's report shall discuss any adverse environmental effects which cannot be avoided upon implementation of the proposed project.

6.3.2 Entergy Response

Section 4 of this ER contains the results of Entergy's review and the analyses of the Category 2 issues as required by 10 CFR 51.53(c)(3)(ii). These reviews take into account the information that has been provided in the GEIS, Appendix B to Subpart A of 10 CFR Part 51, and information specific to IP2 and IP3.

An environmental review conducted at the license renewal stage differs from the review conducted in support of a construction permit because the facility is in existence at the license renewal stage and has operated for a number of years. As a result, adverse impacts associated with the initial construction have been avoided, have been mitigated, or have already occurred.

The environmental impacts to be evaluated for license renewal are those associated with refurbishment and continued operation during the renewal term. The review and analysis of Category 2 issues associated with refurbishment and continued operation of IP2 and IP3 did not identify any significant adverse environmental impacts. The evaluation of structures and components required by 10 CFR 54.21 has been completed. No plant refurbishment activities, outside the bounds of normal plant component replacement and inspections, have been identified to support continued operation of IP2 and IP3 beyond the end of the existing operating license. As a result of these reviews and analyses, Entergy is not aware of significant adverse environmental effects that cannot be avoided upon implementation of the proposed project.

6.4 <u>Irreversible or Irretrievable Resource Commitments</u>

6.4.1 Requirement [10 CFR 51.45(b)(5)]

The applicant's report shall discuss any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

6.4.2 Entergy Response

The continued operation of IP2 and IP3 for the period of extended operation will result in irreversible and irretrievable resource commitments, including the following:

- nuclear fuel, which is consumed in the reactor and converted to radioactive waste;
- the land required to permanently store or dispose of spent nuclear fuel, low-level radioactive wastes generated as a result of plant operations, and sanitary wastes generated from normal industrial operations;
- elemental materials that will become radioactive;
- materials used for the normal industrial operations of IP2 and IP3 that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

Other than the above, there are no refurbishment activities or changes in operation of IP2 and IP3 during the period of extended operation that would irreversibly or irretrievably commit environmental components of land, water, and air.

However, the likely power generation alternatives if IP2 and IP3 cease operations on or before the expiration of the current operating licenses would require a commitment of resources for construction of the replacement plants as well as for fuel to run the plants.

6.5 Short-term Use Versus Long-term Productivity

6.5.1 Requirement [10 CFR 51.45(b)(4)]

The applicant's report shall discuss the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity.

6.5.2 Entergy Response

The current balance between short-term use and long-term productivity of the environment at the site has remained relatively constant since IP2 and IP3 began operating in 1972 and 1975, respectively. The *Final Environmental Statement Related to the Operation of Indian Point Nuclear Generating Plant Unit No. 2* and the *Final Environmental Statement Related to the Operation of Indian Point Nuclear Generating Plant Unit No. 3* evaluated the relationship between the short-term uses of the environment and the maintenance and enhancement of the long-term productivity associated with the construction and operation of IP2 and IP3 [USAEC; NRC 1975]. The period of extended operation will not alter the short-term uses of the environment from the uses previously evaluated in the FES. The period of extended operation will postpone the availability of the site resources (land, air, water). Denial of the application to renew the IP2 and IP3 Operating Licenses would lead to the shutdown of the plants and would alter the balance in a manner that depends on the subsequent uses of the site. For example, the environmental consequences of turning the Indian Point site into a park or an industrial facility are quite different. However, extending operations will not adversely affect the long-term uses of the site.

There are no refurbishment activities or changes in operation of IP2 and IP3 planned for the period of extended operation that would alter the evaluation of the FES for the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity of these resources.

6.6 References

NRC (U.S. Nuclear Regulatory Commission). 1975. Final Environmental Statement Related to the Operation of Indian Point Unit No. 3, Docket No. 50-286. United States Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation.

NRC (U.S. Nuclear Regulatory Commission). 2000. Supplement 1 to Regulatory Guide 4.2, Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses.

USAEC (U.S. Atomic Energy Commission). 1972. Final Environmental Statement Related to the Operation of Indian Point Unit No. 2, Docket No. 50-247. United States Atomic Energy Commission, Directorate of Licensing.

7.0 ALTERNATIVES CONSIDERED

7.1 Introduction

NRC regulations require that an applicant's environmental report discuss alternatives to a proposed action [10 CFR 51.45(b)(3)]. The intent of this review is to enable the Commission to consider the relative environmental consequences of the proposed action as compared to the environmental consequences of other activities that also meet the purpose of the proposed action and meet system generation needs. In addition, this review addresses the environmental consequences of taking no action [NRC 2002, Section 8.2]. The alternatives are discussed below.

7.2 Proposed Action

The site was constructed as a three-unit station, but IP1 has been shut down and is in SAFSTOR until it is decommissioned. A plan has been submitted for the eventual decommissioning of IP1. The proposed action is to renew the operating licenses for IP2 and IP3, which would provide the option for Entergy to continue to operate IP2 and IP3 through the 20-year period of extended operation. IP2 and IP3 utilize pressurized water reactors and turbine generators licensed for outputs of 3,216 and 3,216 MWt, and ratings of 1,078 and 1,080 MWe, respectively, for a combined total of 2,158 MWe.

The review of the environmental impacts required by 10 CFR 51.53(c)(3)(ii) is provided in Section 4. Based on this review, Entergy concludes that the environmental impacts of IP2 and IP3 operations during the license renewal period would be small.

7.3 No-Action Alternative

The "no-action alternative" to the proposed action is not to renew the operating licenses for IP2 and IP3. In this alternative, it is expected that IP2 and IP3 will continue to operate up to the end of the existing operating license, at which time plant operation would cease and decommissioning would begin. Because IP2 and IP3 constitute a significant block of long-term base-load capacity, it is reasonable to assume that a decision not to renew the IP2 and IP3 licenses would necessitate the replacement of its approximately 2,158 gross MWe capacity with other sources of generation. The environmental impacts of the no-action alternative would be

- the environmental impacts from decommissioning IP2 and IP3, and
- the environmental impacts from a replacement power source or sources.

Environmental impacts associated with decommissioning are discussed in Section 7.4. The environmental impacts associated with replacement power would be the impacts from the construction and operation of a source of replacement power at a new location (greenfield) or at the site (brownfield). The environmental impacts of these various types of replacement power are discussed in Section 8 of this ER.

7.4 Decommissioning Impacts

A nuclear power plant licensee is required to submit decommissioning plans within two years following permanent cessation of operation of a unit or at least five years before expiration of the operating license, whichever occurs first, pursuant to the requirements of 10 CFR 50.54(b).

The GEIS defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license [NRC 1996, Section 7.1]. NRC-evaluated decommissioning options include immediate decontamination and dismantlement (DECON) and safe storage of the stabilized and defueled facility (SAFSTOR) for a period of time, followed by decontamination and dismantlement.

Regardless of the option chosen, decommissioning must be completed within a 60-year period. Under the no-action alternative, Entergy would continue operating IP2 and IP3 until the current licenses expire, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of an example reactor (the "reference" reactor is the 1,155 MWe Washington Public Power Supply System's Columbia Nuclear Power Plant) [NRC 1996, Section 7.1]. This plant is similar in size when compared with either of IP2 or IP3 individually, although it is smaller than the combined size when IP2 or IP3 are considered as a whole. However the impacts from decommissioning both units are considered to be similar to the impacts cited for the Columbia Nuclear Power Plant.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include occupational and public radiation dose; impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated in Section 4.3.8 of the *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* [NRC 2002] that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. Entergy adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

Entergy notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. Entergy will eventually have to decommission all units on the site; license renewal would only postpone decommissioning for a maximum of 20 years. NRC has established in the GEIS that the timing of decommissioning operations does not substantially influence their environmental impacts. Entergy adopts by reference the NRC findings (10 CFR Part 51, Appendix B, Table B-1, Decommissioning) to the effect that delaying decommissioning until after the renewal term would have small environmental impacts.

Entergy concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those occurring following license renewal, as identified in the GEIS [NRC 2002, Section 8.4] and in the decommissioning generic environmental impact statement [NRC 2002, Section 6.0]. These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

7.5 Alternative Energy Sources

IP2 and IP3 are used for base-load generation. The GEIS states that coal-fired and gas-fired generation capacity are the feasible alternatives to nuclear power generating capacity, based on current (and expected) technological and cost factors. The following generation alternatives were considered in detail in this ER.

- Coal-fired generation at an alternate site (Section 8.2.1). Entergy did not consider coal-fired generation at the site since it was concluded that there was not enough land to build a comparable coal-fired unit and a coal yard. Based on Table 8.1 of the GEIS, it would take approximately 1.7 acres of land per MWe to construct a coal-fired plant. The site is situated on approximately 239 acres. Therefore, for the 2,040 MWe plant described in Section 8.2.1, a coal-fired plant would require would approximately 3,468 acres of land.

- Natural gas-fired generation at the site and at an alternate site (Section 8.2.2). In order for a natural gas-fired unit to be constructed on-site, additional land would have to be acquired due to limited onsite acreage. The site is situated on approximately 239 acres. For the power block area only, the GEIS estimated that 110 acres are needed for a 1,000 MWe natural gas-fired facility [NRC 1996, Section 8.3.10]. Scaling up for the 2,040 MWe facility would indicate a land requirement of approximately 224 acres, which would not be inclusive of support facilities. In addition, new generation units would have to be constructed in a timely manner concurrent with decommissioning, so the entire site would not be available.

- Nuclear generation at an alternate site (Section 8.2.3). Entergy did not consider nuclear generation at the site since it was concluded that there was not enough land to build a new nuclear unit. Based on Table 8.1 of the GEIS, it would take approximately 0.5 to 1.0 acres of land per MWe to construct a new nuclear plant. The site is situated on 239 acres of which approximately 70 acres is not currently being utilized for plant operations. Therefore, the site acreage would be insufficient for locating the new nuclear generation facilities described in this analysis.

Entergy's experience indicates that, although customized unit sizes can be built, using standardized sizes is more economical. For example, a standard-sized gas-fired combined cycle plant has a net capacity of 408 MWe. This plant would consist of two 135-MWe gas combustion turbines and 135 MWe of heat recovery capacity. For comparability, Entergy set the net power of the hypothetical coal-fired unit equal to the hypothetical gas-fired plant. Together, five such coal- or gas-fired plants would provide close to the same capacity as IP2 and IP3 combined (2,158 MWe). Although these hypothetical coal- or gas-fired plants understates the impacts of replacing 2,158 MWe at IP2 and IP3 by approximately 5%, Entergy believes these differences are insignificant, and ensures against overstating environmental impacts from the alternatives.

These alternatives are presented (Sections 8.2.1, 8.2.2, and 8.2.3, respectively) as if such plants were constructed at the site (natural gas-fired only), using the existing water intake and discharge structures, switchyard, and transmission lines, or at an alternate location that could be either a current industrial site or an undisturbed, pristine site requiring a new generating building and facilities, new switchyard, and at least some new transmission lines. In this ER, a "greenfield" site is assumed to be an undisturbed, pristine site.

Depending on the location of an alternative site, it might also be necessary to connect to the nearest gas pipeline (in the case of natural gas) or rail line (in the case of coal). The requirement for these additional facilities may increase the environmental impacts relative to those that would be experienced at the site.

The potential for using imported power is discussed in Section 8.2.4. Imported power is considered feasible, but would result in the transfer of environmental impacts from the current region in New York to some other location in New York, another state, or a Canadian province. In addition, there is no assurance that the capacity or energy would be available during the required time frame.

As stated in NUREG-1437, Vol.1, Section 8.1, the "NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable" [NRC 1996]. Accordingly, the following alternatives were not considered as reasonable replacement base-load power generation. Although several of these alternatives could be considered in combination for replacement power generation at multiple sites, they do not generally provide base-load generation, and would entail greater environmental impacts.

- wind
- solar
- hydropower
- geothermal
- wood energy
- municipal solid waste
- other biomass-derived fuels
- oil
- fuel cells
- delayed retirement
- utility-sponsored conservation
- purchased/imported power
- combination of alternatives

These technologies were eliminated as possible replacement power alternatives for one or more of the following reasons.

- High land-use impacts. Some of the technologies listed above (wind, solar, and hydroelectric) would require a large area of land and would thus require a greenfield siting plan. This would result in a greater environmental impact than continued operation of IP2 and IP3.

- Low capacity factors. Some of the technologies identified above (wind, solar, and hydroelectric) are not capable of replacing the 2,158 MWe of power at high capacity factors. These generation technologies are used as peaking power sources, as opposed to base-load power sources, and for this reason are not reasonable alternatives.

- Geographic availability of the resource. Some of the technologies are not feasible because there is no feasible location in the area served by the site.

- Emerging technology. Some of the technologies have not been proven as reliable and cost-effective replacements for a large generation facility. Therefore, these technologies are typically used with smaller (lower MWe) generation facilities.

- Availability. There is no assurance of the availability of imported power.

- Lack of control over utility sponsored conservation programs. Entergy does not own or operate the transmission lines that are utilized to distribute electricity generated from the IP2 and IP3 facilities. Therefore, conservation programs are driven by the corporation that purchases and distributes the electricity.

7.6 References

NRC (U.S. Nuclear Regulatory Commission). 1996. NUREG-1437, Generic Environmental Statement for License Renewal of Nuclear Power Plants, Final Report. Washington, DC.

NRC (U.S. Nuclear Regulatory Commission). 2002. NUREG-0586, Supplement 1, Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities Supplement 1, Regarding the Decommissioning of Nuclear Power Reactors. Washington, DC.

8.0 COMPARISON OF IMPACTS

The following key assumptions have been made in the review of alternative energy sources. These key assumptions are intended to simplify the evaluation, yet still allow the no-action alternative review to meet the intent of NEPA requirements and NRC environmental regulations.

- The goal of the proposed action (license renewal) is the production of approximately 2,158 MWe of base-load generation. Alternatives that do not meet this goal are not considered in detail.

- The time frames for the needed generation would be 2013–2033 for IP2 and 2015–2035 for IP3.

- Purchased power is not considered a reasonable alternative because there is no assurance that the capacity or energy would be available during the required time frame. See Section 8.2.4.

- The total combined annual capacity factor of the site based on a five year average is 95%. The capacity factor is targeted to remain at or near this value throughout the plant's operating life.

- The environmental impacts of the continued utilization of once-through cooling for both IP2 and IP3 are considered as part of the proposed action. Closed-cycle cooling systems are considered in this section as an alternative to once-through cooling.

- All necessary Federal permits, licenses, approvals, and other entitlements would be obtained.

8.1 Closed-Cycle Cooling Alternative

A discussion of the potential environmental impacts of IP2 and IP3's once-through cooling systems is provided in Sections 4.2, 4.3, and 4.4. NYSDEC's draft SPDES permit proposed replacement of the existing once-through cooling systems with closed-cycle cooling systems, provided that NRC-issued license renewals are obtained for both stations, feasibility of the closed-cycle cooling system is demonstrated, safety is assured (as determined by NRC), and all necessary permits, authorizations, and approvals for the closed-cycle cooling systems can be obtained. The potential environmental impacts of implementing a closed-cycle cooling system alternative are evaluated in this section.

The site is currently equipped with an upgraded once-through heat dissipation system that withdraws cooling water from the Hudson River using state of the art Ristroph screens and fish return systems in conjunction with variable/dual speed pumps and operational measures to minimize entrainment and impingement, and then discharges back to the river. The details of the plants' cooling systems, intake structures, and discharge systems are provided in Section 3 of this ER. IP2 and IP3 each have shoreline-situated intake structures consisting of seven bays (six for circulating water and one for service water). Additional service water and screen wash water is provided for IP2 from the IP1 intake structure.

IP2 has six, two-speed, circulating water pumps designed to pump 140,000 gpm at full speed and 84,000 gpm at reduced speed. IP3 has six, variable-speed, circulating water pumps designed to pump 140,000 gpm at full speed and 64,000 gpm at the lowest speed. Each unit has six service water pumps, IP2 rated at 5,000 gpm per each pump and IP3 rated at 6,000 gpm per each pump. There are three back-up service water pumps located on a platform at IP3 over the discharge channel. [CHGEC, Section IV.D.2.c]

The circulating water intake bays at IP2 have modified vertical Ristroph-type traveling water screens. Design features incorporated into the machines were developed and tested in concert with the Hudson River Fishermen's Association. Key fish-conserving components of the screens are screen basket lip troughs designed to retain water and minimize vortex stress, a high-pressure spray wash system for debris removal from the front side of the machine, a low-pressure spray wash system for fish removal from the rear side of the machine, and a fish sluice system for collection of the impinged fish for return to the river. The 0.25-by-0.5-inch clear opening slot mesh on the screen basket panels is smooth to minimize fish abrasion across the mesh into the collection sluice. The modified traveling screens consist of a series of panels attached to an endless chain designed to rotate continuously around an upper and lower sprocket shaft system. As baskets rotate out of the intake bay, impinged fish are retained in the water-filled rails and are carried over the headshaft, where they are washed out onto the mesh. A low-pressure wash system facilitates the transfer of fish to the fish collection sluice for return to the Hudson River. [CHGEC, Section IV.B.2.c]

Fish are returned to the estuary through a 12-inch diameter pipe that extends 200 feet into the river on the north side of the IP2 intake structure. The pipe is partially buried in the river bottom, and discharges fish at a depth of 35 feet. The location of the discharge was selected after conducting dye and fish release studies to find a location that would minimize re-impingement. [CHGEC, Section IV.B.2.c] Key components of the IP3 screens are identical to those installed at IP2. At IP3 a fish return system discharges outside the NW corner of the discharge canal [CHGEC, Section IV.D.2.c].

After moving through the condensers, cooling water from IP2 and IP3 flows downward from the discharge water boxes by way of six 96-inch down pipes, and exits under the water surface in a 40-foot-wide discharge canal [CHGEC, Section IV.B.2.e]. The cooling water from the canal is released into the Hudson River. Typically, the temperature increase across the IP3 condenser at 360 rpm is in the range from 14.6°F to 18.0°F (8.1°C to 10°C) and at IP2 with all fast speed pumps from 17°F to 22°F (9.44°C to 12.22°C). Severe fouling due to debris in the Hudson River may cause the water temperature increase across the condensers to go as high as approximately 35°F (19.44°C). [IP2; IP3]

The Indian Point discharge structure is discussed in Section 3.2.2.3. The outfall or discharge structure for the IP2 and IP3 facility is designed to enhance mixing of cooling water and river water in such a way as to minimize thermal impact in the river. The cooling water from the discharge channel is released to the Hudson River via an outfall structure located south of IP3. The outfall structure, depicted schematically in Figure 3-8, consists of 12 submerged rectangular ports equipped with adjustable gates that are in line and parallel to the river axis. The ports, 4 feet high by 15 feet wide and spaced 21 feet apart (center to center), are submerged to a depth of 12 feet (center to surface) at mlw. The first upstream port is approximately 600 feet from the IP3 intake; the length of the total port section is approximately 252 feet. The discharge port gates can be adjusted mechanically to maintain a minimum hydraulic head differential of 1.75 feet across the outfall structure, which assures a discharge velocity of approximately 10 fps. [CHGEC, Section IV.B.2.e]

The permitting history for surface water discharges and cooling water intake structures is addressed in Sections 4.2 and 4.3. Briefly, former owners Consolidated Edison and NYPA submitted an Environmental Report in 1976 to the NRC in which various alternative closed-cycle cooling systems were evaluated from an economic and environmental standpoint. In 1980, the HRSA was negotiated between the USEPA, NYSDEC, and owners of several Hudson River facilities, including IP2 and IP3, among others. As a result of the HRSA, IP2 and IP3 each submitted license amendment requests to the NRC for the removal of the license condition 2.E that required the closed-cycle cooling system [NRC 1981; HRSA]. IP2's License Amendment No. 71 removed Condition 2.E from IP2 (a similar license condition and amendment for IP3, License Amendment No. 37, was granted at the same time), effective May 14, 1981. Some of the measures in the HRSA included (1) equipment retrofitting, including installation of dual or variable speed intake pumps and of angled screens, with fish return systems to minimize impingement; (2) operational measures, including flow limitations and outages; (3) ongoing biological monitoring (a joint requirement of all of the power generators party to the HRSA); and (4) a striped bass fish hatchery (again, a joint requirement of all of the power generators party to the HRSA) [HRSA].

Surface-water discharges at Indian Point currently are regulated under the NYSDEC permit program. The current existing SPDES permit was renewed in 1987, although SPDES population impacts continued to be addressed in a 1998 judicially approved consent order (Order) between and among NYSDEC and the then-owners of IP2 and IP3, among others. Under this current permit and the Order, IP2 and IP3 use best reasonable efforts to operate so as to keep the volume of river water drawn into the plant at the minimum required for efficient operation, considering ambient River water temperature, station operating status and relevant permit conditions. Flow rates are dependent upon intake water temperature, and typically peak between early May and late October.

IP2 and IP3 owners submitted a timely SPDES permit renewal application in 1992 as discussed in Section 9.2. Provisions of the Clean Water Act (CWA) and the New York Administrative Procedures Act provide that facilities, such as IP2 and IP3, may continue to operate under an existing SPDES permit after its technical expiration date, provided that the permittee makes a timely renewal application, as NYSDEC has confirmed IP2 and IP3 did. The NYSDEC issued a draft SPDES permit in 2003 that identified an alternative to the current once-through cooling water system under certain scenarios [NYSDEC 2003c]. The alternative contemplates replacement of the existing once-through cooling systems with closed-cycle cooling systems only if the NRC operating licenses for IP2 and IP3 are extended by the NRC, appropriate safety, feasibility, and permitting/zoning demonstrations are made, and approvals are granted.

As noted above, the impacts of the installation of a close-cycle cooling system were evaluated in 1976. In addition, the site re-evaluated the closed-cycle cooling alternative in conjunction with its most recent permit application [Enercon]. The site will continue to evaluate this option in the pending adjudicatory proceeding before NYSDEC administrative law judges relating to that permitting effort. At this time, however, all available technical information confirms that retrofitting of facilities the size and configuration of IP2 and IP3 is untried and unproven. For this reason, substantial feasibility concerns exist, including with respect to the available acreage for the necessary equipment, the excavation required for the equipment, the ability to alter fundamental station equipment that is at the heart of the currently configured plants, and with respect to the pumping and piping capabilities required for such a retrofit. These factors are exacerbated by on-site easements for a major interstate natural gas pipeline. USEPA has concurred with respect to the lack of demonstrated feasibility or economical practicability of closed cycle cooling retrofits in some circumstances. [69 FR 41576: 41606].

As noted above, the first SPDES permit was granted to the site in 1982, with the HRSA conditions annexed to the permit. An SPDES permit renewal was granted in October 1987 by the NYSDEC (Attachment C). Ristroph screens and fish return systems were installed at IP3 and IP2 in 1990 and 1991, respectively. In 1992, the site owners submitted a timely SPDES permit renewal application to the NYSDEC. The HRSA, which was annexed to the 1982 issued SPDES Permit, expired with the permit and was replaced by four consecutive Consent Orders that were initially executed in 1992 between the owners of IP2 and IP3, other Hudson River power generators, NYSDEC, and other stakeholders [NYSDEC 1997]. The site's current SPDES permit has been extended under the New York State Administrative Procedure Act and the NYSDEC's implementing regulations since 1992.

In July 1992, NYSDEC requested that the Hudson River power generators prepare and submit an Environmental Impact Statement on the impacts of the SPDES permit renewal, to which the utilities responded with a DEIS in 1993, and a revised DEIS in 1999 [CHGEC]. The NYSDEC accepted the DEIS, but determined that additional public involvement and response was needed before the FEIS was issued [NYSDEC 2003c]. The NYSDEC issued its FEIS in 2003. NYSDEC also issued a draft SPDES permit in 2003 that among other conditions required the design and installation of closed-cycle cooling systems for IP2 and IP3, if the site seeks and is granted license renewal for these units [NYSDEC 2003c]. Entergy and other parties are contesting the terms of this permit before the agency's administrative law judges. However, the site considers mitigation measures currently implemented as a result of the HRSA and previous Consent Orders, supported by numerous Hudson River studies, and any measures established as the outcome of SPDES permit negotiations, to be adequate in minimizing impacts from current operations and operations during the license renewal period.

IP2 and IP3 and the other Hudson River power generating utilities have conducted Hudson River aquatic studies since the 1970s. The results of these studies were reported in the 1999 DEIS and 2003 FEIS. Based on the reports summarized in the DEIS and FEIS, studies completed in the 1970s included sampling and evaluation of all trophic levels in the Hudson River estuary. Key species, populations, and communities were defined. During the 1980s, studies focused more closely on the fish species, particularly those adults and larvae that use the estuary as spawning and nursery habitat. As part of the Hudson River Utilities Monitoring Program, extensive environmental studies were conducted by the Hudson River utilities and the NYSDEC in the Hudson River estuary. Many of these studies have specifically addressed potential impacts to the macroinvertebrates, larval fish, adult fish, and anadromous fish populations. Entrainment mitigation measures have been implemented in accordance with the Fourth Amended Consent Order [NYSDEC 1997]. Among others, these mitigation measures have included installation of the dual and multi-speed cooling water intake pumps and minimization of cooling water withdrawal to only that required for efficient plant operation. Ristroph screens and fish return systems were installed on IP3 and IP2 in 1990 and 1991, respectively.

A discussion of the environmental impacts of IP2 and IP3's once-through cooling systems is provided in Sections 4.2, 4.3, and 4.4. Although the DEIS concludes that plant operations have not resulted in any negative trend in overall Hudson River aquatic species populations, NYSDEC's draft SPDES permit would require replacement of the existing once-through cooling systems with closed-cycle cooling systems if certain pre-conditions are met. The impacts of implementing a closed-cycle cooling system alternative are evaluated in this section.

As noted above, the impacts of the installation of a close-cycle cooling system were evaluated in 1976. In addition, the site re-evaluated the closed-cycle cooling alternative in 2003 [Enercon].

Although no method of waste heat dissipation could support IP2 and IP3 performance as well as the existing once-through cooling scheme, NYSDEC historically has asked the owners of IP2 and IP3 to evaluate other technology. Briefly, Entergy and its predecessors have evaluated, and NYSDEC has rejected, the following alternative technologies for heat dissipation.

- Evaporative ponds, spray ponds, or cooling canals—all require significantly more real estate to implement than exists at the site.

- Dry cooling towers, which rely totally on sensible heat transfer, lack the efficiency of wet or hybrid towers using evaporative cooling, and thus require a far greater surface area than is available at the site. Additionally, due to their lower efficiency, dry towers are not capable of supporting condenser temperatures necessary to be compatible with IP2 or IP3 turbine design and, therefore, are not a feasible technology.

- Natural draft cooling towers, while potentially feasible, would be 450 to 500 feet above ground-level with significant adverse aesthetic impacts in an important viewshed corridor, and raise plume-related and sound effects concerns. Indeed, in the original EPA permitting proceeding, New York State opposed natural draft cooling towers on aesthetic grounds.

- Mechanical draft wet cooling towers were rejected for a number of reasons, including, but not limited to, the dense water vapor plumes that compromise station operations and equipment, particularly over time, and which result in increased noise. [Enercon]

A hybrid, also referred to as a "wet/dry" or "plume abated" cooling tower, addresses many of the shortcomings of the tower types previously evaluated, particularly as applied to the Indian Point site. Basically, a hybrid tower is the combination of the wet tower, with its inherent cooling efficiency, and a dry heat exchanger section used to eliminate visible plumes in the majority of atmospheric conditions. After the plume leaves the lower "wet" section of the tower, it travels upward through a "dry" section where heated, relatively dry air is mixed with the plume in the proportions required to achieve a non-visible plume. Hybrid towers are slightly taller than comparable wet towers (typically about 70 feet elevation at the discharge versus 60 feet) due to the addition of the "dry" section, and may require a larger footprint. They are also appreciably more expensive, both in initial costs and in ongoing operating and maintenance costs. A potential exists for increased noise due to additional fans in the dry section, although attenuation to acceptable levels is possible, at increased capital and operating costs. [Enercon]

Because the site is heavily timbered, with rocky terrain and rapid elevation changes, a tower with a minimum footprint would be required to reduce overall excavation and clearing. A single round hybrid cooling tower for each unit would be required to best meet IP2 and IP3's performance needs and to minimize environmental impacts of the towers themselves. [Enercon]

The hybrid tower type would provide the minimum environmental impact of any currently available tower configuration. Feasibility remains uncertain, however, due to the lack of comparable conversions, the complexity of the engineering and to some extent to site-specific conditions. Thus, conversion to closed-loop cooling is extremely complex and expensive, in terms not only of initial direct capital costs, lost generating capacity during construction outages, and the de-rating of Station generating capacity, but also in parasitic energy losses and long-term operation and maintenance costs. Direct capital costs of the proposed conversion are based on a conceptual design. The site aesthetics, particularly from river-side view points, would be somewhat compromised by the addition of the towers, but much less so than by other alternatives. The effluent from the towers would increase salt deposition in the area of the site, but less so than other types of towers with higher effluent drift rates. Construction activities during the implementation phase would have a negative local impact from the associated increased traffic and noise, but would have restrictions to minimize the severity of their impact during construction.

The estimated direct capital cost (in 2003 dollars) is $612,400,000, without any level of contingency. With customary cost of a performance bond and a 20% contingency, the engineering, procurement, and construction costs approach $740,000,000. Since the changes to the condenser cooling systems involve the very heart of the plant, much of the conversion would need to be completed with both IP2 and IP3 in an extended forced outage. Although much of the blasting and excavation work and cooling tower erection could be done pre-outage, new circulating water pumping stations and changes to the Station's common discharge canal would force a major outage. Based on the conceptual construction schedule included in the 2003 evaluation, with as much work designated pre-outage or post-outage as possible, the forced outage duration would be expected to exceed 42 weeks. Again, this is an estimate without any level of contingency, and is likely greatly underestimated. [Enercon] This estimate is similar to the only existing estimate for a much smaller nuclear station that constructed cooling towers late in its original construction program, and therefore has been characterized by USEPA as a retrofit example; in that case, EPA concluded that the ten (10) month forced outage likely understated a more representative retrofit outage period [69 FR 41576: 41605].

New cooling towers would be large due to the required capacity. The outside diameter of each tower, including noise attenuators, would be approximately 560 feet. To provide construction access for tower erection and clearance for air intake, the excavation diameter for each tower would be approximately 700 feet. Height of the towers would be approximately 150 feet. The location for the IP2 tower is expected to be approximately 1,050 feet north of the IP2 reactor, just north of the independent spent fuel storage installation (ISFSI) location. The location of the IP3 tower is expected to be approximately 1,000 feet south of the IP3 reactor. The basin elevation of each tower is dictated by the required head for flow through the condenser, and preliminary analysis indicates an elevation of 31 feet MSL would be required. A detailed description of a round hybrid cooling tower conceptual design is presented in the 2003 cooling tower evaluation. [Enercon]

Based on the 2003 cooling tower evaluation, utilizing mechanical draft cooling towers instead of once-through cooling introduces significant additional electrical loads, termed "parasitic losses", that reduce Station output. Average annual parasitic losses have been estimated for hybrid towers that have "wet" and "dry" section fans, 44 in each section, and at 300 and 350 horsepower, respectively. Additionally, for the closed-loop configuration, circulating water pump horsepower is also increased. The net effect is an annual average parasitic loss of approximately 26 megawatts for each Unit. Lost generation, at maximum load conditions, would be approximately 47 megawatts for IP2 and approximately 27 megawatts for IP3, or a total of 74 megawatts. On an annual average basis, the effect is still significant at about 15 megawatts for IP2 and about 6 megawatts for IP3. [Enercon]

In evaluating the potential impacts of closed-cycle cooling for existing facilities in conjunction with the Phase II regulations for existing facilities, EPA determined "that the energy penalty associated with cooling towers, together with other factors, indicates that this technology is not the best technology available for existing facilities for minimizing adverse environmental impacts associated with [CWIS]" [69 FR 41576: 41605]. EPA also observed that this energy penalty not only may present electric-system impacts, but requires replacement power, the net effect of which would be more consumption of fossil fuel, which in turn increases air emissions [69 FR 41576: 41605].

Major negative impacts of closed-cycle cooling are systemic electric-system reliability and market pricing impacts, as well as the associated air quality impacts attributable to the use of replacement power. In conjunction with its permit renewal application, Entergy retained leading energy-system and economics experts to assess the electric-system impacts of closed-cycle conversion [NERA]. That report confirms that shutdown of IP2 and IP3 would result in substantial reduction of electric-system reliability in New York State and reduction of New York State reserve margins. Reliability is a measure of the electric system's ability to serve needed demand without curtailments, among other options. Reserve margins are the measure chosen to ensure that installed reserves (that is, stations capable of operation) can meet expected demand with some margin of safety. Likewise, shutdown of IP2 and IP3 would increase New York State electricity consumer expenditures on electricity by more than $3.0 billion in the estimated 3.5 year period evaluated in the report. Thus, the report concludes that IP2 and IP3 are essential to the New York State electric system. [NERA]

In addition, Entergy retained leading air quality experts to evaluate potential air emissions increases associated with prolonged outages or shutdown of IP2 and IP3 [TRC]. The TRC report demonstrates that replacement of IP2 and IP3 with existing generating facilities, as is to be expected for a construction outage or to replace parasitic loses, would result in substantial increases in regulated air pollutants, with corresponding potential effects and health hazards from those pollutants, particularly on the very young and old. As TRC noted, these increases would constitute a "major setback" in the area's air-quality goals. USEPA concurred at the federal level and identified air quality as one basis for its rejection of a nation-wide mandate for closed-cycle cooling at existing facilities [69 FR 41576: 41605]. In addition, while not addressed in the TRC report, carbon dioxide—a greenhouse gas and major contributor to climate change—is currently unregulated at the federal level. Replacement power would emit these pollutants, potentially contributing to climate change. New York State is currently considering regulations to control carbon dioxide emissions through an allowance/ cap-and-trade system in conjunction with the Regional Greenhouse Gas Initiative. Replacement of IP2 and IP'3 non-emitting generation with emitting sources would increase the difficulty of making this system work. Other air-quality considerations are addressed in Section 8.1.1.4.

8.1.1 Environmental Impacts of the Closed-Cycle Cooling Alternative

This section discusses the impacts that would occur if the site replaced its existing once-through cooling system with the closed-cycle cooling systems described in the reference [Enercon]. Although the use of linear hybrid mechanical-draft cooling towers would result in a substantial reduction of water withdrawn from the Hudson River, water consumption would increase due to evaporation loss. The assessment examines impacts related to both construction and operation of the linear hybrid mechanical-draft cooling system of the environmental impact categories as defined in the GEIS [NRC 1996].

8.1.1.1 Land Use

Due to the heavily timbered site, with rocky terrain and rapid elevation changes, a tower with a minimum footprint has been considered here to reduce overall excavation and clearing. A single round hybrid cooling tower for each unit was found to best meet the Station performance needs and minimize environmental impacts.

Construction and operation of the two hybrid towers would entail significant excavation of the currently timbered areas at the site. The base of each tower would be constructed on bedrock, at an elevation of about 30 feet above MSL. This would entail the removal of approximately two million cubic yards of material, primarily rock, and would require a significant amount of blasting for excavation. Ultimately, approximately 40 acres of currently wooded land not previously disturbed would need to be cleared for the two cooling towers and new access roads. [Enercon]

The site is seriously constrained as a result of elevation changes and existing uses. Due to limited land availability, the proposed south cooling tower pad would be located in an area that is subject to a permanent right-of-way easement granted to the Algonquin Gas Transmission Company ("Algonquin") for constructing, maintaining and operating three natural gas pipelines (one 30-inch main and two 24-inch mains) that traverse the Indian Point site. These pipelines enter the eastern portion of the Indian Point site at a location on Broadway, between Bleakley Avenue and the Buchanan Substation, and cross the site in a westerly direction to the bank of the Hudson River. Algonquin's pipelines are used to supply natural gas to all of New England.

Under the terms of the easement, Algonquin is required to remove or relocate its pipelines upon the request of Entergy, provided that Entergy can furnish an appropriate substitute location on its land for the three pipelines. There has been no investigation into whether alternative pipeline locations at the IP2 or IP3 sites are feasible in light of pre-existing infrastructure, related plant structures, other site constraints, or are permissible from an environmental and regulatory perspective. Moreover, any relocation of the pipelines by Algonquin would require prior approval of the Federal Energy Regulatory Commission and other relevant permitting authorities, including NRC to the extent blasting is required in the construction of a new pipeline right-of-way. Difficulties associated with moving these pipelines are substantial, and include feasibility of relocation, safety and environmental impacts, permitting, cost, and coordination of third party activities. [Enercon]

Activities related to blasting, excavation, haul roads, cooling tower and piping construction, lay-down areas, and other construction related activities, resulting from cooling tower installation at IP2 and IP3 would result in MODERATE to LARGE land use impacts. Impacts to land-use from the existing site with once-through cooling during the license renewal period would be SMALL.

8.1.1.2 Ecology

8.1.1.2.1 Aquatic Ecology

Construction of the alternative closed-cycle cooling systems may create short-term, localized impacts on aquatic resources from site runoff. Clear cutting of the forest and subsequent excavation of the sites for the two cooling towers would alter the flow pattern of runoff from precipitation events. The volume of runoff potentially reaching the Hudson River would likely increase because of the lack of trees and vegetation to slow the transport of water. These can be mitigated, however, through the use of physical barriers (e.g., silt fences and hay bales) or sediment traps.

The closed-cycle cooling alternative would reduce entrainment and impingement losses when compared with the existing once-through cooling system. The highest water usage would be expected to occur during the summer when the system functions in full evaporative-mode cooling. Total cooling water flow from the Hudson River would amount to approximately 66,000 to 83,000 gpm (service and cooling tower makeup water) for IP2 and IP3, representing a 93-95% reduction in water use relative to the existing once-through system. However, of these flows, 6,000 gpm to 12,000 gpm would be consumed due to evaporation. Enercon]

Under the closed-cycle cooling alternative, most water discharged into the Hudson River would be unheated water. Thus, it would be likely that any thermal impacts would be confined to a small part of the discharge canal and the Hudson River.

Under the closed-cycle cooling alternative, evaporative cooling would result in the discharge of higher salinity water which may contain higher concentrations of biocides, minerals, trace metals, or other chemicals or constituents when compared with the discharge water characteristics associated with the existing once-through systems.

The impacts of the existing once-through cooling systems on aquatic resources would be SMALL. Operation of the closed-cycle cooling alternative would produce even fewer impacts upon the aquatic environment. Therefore, Entergy concludes that the aquatic ecological impacts from the construction and operation of the closed-cycle cooling alternative at IP2 and IP3 would be SMALL.

8.1.1.2.2 Terrestrial Ecology

The adverse impacts of clear-cutting 40 acres would be significant. Approximately 1000 feet of river bank would be deforested to allow excavation for the four large-diameter water pipes (two 120-inch diameter supply pipes and two 144-inch diameter pipes to each condenser) required for each tower. The excavation for the cooling towers would cut into the side of the hills to the immediate east of the Station. These tree-covered hills lie between the Station and the Villages of Buchanan and Verplanck and rise to an elevation of 130 to 145 feet. The base of the tower would be constructed on bedrock, at an elevation of about 30 feet above mean sea level. This would entail the removal of approximately two million cubic yards of material, primarily bedrock. Disposal of two million cubic yards of material would be problematic. To transport the material to an acceptable disposal site by truck, assuming six cubic yards per load, would entail over 300,000 round trips. The excavation would be expected to take 30 months to complete.

Clear-cutting of the forest and subsequent excavation of the sites for the two cooling towers would alter the flow pattern of runoff from precipitation events. The volume of runoff potentially reaching the Hudson River would likely increase because of the lack of trees and vegetation to hold and slow the transport of water. Standard techniques of control of runoff would need to be implemented, such as silt fences and grading, to control the flow of runoff during construction. Because the construction sites would be so close to the river, extra protective measures to prevent runoff carrying excess silt and contaminants, such as petroleum products, would be necessary. Temporary sediment retention basins might have to be constructed to prevent the increased silt load of the runoff from reaching the river. Truck and equipment washing areas would need to be equipped with impermeable basins to intercept petroleum contaminants. Dust from the construction site would need to be controlled by water sprays or, if necessary, other chemical dust suppression agents.

The obvious impacts include destruction of habitat for mammals that normally inhabit eastern hardwood forests, including raccoon, squirrels, opossum, and whitetail deer. A large portion of the area surrounding the site has been developed and the amount of undisturbed eastern deciduous hardwood forest in the vicinity is decreasing.

Impacts on terrestrial ecology would include localized habitat loss and fragmentation, reduced productivity, and reductions in biological diversity. During the construction period, less mobile wildlife could be adversely affected and some wildlife disturbance (such as to bald eagles) could occur from noise, and the presence of construction personnel, and due to cooling tower operation.

The potential physical impacts from a cooling tower plume arise primarily from the moisture content, which can cause icing and fogging during winter conditions; the salt content of the entrained moisture, which can damage vegetation; and the heat content, which could potentially degrade the site's heating, ventilating and air conditioning (HVAC) systems. Although a hybrid tower produces an invisible plume, the plume still exists. The potential adverse impacts from plume and salt drift are presented in the reference [Enercon].

The impacts of the existing once-through cooling systems on terrestrial resources would be SMALL. Operation of the closed-cycle cooling alternative would produce greater impacts upon the terrestrial environment than continued operation of the existing once-through cooling system. Therefore, Entergy concludes that the terrestrial ecological impacts from the construction and operation of the closed-cycle cooling alternative at IP2 and IP3 would be MODERATE.

8.1.1.3 Water Use and Quality

8.1.1.3.1 Surface Water

As discussed above, approximately 66,000 to 83,000 gpm (service and makeup water) would be withdrawn from the Hudson River for a hybrid cooling tower system, of which 6,000 gpm to 12,000 gpm would be consumed due to evaporation. Expressed in terms of gallons per day (gpd), 12,000 gpm amounts to 17,280,000 gpd or 9,540 acre-feet—a substantial river volume lost, as distinct from simply temporarily used (as once-through cooling allows). As noted in the reference, the combined once-through cooling water intake flow from the Hudson River for IP2 and IP3 ranges from approximately 919,000 gpm to 1,371,000 gpm, which is a small fraction of temporary use of the Hudson River flow [Enercon]. However, the tidal flows of the Hudson River were estimated to be 180,000 cfs [NRC 1979].

Potable water demand for workers may increase, but commonly used portable toilet facilities would lessen the overall water demand on-site of the worker population. If concrete was to be mixed on-site, water needs would be a short-lived demand on water resources. This water would likely come from the Village of Buchanan Water System, which, as discussed in Section 2.10.1, has available capacities.

Construction of the closed-cycle cooling systems would require an NYSDEC permit for stormwater discharges from construction activities, in the form of a Construction General Permit.

In addition, a Stormwater Pollution Prevention Plan would be required. The use of silt fencing and other erosion-control practices during construction could minimize impacts on surface-water quality.

The major change in surface water quality impacts would result from increased concentrations of dissolved solids and salts in the plant effluent due to evaporation in the hybrid cooling tower system. Additionally, increased water treatment would be necessary due to the higher concentrations of dissolved solids, chemicals, and biological agents in the system resulting from constant recirculation of the condenser cooling water. The cooling towers would act as air washers as well as distilleries, constantly evaporating large quantities of water and leaving behind the non-volatile residues. The actual concentrations of these agents are wholly based on the cycles of concentration which would be used in the circulating water system.

With a closed-loop cooling system, water treatment requirements would be dramatically increased. The cooling tower fill would be subject to fouling, as would be the dry heat exchanger sections. Both the quantities and frequency of biocide injections must be increased significantly to maintain the tower fill in proper condition. Because of evaporation, the concentrations of dissolved and suspended solids in the circulating water would increase. These minerals would affect the operation and efficiency of the system because of scale deposits.

Makeup water would have to be treated to remove silt, suspended solids, biological material, and windblown debris. Makeup water may need lime softening, resulting in a sludge that requires disposal. Because of the warm environment in the closed-cycle system, biofouling organisms would be expected, and biocides, such as sodium hypochlorite, would be needed. Other chemicals, such as acids, dispersants, scale inhibitors, foam suppressants, and dechlorinators may be needed [NRC 1979; Enercon]. The use of biocides or any other chemicals would require SPDES permit modification and additional monitoring. Storage of additional chemicals at the facility could require revision to the Stations' Chemical Spill Prevention Plans.

The impacts of the existing once-through cooling systems on surface water would be SMALL. Operation of the closed-cycle cooling alternative would produce greater impacts upon the surface water quality due to evaporative loss and concentration of dissolved solids than continued operation of the existing once-through cooling system. However, Entergy concludes that the surface water impacts from the construction and operation of the closed-cycle cooling alternatives at IP2 and IP3 would be SMALL, which is consistent with the 1979 FES that concluded impacts on the Hudson River would be SMALL.

8.1.1.3.2 Groundwater

The site does not use groundwater for any water supply. Other than potential dewatering requirements during construction excavation, no impact on the groundwater from the existing once-through cooling systems and closed-cycle cooling alternative would be expected. Therefore, the overall impacts to groundwater from the existing once-through cooling systems or closed-cycle cooling alternative would be SMALL.

8.1.1.4 Air Quality

As noted above, the potential physical impacts from a tower plume arise primarily from the moisture content, which can cause icing and fogging during winter conditions; the salt content of the entrained moisture, which can damage vegetation; and the heat content, which could potentially degrade the site's HVAC systems [Enercon].

As discussed above, replacement of IP2 and IP3 power generation with replacement power, as would be expected for a construction outage or to replace parasitic losses, would result in substantial increases in regulated air pollutants, with corresponding potential effects and health hazards from those pollutants, particularly on the very young and old. In addition, carbon dioxide—a greenhouse gas and major contributor to climate change—is currently unregulated at the federal level or in New York State, with the result that replacement power would emit these pollutants, contributing to climate change. Other air-quality considerations are addressed below.

The predicted salt deposition from a single tower indicates up to 73 kg/km^2/month would be emitted from the tower. The ambient natural local deposition rates would be measured at an annual rate of 16 $\mu g/cm^2$/month, which is 160 kg/km^2/month. The predicted combined salt deposition from operation of both cooling towers would be approximately 112 kg/km^2/month in the region between the towers. [Enercon]

Construction of new cooling towers at the site would result in fugitive emissions during the construction process. Exhaust emissions would also come from vehicles and motorized equipment used during the construction process.

Westchester County is located in a non-attainment area for particulate emissions. An operating cooling tower could have significant air emissions associated with $PM_{2.5}$ and PM_{10}. The hybrid closed-cycle cooling tower could require a Prevention of Significant Deterioration (PSD) construction permit and a Title V operating permit from the state, since the potential to emit PM_{10} could exceed 250 tons per year. [NRC 2006].

The impacts of the existing once-through cooling systems on air quality are SMALL. On the basis of the above considerations, Entergy concludes that the direct and indirect impacts of the alternative closed-cycle cooling systems on air quality, particularly those related to increases in PM_{10}, which would result from salt drift, would be MODERATE.

8.1.1.5 Waste

Construction of cooling towers would entail disposal of two million cubic yards of material. To transport the material to an acceptable disposal site by truck, assuming six cubic yards per load, would entail over 300,000 round trips. The excavation would be expected to take 30 months to complete. This scenario would result in impacts due to noise and traffic volume to the Village of Buchanan and the surrounding communities. The alternative disposal scenario would be to transport the material by barge to a suitable disposal site.

Small amounts of biocides or other materials used in the cooling systems would be produced during operations. Some of this material would be released to the environment in the blowdown water released to the discharge canal and the Hudson River in accordance with IP2 and IP3's SPDES permit. Any other such waste would be managed and disposed of in accordance with applicable State regulations at approved offsite facilities.

Overall, waste impacts for the existing once-through cooling systems is SMALL. The waste impacts for the proposed closed-cycle cooling systems are considered MODERATE to LARGE.

8.1.1.6 Human Health

Human health impacts for an operating nuclear power plant are identified in 10 CFR Part 51 Subpart A, Appendix B, Table B-1. Overall, human health impacts from the existing once-through cooling systems and any closed-cycle cooling alternatives are considered SMALL (see Section 8.2.3.1.6) [NRC 1996].

8.1.1.7 Socioeconomics

Construction and operation of the closed-cycle cooling systems could result in adverse impacts on housing, public services, and traffic in the local area. Construction of the cooling towers would require an average workforce of 300 and could take an estimated 62 months. During the outage phase of the effort, the cooling tower construction workforce could peak at 600. It is anticipated that the majority of the workforce would be temporary. Only a small percentage may look for permanent residence in the area. For comparison purposes, a workforce of approximately 950 additional workers is on-site during a routine refueling outage.

As of June 2006 the site has approximately 1,255 full time workers (Entergy employees and baseline contractors) during normal plant operations. The majority of these employees live within a five-county area surrounding the plant. As discussed in Section 2.9, steady growth in the housing market has occurred in the five-county area near the site since 1990. In addition, vacancy rates have reduced, while the total number of new housing units has increased. This increase has kept pace with the low-to-moderate growth in the area population. The increased construction workforce would add a temporary burden on area housing, which would be added to the temporary housing needs during outages.

A study of the logistics for construction of cooling towers has not been performed. However, adverse transpiration impacts would be expected to be significant. Offsite disposal of the estimated two million cubic yards of excavation rock and debris would be expected to have a significant impact on local traffic during clearing of any cooling tower option at the site. As noted above, the excavation phase of construction would be expected to take at least 30 months to complete. In addition, to transport the material to an acceptable disposal site by truck, assuming six cubic yards per load, this disposal would entail over 300,000 round trips over the 30 months. Assuming seven days per week construction debris removal to offsite disposal, this would result in an estimated 370 truckloads per day, assuming six yard dump trucks would be used. This would amount to more than 740 entry/exits per day, or 74 per hour (10-hour day) to and from the site, in addition to existing site worker traffic, and in addition to any temporary worker traffic for outages and/or tower construction. If construction were limited to weekdays, the number of loads would increase significantly to more than 530 round trips per day, or potentially more than 105 trucks per hour. Traffic in the area is heavy and the additional traffic from construction and site workers would cause increased traffic delays, particularly along the major routes, i.e., US Highways 9 and 9A.

Even if transport of construction debris and new equipment could be completed via barges on the Hudson River, the impact of a closed-cycle cooling system at the site would be significant. Assuming 1000-ton barges were used for excavation debris removal, at least five barges per day would have to be loaded and leave the site per day, with additional barge staging required for returning barges. Depending upon the ultimate disposal of waste, truck traffic offloading the barges could be transferred to another location, which could also be significant to that locale. Construction of loading facilities at the site to accommodate this type of activity could have adverse impacts on both aquatic and terrestrial ecological communities.

Socioeconomic impacts resulting from once-through cooling are SMALL. Socioeconomic impacts related to housing during the construction of cooling towers at the site would be SMALL. Socioeconomic impacts related to transportation during the construction of cooling towers at the site could be MODERATE to LARGE.

8.1.1.8 Aesthetics

When IP2 and IP3 were constructed, the goal was to maintain a low physical profile for the station relative to the Hudson River Valley through visual containment of structures within the confines of the surrounding forest-covered high ground [Enercon]. Construction of the cooling towers would require permanent modification of the terrain along the shore of the Hudson River. The cooling towers would be located approximately 200 to 300 feet from the bank of the Hudson River at an elevation of about 30 feet MSL. The cooling towers would be the largest structures on the site.

Each cooling tower would be approximately 165 feet tall, about the height of a 14-story building, sitting at an elevation of 30 feet MSL, for a total height of 195 feet. Each cooling tower would be approximately 525 feet in diameter. By comparison, the reactor containment structures are approximately 160 feet in diameter and 250 feet tall. The cooling towers would have a significant adverse aesthetic impact [Enercon, Attachment 2, page 2, Rendering]. An area approximately 700 feet in diameter would be excavated for each cooling tower. In addition, approximately 1,000 feet of river bank would be deforested to allow excavation for the four large diameter water pipes (two 120-inch diameter supply pipes and two 144-inch diameter pipes to each condenser) required for each cooling tower.

Views from the Hudson River, scenic overlooks on area highways, and Palisades Interstate State Park on the western shore would be impacted. The site is an industrial facility already visible from these vantage points. However, the addition of the two towers would make the entire facility more visible. The clear-cutting of the forest required for construction of the towers and to allow maximum airflow to the towers would remove a visual buffer from vantage points both up and down river. As many trees as possible would be left between the construction sites and the river.

In addition, upon completion of construction, trees would be planted between the cooling towers and the river bank to re-establish a visual buffer and help attenuate noise from the operation of the towers. The New York State Historic Preservation and Parks Office opposed cooling towers at IP2 and IP3 on aesthetic grounds and there is no indication that NYSHP will not oppose any future effort.

The excavation for the cooling towers would cut into the side of the hills to the immediate east of the site. These tree-covered hills lie between the site and the Villages of Buchanan and Verplanck and rise to an elevation of 130 to 145 feet, which would shield most of the towers from view. However, many of the residents may still be able to see the tops of the towers above the tree tops. Because of the nature of hybrid cooling towers, no plume would be visible during the daylight hours. However, at night the towers would be run in wet mode, resulting in a plume of water vapor that may obscure the night sky for some residents.

Aesthetic impacts from the existing once-through cooling systems are SMALL. Impacts to aesthetics from the closed-cycle cooling alternative could be MODERATE to LARGE.

8.1.1.9 Noise

An ambient noise level monitoring program was conducted in the vicinity of Indian Point 2 and Indian Point 3 between September 2001 and January 2002. Ambient noise levels were determined for seven representative sound receptor locations. The Village of Buchanan has a sound ordinance (Chapter 211-23 of the Village Zoning Code) that limits allowable sound levels from a facility by octave band levels and is applicable at the property line of the sound generating facility. The combined octave band center frequencies equate to an overall level of 48 dB(A). [Enercon, Section 4.2]

Hybrid cooling towers that could be installed at IP2 and IP3 would have to be equipped with sound attenuators. The resulting noise level was estimated to be 30 dB(A) at 2,750 feet, approximately 940 feet east of the intersection of Bleakley Avenue and Broadway. The sound level at the intersection of Bleakely Avenue and Broadway was calculated to be approximately 34 dB(A). This is less than the late night ambient noise levels at this location [Enercon, Table 4.2]. The sound level at the residence nearest the proposed location for the Unit 3 cooling tower was calculated to be approximately 31 dB(A). The Village of Buchanan Sound Standard of 48 dB(A) would be met at approximately 350 feet from each tower, well within IP2 and IP3 property boundaries. The cooling towers would be constructed in the side of a hill. The topography between the cooling towers and sensitive receptors would further attenuate the sound levels. Enercon's cooling tower evaluation, shown in Table 8-1, presents the calculated noise level at sensitive receptors including existing background noise and the operational noise of both cooling towers. [Enercon]

Table 8-1
Cumulative Sound Levels and Sensitive Receptors (dB(A))

Receptor	Cooling Tower Noise Level [a]	Existing Daytime L_{90} [b]	Total Daytime Noise Level	Existing Late Night L_{90} [b]	Total Late Night Noise Level
Saint Patrick's Church	29	41	41	42	42
16th St and Broadway	30	38	39	40	40
Pheasant's Run	30	36	37	36	37
Buchanan Town Hall	28	44	44	38	38
Bleakley Ave. and Broadway	33	45	45	38	39
Elementary School	30	36	37	36	37
Nearest Residence	31	38	39	40	41
Centerville Park	30	36	37	36	37
China Pier	29	51	51	No Data	No Data

a. Both towers operating continuously
b. L_{90}: the level of noise (dB(A)) exceeded for ninety percent of the time.

Source: Enercon, Table 4.4

Table 8-1 reveals that both cooling towers operating continuously would cause in increase in noise levels at sensitive receptors of 1 dB(A) or less. This increase would probably not be noticed by the residents of the Village of Buchanan. [Enercon, Section 4.2]

Noise impacts from the existing once-through cooling systems are SMALL. Assuming noise attenuation systems are added, impacts due to noise from the closed-cycle cooling alternative would be SMALL.

8.1.1.10 Historic and Archaeological Resources

Before construction of cooling towers site, studies would be needed to identify, evaluate, and address mitigation of the potential impacts of construction on cultural resources. The studies would be needed for areas of potential disturbance at the proposed plant site and along associated corridors where new construction would occur (e.g., roads, transmission corridors, rail lines, or other rights-of-way). Historic and archaeological resource impacts from the existing once-through cooling systems are SMALL. Impacts from the closed-cycle alternative can generally be effectively managed and as such are considered SMALL.

8.1.1.11 Conclusion

Entergy has evaluated and compared the retrofitting of IP2 and IP3 with closed-cooling cycle cooling towers to current once-through cooling operations and has determined that current operations would result in smaller environmental impacts. Table 8-2 provides a comparison of impacts between the proposed action to continue the use of once-through cooling (described in Section 4), and those impacts anticipated if closed-cycle cooling systems were to be constructed for IP2 and IP3 (described above).

Table 8-2
Summary of Environmental Impacts from Once-Through Cooling Compared to Closed-Cycle Cooling at Indian Point

Impact Category	Once-Through Cooling Impact	Closed-Cycle Cooling Impact
Land Use	SMALL	MODERATE to LARGE
Ecology • Aquatic Ecology • Terrestrial Ecology	 SMALL SMALL	 SMALL MODERATE
Water Use and Quality • Surface Water • Groundwater	 SMALL SMALL	 SMALL SMALL
Air Quality	SMALL	MODERATE
Waste	SMALL	MODERATE to LARGE
Human Health	SMALL	SMALL
Socioeconomics • Population Driven Land-Use • Transportation	 SMALL SMALL	 SMALL MODERATE to LARGE
Aesthetics	SMALL	MODERATE to LARGE
Noise	SMALL	SMALL
Historic and Archaeological Resources	SMALL	SMALL

8.2 Comparison of Environmental Impacts for Reasonable Generation Alternatives

As stated in the GEIS, the "NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable" [NRC 1996, Section 8.1]. A discussion is provided below of the supply side alternative energy technologies that Entergy could utilize if the IP2 and IP3 Operating Licenses were not renewed. These alternatives are within the range of alternatives capable of meeting the goal of approximately 2,040 gross MWe as base-load generation analyzed in this report (i.e., approximate replacement power for the site).

Conventional coal-fired and natural gas-fired combined cycle and advanced light-water reactor are currently available conventional base-load technologies considered to replace site generation upon its termination of operation. These sources are considered viable alternatives based upon current Entergy planning strategies.

The environmental impacts discussed in this chapter are for the construction and operation of these generation facilities. Impacts are evaluated for a greenfield case (building on a new, pristine condition site) and a brownfield case (constructing new generation on the existing site, with exception of coal-fired and advanced light water reactor units).

As discussed below, the continued operation of IP2 and IP3 for the period of extended operation would result in less environmental impact than that of the replacement power option that could be obtained from other reasonable generating sources. In addition, the current transmission system constraints in New York State would preclude transmission of power from Northern and Western New York State to elsewhere within the state [National].

8.2.1 Coal-Fired Generation

NRC evaluated coal-fired generation alternatives in each of the plant-specific Supplements to the GEIS. For the V. C. Summer pressurized water reactor, NRC analyzed two 408 MWe coal-fired generation capacity plants [NRC 2004, Section 8.2.1]. Entergy has reviewed the NRC analysis and believes it to be sound. In defining the site coal-fired alternative, Entergy has used site-specific fuel and input data and has scaled from the NRC analysis to evaluate a 2,040 MWe coal-fired plant that would be close to the MWe power produced by the IP2 and IP3 plants (2,158 MWe). Although the hypothetical coal-fired plant understates the impacts of replacing 2,158 MWe by approximately 5 percent, Entergy believes these differences are insignificant and ensures against overstating the environmental impacts.

The coal-fired alternative that Entergy has defined would be located at an alternative site. Tables 8-3 through 8-5 present the basic coal-fired alternative emission control characteristics, emission estimates and waste generation volumes. Entergy based its emission control technology and percent control assumptions on alternatives that the EPA has identified as being available for minimizing emissions [USEPA 1998, Section 1.1]. For the purposes of analysis, it is assumed that coal and lime (calcium hydroxide) could be delivered either by rail or barge to a newly-constructed receiving dock on the site.

8.2.1.1 Closed-Cycle Cooling System

The following sections discuss the overall impacts at an alternate greenfield site of the coal-fired generating system using a closed-cycle cooling system with cooling towers. The magnitude of impacts for the alternative site would depend on the location of the particular site selected. The site currently uses once-through cooling systems. For the purposes of comparison with an alternative site, it is assumed that the replacement coal-fired plant sited at an alternative site also would use a closed-cycle cooling system.

The environmental impacts of building a coal-fired generation facility with a closed-cycle cooling system at an alternative site are summarized in Table 8-6.

8.2.1.1.1 Land Use

Based on Table 8.1 of the GEIS, it is estimated that it would take approximately 1.7 acres of land per MWe to construct a coal-fired plant. Therefore, for the 2,040 MWe plant evaluated in this analysis, it would take approximately 3,468 acres of land (5.4 mi^2). This could result in a considerable loss of natural habitat or agricultural land for the plant site alone, excluding that required for mining and other fuel-cycle impacts.

Additional land might also be needed for transmission lines and rail lines, depending on the location of the site relative to the nearest inter-tie connection and rail spur. Depending on the transmission line routing and nearest rail line, these alternatives could result in MODERATE to LARGE land use impacts.

Land-use changes would occur off-site in an undetermined coal-mining area to supply coal for the plant. In the GEIS, analysts estimated that approximately 22 acres of land per MWe would be affected for mining the coal and disposing of the waste to support a coal-fired plant during its operational life [NRC 1996]. Therefore, for the 2,040 MWe plant utilized in this analysis, approximately 44,880 acres (70 mi^2) of land could be affected. Partially offsetting this offsite land use would be the elimination of the need for uranium mining and processing to supply fuel for IP2 and IP3. In the GEIS, the staff estimated that approximately one acre per MWe would be affected by mining and processing the uranium during the operating life of a nuclear power plant [NRC 1996]. Therefore, for the 2,040 MWe plant considered in this analysis, uranium mining would affect approximately 2,040 acres of land.

Overall, land use impacts of a coal-fired generating unit with a closed-cycle cooling system located at an alternate site are considered to be MODERATE to LARGE.

8.2.1.1.2 Ecology

Constructing a coal-fired plant at an alternate site could alter ecological resources because of the need to convert roughly 3,468 acres of land to use for a plant, coal storage, and ash and scrubber sludge disposal. However, some or all of this land might already have been previously disturbed.

Coal-fired generation at an alternative site would introduce construction impacts and new incremental operational impacts. Even assuming siting at a previously disturbed area, the impacts would alter the ecology. Impacts could include wildlife habitat loss, reduced productivity, habitat fragmentation, and a local reduction in biological diversity.

Use of cooling system makeup water from a nearby surface water body could have adverse impacts on aquatic resources. If needed, construction and maintenance of an electric power transmission line and a rail spur would have ecological impacts. There would be some impact on terrestrial ecology from water drift from the cooling towers. Overall, the ecological impacts of constructing a coal-fired plant with a closed-cycle cooling system at an alternate site are considered to be MODERATE to LARGE.

8.2.1.1.3 Water Use and Quality

Surface Water: Cooling water at an alternate site would likely be withdrawn from a surface water body and would be regulated by a permit. Depending on the water source, the impacts of water use for cooling system makeup water and the effects on water quality caused by cooling tower blowdown could have noticeable impacts. Therefore, the impacts of a new coal-fired plant utilizing a closed-cycle cooling system at an alternate site are considered SMALL to MODERATE.

Groundwater: Impacts of groundwater withdrawal would be SMALL if only used for potable water. If groundwater is used to supply makeup water, then the impacts could be MODERATE to LARGE. Therefore, groundwater impacts from a coal-fired plant on the aquifer would be site-specific and dependent on aquifer recharge and other withdrawals. The overall impacts would be SMALL to LARGE.

8.2.1.1.4 Air Quality

Air quality impacts of coal-fired generation are considerably different from those of nuclear power. A coal-fired plant emits oxides of sulfur (SO_x), nitrogen oxides (NO_x), particulate matter, and carbon monoxide, all of which are regulated pollutants. As already stated, Entergy has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. Entergy estimates the coal-fired alternative emissions to be as follows (from Table 8-4).

Oxides of sulfur = 6,284 tons per year

Oxides of nitrogen = 1,476 tons per year

Carbon monoxide = 1,476 tons per year

Particulates:

Total suspended particulates = 210 tons per year

PM_{10} (particulates having a diameter of less than 10 microns) = 48 tons per year

The acid rain requirements of the Clean Air Act amendments capped the nation's SO_x emissions from power plants. Under the Clean Air Act amendments, each company with fossil-fuel-fired units was allocated SO_x allowances. To be in compliance with the Act, the companies must hold enough allowances to cover their annual SO_x emissions. Entergy would have to purchase allowances to cover its SO_x emissions. It is also likely that Entergy would be required to purchase NO_x emission allowances under New York State's program to comply with the National Ambient Air Quality Standards.

Since emissions exceed the 250 tons/year (SO_x, NO_x, and CO) major source definition under the PSD new-source construction and under the Title V operating permit regulations of the CAA, the coal-fired alternative would require a PSD construction permit and Title V operating permit.

NRC did not quantify coal-fired emissions in the GEIS, but implied that air impacts would be substantial. NRC noted that adverse human health effects from coal combustion have led to important federal legislation in recent years and that public health risks, such as cancer and emphysema, have been associated with coal combustion. NRC also mentioned global warming and acid rain as potential impacts. Entergy concludes that federal legislation and large-scale concerns, such as global warming and acid rain, are indications of concerns about destabilizing important attributes of air resources. However, SO_x emission allowances, NO_x emission offsets, low NO_x burners with overfire air and selective catalytic reduction, fabric filters or electrostatic precipitators, and scrubbers are provided as mitigation measures. As such, Entergy concludes that the coal-fired alternative would have MODERATE impacts on air quality. The emission of "greenhouse" gases would be significantly greater than for the existing IP2 and IP3 emissions or for a greenfield site nuclear plant.

8.2.1.1.5 Waste

Entergy concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste. The coal-fired plant would annually consume approximately 5,905,938 tons of coal having an ash content of 7.11%. After combustion, 99.9% of this ash (approximately 419,492 tons per year) would be collected and disposed of at either an on-site or off-site landfill. In addition, approximately 342,489 tons of scrubber waste would be disposed of each year. Entergy estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 402 acres. The amount of land needed for final disposal of ash may be less, dependant upon the availability of local recycling options for the ash. Table 8-5 shows how Entergy calculated ash and scrubber waste volumes. While only half this waste volume and land use would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact.

Entergy believes that, with proper siting coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. Some wooded terrestrial habitat would be dedicated to the waste site. However, after closure of the waste site and revegetation, the land would be available for other uses. For these reasons, Entergy believes that waste disposal for the coal-fired alternative would have MODERATE impacts.

8.2.1.1.6 Human Health

Coal-fired power generation introduces worker risk from coal and limestone mining, worker and public risk from coal and lime/limestone transportation, worker and public risk from disposal of coal combustion wastes, and public risk from inhalation of stack emissions. Emission impacts can be widespread and health risk is difficult to quantify. The coal alternative also introduces the risk of coal pile fires and attendant inhalation risk.

The NRC stated in the GEIS that there could be human health impacts (cancer and emphysema) from inhalation of toxins and particulates from a coal-fired plant, but the GEIS does not identify the significance of these impacts [NRC 1996]. In addition, the discharges of uranium and thorium from coal-fired plants can potentially produce radiological doses in excess of those arising from nuclear power plant operations [Gabbard].

Regulatory agencies, including the EPA and State agencies, set air emission standards and requirements based on human health impacts. These agencies also impose site-specific emission limits as needed to protect human health. EPA has recently concluded that certain segments of the U.S. population (e.g., the developing fetus and subsistence fish-eating populations) are believed to be at potential risk of adverse health effects due to mercury exposures from sources such as coal-fired power plants. However, in the absence of more quantitative data, human health impacts from radiological doses and inhaling toxins and particulates generated by a coal-fired plant at an alternate site are considered to be SMALL.

8.2.1.1.7 Socioeconomics

The peak workforce is estimated to range from 1.2 to 2.5 additional workers per MWe during the construction period, based on estimates given in Table 8.1 of the GEIS. For the 2,040 MWe plant utilized in this analysis, it would take approximately ten years to construct the plant (assuming the coal fired units were built in parallel) with a total workforce ranging from approximately 2,448 to 5,100 workers.

Communities around the new site would have to absorb the impacts of a large, temporary work force (up to approximately 5,100 workers at the peak of construction) and a permanent work force of approximately 0.25 workers per MWe based on Table 8.2 of the GEIS or approximately a total of 510 total workers for the 2,040 MWe plant utilized in this analysis.

In the GEIS, the staff stated that socioeconomic impacts at a rural site would be larger than at an urban site, because more of the peak construction workforce would need to move to the area to work. Alternate sites would need to be analyzed on a case-by-case basis. Therefore, socioeconomic impacts at an isolated rural site could be LARGE.

Transportation related impacts associated with commuting construction workers at an alternate site would be site dependent, but could be MODERATE to LARGE.

Transportation impacts related to commuting of plant operating personnel would also be site dependent, but can be characterized as SMALL to MODERATE.

At most alternate sites, coal and lime would be delivered by rail, although barge delivery is feasible for a location on navigable waters. Transportation impacts would depend upon the site location. Socioeconomic impacts associated with rail transportation would be MODERATE to LARGE. Transportation from barge delivery of coal and lime/limestone would have SMALL socioeconomic impacts.

8.2.1.1.8 Aesthetics

Alternative site locations could reduce the aesthetic impact of coal-fired generation if siting were in an area that was already industrialized. In such a case, however, the introduction of tall stacks and cooling towers would probably still have a MODERATE incremental impact. Locating at other, largely undeveloped sites could show a LARGE impact.

There would also be an aesthetic impact if construction of a new transmission line and/or rail spur were needed. Noise impacts associated with rail delivery of coal and lime/limestone would be most significant for residents living in the vicinity of the facility and along the rail route. Although noise from passing trains significantly raises noise levels near the rail corridor, the noises would be of short duration. In a more suburban location, the impacts are considered MODERATE. This is due to the frequency of train transport, the fact that many people are likely to be within hearing distance of the rail route, and the impacts of noise on residents in the vicinity of the facility and the rail line. At a more rural location, the impacts could be SMALL. Noise and light from the plant would be detectable off-site. Overall, the aesthetic impacts associated with locating at an alternative site can be categorized as SMALL to LARGE, depending on the characteristics of the alternative site.

8.2.1.1.9 Historic and Archaeological Resources

Before construction at an alternate site, studies would be needed to identify, evaluate, and address mitigation of the potential impacts of new plant construction on cultural resources. The studies would be needed for areas of potential disturbance at the proposed plant site and along associated corridors where new construction would occur (e.g., roads, transmission corridors, rail lines, or other rights-of-way). Historic and archaeological resource impacts can generally be effectively managed and as such are considered SMALL.

Table 8-3
Coal-Fired Alternative Emission Control Characteristics

Characteristic	Basis
Unit size = 408 MW ISO rating net[a]	Chosen as a reasonable plant for approximating IP2 and IP3.
Unit size = 430 MW ISO rating gross[a]	Chosen as a reasonable plant for approximating IP2 and IP3.
Number of units = 5	Close to IP2 and IP3's MWe generating capacity.
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxide emissions [USEPA 1998, Table 1.1-3]
Fuel type = bituminous, pulverized coal	Typical for coal used in New York [USDOE 2001, Table 4]
Fuel heating value = 13,117 Btu/lb	2000 value for coal used in New York [USDOE 2001, Table 4]
Fuel ash content by weight = 7.11%	2000 value for coal used in New York [USDOE 2001, Table 22]
Fuel sulfur content by weight = 1.12%	2000 value for coal used in New York [USDOE 2001, Table 22]
Uncontrolled NO_x emission = 10 lb/ton Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS [USEPA 1998, Table 1.1-3]
Heat rate = 10,200 Btu/kWh	Typical for coal-fired, single-cycle steam turbines [USDOE 2002a, page 110]
Capacity factor = 0.85	Typical for newer large coal-fired units
NO_x control = low NO_x burners, overfire air and selective catalytic reduction (95% reduction)	Best available and widely demonstrated for minimizing NO_x emissions [USEPA 1998, Table 1.1-2]
Particulate control = fabric filters (baghouse - 99.9% removal efficiency)	Best available for minimizing particulate emissions [USEPA 1998, pp. 1.1-6 and 1.1-7]
SO_x control = Wet scrubber – lime (95% removal efficiency)	Best available for minimizing SO_x emissions [USEPA 1998, Table 1.1-1]

Btu = British thermal unit
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60% relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt-hour
NSPS = New Source Performance Standard
lb = pound
MW = megawatt
NO_x = nitrogen oxides
SO_x = oxides of sulfur

a. The difference between "net" and "gross" is electricity consumed by auxiliary equipment and environmental control devices [USDOE 2002a, page 109].

Table 8-4
Air Emissions from Coal-Fired Alternative

Parameter	Calculation	Result
Annual coal consumption	$5 \text{ units} \times \frac{408 \text{ MW}}{\text{unit}} \times \frac{10,200 \text{ Btu}}{\text{kW} \times \text{hr}} \times \frac{1,000 \text{ kW}}{\text{MW}} \times \frac{\text{lb}}{13,117 \text{ Btu}} \times \frac{24 \text{ hr}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{\text{ton}}{2,000 \text{ lb}} \times 0.85$	5,905,938 tons of coal per year
SO_x[a,b]	$\frac{5,908,938 \text{ tons}}{\text{yr}} \times \frac{1.12\% \times 38 \text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2,000 \text{ lb}} \times \frac{100 - 95}{100}$	6,284 tons SO_x per year
NO_x[b,c]	$\frac{5,905,938 \text{ tons}}{\text{yr}} \times \frac{10 \text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2,000 \text{ lb}} \times \frac{100 - 95}{100}$	1,476 tons NO_x per year
CO[b]	$\frac{5,905,938 \text{ tons}}{\text{yr}} \times \frac{0.5 \text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2,000 \text{ lb}}$	1,476 tons CO per year
TSP[d]	$\frac{5,905,938 \text{ tons}}{\text{yr}} \times \frac{7.11\% \times 10 \text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2,000 \text{ lb}} \times \frac{100 - 99.9}{100}$	210 tons TSP per year
PM_{10}[d]	$\frac{5,905,938 \text{ tons}}{\text{yr}} \times \frac{7.11\% \times 2.3 \text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2,000 \text{ lb}} \times \frac{100 - 99.9}{100}$	48 tons PM_{10} per year

CO = carbon monoxide
NO_x = nitrogen oxides
PM_{10} = particulates having diameter less than 10 microns
SO_x = oxides of sulfur
TSP = total suspended particulates

a. USEPA 1998, Table 1.1-1
b. USEPA 1998, Table 1.1-3
c. USEPA 1998, Table 1.1-2
d. USEPA 1998, Table 1.1-4

Table 8-5
Solid Waste from Coal-Fired Alternative

Parameter	Calculation	Result
Annual SO_x generated[a]	$\frac{5{,}905{,}938 \text{ tons Coal}}{\text{yr}} \times \frac{1.12 \text{ tons}}{100 \text{ tons Coal}} \times \frac{64.1 \text{ tons } SO_2}{32.1 \text{ tons S}}$	132,087 tons of SO_x per year
Annual SO_x removed	$\frac{132{,}087 \text{ tons } SO_2}{\text{yr}} \times \frac{95}{100}$	125,483 tons of SO_x per year
Annual ash generated	$\frac{5{,}905{,}938 \text{ tons Coal}}{\text{yr}} \times \frac{7.11 \text{ tons ash}}{100 \text{ tons Coal}} \times \frac{99.9}{100}$	419,492 tons of ash per year
Annual lime consumption[b]	$\frac{132{,}087 \text{ tons } SO_2}{\text{yr}} \times \frac{56.1 \text{ tons CaO}}{64.1 \text{ tons } SO_2}$	115,602 tons of CaO per year
Calcium sulfate[c]	$\frac{125{,}483 \text{ tons } SO_2}{\text{yr}} \times \frac{172 \text{ tons } CaSO_4 \bullet 2H_2O}{64.1 \text{ tons } SO_2}$	336,709 tons of $CaSO_4 \cdot 2H_2O$ per year
Annual scrubber waste[d]	$\frac{115{,}602 \text{ tons CaO}}{\text{yr}} \times \frac{100 - 95}{100} + 336{,}709 \text{ tons } CaSO_4 \bullet 2H_2O$	342,489 tons of scrubber waste per year
Total volume of scrubber waste[e]	$\frac{342{,}489 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{144.8 \text{ lb}}$	189,220,442 ft^3 of scrubber waste
Total volume of ash[f]	$\frac{419{,}492 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	335,593,600 ft^3 of ash
Total volume of solid waste	$189{,}220{,}442 \ ft^3 + 335{,}593{,}600 \ ft^3$	524,814,042 ft^3 of solid waste
Waste pile area (acres)	$\frac{524{,}814{,}042 \ ft^3}{30 \text{ ft}} \times \frac{\text{acre}}{43{,}560 \ ft^2}$	402 acres of solid waste 30 ft high
Waste pile area (ft x ft square)	$\sqrt{524{,}814{,}042 \ ft^3 / 30 \text{ ft}}$	4,183 ft by ft square of solid waste, 30 ft high

Based on annual coal consumption of 5,905,938 tons per year (see Table 8-4).

S = sulfur
SO_2 = sulfur dioxide
SO_x = oxides of sulfur
CaO = calcium oxide (lime)
$CaSO_4 \bullet 2H_2O$ = calcium sulfate dihydrate

a. Calculations assume 100% combustion of coal.
b. Lime consumption is based on total SO_2 generated.
c. Calcium sulfate generation is based on total SO_2 removed.
d. Total scrubber waste includes scrubbing media carryover.
e. Density of $CaSO_4 \cdot 2H_2O$ is 144.8 lb/ft^3.
f. Density of coal bottom ash is 100 lb/ft^3 [FHA].

Table 8-6
Summary of Environmental Impacts from Coal-Fired Generation Using Closed-Cycle Cooling at an Alternate Greenfield Site

Impact Category	Impact	Comments
Land Use	MODERATE to LARGE	Approximately 3,468 acre site with additional land for mining and disposal.
Ecology	MODERATE to LARGE	Impact will depend on ecology of site and need for additional transmission lines.
Water Use and Quality:		
- Surface Water	SMALL to MODERATE	Impact will depend on volume and other characteristics of receiving water.
- Groundwater	SMALL to LARGE	Impact will depend on site characteristics and availability of groundwater.
Air Quality	MODERATE	SOx – 6,284 tons/yr – allowances required NOx – 1,476 tons/yr – allowances required Particulate – 210 tons/yr (filterable) – 48 tons/yr (unfilterable) Carbon monoxide – 1,476 tons/yr Trace amounts of mercury, arsenic, chromium, beryllium, and selenium
Waste	MODERATE	Total waste volume would be estimated around 524,814,042 ft^3 of ash and scrubber sludge.
Human Health	SMALL	Impacts considered minor.

Table 8-6 (Continued)
Summary of Environmental Impacts from Coal-Fired Generation Using Closed-Cycle Cooling at an Alternate Greenfield Site

Impact Category	Impact	Comments
Socioeconomics	SMALL to LARGE	Communities would need to absorb impacts of a large, temporary total workforce (up to approximately 5,100 workers at the peak of construction) and a total permanent work force of approximately 510 workers. Impacts at a rural site would be larger. Transportation-related impacts associated with commuting construction workers would be site dependent.
Aesthetics	SMALL to LARGE	Could reduce aesthetic impact if siting is in an industrial area. Impact would be large if siting is largely in an undeveloped area.
Historic and Archaeological Resources	SMALL	Would necessitate cultural resource studies.

8.2.1.2 Once-Through Cooling System

The environmental impacts of constructing a coal-fired generation system at an alternate greenfield site using once-through cooling are similar to the impacts for a coal-fired plant using a closed-cycle cooling system. However, there are some environmental differences between the closed-cycle and once-through cooling systems. Table 8-7 summarizes the incremental differences.

Table 8-7
Summary of Environmental Impacts from Coal-Fired Generation Using Once-Through Cooling at an Alternate Greenfield Site

Impact Category	Comments
Land Use	Compared with a closed-cycle cooling system, less land would be required because cooling towers and associated infrastructure not needed.
Ecology	Slightly reduced environmental impacts because there are no cooling towers; however, increased water withdrawal may impact aquatic resources.
Water Use and Quality:	
- Surface Water	Impact would depend on surface water body characteristics, volume of water withdrawn, and characteristics of the discharge.
- Groundwater	Impact would depend on site characteristics and availability of groundwater. It is unlikely that groundwater would be used for once-through cooling, but could be used for sanitary water.
Air Quality	No change.
Waste	No change.
Human Health	No change.
Socioeconomics	No change.
Aesthetics	Reduced aesthetic impact because cooling towers would not be used.
Historic and Archaeological Resources	Less land impacted.

8.2.2 Natural Gas-Fired Generation

Entergy has chosen to evaluate gas-fired generation, using combined-cycle turbines, because it has determined that the technology is mature, economical, and feasible. Table 8-8 presents the basic gas-fired alternative characteristics and Table 8-9 presents emission estimates.

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. For the V. C. Summer pressurized water reactor, NRC analyzed two 408 MWe of gas-fired generation capacity [NRC 2004, Section 8.2.1]. Entergy has reviewed the NRC analysis and believes it to be sound. In defining the gas-fired alternative, Entergy has used site-specific fuel and input data, and has scaled from the NRC analysis to five 408 MWe combined cycle gas-fired units for a total of 2,040 MWe that would be very close to the MWe power produced by IP2 and IP3 (2,158 MWe). Although the hypothetical gas-fired plant understates the impacts of replacing 2,158 MWe by approximately 5 percent, Entergy believes these differences are insignificant and ensures against overstating the environmental impacts.

8.2.2.1 Closed-Cycle Cooling System

The overall impacts of the natural-gas-generating system with a closed-cycle cooling system located at the site or an alternate site were evaluated. As noted in the evaluation of land use impacts below, the available land on-site is inadequate for construction of replacement power. Therefore, offsite brownfield and greenfield sites are evaluated, summarized in Table 8-10, and discussed in the following sections. The magnitude of impacts at an alternate site will depend on the location of the particular site selected.

8.2.2.1.1 Land Use

The feasibility of peaking capacity was discussed in Entergy's Preliminary Scoping Statement filed with the New York Public Service Commission (NYPSC) on March 18, 2002, to construct a 330 MWe simple cycle plant. The plant was originally to be comprised of eight 45-MW aero-derivative gas turbines, later amended to two 165-MW GE 7FA industrial frame gas turbines. The plant was to utilize a five-acre parcel on the IP site outside of the "protected area" that houses the reactors. The plant would have tied into the Buchanan electric substation, less than 2,000 feet to the northeast [Levitan]. However, Entergy's evaluation of adding peaking capacity to the base-load capacity of IP2 and IP3 did not include replacement of the existing 2,158 MWe. As discussed below, replacement capacity would require the purchase of additional land off-site, and environmental impacts would be equivalent to a greenfield site.

Gas-fired generation at the site would require converting the existing industrial site to a gas plant. Almost all the converted land would be used for the power block. Additional land would be disturbed during pipeline construction. Some additional land would also be required for backup oil storage tanks. However, the existing 239 acres currently owned by Entergy at the site is not adequate for replacement gas-fired base-load generation capacity. The GEIS estimated that 110 acres are needed for a 1,000 MWe natural gas-fired facility [NRC 1996, Section 8.3.10]. Scaling up for the 2,040 MWe facility would indicate a land requirement of approximately 224 acres, which is not currently available on-site. Therefore, additional land would have to be purchased. If land adjacent to the site were available and used, the impact would probably be equivalent to the environmental impacts of a greenfield site in another area. Another offsite brownfield site could be selected, which may minimize environmental impacts. Construction and operation of replacement power at a brownfield site would require construction of a new cooling system, switchyard, offices, gas-transmission pipelines, and transmission line right(s)-of-way, but would minimize many environmental impacts. Gas-fired generation land use impacts at a brownfield site are considered to be SMALL to MODERATE; gas-fired generation at a greenfield site (or adjacent to the existing site) would be MODERATE to LARGE.

While the existing Algonquin main pipeline line may be adequate for a 330 MWe simple cycle plant that would operate in peaking mode during the summer season, a report prepared by Levitan and Associates, Inc. concluded that substantial and expensive site pipeline upgrades would probably be required to supply natural gas to a combined cycle plant throughout the winter heating season, November–March, and for the additional base-load capacity (i.e., greater than 330 MW) throughout the year. [Levitan]

Table 8-8
Gas-Fired Alternative Emission Control Characteristics

Characteristic	Basis
Unit size = 408 MW ISO rating net[a] Two 135 MW combustion turbines and a 138 MW heat recovery boiler	Manufacturer's standard size gas-fired combined cycle plant
Unit size = 424 MW ISO rating gross[a] Two 140.5 MW Combustion Turbines 143 MW Heat Recovery Boiler	Calculated based on 4% on-site power
Number of units = 5	Close to IP2 and IP3 MWe generating capacity.
Fuel type = natural gas	Assumed
Fuel heating value = 1,019 Btu/ft^3	2000 value for gas used in New York [USDOE 2001, Table 14]
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available [USEPA 2000, Table 3.1-2a]
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_x emissions [USEPA 2000, Table 3.1 Database]
Fuel NO_x content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas-fired units with water injection [USEPA 2000 Table 3.1 Database]
Fuel CO content = 0.0023 lb/MMBtu	Typical for large SCR-controlled gas-fired units [USEPA 2000, Table 3.1]
Heat rate = 8,200 Btu/kWh	Typical for combined cycle gas-fired turbines [USDOE 2001, page 110]
Capacity factor = 0.85	Typical for large gas-fired base-load units (Entergy experience)

Btu = British thermal unit
ft^3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60% relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt-hour
MM = million
MW = megawatt
NO_x = nitrogen oxides
< = less than
SCR = selective catalytic reduction

a. The difference between "net" and "gross" is electricity consumed by auxiliary equipment and environmental control devices [USDOE 2001, page 109].

Table 8-9
Air Emissions from Gas-Fired Alternative

Parameter	Calculation	Result
Annual gas consumption	$5\text{ units} \times \frac{408\text{ MW}}{\text{unit}} \times \frac{8,200\text{ Btu}}{\text{kW} \times \text{hr}} \times \frac{1,000\text{ kW}}{\text{MW}} \times 0.85 \times \frac{\text{ft}^3}{1,019\text{ Btu}} \times \frac{24\text{ hr}}{\text{day}} \times \frac{365\text{ days}}{\text{yr}}$	122,234,237,500 ft^3 per year
Annual Btu input	$\frac{122,234,237,500\text{ ft}^3}{\text{yr}} \times \frac{1,019\text{ Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\text{ Btu}}$	124,556,688 MMBtu per year
SO_x[a]	$\frac{0.0034\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2000\text{ lb}} \times \frac{124,556,688\text{ MMBtu}}{\text{yr}}$	212 tons SO_x per year
NO_x[b]	$\frac{0.0109\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2,000\text{ lb}} \times \frac{124,556,688\text{ MMBtu}}{\text{yr}}$	679 tons NO_x per year
CO[b]	$\frac{0.0023\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2,000\text{ lb}} \times \frac{124,556,688\text{ MMBtu}}{\text{yr}}$	143 tons CO per year
TSP[a]	$\frac{0.0019\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2,000\text{ lb}} \times \frac{124,556,688\text{ MMBtu}}{\text{yr}}$	118 tons filterable TSP per year
PM_{10}[a]	$\frac{118\text{ tons TSP}}{\text{yr}}$	118 tons filterable PM_{10} per year
CO = carbon monoxide NO_x = oxides of nitrogen PM_{10} = particulates having diameter less than 10 microns SO_x = oxides of sulfur TSP = total suspended particulates		

a. USEPA 2000, Table 3.1-2a
b. USEPA 2000, Table 3.1-1

8.2.2.1.2 Ecology

Siting gas-fired generation at an offsite brownfield site would have MODERATE ecological impacts because the facility would be constructed partly on previously disturbed areas.

If additional land were available for purchase adjacent to the existing IP2 and IP3 site, ecological impacts may not be significantly different than for a greenfield site, even though there are existing Algonquin gas pipelines that traverse the site. According to a Preliminary Scoping Statement prepared by Entergy, the Algonquin 26-inch and 30-inch gas pipelines traverse the IP site, and the gas interconnection would extend less than 1,000 feet for a proposed gas-fired peaking plant. However, the Algonquin lines may not have sufficient capacity to supply the fuel requirements cited in this analysis. Upgrades to this system would likely be required to obtain a sufficient and reliable fuel supply [Levitan]. Additional pipeline construction or upgrades might also be required at an alternative site. Habitat would be disturbed by such pipeline construction.

For brownfield and greenfield sites, the GEIS noted that land-dependent ecological impacts from construction would be SMALL unless site-specific factors indicate a particular sensitivity and that operational impact would be smaller than for other fossil fuel technologies of equal capacity. Therefore, in this case, the appropriate characterization of gas-fired generation ecological impacts is SMALL to MODERATE, depending on the area selected for replacement power construction and operations.

Construction at a greenfield site could alter the ecology of the site and could impact threatened and endangered species. These ecological impacts could be SMALL to MODERATE.

8.2.2.1.3 Water Use and Quality

Surface Water: If the plant could use the existing IP2 and IP3 intake and discharge structures as part of a closed-cycle cooling system (assuming the new plant were immediately adjacent to the existing site), the water quality impacts would continue to be SMALL. If a feasible brownfield site were available with existing surface water intake, the impact may also be SMALL.

Water quality impacts from sedimentation during construction is another land related impact that the GEIS categorized as SMALL. The GEIS also noted that operational water quality impacts would be similar to, or less than, those from other centralized generating technologies. The NRC has concluded that water quality impacts from coal-fired generation would be SMALL, and gas-fired alternative water usage would be less than that for coal-fired generation. Therefore, surface water impacts would remain SMALL.

For alternative greenfield sites, the impact on surface water would depend on the volume and other characteristics of the receiving body of water. The impacts would be SMALL.

Groundwater: For alternative brownfield or greenfield sites, the impact to the groundwater would depend on the site characteristics, including the amount of groundwater available. The impacts would range between SMALL to LARGE.

8.2.2.1.4 Air Quality

Natural gas is a relatively clean-burning fossil fuel; the gas-fired alternative would release similar types of emissions, but in lesser quantities, than the coal-fired alternative. Control technology for gas-fired turbines focuses on NO_x emissions. Entergy estimates the five plant gas-fired alternative emissions to be as follows (from Table 8-9):

Sulfur oxides = 212 tons per year

Oxides of nitrogen = 679 tons per year

Carbon monoxide = 143 tons per year

Filterable Particulates = 118 tons per year (all particulates are PM_{10})

Since emissions exceed the 250 tons/year (NO_x) major source definition under the PSD new-source construction and under the Title V operating permit regulations of the CAA, the coal-fired alternative would require a PSD construction permit and Title V operating permit.

Regional air quality and Clean Air Act requirements also are applicable to the gas-fired generation alternative. NO_x effects on ozone levels, SO_x allowances, and NO_x emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. Entergy concludes that emissions from the gas-fired alternative located near the site would noticeably alter local air quality, but would not destabilize regional resources. Westchester County is located in a non-attainment area for particulates, and a severe non-attainment area for ozone. Air quality impacts would therefore be MODERATE, but substantially smaller than those of coal-fired generation.

Siting the gas-fired plant elsewhere would not significantly change air quality impacts because the site could be in a greenfield area that is not a serious non-attainment area for ozone. In addition, the location could result in installing more or less stringent pollution control equipment to meet the regulations. Therefore, the impacts would be MODERATE. The emission of "greenhouse" gases would be significantly greater than for the existing IP2 and IP3 emissions, or for a greenfield site nuclear plant.

8.2.2.1.5 Waste

There are only small amounts of solid waste products (i.e., ash) from burning natural gas fuel. The GEIS concluded that waste generation from gas-fired technology would be minimal. Gas firing results in very few combustion by-products because of the clean nature of the fuel. Waste generation would generally be limited to typical office wastes, but other industrial waste would be generated from maintenance activities. This impact would be SMALL.

Siting the facility at a greenfield site would not alter the waste generation; therefore, the impacts would continue to be SMALL.

8.2.2.1.6 Human Health

The GEIS analysis mentions potential gas-fired alternative health risks (cancer and emphysema). The risk may be attributable to NO_x emissions that contribute to ozone formation, which in turn contributes to health risks. As discussed in Section 8.2.1.1.6 for the coal-fired alternative, legislative and regulatory control of the nation's emissions and air quality are protective of human health, and the human health impacts from gas-fired generation would be SMALL.

Siting of the facility at a greenfield site would not alter the possible human health effects. Therefore, the impacts would be SMALL.

8.2.2.1.7 Socioeconomics

It is assumed that gas-fired construction would take place while IP2 and IP3 continue operation, with the replacement gas-fired plant construction completed at the time the existing plants halt operation. Construction of the gas-fired alternative would take much less time than constructing other plants. During the time of construction, the surrounding communities would experience demands on housing and public services that could have SMALL to MODERATE impacts. After construction, the communities would be impacted by the loss of jobs, construction workers would leave, and the IP2 and IP3 nuclear plant workforce would decline through a decommissioning period to a minimal maintenance size.

The GEIS concluded that socioeconomic impacts from constructing a gas-fired plant would not be very noticeable and that the small operational workforce would have the lowest socioeconomic impacts (local purchases and taxes) of nonrenewable technologies. Compared to the coal-fired alternative, the smaller size of the construction workforce, the shorter construction time-frame, and the smaller size of the operations workforce would reduce some of the socioeconomic impacts. For these reasons, the socioeconomic impacts, including but not limited to transportation, of gas-fired-generation would be SMALL to MODERATE.

Construction at another site would relocate some socioeconomic impacts, but would not eliminate them. The community around the site would still experience the impact of the loss of IP2 and IP3 operational jobs and the tax base. The communities around the new site would have to absorb the impacts of a temporary workforce and a small permanent workforce. Therefore, the impacts would be MODERATE to LARGE, based on net job and tax-base losses from IP2 and IP3 closure. This impact is about the same in the site area as in the no-action alternative (i.e., license renewal for IP2 and IP3 is not granted).

8.2.2.1.8 Aesthetics

The combustion turbines and heat-recovery boilers would be relatively low structures and would be screened from most offsite vantage points by intervening woodlands. The steam turbine building would be taller and, together with the exhaust stacks, could be visible off-site.

The GEIS analysis noted that land-related impacts, such as aesthetic impacts, would be small unless site-specific factors indicate a particular sensitivity. As in the case of the coal-fired alternative, aesthetic impacts from the gas-fired alternative would be noticeable. However, because the gas-fired structures are shorter than the coal-fired structures and more amenable to screening by vegetation, it was determined that the aesthetic resources would not be destabilized by the gas-fired alternative. For these reasons, aesthetic impacts from a gas-fired plant would be SMALL to MODERATE.

Alternative locations could reduce the aesthetic impact of gas-fired generation if siting was in an area that was already industrialized. In such a case, however, the introduction of the steam generator building, stacks, and cooling tower plumes would probably still have a SMALL to MODERATE incremental impact.

Natural gas generation would introduce mechanical sources of noise that would be audible off-site. Sources contributing to total noise produced by plant operation are classified as continuous or intermittent. Continuous sources include the mechanical equipment associated with normal plant operations. Intermittent sources included the use of outside loudspeakers and the commuting of plant employees. However, it is expected that the plant would comply with all applicable noise ordinances and standards. Therefore, the noise impacts of a natural gas-fired plant at the site are considered to be SMALL.

At a greenfield site (or a site adjacent to the existing IP2 and IP3 site), these noise impacts would be SMALL to LARGE depending on the site.

8.2.2.1.9 Historic and Archaeological Resources

The GEIS analysis noted, as for the coal-fired alternative, that cultural resource impacts of the gas-fired alternative would be SMALL unless important site-specific resources were affected. Gas-fired alternative construction at any site would affect a smaller area than within the footprint of the coal-fired alternative. Construction at any offsite location could necessitate instituting cultural resource preservation measures, but impacts can generally be managed and maintained as SMALL. Cultural resource surveys would be required for the pipeline construction and other areas of ground disturbance associated with this alternative.

Table 8-10
Summary of Environmental Impacts from Gas-Fired Generation Using Closed-Cycle Cooling

Impact Category	Brownfield Site		Site Adjacent to IP2 and IP3 or Greenfield Site	
	Impact	Comments	Impact	Comments
Land Use	SMALL to MODERATE	Approximately 224 acres required for power block. Possible additional acreage disturbed for pipeline construction.	MODERATE to LARGE	Approximately 224 acres required for site. Possible additional land disturbed for pipeline construction.
Ecology	SMALL to MODERATE	Constructed on land within IP2 and IP3 region. Possible habitat loss due to pipeline construction.	SMALL to MODERATE	Impact depends on location and ecology of site; potential habitat loss and fragmentation; reduced productivity and biological diversity.
Water Use and Quality				
- Surface Water	SMALL	Assumes use of existing intake and discharge structures and cooling system, otherwise same as greenfield site.	SMALL	Impact depends on volume and characteristics of receiving water body.
- Groundwater	SMALL to LARGE	Groundwater impacts would depend on uses and available supply.	SMALL to LARGE	Groundwater impacts would depend on uses and available supply.
Air Quality	MODERATE	Primarily nitrogen oxides. Impacts could be noticeable, but not destabilizing.	MODERATE	Primarily nitrogen oxides. Impacts could be noticeable, but not destabilizing.
Waste	SMALL	Small amount of ash produced.	SMALL	Small amount of ash produced.
Human Health	SMALL	Impacts considered minor.	SMALL	Impacts considered minor.

Table 8-10 (Continued)
Summary of Environmental Impacts from Gas-Fired Generation Using Closed-Cycle Cooling

Impact Category	Brownfield Site		Site Adjacent to IP2 and IP3 or Greenfield Site	
	Impact	Comments	Impact	Comments
Socioeconomics	SMALL to MODERATE	Construction impacts would be relocated. Community near IP2 and IP3 site would still experience workforce reduction from current IP2 and IP3 workforce.	MODERATE to LARGE	Construction impacts would be relocated. Community near IP2 and IP3 site would experience workforce reduction.
Aesthetics	SMALL to MODERATE	Visual impact of stacks and equipment would be noticeable, but not as significant as coal option. If siting is in an industrial area, could reduce impact.	SMALL to LARGE	Offsite location could increase aesthetic impact.
Historic and Archaeological Resources	SMALL	Areas offsite would be affected.	SMALL	Offsite location would necessitate cultural resource studies.

8.2.2.2 Once-Through Cooling System

The environmental impacts of once-through cooling for an alternative brownfield or greenfield site to replace the 2,158 MWe base-load capacity of IP2 and IP3 are provided as a comparative analysis of impacts equivalent to the existing site. The environmental impacts of constructing a natural-gas-fired generation system at an alternate site using a once-through cooling system are similar to the impacts for a natural-gas-fired plant using closed-cycle cooling with cooling towers. However, there are some environmental differences between the closed-cycle and once-through cooling systems. Table 8-11 summarizes the incremental differences.

Table 8-11
Summary of Environmental Impacts from Gas-Fired Generation Using Once-Through Cooling

Impact Category	Brownfield Site	Site Adjacent to IP2 and IP3 or Greenfield Site
	Comments	**Comments**
Land Use	Approximately 45 to 60 acres less land required because cooling towers and associated infrastructure are not needed.	Approximately 45 to 60 acres less land required because cooling towers and associated infrastructure are not needed.
Ecology	Less terrestrial habitat lost and cooling tower effects eliminated; Increased water withdrawal may result, and aquatic impact may be similar to or greater than current IP2 and IP3 site operations.	Impact would depend on ecology at the site. No impact to terrestrial ecology from cooling tower drift. Increased water withdrawal may result, and aquatic impact may be similar to or greater than current IP2 and IP3 site operations Thermal discharges could result in greater impacts to aquatic ecology.
Water Use and Quality		
- Surface Water	No discharge of cooling tower blowdown containing dissolved solids. Increased water withdrawal and more thermal load on receiving body of water.	No discharge of cooling tower blowdown containing dissolved solids. Increased water withdrawal and more thermal load on receiving body of water.
- Groundwater	Groundwater impacts would depend on uses and available supply. It is unlikely that groundwater would be used for once-through cooling, but could be used for sanitary water.	Groundwater impacts would depend on uses and available supply. It is unlikely that groundwater would be used for once-through cooling, but could be used for sanitary water.
Air Quality	Minor reduction of impact due to particulate emissions from cooling towers.	Minor reduction of impact due to particulate emissions from cooling towers.
Aesthetics	Reduced aesthetic impact because cooling towers would not be used.	Reduced aesthetic impact because cooling towers would not be used.
Historic and Archaeological Resources	Less land affected.	Less land affected.
Waste	No change.	No change.
Human Health	No change.	No change.
Socioeconomics	No change.	No change.

8.2.3 Nuclear Power Generation

Since 1997, the NRC has certified four new standard designs for nuclear power plants under 10 CFR Part 52, Subpart B. These designs are the U.S. Advanced Boiling Water Reactor (10 CFR Part 52, Appendix A), the System 80+ Design (10 CFR Part 52, Appendix B), and the AP600 Design (10 CFR Part 52, Appendix C), and the AP1000 Design (10 CFR Part 52, Appendix D). All of these plants are light-water reactors. Currently, the NRC is reviewing the Design Certification application for the Economic Simplified Boiling Water Reactor (ESBWR). Finally, Title VI of the Energy Policy Act of 2005 includes several provisions to encourage the use of new nuclear power [USEPA 2005]. The nuclear power industry is also preparing combined construction and operating license applications for several new nuclear units. In addition, recent volatility of natural gas and electricity has made new nuclear power plant construction more attractive from a cost standpoint. Consequently, construction of a new nuclear power plant at an alternate site using closed-cycle and once-through cooling systems is considered in the following sections. It was assumed that the new reactor would have an initial operating term of 40 years.

8.2.3.1 Closed-Cycle Cooling System

The environmental impacts of constructing a nuclear power plant at an alternate site using closed-cycle cooling are summarized in Table 8-12.

8.2.3.1.1 Land Use

Land use requirements at an alternate site would require land for the nuclear power plant plus the possible need for land for a new transmission line. In addition, it may be necessary to construct a rail spur to an alternate site to bring in equipment during construction.

Land use is discussed in the GEIS regarding replacement power utilizing new advanced Light Water Reactors (LWR). The environmental impacts of constructing an advanced LWR nuclear plant are expected to be equivalent to the impacts of building any large energy facility. Impacts could be moderated somewhat if the plant were built at a current nuclear plant site rather than at a greenfield site because the prevailing land use would be compatible at the former site. Thus, building a plant on a greenfield site would produce more severe impacts.

Advanced LWRs require perhaps 500 to 1000 acres excluding transmission lines, which could add hundreds to thousands of acres depending upon the distance of the plant from connecting transmission lines or load centers. Destruction of wildlife habitat would occur, and threatened and endangered species would require special consideration to avoid adverse impacts. Erosion, sedimentation, fugitive dust, aesthetic intrusions, and disturbance to cultural artifacts would tend to be proportional to the amount of land disturbed.

Construction of new nuclear generation facilities is not feasible on the existing 239 acres of the plant site. Thus, an appropriate brownfield or greenfield site would have to be identified that met appropriate siting requirements, including, but not limited to, water and public services availability, seismic parameters, population, and socioeconomic considerations. In addition, the selected brownfield or greenfield site would need to be located in southern New York to provide power to the New York City metropolitan area due to the current limitations of the New York power grid.

Depending on transmission line routing, siting a new nuclear plant at an alternate site would result in MODERATE to LARGE land use impacts, and probably would be LARGE for a greenfield site.

8.2.3.1.2 Ecology

At an alternate site, there would be construction impacts and new incremental operational impacts. Even assuming siting at a previously disturbed area, the impacts would alter the ecology. Impacts could include wildlife habitat loss, reduced productivity, habitat fragmentation, and a local reduction in biological diversity. Use of cooling water from a nearby surface water body could have adverse aquatic resource impacts. Construction and maintenance of the transmission line would have ecological impacts. Overall, the ecological impacts at an alternate site would be MODERATE to LARGE.

8.2.3.1.3 Water Use and Quality

Surface Water: For a replacement reactor located at an alternate site, new intake structures would need to be constructed to provide water needs for the facility. Impacts would depend on the volume of water withdrawn for makeup, relative to the amount available from the intake source, and the characteristics of the surface water. Plant discharges would be regulated by the State of New York or other state jurisdiction. Some erosion and sedimentation may occur during construction. The impacts would be SMALL to MODERATE.

Groundwater: Use of groundwater for a nuclear power plant sited at an alternate site is a possibility. Groundwater withdrawal would require a permit from the local permitting authority. The impacts of such a withdrawal rate on an aquifer would be site-specific and dependent on aquifer recharge and other withdrawal rates from the aquifer. Therefore, the overall impacts would be SMALL to LARGE.

8.2.3.1.4 Air Quality

Construction of a new nuclear plant at an alternate site would result in particulate emissions during the construction process. Exhaust emissions would also come from vehicles and motorized equipment used during the construction process. An operating nuclear plant would have minor air emissions associated with diesel generators. These emissions would be regulated [NRC 2003, Section 8.2.3.1]. Emissions for a plant sited in New York would be regulated by the state. Overall, emissions and associated impacts are considered SMALL.

8.2.3.1.5 Waste

The NRC summarized environmental data associated with the uranium fuel cycle in Table S-3 of 10 CFR 51.51. The impacts shown in Table S-3 are representative of the impacts that would be associated with a replacement nuclear power plant built to one of the certified designs, sited at an alternate site. The impacts shown in Table S-3 are for a 1,000 MWe reactor which is approximately equal to one of the IP2 and IP3 nuclear power plants (IP2 and IP3 have a combined capacity of 2,158 gross MWe). The environmental impacts associated with transporting fuel and waste to and from a light-water cooled nuclear power reactor are summarized in Table S-4 of 10 CFR 51.52. The summary of NRC's findings on NEPA issues for license renewal of nuclear power plants in Table B-1 of 10 CFR Part 51 Subpart A, Appendix B, is also relevant, although not directly applicable, for consideration of environmental impacts associated with the operation of a replacement nuclear power plant [NRC 2003]. Overall, waste impacts are considered SMALL.

8.2.3.1.6 Human Health

Human health impacts for an operating nuclear power plant are identified in 10 CFR Part 51, Subpart A, Appendix B, Table B-1. Overall, human health impacts are considered SMALL.

8.2.3.1.7 Socioeconomics

For two 1,000 MWe reactors it is assumed that operating licenses could be obtained by the time IP2 and IP3 operating licenses expire. Construction would overlap with the first 1,000 MWe of new generation available to timely replace IP2 capacity in 2013 and the second 1,000 MWe unit would replace IP3 in 2015. The new reactors would be located on a common site with construction proceeding in parallel. Construction duration for each reactor would be approximately five years with a total duration of seven years (second unit would start two years after start of first unit). The total peak workforce could be approximately 5,000 workers.

It is also assumed that construction would take place at this alternate site while IP2 and IP2 continued operation until license expiration, at which time socioeconomic impacts would change for the existing site.

Construction of a replacement nuclear power plant at an alternate site would relocate some socioeconomic impacts, but would not eliminate them. The communities around IP2 and IP3 would still experience the impact of operational job loss (although potentially tempered by projected economic growth), and the communities around the new site would have to absorb the impacts of a large, temporary work force (approximately 5,000 workers at the peak of construction) and a permanent work force of approximately 1,356 workers. In the GEIS, the NRC noted that socioeconomic impacts at a rural site would be larger than at an urban site because more of the peak construction work force would need to move to the area to work. Alternate sites would need to be analyzed on a case-by-case basis. Socioeconomic impacts at rural sites could be LARGE.

The impacts of operating the nuclear alternative at the alternate site could be smaller or larger than those at the site, depending on how close the alternate site is to an economic center. These impacts are considered SMALL to LARGE, depending on the site.

During the seven-year construction period, up to approximately 5,000 construction workers could be working at the site. The addition of the construction workers could place significant traffic loads on existing highways. Such impacts would be MODERATE to LARGE. Transportation impacts related to commuting of plant operating personnel would be similar to current impacts associated with operation of IP2 and IP3 and are considered SMALL.

Transportation-related impacts associated with commuting workers at an alternate site are site dependent, but could be MODERATE to LARGE. Transportation impacts related to commuting of plant operating personnel would also be site dependent, but can be characterized as SMALL.

8.2.3.1.8 Aesthetics

At an alternate site, depending on placement, there would be an aesthetic impact from the buildings. There would also be a significant aesthetic impact associated with construction of a new transmission line to connect to other lines to enable delivery of electricity. Noise and light from the plant would be detectable off-site. The impact of noise and light would be mitigated if the plant is located in an industrial area adjacent to other power plants, in which case the impact could be SMALL. The impact could be MODERATE if a transmission line needs to be built to the alternate site. The impact could be LARGE if a greenfield site is selected.

8.2.3.1.9 Historic and Archaeological Resources

Before construction at an alternate site, studies would be needed to identify, evaluate, and address mitigation of the potential impacts of new plant construction on cultural resources. The studies would be needed for areas of potential disturbance at the proposed plant site and along associated corridors where new construction would occur (e.g., roads, transmission corridors, rail lines, or other rights-of-way). Historic and archaeological resource impacts can generally be effectively managed and as such are considered SMALL.

Table 8-12
Summary of Environmental Impacts from Nuclear Power Generation Using Closed-Cycle Cooling at Alternate Greenfield Site

Impact Category	Alternative Greenfield Site	
	Impact	**Comments**
Land Use	MODERATE to LARGE	Could require as much as 1,000 to 2,000 acres for the plant and 2,000 acres for uranium mining.
Ecology	MODERATE to LARGE	Impact depends on location and ecology of the site, surface water body used for intake and discharge, and transmission line routes; potential habitat loss and fragmentation; reduced productivity and biological diversity.
Water Use and Quality		
- Surface Water	SMALL to MODERATE	Impact will depend on the volume of water withdrawn and discharged and the characteristics of the surface water body.
- Groundwater	SMALL to LARGE	Groundwater impacts would depend on uses and available supply.
Air Quality	SMALL	Fugitive emissions and emissions from vehicles and equipment during construction. Small amount of emissions from diesel generators and possibly other sources during operation. Emissions are similar to current releases at the IP2 and IP3 site.
Waste	SMALL	Waste impacts for an operating nuclear power plant are set out in 10 CFR Part 51, Appendix B, Table B-1. Debris would be generated and removed during construction.
Human Health	SMALL	Human health impacts for an operating nuclear power plant are set out in 10 CFR Part 51, Appendix B, Table B-1.
Socioeconomics	SMALL to LARGE	Construction impacts depend on location. Impacts at a rural location could be LARGE. Surrounding community would experience loss of tax base and employment with MODERATE impacts. Transportation impacts associated with construction workers could be MODERATE to LARGE. Transportation impacts of commuting workers during operations would be SMALL.

Table 8-12 (Continued)
Summary of Environmental Impacts from Nuclear Power Generation Using Closed-Cycle Cooling at Alternate Greenfield Site

Impact Category	Alternative Greenfield Site	
	Impact	**Comments**
Aesthetics	SMALL to LARGE	Impacts would depend on the characteristics of the alternate site. Impacts would be SMALL if the plant is located adjacent to an industrial area. New transmission lines would add to the impacts and could be MODERATE. If a greenfield site is selected, the impacts could be LARGE.
Historic and Archaeological Resources	SMALL	Potential impacts can be effectively managed.

8.2.3.2 Once-Through Cooling System

The environmental impacts of once-through cooling for an alternative brownfield or greenfield site to replace the 2,158 MWe base-load capacity of IP2 and IP3 are provided as a comparative analysis of impacts equivalent to the existing site. The environmental impacts of constructing a nuclear power plant that uses once-through cooling at an alternate site are similar to the impacts for a nuclear power plant using closed-cycle cooling with cooling towers. However, there are some differences in the environmental impacts between the closed-cycle and once-through cooling systems. In those impact categories related to land-area requirements, such as land use, terrestrial ecology, and cultural resources, the impacts are likely to be smaller if the site uses a once-through cooling system rather than a closed-cycle cooling system. However, the impacts of a plant with a once-through cooling system are likely to be greater than a plant with a closed-cycle cooling system in the areas of water use and aquatic ecology because of the need for greater quantities of cooling water. Table 8-13 summarizes the incremental differences.

Table 8-13
Summary of Environmental Impacts from Nuclear Power Generation Using Once-Through Cooling at Alternate Greenfield Site

	Alternative Greenfield Site
Impact Category	**Impact**
Land Use	Requires as much as 1,000 to 2,000 acres for the plant and 2,000 acres for uranium mining. 75 to 90 acres less land required because cooling towers and associated infrastructure are not needed.
Ecology	Impact would depend on ecology of the site. No impact to terrestrial ecology from cooling tower drift. Increased water withdrawal with possible greater impact to aquatic ecology.
Water Use and Quality	
- Surface Water	No discharge of cooling tower blowdown. Increased water withdrawal and more thermal load on the receiving body of water.
- Groundwater	No change.
Air Quality	No change.
Waste	No change.
Human Health	No change.
Socioeconomics	No change.
Aesthetics	Reduced aesthetic impact because cooling towers would not be used, but impacts could still be large if lengthy transmission line is required.
Historic and Archaeological Resources	Less land impacted.

8.2.4 Purchased Electrical Power

If available, purchased power from other sources could potentially obviate the need to renew the IP2 and IP3 Operating Licenses. "Purchased power" is power purchased and transmitted from electric generation plants that the applicant does not own and that are located elsewhere within the region, nation, Canada, or Mexico.

In theory, purchased power is a feasible alternative to IP2 and IP3 license renewal. There is no assurance, however, that sufficient capacity or energy would be available in the 2013 through 2035 time-frame to replace the 2,158 gross MWe base-load generation. For example, EIA projects that total gross U.S. imports of electricity from Canada and Mexico will gradually increase from 38.4 billion kWh in year 2001 to 47.2 billion kWh in year 2010 and then gradually decrease to 28.94 billion kWh in year 2020 [USDOE 2004]. On balance, it appears unlikely that electricity imported from Canada or Mexico would be able to replace the IP2 and IP3 generating capacity. Failure to obtain a sufficient power source replacement might result in subsequent brownouts. In addition, purchased electrical power may require additional improvements in or addition to the existing transmission systems, which would incur additional environmental impacts.

More importantly, regardless of the technology used to generate purchased power, the generating technology would be one of those described in this ER and in the GEIS (probably coal, natural gas, nuclear, or hydroelectric). The GEIS description of other technology impacts is representative of imported power impacts related to IP2 and IP3 license renewal alternatives [NRC 2001, Section 8.2.3].

8.3 Alternative Generation Not Within the Range of Reasonable Alternatives

Other commonly known generation technologies considered are listed in the following paragraphs. However, these sources have been eliminated as reasonable alternatives to the proposed action because the generation of approximately 2,158 gross MWe of electricity as a base-load supply using these technologies is not technologically feasible. Failure to obtain a sufficient power source replacement might result in subsequent brownouts and power grid instability problems. In addition, the current transmission system constraints in New York State would preclude transmission of power from Northern and Western New York State to elsewhere within the state [National].

8.3.1 Wind

Wind power by itself is not suitable for large base-load capacity. As discussed in Section 8.3.1 of the GEIS, wind has a high degree of intermittency and average annual capacity factors for wind plants are relatively low (less than 30%). Wind power in conjunction with energy storage mechanisms, might serve as a means of providing base-load power. However, current energy storage technologies are too expensive for wind power to serve as a large base-load generator. [NRC 2005, Section 8.2.5.2]

Most of western New York is in wind power Class 2 or 3 regions (average wind speeds at 30-ft elevation of 9.8 to 12.5 mph) with a narrow band of Class 3 or 4 along the shore of Lake Ontario [Elliot]. Wind turbines are economical in wind power Classes 4 through 7 (average wind speeds of 16 to 20 mph) [USDOE 2006b]. Wind turbines typically operate at a 25 to 35 percent capacity factor, compared to 80 to 95 percent for a base-load plant [NPPC]. The largest commercially available wind turbines are in the range of 1 to 3 MWe. Therefore, from a practical perspective, the scale of this technology is too small to directly replace a power generating plant the size of IP2 and IP3 and the functionality is not equivalent.

There are Class 4 to 7 winds in offshore areas along the northeastern coast, including New York [Bailey]. The Department of Interior Mineral Management Service has received a request from Long Island Offshore Wind Park, LLC (LIOWP) for a lease, easement, or right-of-way to construct and operate a wind energy facility in Federal waters off Long Island, 3.6 miles southwest of Jones Beach Island, in Nassau and Suffolk Counties, New York. The purpose of this project is to provide a utility-scale renewable energy facility providing power to the New York electrical grid. Forty wind turbine generators are proposed to generate 140 MW of electricity and deliver it to an existing substation near West Amityville by means of a buried transmission line. MMS is preparing an Environmental Impact Statement for the proposed project. The LIOWP proposal is for construction and operation of a wind energy facility on approximately 8 square miles of the OCS off Long Island [USDOI]. The American Wind Energy Association reports as of July 2006 there are 280 megawatts of wind energy currently online or planned to be online in 2006, with an additional 235 megawatts planned including the LIOWP project, and a wind energy potential of 7,080 MWe in New York State [AWEA 2006b].

As of April 2005, there were approximately 48 MWe of grid-connected wind power facilities in New York State, with approximately 637 MWe of additional capacity in various stages of planning [AWEA 2005]. Statewide, the New York State Energy Research and Development Authority (NYSERDA) estimates that there is a potential for approximately 17,000 MWe of installed capacity, of which approximately 3,200 MWe would be available for the peak summer load [NYSERDA]. Access to many of the best wind power sites would require extensive road building, as well as clearing (for towers and blades) and leveling (for the tower bases and associated facilities) in steep terrain. In open, flat terrain, a utility-scale wind plant will require about 60 acres per megawatt of installed capacity. However, only 5% (3 acres) or less of this area is actually occupied by turbines, access roads, and other equipment—95% remains free for other compatible uses such as farming or ranching [AWEA 2006a]. Based on 60 acres per MWe, approximately 129,480 acres would be required, with 6,474 acres occupied by the turbines, access roads and other equipment, to replace the generation capacity of IP2 and IP3. This far exceeds the land available at the IP2 and IP3 site. Also, many of the best quality wind sites are on ridges and hilltops that could have greater archaeological sensitivity than surrounding areas. For these reasons development of large-scale, land-based wind power facilities are likely not only to be costly, but to have LARGE impacts on aesthetics, archaeological resources, land use, and terrestrial ecology.

The offshore wind speeds in Lake Ontario and along the Atlantic Coast are higher than those onshore and could thus support greater energy production than onshore facilities. However, it is very unlikely that offshore wind power facilities could replace the electrical output. Development of an offshore wind power facility could impact shipping lanes, may disrupt the aquatic ecology, and would be visible for many miles, resulting in considerable aesthetic impacts. These impacts could be MODERATE to LARGE.

Wind power could be included in a combination of alternatives to replace the IP2 and IP3 generation capacity of approximately 2,158 MWe. The environmental impacts of a large-scale wind farm are described in the GEIS [NRC 1996, Section 8.3.1]. The construction of roads, transmission lines, and turbine tower supports would result in short-term impacts, such as increases in erosion and sedimentation, and decreases in air quality from fugitive dust and equipment emissions. Construction in undeveloped areas would have the potential to disturb and impact cultural resources or habitat for sensitive species. During operation, some land near wind turbines could be available for compatible uses such as agriculture. The continuing aesthetic impact would be considerable, and there is a potential for bird collisions with turbine blades. Wind farms generate very little waste and pose no human health risk other than from occupational injuries. Although most impacts associated with a wind farm are SMALL or can be mitigated, some impacts such as the continuing aesthetic impact and impacts to sensitive habitats could be LARGE, depending on the location.

8.3.2 Solar

The average capacity factor for this technology is estimated to be 25–40% annually. This technology has high capital costs and lacks base-load capability unless combined with natural gas backup. It requires very large energy-storage capabilities. Based upon solar energy resources, the most promising region of the country for this technology is the West. [NRC 2001, Section 8.2.4.2]

There are also substantial impacts to natural resources (wildlife habitat, land-use, and aesthetic impacts) from construction of solar-generating facilities. As stated in the GEIS, land requirements are high. Based on the land requirements of 14 acres for every one MWe generated, approximately 30,212 acres would be required to replace the 2,158 gross MWe produced by IP2 and IP3. There is not enough land for a solar energy system at the existing site, and environmental impacts at an alternate site would be LARGE.

The construction impacts would be similar to those associated with a large wind farm as discussed in Section 8.3.1. The operating facility would also have considerable aesthetic impact. Solar installations pose no human health risk other than from occupational injuries. The manufacturing process for constructing a large amount of photovoltaic cells would result in waste generation, but this waste generation has not been quantified. Some impacts, such as impacts to sensitive areas, loss of productive land, and the continuing aesthetic impact, could be LARGE, depending on the location.

8.3.3 Hydropower

New York State has a technical potential for 2,527 MWe of additional installed hydroelectric capacity by 2022, of which only 909 MWe represents peak summer capacity [NRC 2005, Section 8.2.5.4]. If all this capacity were developed, it would be insufficient to replace the approximately 2,158 MWe generating capacity (during the summer period) of IP2 and IP3. Moreover, as stated in Section 8.3.4 of the GEIS, hydropower's percentage of U.S. generating capacity is expected to decline because the facilities have become difficult to site as a result of public concern about flooding, destruction of natural habitat, and alteration of natural river courses. DOE/EIA states that potential sites for hydroelectric dams have already been largely established in the U.S. and environmental concerns are expected to prevent the development of any new sites in the future [USDOE 2002b].

The GEIS estimates that land requirements for hydroelectric power are approximately one million acres per 1,000 MWe. Replacement of the IP2 and IP3 generating capacity would therefore require flooding a substantial amount of land (2,158,000,000 acres). Due to the large land-use and related environmental and ecological resource impacts associated with siting hydroelectric facilities large enough to replace IP2 and IP3, it can be concluded that local hydropower alone is not a feasible alternative to the renewal of the IP2 and IP3 Operating Licenses on its own. Any attempts to site hydroelectric facilities large enough to replace IP2 and IP3 would result in LARGE environmental impacts.

8.3.4 Geothermal

Geothermal has an average capacity factor of 90% and can be used for base-load power where available. However, as illustrated by Figure 8.4 in the GEIS, geothermal plants might be located in the western continental U.S., Alaska, and Hawaii where geothermal reservoirs are prevalent. This technology is not widely used as base-load generation due to the limited geographic availability of the resource and the immature status of the technology [NRC 2001, Section 8.2.4.4]. This technology is not applicable to the region where the replacement of approximately 2,158 gross MWe is needed. While this region possesses low-temperature resources suitable for geothermal heat pumps, it lacks sufficient resources to utilize other geothermal technologies.

8.3.5 Wood Energy

A wood-burning facility can provide base-load power and operate with an average annual capacity factor of around 70 to 80% and with 20 to 25% efficiency. The cost of the fuel required for this type of facility is highly variable and very site-specific. For example, the 53 MW McNeil Station (the largest wood-fired generator in the world when it came on line) was developed with great promise as an in-state generating source, a market for low-grade wood to aid Vermont forest management, insulation from volatile oil prices, and a significant employer generating other associated economic benefits [DPS]. However, since the plant opened in June 1984, McNeil's fuel price of about 3.5 cents/kWh was not competitive with the post-1986 regime of low oil prices [DPS]. Among the factors influencing costs are the environmental considerations and restrictions that are influenced by public perceptions, easy access to fuel sources, and environmental factors. In addition, the technology is expensive and inefficient. Current conditions still do not allow McNeil to operate as a base-load facility as originally envisioned, but instead gives its owners a price ceiling on the market prices they face [DPS].

Review of available literature indicates limited wood burning energy generation continues to be developed in the northeastern States. The New York Biomass Energy Project 7-MW wood-fired generation plant is being built in western New York [USDOE 2006a]. Interest and research is likely to continue in wood-fired electric power generation as the prices for oil and other fossil fuels rise. However, like other fossil fuel plants, greenhouse gases emissions and other emissions pose considerable obstacles to wood-fired electric power generation as a replacement for base-load capacity.

Estimates in the GEIS suggest that the overall level of construction impact per MW of installed capacity should be approximately the same as that for a coal-fired plant, although facilities using wood waste for fuel would be built at smaller scales [NRC 1996]. Like coal-fired plants, wood-waste plants require large areas for fuel storage and processing and involve the same type of combustion equipment. Because of uncertainties associated with obtaining sufficient wood and wood waste to fuel a base load generating facility, ecological impacts of large-scale timber cutting (e.g., soil erosion and loss of wildlife habitat), and relatively low energy conversion efficiency, Entergy has determined that wood waste is not a feasible alternative to renewing the IP2 and IP3 Operating Licenses.

8.3.6 Municipal Solid Waste

The initial capital costs for this technology are much greater than the comparable steam-turbine technology found at wood-waste facilities. This is due to the need for specialized municipal solid waste-handling and waste-separation equipment and stricter environmental emissions controls. The decision to burn municipal waste to generate energy is usually driven by the need for an alternative to landfills rather than by energy considerations. High costs prevent this technology from being economically competitive. Thus, municipal solid waste generation is not a reasonable alternative. [NRC 2001, Section 8.2.4.6]

Currently, there are approximately 89 waste-to-energy plants operating in the United States. These plants generate approximately 2,500 MWe, or an average of approximately 28 MWe per plant [WTE]. Approximately 77 typical waste-to-energy plants would be required to replace the 2,158 gross MWe base load capacity of IP2 and IP3. Therefore, the generation of electricity from municipal solid waste would not be a feasible alternative to renewal of the IP2 and IP3 Operating Licenses.

8.3.7 Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol (ethanol is primarily used as a gasoline additive for automotive fuel), and gasifying energy crops (including wood waste). The GEIS points out that none of these technologies has progressed to the point of being competitive on a large scale or of being reliable enough to replace a base-load plant such as IP2 and IP3. For these reasons, such fuels do not offer a feasible alternative to renewing the IP2 and IP3 Operating Licenses. In addition, these systems have LARGE impacts on land use. [NRC 2001, Section 8.2.4.7]

8.3.8 Oil

Oil is not considered a stand-alone fuel because it is not cost-competitive when natural gas is available. The cost of an oil-fired operation is about eight times as expensive as a nuclear or coal-fired operation. In addition, future increases in oil prices are expected to make oil-fired generation increasingly more expensive than coal-fired generation. For these reasons, oil-fired generation is not a feasible alternative to renewing the IP2 and IP3 Operating Licenses, nor is it likely to be included in a mix with other resources, except as a back-up fuel. [NRC 2001, Section 8.2.4.8]

8.3.9 Fuel Cells

Phosphoric acid fuel cells are the most mature fuel-cell technology, but they are only in the initial stages of commercialization. Two-hundred turnkey plants have been installed in the U.S., Europe, and Japan. Recent estimates suggest that a company would have to produce 100 MWe of fuel-cell stacks annually to achieve a price of $1,000 to $1,500 per kilowatt. However, the current production capacity of all fuel-cell manufacturers only totals about 60 MW per year. The use of fuel cells for base-load capacity requires very large energy-storage devices that are not feasible for storage of sufficient electricity to meet the base-load generating requirements. This is a very expensive source of generation, which prevents it from being competitive. This technology also has a high land use impact, which, like wind technology, results in a LARGE impact to the natural environment. Approximately 75,530 acres of land (35 acres per MWe) would be required to generate 2,158 MWe of electricity. Therefore, fuel cells are not considered a feasible alternative to renewing the IP2 and IP3 Operating Licenses. [NRC 2001, Section 8.2.4.10]

As market acceptance and manufacturing capacity increase, natural-gas-fueled fuel cell plants in the 50- to 100-MW range are projected to become available. At the present time, however, fuel cells are not economically or technologically competitive with other alternatives for base-load electricity generation, and progress in market growth and cost reduction has been slower than alternatives anticipated [CSFCC 2003]. Fuel cells are, consequently, not a feasible alternative to renewal of the IP2 and IP3 Operating Licenses.

8.3.10 Delayed Retirement

Even without retiring any Entergy owned or non-Entergy owned generating units, it is expected that additional capacity will be required in the near future. Thus, even if substantial capacity were scheduled for retirement and could be delayed, some of the delayed retirement would be needed just to meet load growth.

IP2 and IP3 would be required, in part, to offset any actual retirements that occur. Delayed retirement of other Entergy or non-Entergy generation units is unlikely to displace the need for 2,158 MWe of capacity over the twenty years of extended operation and therefore would not be a feasible alternative to renewing the IP2 and IP3 Operating Licenses.

8.3.11 Utility-Sponsored Conservation

The concept of conservation as a resource does not meet the primary NRC criterion "that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable". Conservation is neither single, nor discrete, nor is it a source of generation. [NRC 2001, Section 8.2.4.12]

Since IP2 and IP3 operate in a deregulated environment, utility-sponsored conservation programs are driven by the corporation that purchases and distributes the power. Entergy's conservation programs are confined to those service territories associated with regulated plants (i.e., Arkansas Nuclear One, Grand Gulf Nuclear Station, River Bend Station, Waterford 3). However, Entergy does have conservation programs as discussed below.

Energy Efficiency Programs at Entergy

Energy efficiency is an important environmental strategy since it lowers emissions by reducing energy consumption. Entergy has an ongoing partnership with Energy Star® - a government backed program helping businesses and individuals save money through better energy efficiency - to provide information and tools to customers to help them conserve energy.

In addition, Entergy has taken specific steps to increase energy efficiency across its' regulated service territory. Some examples are as follows:

- Mississippi's first Energy Star certified Habitat for Humanity home was built by Entergy.
- Entergy has worked to weatherize homes across its' regulated service territory through employee volunteer efforts in partnership with churches, schools and other agencies and through educational efforts that included training and informational events as well as the distribution of brochures.
- The New Orleans, Louisiana City Council has introduced a resolution that Entergy supports that will establish net metering for customer homes. Net metering will allow customers to invest in distributed renewable generation using energy for their use and selling excess back to the grid.
- Entergy continues to upgrade and promote the Ensight Web site, which includes energy efficiency calculators and related information.

The environmental impacts of an energy conservation program would be SMALL, but the potential to displace the entire generation at the site solely with conservation is not realistic. Therefore, the conservation option by itself is not considered a reasonable replacement for the IP2 and IP3 Operating License renewal alternative.

8.3.12 Combination of Alternatives

NRC indicated in the GEIS that, while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, such expansive consideration would be too unwieldy given the purposes of the alternatives analysis. Therefore, NRC determined that a reasonable set of alternatives should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically reasonable and commercially viable [NRC 1996, Section 8.1]. Consistent with the NRC determination, Entergy has not evaluated mixes of generating sources.

8.4 Proposed Action vs. No-Action

The proposed action is the renewal of the IP2 and IP3 Operating Licenses. The specific review of the eleven Category 2 environmental impacts, required by 10 CFR 51.53(c)(3)(ii), concluded that there would be no adverse impact to the environment from the continued operation of IP2 and IP3 through the period of extended operation. This section investigates the consequences of the early retirement of IP2 and IP3.

The no-action alternative to the proposed action is the decision not to renew the IP2 and IP3 Operating Licenses for the site. The environmental impacts of the no-action alternative would be the impacts associated with the construction and operation of alternative replacement electric power. In effect, the net environmental impacts would be transferred from the continued operation of the site to the environmental impacts associated with the construction and operation of a new generating facility. This new generating facility would almost certainly be constructed at a greenfield location due to the air impacts associated with constructing one of the viable technologies on the IP2 and IP3 site due to air quality non-attainment status and the lack of available land onsite. Therefore, the no-action alternative would have no net environmental benefits.

In the event that the IP2 and IP3 Operating Licenses are not renewed for an additional 20 years, then adverse impacts can be expected due to loss of tax revenues (see Table 2-9).

8.4.1 Energy Replacement Feasibility

According to a recently published report by the National Academies' National Research Council, concerning the early closure of IP2 and IP3, the committee concluded that it is technically feasible to replace the energy generated by New York's Indian Point nuclear power plant if it closes in coming years. However, political, regulatory, and financial hurdles would make doing so difficult. Given the time it takes to obtain a suitable site, navigate the regulatory issues and obtain permits, and then construct a power plant, new generating capacity may not be available until existing reserves are dangerously low. Forestalling a crisis may require extraordinary efforts on the part of policy makers and regulators. [National, Summary and Findings]

The National Academies report indicates significant challenges exist just to supply projected increases in capacity demand, even if IP2 and IP3 Operating Licenses are renewed. Replacement for Indian Point would most likely consist of a portfolio of approaches, including investments in energy efficiency, transmission, and new generation. The National Academies committee that studied energy replacement concluded in that existing generation and transmission capacity could make little contribution to replacing Indian Point [National, Chapter 3]. According to the report, shutdown would require new energy sources and reduced demand for electricity that add up to about 5000 megawatts—2000 to replace the lost production of Indian Point and the balance to meet projected increases in demand and to compensate for other possible power plant closings. [National, Chapter 5]

The committee states that advanced natural-gas-fired combined-cycle plants are the generation option capable of making the biggest contribution at the lowest cost by 2015. But, although it seems that sufficient gas might be available to replace Indian Point generating capacity, in fact all of the excess may well be committed some time before the plants shut down. The long-term gas supply picture is not encouraging unless resources such as liquefied natural gas (LNG) imports are increased, and LNG imports are uncertain with respect to timing, volumes, and locations for terminal facilities. All new generating capacity currently being built in New York State, over 2000 MW, is gas fired. As much as 1600 MW could be needed by 2010 to meet reliability requirements even without closing Indian Point. [National, Chapter 3]

With respect to socioeconomic and ecological costs, the report concluded that electricity from new plants would almost certain be more costly than that from Indian Point. In addition, to the extent that the reactors are replaced with plants that burn fossil fuel, emissions of carbon dioxide will be higher, complicating efforts by New York to reduce greenhouse gases under the Regional Greenhouse Gas Initiative. [National]

8.4.2 Replacement and Siting Suitability Problems

One generation replacement option would be for Entergy or another developer to build and operate a gas-fired simple cycle or combined cycle power plant at the IP2 and IP3 site. The feasibility of peaking capacity was discussed in Entergy's Preliminary Scoping Statement filed with the New York Public Service Commission (NYPSC) on March 18, 2002, to construct a 330 MWe simple cycle plant. The plant was originally to be comprised of eight 45-MW aero-derivative gas turbines, later amended to two 165-MW GE 7FA industrial frame gas turbines. The plant was to utilize a five-acre parcel on the site outside of the "protected area" that houses the reactors. The plant would have tied into the Buchanan electric substation, less than 2000 feet to the northeast [Levitan].

While the existing Algonquin main pipeline line may be adequate for a 330 MWe simple cycle plant that would operate in peaking mode during the summer season, a report prepared by Levitan and Associates, Inc. concluded that substantial and expensive site pipeline upgrades would probably be required to supply natural gas to a combined cycle plant throughout the winter heating season, November–March, and for the additional base load capacity (i.e., greater than 330 MW) throughout the year.

8.4.3 Impacts

The following sections describe ecological and socioeconomic impacts associated with retiring IP2 and IP3.

8.4.3.1 Fish

In December 1999, IP2 and IP3 filed a DEIS with the NYSDEC which formed the basis for an FEIS that was issued in June 2003. The NYSDEC issued a draft SPDES permit (#NY-0004472) under which Entergy would be required to implement a closed-cycle cooling system that would reduce the water intake from the Hudson River [Levitan]. The impacts of the closed-cycle cooling alternative were presented in Section 8.1. The impacts of entrainment and impingement were discussed in Sections 4.2 and 4.3, respectively. Based on extensive fisheries studies completed for more than 30 years on the Hudson River estuary, the impacts of continued operation of IP2 and IP3 through the license renewal term is expected to be SMALL. Consequently, the impact on the Hudson River fisheries from a decision not to renew the operating license for IP2 and IP3 would also be expected to be SMALL.

8.4.3.2 Air Emissions

If IP2 and IP3 are retired, replacement generation (and generation to meet addition demand) would need to be constructed and brought online to make up for the energy deficit that would be produced by its retirement.

Levitan and Associates, Inc. roughly estimated air emissions in New York during two specific years, 2009 and 2016, to measure the impact of retiring IP2 and IP3. The retirement of IP2 and IP3 was projected to increase New York power plants emissions by approximately 4.0% - 4.3% in NO_x and 2.6% - 2.7% in SO_2 emissions (Table 8-14). These projections should be viewed as preliminary indicative estimates only [Levitan].

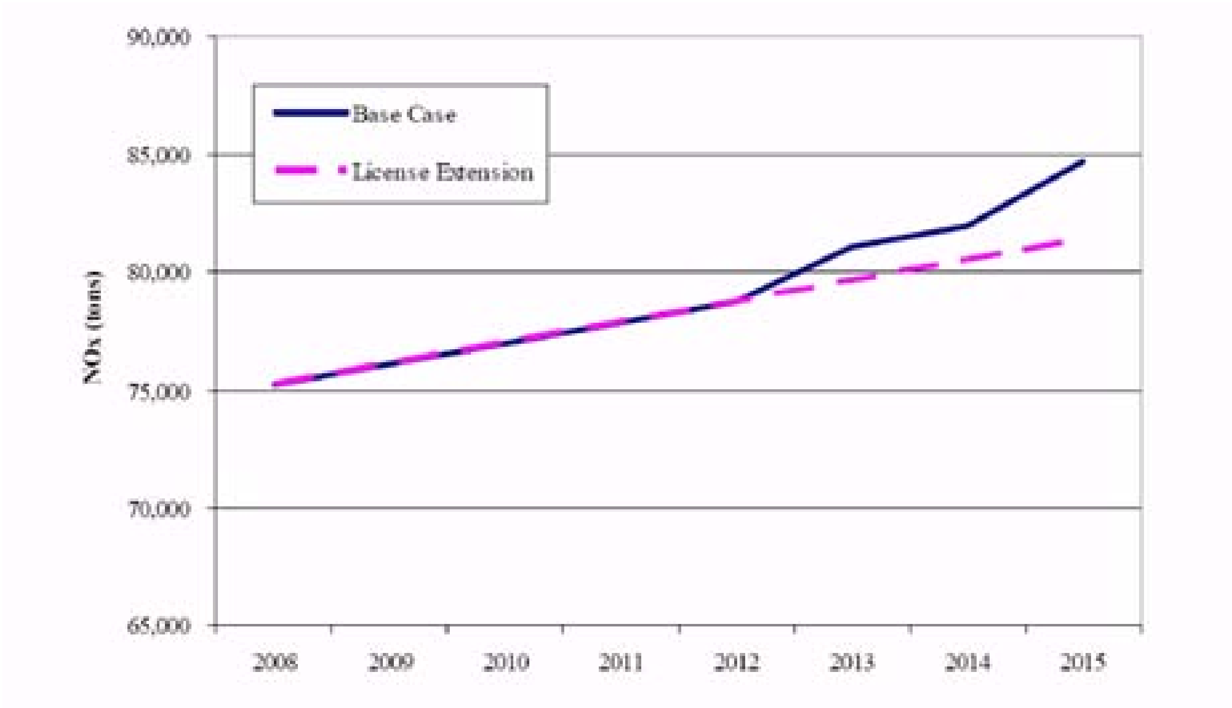
Table 8-14
Indicative New York State Air Emissions Impacts

Retirement Dates	Emission	Emissions with IP	Emissions without IP	Net Power Plant Increase	Net State – Wide Increase
2009 vs. 2013/15	NO_x	76.1 ktons	79.4 ktons	+ 3.3 ktons	
				+ 4.3%	+ 0.5%
	SO_2	250.8 ktons	257.6 ktons	+6.8 ktons	
				+ 2.7%	+ 1.4%
2016 vs License Renewal	NO_x	82.3 ktons	85.6 ktons	+ 3.3 ktons	
				+ 4.0%	+ 0.5%
	SO_2	268.5 ktons	275.6 ktons	+ 7.0 ktons	
				+ 2.6%	+ 1.4%

Source: Levitan

Levitan and Associates, Inc. made adjustments to the projected emission values to account for the staggered termination of IP2 and IP3. The estimates for emissions for the most likely replacement electric power generation are presented in Tables 8-4 and 8-9, for coal or natural gas, respectively. The Levitan report, as described above, estimates additional NO_x emissions at 3.3 kilotons or 3,637 tons per year if IP2 and IP3 were not to be granted license renewal.

Additional SO_x emissions were estimated at 7 kilotons, or 7,716 tons. As noted in Table 8-4, the annual emission for only replacing the base-load generation capacity of IP2 and IP3 would be 6,284 tons per year of SO_x and 1,476 tons per year of NO_x. Figure 8-1 shows the projected increase in NO_x emissions if IP2 is removed from service in 2013, and IP3 in 2015 [Levitan]. The pattern for SO_2 emissions would be similar.



[Levitan]

Figure 8-1
NO_x Emissions Under Base Case and License Renewal Scenarios

8.4.3.2.1 Carbon Dioxide Emissions and Global Warming

Carbon Dioxide (CO_2) emissions are suspected to be a major contributor to anthropogenic greenhouse gas emissions and recent climate global warming. These emissions result from the efficiency of the technologies utilized to produce and deliver the energy and carbon content of the fuel being utilized. Based on the U.S. DOE report, "Voluntary Reporting of Greenhouse Gas Emission, Fuel and Energy Emission Coefficients," a comparison of the CO_2 content of various fuels is cited below.

Fuel	**Pounds CO_2 per Million Btu**
Subbituminous Coal	212.7
Bituminous Coal	205.3
#6 Fuel Oil	173.9
Natural Gas	117.1
Nuclear	0
Renewable Sources	0

Estimates of CO_2 emissions are provided below that would result if other fuel technologies were utilized to supply the approximately 2,158 gross MWe of electricity that is currently being generated by IP2 and IP3. The technologies, fuels, and production efficiencies shown are based upon "greenfield plants" that have recently been permitted as having "Best Available Control Technology (BACT)" under the New Source Review (NSR) Permit program. In addition, estimates are also based on a 92% capacity factor, which is what the Entergy's northeast nuclear fleet achieved overall during 2004.

Technology	**Fuel**	**Heat Rate (Btu/KWh)**	**Electricity (MWH/yr)**	**CO_2 Emissions (MT/yr)**
Pulverized Coal	Bituminous Coal	9,928	17,391,353	16,079,300
Pulverized Coal	Sub-bituminous Coal	9,700	17,391,353	16,276,175
Combined Cycle Gas Turbine	Natural Gas	6,814	17,391,353	6,294,705

The environmental impacts of the continued operation of IP2 and IP3, providing approximately 2,158 gross MWe of base-load power generation through 2035, are significantly smaller than impacts associated with the best case among reasonable alternatives. The continued operation of IP2 and IP3 would create significantly less environmental impact than the construction and operation of new base-load generation capacity.

8.4.3.3 Socioeconomic Impact

A significant negative impact of retiring IP2 and IP3 before their licenses expire in 2013 and 2015, respectively, would be a rise in market energy prices, even with the timely addition of replacement generation.

If IP2 and IP3 were retired, the short-term impacts would include loss of Payment-in-Lieu-of-Taxes (PILOT) for Westchester County and the other counties surrounding the site, due to loss of revenue to vendors and contractors, loss of employment, and secondary impacts. If IP2 and IP3 are not relicensed, higher energy prices, even with sufficient replacement capacity, would result for those in the southeastern New York area, where IP2 and IP3 provide 23 percent of current generation supply [National, Summary and Findings].

If the IP2 and IP3 licenses are extended, the local community would benefit from continued PILOT, employee compensation, and local spending, as well as from lower electric energy prices. Levitan and Associates, Inc. included a Base Case forecast of market energy prices assuming that IP2's and IP3's Operating Licenses would not be renewed, as well as forecasts for the alternative scenarios in which IP2 and IP3 are retired immediately, retired in 2008, and the licenses are renewed for twenty years.

Figures 8-2 and 8-3 show the year-to-year trend of benefits and costs for four scenarios at the County and State level. The graphs show the total benefits and costs of the specific scenarios, not the relative benefits and costs against the base case assumption of 2013 and 2015 retirement and no on-site replacement generation [Levitan].

Figure 8-2
Total Economic Impact to the County by Scenario *($ millions)*

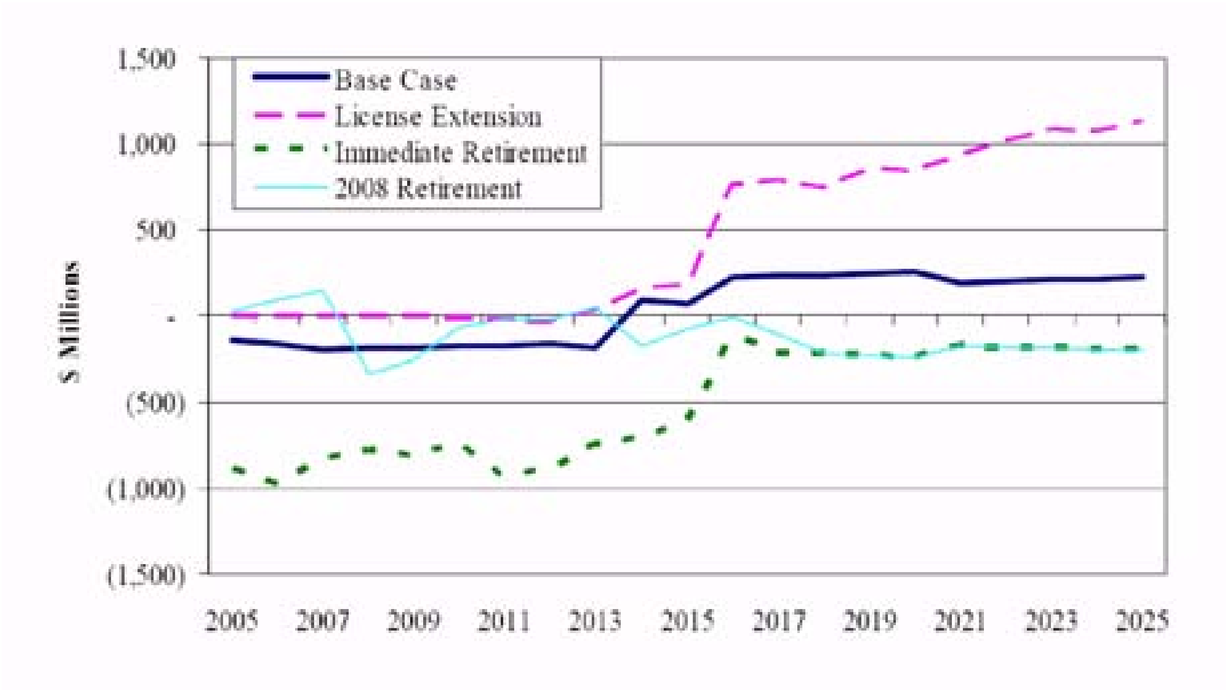


Figure 8-3
Total Economic Impact to the State by Scenario *($ millions)*

Table 8-15 describes changes to regional spot market energy prices that Levitan and Associates, Inc. forecasted using MarketSym if IP2 and IP3 were retired in 2005, in 2008, or have their licenses extended. Values represent percentage changes against the Base Case of IP2 and IP3 retirement in 2013 and 2015 [Levitan].

Table 8-15
Average Change in Market Energy Prices

Region	NYISO Zone(s)	2005 Retirement	2008 Retirement	License Renewal
Westchester County	GHI	11.3%	8.4%	- 7.5%
New York City	J	4.5%	3.8%	- 2.9%
Albany	F	7.6%	6.5%	- 3.7%
Western NY	A-E	0.1%	0.6%	-0.2%
Long Island	K	4.3%	3.9%	-3.1%

Source: Levitan

If IP2 and IP3 are retired in 2008 and developers have sufficient notice to install replacement generation, market energy prices in Westchester County are projected to increase by 8.4% on average through 2015. If the IP2 and IP3 Operating Licenses are extended so that 2,158 MW of replacement generation is not required, market energy prices in Westchester County are projected to decrease 7.5% on average from 2013 through the term of the license renewal.

The *Joint DOE-Electric Power Research Institute Strategic Research and Development Plan to Optimize U.S. Nuclear Power Plants* stated "… nuclear energy was one of the prominent energy technologies that could contribute to alleviate global climate change and also help in other energy challenges including reducing dependence on imported oil, diversifying the U.S. domestic electricity supply system, expanding U.S. exports of energy technologies, and reducing air and water pollution." The Department of Energy agreed with this perspective and stated "…it is important to maintain the operation of the current fleet of nuclear power plants throughout their safe and economic lifetimes" [USDOE 1998]. The renewal of the IP2 and IP3 Operating Licenses is consistent with these goals.

8.5 <u>Summary</u>

The proposed action is the renewal of the IP2 and IP3 Operating Licenses. The proposed action would provide the continued availability of approximately 2,158 gross MWe of base-load power generation through 2033 - 2035.

The environmental impacts of the proposed action (the continued operation of IP2 and IP3) have been compared to the environmental impacts from the no-action alternative (the construction and operation of other reasonable sources of electric generation). The environmental impacts of the continued operation of IP2 and IP3, providing approximately 2,158 gross MWe of base-load power generation through 2033 - 2035, are superior to impacts associated with the best case among reasonable alternatives. The continued operation of IP2 and IP3 would create significantly less environmental impact than the construction and operation of new base-load generation capacity, including construction and operation of closed-cycle cooling towers at the existing site.

Finally, the continued operation of IP2 and IP3 will have a significant positive economic impact on the communities surrounding the station. Positive impacts include, but are not limited to, reduced local unemployment, significant contributions to local property tax revenue, economic support of southeastern New York, and lower energy costs.

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9.0 STATUS OF COMPLIANCE

9.1 Requirement [10 CFR 51.45(d)]

"The environmental report shall list all Federal permits, licenses, approvals, and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with these requirements. The environmental report shall also include a discussion of the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection. The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements."

9.2 Environmental Permits

Table 9-1 provides a list of the environmental permits held by IP2 and IP3 and the compliance status of these permits. These permits will be in place as appropriate throughout the period of extended operation given their respective renewal schedules. In addition, Table 9-2 lists environmental consultations related to the renewal of the IP2 and IP3 Operating Licenses.

9.3 Coastal Zone Management Program Compliance

The Federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on applicants for a federal license to conduct an activity that could affect a state's coastal zone. The Act requires the applicant to certify to the licensing agency that the proposed activity would be consistent with the state's federally approved coastal zone management program (16 USC 1456(c)(3)(A)). The National Oceanic and Atmospheric Administration has promulgated implementing regulations that indicate that the requirement is applicable to renewal of federal licenses for activities not previously reviewed by the state (15 CFR 930.51(b)(1)). The regulation requires that the license applicant provide its certification to the federal licensing agency and a copy to the applicable state agency (15 CFR 930.57(a)).

The NRC's office of Nuclear Reactor Regulation has issued guidance to its staff regarding compliance with the Act. This guidance acknowledges that New York has an approved coastal zone management program [NRC 2004]. The IP2 and IP3 site, located in Westchester County, is within the New York coastal zone.

The NRC is expected to issue the draft SEIS for IP2 and IP3 in early 2008. At that time, Entergy will submit an application for a Coastal Zone Consistency Certification (see Attachment D) to the NYSDOS which will include a copy of the License Renewal Application for IP2 and IP3 and a copy of the draft SEIS in fulfillment of the regulatory requirement for submitting a copy of the coastal zone consistency certification to the appropriate state agency.

9.4 Water Quality (401) Certification

Federal CWA, Section 401, requires an applicant for a federal license to conduct an activity that might result in a discharge into navigable waters to provide the licensing agency a certification from the state that the discharge will comply with applicable CWA requirements (33 USC 1341). The NYSDEC issued a Section 401 State Water Quality Certification for IP1 and IP2 on December 7, 1970 and IP3 on May 2, 1975 (provided in Attachment C). The NRC has indicated in its GEIS that issuance of an NPDES permit implies continued certification by the state [NRC 1996, Section 4.2.1.1]. The EPA granted New York State the authority to issue NPDES permits under its own program, the New York State SPDES program. Attachment C contains the SPDES permit that authorizes plant discharges at IP2 and IP3. Consistent with the GEIS, Entergy is providing a copy of its SPDES permit as evidence of a state water quality (401) certification.

NYSDEC has taken the position that it will require submission of an application for a new state water quality (401) certification in conjunction with the license renewal application, rather than relying on the SPDES permit as evidence of continued certification [Merchant]. To initiate the approval process, Entergy will file the Joint Application for Permit with the NYSDEC for the water quality certification at a date determined by the NYSDEC.

As identified in Table 9-1, the SPDES permit for discharges at the site expired on October 1, 1992. However in accordance with the New York State Administrative Procedures Act, Entergy filed a timely SPDES permit renewal application 180 days prior to the current permit's expiration date on April 3, 1992. Therefore, the SPDES permit has been administratively continued.

9.5 Environmental Permits—Discussion of Compliance

General

IP2 and IP3 have established control measures in place to ensure compliance with its environmental permits, including monitoring, reporting, and operating within specified limits. Chemistry personnel are primarily responsible for monitoring and ensuring that the site complies with its environmental permits and applicable regulations. Sampling results are submitted to appropriate agencies.

Water Quality

As identified in Table 9-1, the SPDES permit (NY-0004472) for discharges at the site expired on October 1, 1992. However, in accordance with the New York State Administrative Procedures Act, Entergy filed a timely SPDES permit renewal application 180 days prior to the current permit's expiration date on April 3, 1992. Therefore, the SPDES permit has been administratively continued. Compliance with the SPDES Permits over previous years has been excellent. For example, there has never even been an exceedance relative to thermal discharge limits as identified in the Station's SPDES permit. In addition, compliance with the other SPDES permits listed in Table 9-1 has been favorable over the last three years (2004-2006), with any deviations or potential violations properly addressed and reported in accordance with either the conditions outlined in the permit or as recommended by the regulatory agency.

Potable water for the site is supplied by the Village of Buchanan. Sanitary wastewaters from all plant locations are transferred to the Village of Buchanan publicly owned treatment works (POTW) system where it is managed appropriately, except for a few isolated areas which have their own septic tanks which are pumped out by a septic company, as needed, and taken to an offsite facility for appropriate management. Although sanitary wastewaters at the site are nonradioactive, a radiation monitoring system is provided to continuously monitor the effluent from the protected area.

The EPA's Oil Pollution Prevention Rule became effective January 10, 1974 and was published under the authority of Section 311(j)(1)(C) of the Federal Water Pollution Control Act (Clean Water Act). The regulation has been published in 40 CFR 112 and facilities subject to the rule must prepare and implement a Spill Prevention, Control, and Countermeasure (SPCC) Plan to prevent any discharge of oil into or upon navigable waters of the United States or adjoining shorelines. IP2 and IP3 are subject to this rule and have written SPCC Plans that identify and describe the procedures, materials, equipment and facilities that are utilized at the stations to minimize the frequency and severity of oil spills in order to meet the requirements of this rule.

Due to a variety of historical operational events, there have been a number of instances where petroleum contamination has been detected in the groundwater. As a result of these events, IP2 and IP3 implemented corrective action and monitoring programs in coordination with the NYSDEC. Based on the results of these programs, NYSDEC has determined that no additional actions are necessary at this time.

Air Quality

The station has permits to operate boilers, emergency diesel generators, gas turbines, and vapor extractors as shown in Table 9-1. Operation of these air emission sources is maintained within the operating limits established in the station's Air Permits, issued by NYSDEC and Westchester County Department of Health. For purposes of the Clean Air Act, IP2 and IP3 are considered minor air emission sources and are reflected as such in the air permits.

Solid Waste

As a generator of both low-level and high-level radioactive wastes, IP2 and IP3 are subject to and comply with provisions and requirements of the Low-Level Radioactive Waste Policy Amendment Act of 1985 and the Nuclear Waste Policy Act of 1982, as subsequently amended, and the Nuclear Waste Policy Act of 1982.

IP2 and IP3 occasionally generate both hazardous and mixed wastes. Therefore, they are subject to and comply with the provisions of the Resource Conservation and Recovery Act and amendments, as well as the NYSDEC regulatory requirements as set forth in 6 NYCRR Parts 371-376.

Although the EPA final Hazardous and Solid Waste Act Permits for IP2 and IP3 for accumulation and temporary onsite storage of mixed waste for greater than 90 days have expired, these permits have been administratively extended by letter. IP2 and IP3 are currently operating under the conditional exemption for low-level mixed waste storage and disposal per 6 NYCRR Part 374-1.9. IP3's NYSDEC Part 373 Permit for the storage of mixed waste (NYD095503746) was allowed to expire in September 2006.and Entergy has requested that NYSDEC terminate the IP2 Hazardous Waste Part 373 Permit NYD991304411 upon its scheduled expiration date of February 27, 2007. However, NYSDEC has indicated that it is considering converting the Hazardous Waste Part 373 Permit into a Corrective Action Permit relative to the current groundwater investigation program. Since Entergy submitted a permit renewal application in the form of a request for a Corrective Action Permit at NYSDEC's direction, the Hazardous Waste Part 373 Permit has been administratively continued and the Corrective Action Permit Application is currently under review. Although some radioactive solvent wastes are being accumulated in a satellite area, no mixed wastes are currently being stored on-site at IP3. At IP2, various crates, high-integrity containers, and 55-gallon drums containing PCB mixed wastes are being stored in Unit 1 until such time as the radioactive waste processing vendor can obtain the necessary permits and approvals to accept these wastes.

Emergency Planning and Community Right-to-Know

IP2 and IP3 comply with the Emergency Planning and Community Right-to-Know Act that requires the submittal of an emergency and hazardous chemical inventory report (Tier II) to the Local Emergency Planning Commission, the State Emergency Response Commission, and the local fire department. These reports are submitted to these agencies annually. However, IP2 and IP3 are not subject to the Risk Management Plan (RMP) requirements described in 40 CFR 68 since no threshold quantities of a regulated substance are exceeded.

Hazardous Materials

There are several stationary bulk petroleum and chemical storage tanks located on-site. The IP2 and IP3 stationary bulk chemical storage tanks are registered with the NYSDEC via Hazardous Substance Bulk Storage Registration Certificates, and management of bulk chemicals is in accordance with the Chemical Spill Plans required under NYSDEC's Chemical Bulk Storage Regulations. Bulk petroleum storage tanks for IP2 are registered with NYSDEC via the Major Oil Storage Facility License and for IP3 are registered with the Westchester County Department of Health via the Petroleum Bulk Storage Registration Certificate (refer to Table 9-1). In addition, the IP2 and IP3 Spill Prevention, Control and Countermeasures Plans also include all bulk oil storage tanks, including oil-filled operational and electrical equipment located on-site.

Herbicide and pesticide usage occurs periodically at the site. Herbicides utilized for weed control and pesticides utilized for control of insects such as wasps, is hand-applied by vendors via sprayers. Sodium hypochlorite which is injected by station personnel into plant systems for chlorination purposes is also listed as a pesticide under New York State law. In accordance with NYSDEC 6 NYCRR Part 325, sodium hypochlorite usage at the site is controlled in accordance with IP2 Pesticide Application Business Registration 12696 and IP3 Pesticide Application Business Registration 13163. Vendor application of other herbicides and pesticides is also managed in accordance with 6 NYCRR Part 325.

The Toxic Substances Control Act (TSCA) of 1976 regulates polychlorinated biphenyls (PCBs) and asbestos, both of which are present at IP2 and IP3. Entergy is in compliance with the PCB and asbestos regulations applicable to the IP2 and IP3 facilities.

IP2 and IP3 are also subject to the hazardous substance release and reporting provisions of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980, as subsequently amended. Any release of reportable quantities of listed hazardous substances to the environment requires a report to the National Response Center and subsequent written follow-up. IP2 and IP3 are also subject to hazardous material release reporting requirements of New York State in accordance with the NYSDEC's Petroleum Bulk Storage and Chemical Bulk Storage program requirements in accordance with New York State's Environmental Conservation Law Articles 17 and 40 and 6 NYCRR Parts 595 and 613.

Herbicide and pesticide usage occurs periodically at the site. Herbicides utilized for weed control and pesticides utilized for control of insects such as wasps, is hand-applied by vendors via sprayers. Sodium hypochlorite which is injected by station personnel into plant systems for chlorination purposes is also listed as a pesticide under New York State law. In accordance with NYSDEC 6 NYCRR Part 325, sodium hypochlorite usage at the site is controlled in accordance with IP2 Pesticide Application Business Registration 12696 and IP3 Pesticide Application Business Registration 13163. Vendor application of other herbicides and pesticides is also managed in accordance with 6 NYCRR Part 325.

The Toxic Substances Control Act (TSCA) of 1976 regulates polychlorinated biphenyls (PCBs) and asbestos, both of which are present at IP2 and IP3. In New York State, PCBs are also regulated by NYSDEC as a hazardous waste and asbestos management is regulated by the NYS Department of Labor. Entergy is in compliance with the PCB and asbestos regulations applicable to the IP2 and IP3 facilities.

IP2 and IP3 are also subject to the hazardous substance release and reporting provisions of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980, as subsequently amended. Any release of reportable quantities of listed hazardous substances to the environment requires a report to the National Response Center and subsequent written follow-up. IP2 and IP3 are also subject to hazardous material release reporting requirements of New York State in accordance with the NYSDEC's Petroleum Bulk Storage and Chemical Bulk Storage program requirements in accordance with New York State's Environmental Conservation Law Articles 17 and 40 and 6 NYCRR Parts 595 and 613.

<u>Biological</u>

Potential impacts on federal- and state-listed species were considered in Entergy's review and analysis and impacts determined to be SMALL. However, per Section 7 of the Endangered Species Act, a more structured consultation process with the USFWS and NMFS will be initiated by the NRC. In addition, the consultation requirements of Section 305(b) of the Magnuson-Stevens Fishery Conservation and Management Act, as amended by the National Marine Fisheries Service Sustainable Fisheries Act of 1996, provide that Federal agencies must consult with the Secretary of Commerce on all actions or proposed actions authorized, funded, or undertaken by the agency that may adversely affect essential fish habitat. Therefore, the NRC staff will also initiate an essential fish habitat consultation with the NMFS.

Zoning Related Codes (Village of Buchanan, New York)

The 239 acres occupied by the Indian Point site lie entirely within the Village of Buchanan corporate limits. As such, the zoning codes such as those related to construction, wetlands and noise that are applicable to IP2 and IP3 are defined in the Village of Buchanan Village Zoning Code. The Indian Point site is currently in compliance with the applicable Village of Buchanan zoning codes.

Wetlands

As discussed in Section 2.4 of this ER, there are no state or federal jurisdictional wetlands on the site. However, the Village of Buchanan has a wetland's law (Chapter 203) that requires a permit prior to conducting certain activities upon any wetland, water body or watercourse or within a hundred (100) feet of the boundary of any wetland, water body or watercourse. The site is subject to this law and complies with the requirements when site activities as defined in the law occur.

Noise

As discussed in Section 2.1 of this ER, the Village of Buchanan has a sound ordinance (Chapter 211 - 223 of the Village Zoning Code) that limits allowable sound levels from a facility by octave band levels and is applicable at the property line of the sound generating facility. Although noise is detectable off-site, IP2 and IP3 are in compliance with this sound ordinance.

Air Navigation

Coordination with the Federal Aviation Administration (FAA) is required when it becomes necessary to ensure that the highest structures associated with the project do not impair the safety of aviation. Submission of a letter of notification (with accompanying maps and project description) to the FAA would result in a written response from the FAA certifying that no hazard exists or recommending project changes and/or the installation of warning devices such as lighting.

The site elevation is dominated by the 334-foot high IP1 superheater stack and 400-foot high primary meteorological tower, which are equipped with FAA lighting systems. There are no plans at this time to build any new structures during the license renewal periods; therefore, no new notifications to the FAA are required.

Health and Safety

The federal Occupational Safety and Health Administration (OSHA) governs the occupational safety and health of the construction workers and the operational staffs. These requirements are incorporated into the sites occupational health and safety practices. Entergy complies with

OSHA requirements and as discussed in Section 4.13.5 of this ER, Entergy complies with requirements of the NESC.

Environmental Reviews

Entergy has fleet procedural controls in place to ensure that environmentally sensitive areas, if present, are adequately protected during site operations and project planning [Entergy]. These controls, which encompass nonradiological program areas such as air, stormwater, SPDES, spill prevention, and waste, consist of the following:

- required review and documentation process prior to engaging in additional construction or operational activities that may result in an environmental impact or change conditions set forth in an existing permit, and
- required review for protection of either existing or potentially existing cultural resources.

These measures ensure that appropriate local, state, and/or federal permits are obtained or modified as necessary, that cultural resources and threatened and endangered species are protected if present, and that other regulatory issues are adequately addressed if necessary.

Table 9-1
IP2 and IP3 Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NRC	Atomic Energy Act, 10 CFR 50	IP1 License to Possess	DPR-5	September 28, 2013	Maintain IP1 in SAFSTOR condition.
NRC	Atomic Energy Act, 10 CFR 50	IP2 License to Operate	DPR-26	September 28, 2013	Operation of IP2.
NRC	Atomic Energy Act, 10 CFR 50	IP3 License to Operate	DPR-64	December 12, 2015	Operation of IP3.
DOT	49 CFR 107, Subpart G	IP2 DOT Hazardous Materials Certificate of Registration	0627065520610Q	June 30, 2009	Radioactive and hazardous materials shipments.
DOT	49 CFR 107, Subpart G	IP3 DOT Hazardous Materials Certificate of Registration	0627065520690Q	June 30, 2009	Radioactive and hazardous materials shipments.
NYSDEC	6 NYCRR Part 325	IP2 Pesticide Application Business Registration	12696	April 30, 2009	Pesticide application.
NYSDEC	6 NYCRR Part 325	IP3 Pesticide Application Business Registration	13163	April 30, 2009	Pesticide application.
NYSDEC	6 NYCRR Parts 704 and 750	IP1, 2, and 3 SPDES Permit	NY 000 4472	October 1, 1992[1]	Discharge of wastewaters and stormwaters to waters of the State.
NYSDEC	6 NYCRR Part 704	Simulator Transformer Vault SPDES Permit	NY 025 0414	March 1, 2008	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 704	Tank Farm SPDES Permit	NY 025 1135	February 1, 2010	Discharge of wastewaters to waters of the State.

Table 9-1 (Continued)
IP2 and IP3 Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NYSDEC	6 NYCRR Part 704	Buchanan Gas Turbine SPDES Permit	NY 022 4826	March 1, 2008	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 750	ISFSI Stormwater SPDES General Permit for Construction Activities	NYR 10H166	Not Applicable	Stormwater Discharge during Construction of the Dry Fuel Cask Storage.
NYSDEC	6 NYCRR Parts 200 and 201	IP2 Air Permit	3-5522-00011/00026	Not Applicable	Operation of air emission sources (boilers, turbines, and generators).
NYSDEC	6 NYCRR Parts 200 and 201	IP3 Air Permit	3/5522-00105/00009	Not Applicable	Operation of air emission sources (boilers, turbines, and generators).
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Gas Turbine 1 Air Permit	#00021	December 31, 2006[2]	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Gas Turbine 2 Air Permit	#00022	December 31, 2006[2]	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Gas Turbine 3 Air Permit	#00023	December 31, 2006[2]	Operation of an air contamination source

Table 9-1 (Continued)
IP2 and IP3 Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Boiler Permit	52-4493	Not Applicable	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Vapor Extractor Air Permit	52-5682	December 31, 2006[2]	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP3 Boiler Permit	52-6497	Not Applicable	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP3 Training Center Boiler Permit	52-6498	Not Applicable	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP3 Vapor Extractor Air Permit	--[3]	--[3]	Operation of an air contamination source
NYSDEC	6 NYCRR Part 596	IP2 Hazardous Substance Bulk Storage Registration Certificate	3-000107	September 4, 2007	Onsite bulk storage of hazardous substances.
NYSDEC	6 NYCRR Part 596	IP3 Hazardous Substance Bulk Storage Registration Certificate	3-000071	August 16, 2008	Onsite bulk storage of hazardous substances.

Table 9-1 (Continued)
IP2 and IP3 Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NYSDEC	6 NYCRR Part 610	IP2 Major Oil Storage Facility	3-2140	--[1]	Onsite bulk storage of > 400K gallons of petroleum products.
WCDOH	Westchester County Sanitary Code, Article XXV	IP3 Petroleum Bulk Storage Registration Certificate	3-166367	September 7, 2010	Onsite bulk storage of petroleum products.
NYSDEC	6 NYCRR Part 372	IP2 Hazardous Waste Generator Identification	NYD000765073	Not Applicable	Hazardous waste generation
NYSDEC	6 NYCRR Part 372	IP3 Hazardous Waste Generator Identification	NYD000765073	Not Applicable	Hazardous waste generation
NYSDEC	6 NYCRR Part 373	IP2 Hazardous Waste Part 373 Permit	NYD991304411	February 28, 2007[1]	Accumulation and temporary onsite storage of mixed waste for > 90 days.
EPA	40 CFR 264	IP2 Hazardous Solid Waste Amendment Permit	NYD991304411	October 14, 2002[4]	Accumulation and temporary onsite storage of mixed waste for > 90 days.
EPA	40 CFR 264	IP3 Hazardous Solid Waste Amendment Permit	NYD085503746	October 17, 2001[4]	Accumulation and temporary onsite storage of mixed waste for > 90 days.
SCDHEC	Act No. 429 of 1980, South Carolina Radioactive Waste Transportation and Disposal Act	IP2 Radioactive Waste Transport Permit	0019-31-07	December 31, 2007	Transportation of radioactive waste into the State of South Carolina
		IP3 Radioactive Waste Transport Permit	0072-31-07	December 31, 2007	

Table 9-1 (Continued)
IP2 and IP3 Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
TDEC	Tennessee Department of Environment and Conservation Regulations	IP2 Radioactive Waste-License-for-Delivery	T-NY-010-L07	December 31, 2007	Shipment of radioactive material into Tennessee to a disposal/processing facility
		IP3Radioactive Waste-License-for-Delivery	T-NY-005-L07	December 31, 2007	

DOT: U.S. Department of Transportation
EPA: Environmental Protection Agency
NRC: U.S. Nuclear Regulatory Commission
NYSDEC: New York State Department of Environmental Conservation
SCDHEC: South Carolina Department of Health and Environmental Control
TDEC: Tennessee Department of Environment and Conservation (Division of Radiological Health)
WCDOH: Westchester County Department of Health

1. Timely renewal application was submitted; therefore, permit is administratively continued under New York State Administrative Procedures Act.
2. Timely renewal application was submitted; therefore permit is administratively continued by WCDOH.
3. Application has been submitted to WCDOH, but a permit has not yet been issued.
4. Permit has been administratively continued based on conditional mixed waste exemption.

Table 9-2
Environmental Consultations Related to License Renewal

Agency	Authority	Activity Covered
U.S. Fish and Wildlife Service and National Marine Fisheries Service	Endangered Species Act Section 7 (16 USC 1636)	Requires federal agency issuing a license to consult with USFWS and NMFS.
New York Natural Heritage Program	Endangered Species Act Section 7 (16 USC 1636)	Requires federal agency issuing a license to consult with the fish and wildlife agency at the state level.
New York State Office of Parks, Recreation, and Historic Preservation	National Historic Preservation Act Section 106	Requires federal agency issuing a license to consider cultural impacts and consult with SHPO.
New York State Department of State	Federal Coastal Zone Management Act (16 USC 1451 et seq.)	Requires an applicant to provide certification to the federal agency issuing the license that license renewal would be consistent with the federally-approved state coastal zone management program.
New York State Department of Environmental Conservation	Clean Water Act, Section 401 (33 USC 1341)	Requires New York State certification that discharge would comply with state water quality standards

9.6 References

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