Appendix E

Applicant's Environmental Report

Operating License Renewal Stage

James A. FitzPatrick Nuclear Power Plant

Introduction

Entergy Nuclear FitzPatrick, LLC, and Entergy Nuclear Operations, Inc., (hereafter referred to as the singular entity "Entergy" or "the applicant") submit this Environmental Report (ER) in conjunction with the application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for James A. FitzPatrick Nuclear Power Plant (JAFNPP) for twenty years beyond the end of the current license. In compliance with applicable NRC requirements, this ER analyzes potential environmental impacts associated with renewal of the JAFNPP operating license. This ER is designed to assist the NRC staff with the preparation of the JAFNPP specific Supplemental Environmental Impact Statement required for license renewal.

The JAFNPP ER is provided in accordance with 10 CFR 54.23, which requires license renewal applicants to submit a supplement to the ER that complies with the requirements of Subpart A of 10 CFR 51. This report also addresses the more detailed requirements of NRC environmental regulations in 10 CFR 51.45 and 10 CFR 51.53, as well as the underlying intent of the National Environmental Policy Act (NEPA), 42 USC 4321 et seq. For major federal actions, the NEPA requires federal agencies to prepare a detailed statement that addresses significant environmental impacts, adverse environmental effects that cannot be avoided if the proposal is implemented, alternatives to the proposed action, and irreversible and irretrievable commitments of resources associated with implementation of the proposed action.

Supplement 1 to Regulatory Guide 4.2, "Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses," was used as guidance on the format and content of this ER. The level of information provided on the various topics and issues in this ER are commensurate with the environmental significance of the particular topic or issue.

Based upon the evaluations discussed in this ER, Entergy concludes that the environmental impacts associated with renewal of the JAFNPP operating license are small. No major plant refurbishment activities have been identified as necessary to support the continued operation of JAFNPP beyond the end of the existing operating license term. Although normal plant maintenance activities may be performed for economic and operational reasons, no significant environmental impacts associated with such activities are expected.

The application to renew the operating license of JAFNPP assumes that licensed activities are now conducted, and will continue to be conducted, in accordance with the facility's current licensing basis (e.g., use of low enriched uranium fuel only). Changes made to the current licensing basis of JAFNPP during the staff review of this application are to be made in accordance with the Atomic Energy Act of 1954, as amended, and in accordance with Commission regulations.

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ACRONYMS AND ABBREVIATIONS

ABWR	Advanced Boiling Water Reactor
BTA	best technology available
Btu	British thermal unit
BWR	boiling water reactor
°C	degrees centigrade
CaO	calcium oxide (lime)
$CaSO_4$ $2H_2O$	calcium sulfate dihydrate
CDF	core damage frequency
CEQ	Council on Environmental Quality
CET	containment event tree
cfm	cubic feet per minute
CFR	code of federal regulations
Ci/ml	curies per milliliter
CO	carbon monoxide
CO_2	carbon dioxide
COE	cost of enhancement
CVDEM	Commonwealth of Virginia Department of Emergency Management
CWA	Clean Water Act
DOE	U.S. Department of Energy
DOT	Department of Transportation
EDG	emergency diesel generator

Acronyms and Abbreviations (continued)

EEI	Edison Electric Institute
El	elevation
EIA	Energy Information Administration
ENF	Entergy Nuclear FitzPatrick, LLC
ENO	Entergy Nuclear Operations, Inc.
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ER	environmental report
°F	degrees Fahrenheit
FDS	fish deterrence system
FES	Final Environmental Statement
fps	feet per second
ft	feet
ft^3	cubic foot
GE	General Electric
GEIS	Generic Environmental Impact Statement
GLWQA	Great Lakes Water Quality Agreement
gpd	gallons per day
gpm	gallons per minute
HEPA	high efficiency particulate air filters
HPCI	high pressure core injection
Hz	hertz

Acronyms and Abbreviations (continued)

IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events
ISFSI	Independent Spent Fuel Storage Installation
ISO	International Standards Organization
JAFNPP	James A. FitzPatrick Nuclear Power Plant
km	kilometer
Kr	krypton
kV	kilovolts
kW	kilowatt
kWh	kilowatt-hour
lb	pounds
m	meters
m^2	square meters
m^3	cubic meters
mA	milliamperes
MACCS2	Melcor Accident Consequences Code System 2
MFTDS	Modular Fluidized Transfer Demineralization and Sluice System
µg/l	micrograms/liter
mg/l	milligrams per liter
mGy	milligray
mho	milliohm
ml	milliliter

Acronyms and Abbreviations (continued)

MM	million
MMBtu	million British thermal unit
mph	miles per hour
mrad	millirad
mrem	millirem
mSv	millisievert
MT	metric ton
MW	megawatt
MWD/T	megawatt day/ton
MWe	megawatts, electric
MWh	megawatt, hour
MWP	Metropolitan Water Board
MWt	megawatts, thermal
N-16	Nitrogen-16
NA	not applicable
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NESC	National Electrical Safety Code
NGVD	National Geodetic Vertical Datum
NHL	National Historic Landmark
NMP	Nine Mile Point
NMPNS	Nine Mile Point Nuclear Station
NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission

Acronyms and Abbreviations (continued)

NRHP	National Register of Historic Places
NRR	(Office of) Nuclear Reactor Regulation
NSPS	New Source Performance Standard
NUREG	U.S. Nuclear Regulatory Commission Document
NYISO	New York Independent System Operator
NYCRR	New York Code of Rules and Regulations
NYPA	New York Power Authority
NYSDEC	New York State Department of Environmental Conservation
NYSERDA	New York State Energy Research and Development Authority
OCWA	Onondaga County Water Authority
ODCM	Offsite Dose Calculation Manual
OL	Operating License
PBTs	persistent, bioaccumulative, toxic chemicals
PILOT	Payment-in-Lieu-of-Taxes
PM_{10}	particulates having diameter less than 10 microns
PSA	probabilistic safety assessment
psig	pounds per square inch
PV	solar photovoltaic
RCIC	Reactor Core Isolation Cooling
rem	roentgen equivalent man
ROW	right-of-way
rpm	revolutions per minute

Acronyms and Abbreviations (continued)

SAMA	severe accident mitigation alternative
SAMDA	severe accident mitigation design alternative
SBO	station blackout
SCDHEC	South Carolina Department of Health and Environmental Control
scfm	standard cubic foot per minute
SCR	selective catalytic reduction
SEIS	Supplemental Environmental Impact Statement
SEQRA	State Environmental Quality Review Act
SHPO	State Historic Preservation Officer
SJAE	Steam Jet Air Ejector
SO_x	oxides of sulfur
SPDES	State Pollutant Discharge Elimination System
SQUG	Seismic Qualification Utility Group
TDEC	Tennessee Department of Environment and Conservation (Division of Radiological Health)
TSP	total suspended particulates
U.S.	United States
USC	United States Code
USFWS	United States Fish and Wildlife Service
USWAG	Utility Solid Waste Activities Group
V	volts
Xe	xenon

Acronyms and Abbreviations (continued)

yd^2	square yards
yr	year

1.0 PURPOSE AND NEED FOR THE PROPOSED ACTION

For license renewal, the NRC has adopted the following definition of purpose and need, stated in Section 1.3 of the NRC Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, NUREG-1437: "The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by State, utility, and, where authorized Federal (other than NRC) decision makers."

Nuclear power plants are licensed by the NRC to operate up to 40 years, and the licenses may be renewed [10 CFR 50.51] for periods up to 20 years. 10 CFR 54.17(c) states that "[a]n application for a renewed license may not be submitted to the Commission earlier than 20 years before the expiration of the operating license currently in effect."

The proposed action is to extend the operating license for the James A. FitzPatrick Nuclear Power Plant (JAFNPP) for a period of twenty (20) years beyond the current operating license expiration date. For JAFNPP (Facility Operating License DPR-59), the requested renewal would extend the existing license expiration date from midnight October 17, 2014, until midnight October 17, 2034.

1.1 Environmental Report

NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled, "Applicant's Environmental Report - Operating License Renewal Stage." This appendix to the James A. FitzPatrick Nuclear Power Plant license renewal application fulfills that requirement.

1.2 JAFNPP Licensee and Ownership

JAFNPP is owned by Entergy Nuclear FitzPatrick, LLC (ENF), and operated by Entergy Nuclear Operations, Inc. (ENO). Formerly operated and maintained by Niagara Mohawk Power Corporation, the responsibility for operation of the JAFNPP facility was transferred to the New York Power Authority ("the Authority") on June 4, 1977. The Authority owned and operated the plant until November 20, 2000, when the operating license was transferred to ENF and ENO.

2.0 SITE AND ENVIRONMENTAL INTERFACES

2.1 Location and Features

James A. FitzPatrick Nuclear Power Plant (JAFNPP) is located on a 702-acre site on the south shore of Lake Ontario, known as Nine Mile Point, in the Town of Scriba, Oswego County, New York. The site is in a rural area approximately seven miles northeast of Oswego, 36 miles north-northwest of Syracuse, and 65 miles east of Rochester, New York. Syracuse is the largest city within 50 miles of JAFNPP. Constellation Nuclear Nine Mile Point Nuclear Station, LLC, Unit 1 (NMPNS) is located immediately west of the site. The location of JAFNPP is shown in Figure 2-1 and Figure 2-2.

The local site terrain is generally flat, with the surrounding area around the Station largely forested and rural. The most prominent feature on the site is the off-gas stack, which is 385 feet high. Due to the forest cover in the area, the physical plant is not visible from local communities. However, the plant structures can be seen by recreational users on Lake Ontario. Noise has not been considered a problem at the site due to the plant's distance from local communities.

Lake Road (County Road 1A) provides road access to the site and transverses JAFNPP property in an east-west direction just south of the main operational facilities. Lake Road connects to the Oswego County Highway Route No. 29, which extends to the City of Oswego to the west and on the east connects with U.S. Highway 104, three and three-fourths miles south of the site. A spur of the Conrail Railroad provides rail service to the plant [Reference 2-4, Section 2.1.1]. This spur is currently blocked for security purposes, but can be re-opened and utilized if needed. Since the site is located on a navigable portion of Lake Ontario, the plant can be reached by barges for construction and supply purposes [Reference 2-4, Section 2.1.1].

The site lies mainly within the Erie-Ontario Lowlands physiographic province. This province consists of a relatively flat plain which rises gently from Lake Ontario to the Appalachian Uplands that form its southern border. The Erie-Ontario Lowlands is bounded on the east by the Tug Hill Upland, through which small portions of the transmission line also pass. The site is a generally flat and featureless plain. It has an elevation of 270 feet rising to 310 feet one mile away at its southern extremity. The surface soils consist of bouldery-ablation tills which immediately overlay a compact basal till lying on bedrock. The underlying rock is flat-lying sandstone imbedded with shale of Ordovician Age. This bedrock is known as Oswego Sandstone. The shale content increases with depth; at approximately 130 feet below the surface, the Oswego Sandstone grades into the underlying Lorraine group, which is predominantly shale with some sandstone members. [Reference 2-15, Section 2.4]

The JAFNPP site consists of partially wooded land that was used almost exclusively for residential and recreational purposes prior to the construction of the NMPNS. For many miles west, east and south of the site, the country is characterized by rolling terrain rising gently up from the lake. There are no residences and no agricultural or industrial developments on the JAFNPP site. Site boundaries are posted as private property and access to both the exclusion area and the plant buildings is controlled. [Reference 2-4, Section 2.1.1]

The map of the site boundary is shown in Figure 2-3. Exclusion distances for the JAFNPP site are approximately 3000 feet to the east, over a mile to the west, and about one and one-half miles to the southern site boundary. The nearest point on the property line from the reactor building and any points of potential gaseous effluents, with the exception of the lake shoreline, are located at the northeast corner of the property. [Reference 2-4, Section 2.1.1] The nearest residence lies outside the site boundary to the east-southeast at 0.71 miles [Reference 2-2].

Within the 50-mile radius of the site, there are seventeen state parks and one national wildlife refuge, which is located about 44 miles to the southwest. Approximately twenty State Wildlife Management Areas are also located within 50 miles of JAFNPP, with the closest one being approximately 19 miles east-southeast of the site. The closest public parks are Scriba Town Park, Sunset Bay Park, and Independence Park. Scriba Town Park is located 5 miles to the south of the Town of Scriba. The park offers a picnic area, playground, and swimming facilities. Sunset Bay Park is located approximately 1 mile east of JAFNPP on the shore of Lake Ontario. It encompasses 48 acres of mostly woods and brush land, and offers a boat launch, nature trail, and picnic area. Independence Park is located approximately 2 miles to the southwest on Lake Ontario. It is a 50-acre wooded tract of land with walking trails and an observation deck. [Reference 2-20, Section 2.1.1]

The only Native American land within a 50-mile radius of JAFNPP is the Onondaga Indian Reservation located in Onondaga County (Figure 2-4). State and federal lands within a 50-mile radius of JAFNPP are shown in Figure 2-4.

JAFNPP features consist of the reactor building, turbine building with electrical and heater bays, administration building and control room, radioactive waste building, screenwell pump house building with intake and discharge tunnels and structures, diesel generator building, auxiliary boiler building, main stack, Independent Spent Fuel Storage Installation (ISFSI), sewage treatment plant, interim rad waste storage building, and switchyard and associated transmission lines. Figure 3-1 shows the general features of the JAFNPP site. Section 3.2 describes key features of JAFNPP, including reactor and containment systems, cooling and auxiliary water systems, radwaste system, and transmission facilities.

2.2 Aquatic and Riparian Ecological Communities

The JAFNPP facility is located in Scriba, New York, on Nine Mile Point, a slight promontory on the southeastern shore of Lake Ontario adjacent to the NMPNS. The offshore slope at the plant site is steep (5 - 10% grade) at the beach, flattening to a 2-3% grade at the 15 foot depth contour, then increasing to a 4% slope lakeward [Reference 2-5, Section 2.0].

There is little sediment deposition along the shoreline in the vicinity of JAFNPP, especially in areas where water depth is less than 40 feet. In general, bottom sediments in the nearshore area are composed primarily of bedrock overlain with boulders, cobble, pebbles, and coarse sand; finer sediments occur further offshore at the 40 and 60 foot depth contours. Lake Ontario, the easternmost of the five Great Lakes, is roughly 193 miles long and 53 miles wide at its maximum dimensions. Although the smallest of the Great Lakes, based on volume, Lake Ontario ranks as the twelfth largest lake in the world. Approximately 52% of Lake Ontario's 7,340 square miles of surface area lies within the Province of Ontario and the remainder is in the state of New York. Lake Ontario is relatively deep, with an average depth of 283 feet and a maximum depth of 802 feet. Lake Ontario has a volume of approximately 390 cubic miles. [Reference 2-5, Section 2.0]

Although the bottom topography of Lake Ontario is relatively smooth, there are two distinct sedimentary basins. The Kingston Basin is located in the northeastern end of the lake and is separated from the deeper main basin by the Duck-Galoo Sill. Within the main basin there are three deep sub-basins from west to east: the Niagara, Mississauga, and Rochester Basins. These basins are bordered by a shallow inshore zone that extends along the perimeter of the main basin. The differentiation among the three most westerly sub-basins is relatively subtle while the Duck-Galoo Sill provides a pronounced distinction between the Rochester sub-basin and Kingston Basin. Kingston Basin is shallower and has unique water quality characteristics compared to the three westerly basins. [Reference 2-5, Section 2.0]

The lake's drainage area of 24,720 square miles is dominated by forests (49%) and agriculture (39%), with 7% of the basin urbanized. Major urban centers include Hamilton, Toronto, and Rochester. There are approximately 6.6 million people living within the Lake Ontario Basin with most of the population concentrated in the western half including the Toronto-Hamilton crescent. The New York shore is less urbanized and not as intensively farmed. The Lake Ontario Basin in New York State drains an area of about 3,000 square miles inhabited by approximately 700,000 people. [Reference 2-5, Section 2.0]

Approximately 86% of inflow in Lake Ontario originates from the upper Great Lakes and Lake Erie via the Niagara River. The remaining water inflow comes from Lake Ontario Basin tributaries and precipitation. The St. Lawrence River is the sole outlet for Lake Ontario and flows northeast in the Gulf of St. Lawrence. Approximately 93 percent of the water in Lake Ontario flows out to the St. Lawrence River, with the remaining 7 percent leaving through evaporation. Water retention time is estimated to be approximately 7 years. [Reference 2-5, Section 2.0]

Since 1960, lake water levels have been regulated by a series of dams and locks in the St. Lawrence River under the authority of the International St. Lawrence River Board of Control. The current plan regulating Lake Ontario outflows is Plan 1958D, which specifies weekly outflows based on the water level of the Lake and water supplies to the Lake that seeks to balance a number of interests including hydropower, commercial navigation, and shoreline property owners. By managing lake water elevations, the natural range in water level fluctuations has been reduced to a target range from 243.3 feet to 247.3 feet International Great Lakes Datum. [Reference 2-5, Section 2.0]

The prevailing west-northwest winds combined with the eastward flow of water from the Niagara River are the most important features on lake circulation. In its simplest form, the largest general circulation of Lake Ontario is counterclockwise with flow to the east along the south shore in a relatively narrow band and somewhat less pronounced flow to the west along the north shore. Circulation of water generally occurs along the eastern shore and within the sub-basins of the main lake; there is little net flow along the north, inshore zone. [Reference 2-5, Section 2.0]

However, circulation patterns on a shorter temporal scale observed at any given time are more complex and affected by transient winds which can alter currents in a matter of hours. During preoperational studies at JAFNPP, currents off Nine Mile Point were measured from May to October 1969 and July 1970. Wind speed frequency data averaged over a six-hour period indicate that winds exceeding 20 miles per hour (mph) occurred 21.6% of the time over the year. From June through September, winds in excess of 20 mph occurred 13.9% of the time. At the 19-feet depth contour, the measured current speed of six-hour duration exceeded with comparable frequency is about 0.2 feet per second (fps). The predominant direction of currents was alongshore, as dictated by continuity. On the occasions when onshore or offshore currents were observed, their magnitudes were substantially less than those of alongshore currents. During the summer, alongshore currents from either the west or east were equally frequent about 33% of the time. Onshore and offshore currents each accounted for nearly 5% of the observations; the remaining 30% of the observations were below the flow meter threshold of 0.5 knots. Lake currents were measured at selected locations in the vicinity of the Oswego Steam Station (about 6 miles west of Nine Mile Point) for 5 days between October 12 and November 19, 1970. These surface current velocities were mostly alongshore, with speeds ranging from less than 0.08 fps to 0.50 fps. [Reference 2-5, Section 2.0]

Two other important examples of wind-induced effects on the general circulation pattern in Lake Ontario are upwelling and internal oscillation of thermocline depth. Upwelling is characterized by the rising of colder, denser, bottom water toward the surface. A variety of theories have been proposed to account for the oscillations, which are a common feature of Lake Ontario temperature records. The most direct explanation is that an upwelling displaces the thermocline from equilibrium by converting the kinetic energy from wind gusts into potential energy that alters the thermocline position. When the wind stress is removed, internal waves are set in motion and contribute to the dissipation of this energy. Internal waves increase in amplitude after storms. In Lake Ontario, approximately three complete oscillations occur every two days. [Reference 2-5, Section 2.0]

Lake Ontario has a seasonally dependent pattern of both horizontal and vertical stratification which alter circulation patterns. Changes in stratification result from atmospheric heat exchange and wind-induced mixing. In the spring, nearshore waters warm up more quickly than deep offshore waters which sets up isotherms relatively parallel to shore. As temperatures continue to warm, the lake becomes vertically stratified between the nearshore and offshore zones with little mixing. This thermal stratification lasts until about the middle of June when offshore waters warm and mixing occurs. As summer progresses the Lake experiences a period of horizontal stratification with little mixing between the warm surface waters and cool deeper waters. Summer stratification is characterized by warmer, less dense water at the surface layers and cooler, denser water in the lower layer. Progressive heating develops stable thermal stratification and a well-defined epilimnion (warm surface water layer), mesolimnion (transition mid-depth temperatures), and hypolimnion (cool deep water layer). This thermal stratification in Lake Ontario generally extends from late June to October of each year, when the epilimnion averages nearly 70°F and the hypolimnion averages approximately 39°F. Mixing of these thermal strata begins as the thermocline breaks down in the fall as surface waters cool. In late fall after overturn has occurred, the lake is essentially isothermal, thereby permitting a free exchange of water from surface to bottom. The Great Lakes mix from top to bottom (overturn) twice yearly, in the spring and in the fall. The timing of the overturn is closely related to the time when the surface water temperatures fluctuate through the temperature of maximum density of fresh water (i.e., 39°C). [Reference 2-5, Section 2.0]

Towards the end of winter, the entire water mass cools down to below 39°F, with the coldest water remaining close to the shore. During winter, ice begins to form in the nearshore waters of the Great Lakes in December and January and in the deeper offshore waters in February and March, reaching its greatest extent in late February or early March. Expected maximum ice cover for Lake Ontario is 24 percent; however, during a severe winter maximum ice cover can exceed 90 percent. During a mild winter, maximum ice cover is usually limited to the nearshore waters. [Reference 2-5, Section 2.0]

2.2.1 Water Quality

A long period of habitat loss and water quality degradation followed European colonization of the Lake Ontario watershed. Initially, water quality deteriorated slowly from the effects of forest clearance, but accelerated during 1940-1970 in response to increasing urban runoff. Historic changes in land use and uncontrolled pollutant discharge into the Great Lakes contributed to eutrophication of the entire lake system characterized by high phosphorus concentrations and high turbidity until the late 1970s. [Reference 2-5, Section 6.1].

Because of its depth and dilution capacity, adverse eutrophication effects have been minimal in Lake Ontario compared with those for parts of Lake Erie. Oxygen saturation is usually above 80% in the hypolimnion during summer and averages over 90% in the epilimnion throughout the year. There are no persistent lakewide eutrophication problems at this time, although near shore and major tributary impairments have been noted. [Reference 2-5, Section 6.1]

Changes in selected water quality parameters over a period of 28 years are shown in Table 2-1. This data was collected at the Nine Mile Point area in 1972 and 1978, at the City of Oswego water intake located about eight miles southwest of JAFNPP in 1998 and 1999, and at the Monroe County water intake in 2000, approximately 50 miles west of JAFNPP. General reductions in pollutants such as phosphorus and dissolved solids, and in turbidity levels, have been observed over a period of 28 years. Water clarity, measured by a Secchi disk, increased by more than 100% in Lake Ontario during the 1990s. [Reference 2-5, Section 6.1]

The largest source of primary nutrients into Lake Ontario is Lake Erie via the Niagara River. Additional phosphorus and nitrogen enter Lake Ontario from runoff from agricultural lands, urban areas, and sewage outflows. With the intent of preventing further pollution and eutrophication of the Great Lakes system from continuing population growth, resource development, and increasing use of water, the United States and Canada signed the Great Lakes Water Quality Agreement (GLWQA) in 1972. Since the implementation of the GLWQA, phosphorus levels in the Great Lakes have been significantly reduced as a result of better sewage treatment and land use practices in the watershed which has shifted Lake Ontario back towards its historical oligotrophic condition. [Reference 2-5, Section 6.1]

Spring open-lake (offshore) total surface phosphorus levels peaked in 1973 at 25 to 30 μg/l and then declined at an average rate of 1.35 μg/l per year between 1973 and 1986. By 1986, the 10 μg/l target for open-lake phosphorus had been achieved. Decreases in phosphorus were accompanied by decreases in Lake Ontario algal biomass. Eutrophic conditions of the 1960s and 1970s resulted in explosive growth of *Cladophora*, a green filamentous algae. After the implementation of phosphorus reduction programs in the early 1970s, Lake Ontario *Cladophora* biomass and growth rate decreased 50% between 1972 and 1982. Similar decreases were seen in phytoplankton biomass over the same time period. [Reference 2-5, Section 6.1]

Nitrogen concentrations in Lake Ontario, although not considered as major a cause of eutrophication in the 1960s and 1970s as phosphorus, have been increasing in all the Great Lakes. The causal factors are not well understood, but agricultural runoff and atmospheric deposition are considered the most likely sources. It was concluded that the increase in nitrate was associated with higher loading from the watershed and was not associated with reduced algal demand because the nitrate increase occurred before implementation of phosphorus control. It was shown that the rate of nitrate increase paralleled nitrogen fertilizer use in the Great Lakes basin and mirrored the observed Lake Ontario mid-lake increase up to the mid-1980s. [Reference 2-5, Section 6.1]

Nutrient concentrations are greatest in early spring, before algal production begins. During thermal stratification, nutrients such as orthophosphate, nitrate, and silica generally increase from surface to bottom, reflecting uptake by phytoplankton in the photosynthetic zone and perhaps release from bottom sediments. [Reference 2-5, Section 6.1]

Because Lake Ontario is the most downstream of the Great Lakes, it is impacted by human activities occurring throughout the Lake Superior, Michigan, Huron, and Erie Basins. Persistent, bioaccumulative, toxic chemicals (PBTs), which include mirex, polychlorinated biphenyls, dioxins, etc., entered Lake Ontario via tributaries and historically were accumulated in the sediments. Concentrations of toxic chemicals in Lake Ontario led the International Joint Commission to designate Lake Ontario as the most contaminated of the Great Lakes. Canada and the United States developed the "Lake Ontario Toxics Management Plan" in 1989 to address the PBTs through regulation of the toxic chemicals' manufacture and use. The reductions have been generally attributed to restrictions placed on the manufacture and use of those chemicals. The downward trend of toxic chemical concentrations has leveled off since the 1980s and may be due, in part, to a sequestering of the chemicals in benthic sediments. Consumption advisories for numerous fish species based on concentrations of PBTs found in fish tissue samples continue to be issued by the New York State Department of Environmental Conservation (NYSDEC). [Reference 2-5, Section 6.1]

Monthly and semimonthly water quality sampling programs conducted in the Nine Mile Point vicinity from 1973 through 1978 included weekly thermal profiles at the 100 foot depth contour. Although many of the parameters analyzed fluctuated monthly and annually, there were no persistent trends. During any given year, there were temporal cycles for many of the parameters, particularly nutrients and water temperatures. Inorganic nitrogen and phosphorus characteristically increased during winter and decreased during summer with a corresponding summer increase in organic nitrogen and organic phosphorus compounds. Data collected from 1973–1978 showed no short-term or long-term effects from operation of NMPNS or JAFNPP. The Oswego River, west to east longshore currents and hypolimnetic upwellings of cold, often nutrient rich waters exert the most influence on the physiochemical parameters at Nine Mile Point. [Reference 2-5, Section 6.1]

Table 2-1
Selected Water Quality Parameters of Lake Ontario, 1972 - 2000

Parameter	1972	1978	1998 – 1999	2000
pH	8.0	8.4	8.0	7.6
Total Alkalinity (mg/l)	72–90	94	92	83
Total Phosphorous (mg/l)	0.01–0.28	0.03	ND	ND
Total Dissolved Solids (mg/l)	107–186	202	ND	160
Total Nitrates (mg/l)	0.04–0.40	< 0.18	ND	0.34
Turbidity	2.0–6.0 (JTU)	3.0 (NTU)	0.5 (NTU)	0.09 (NTU)
JTU = Jackson Turbidity Unit(s) mg/l = milligram(s) per liter ND = no data available NTU = Nephelometric Turbidity Unit(s)				
SOURCE: Reference 2-5, Table 6-1				

2.2.2 Planktonic Communities

Historical phosphorus loadings from wastewater discharge and runoff from urban and agricultural sources contributed to significant eutrophication of Lake Ontario and accompanying algal community during the 1960s–1970s. The increased phytoplankton and zooplankton productivity contributed to increasing turbidity within Lake Ontario during that period. Nutrient loading reductions that were a result of the United States Clean Water Act and the GLWQA have allowed Lake Ontario's plankton community to shift back to a more balanced, oligotrophic state. Net productivity has declined by 18% and late summer zooplankton production had been reduced by 50% since the 1970s. Comparison of lakewide surveys conducted in 1970 (high phosphorus) and 1990 (low phosphorus) showed an increase of oligotrophic over eutrophic phytoplankton species. Shifts in phytoplankton community structure indicate improvement in Lake Ontario's trophic status and have closely resembled the changes in the available nutrients. Predominant eutrophic species of diatoms and cyanobacteria have either been replaced by oligotrophic species or occur in very low numbers, and the relative abundance of oligotrophic species of diatoms and chrysophytes has increased. Recently invading *Dreissena* spp. mussels have caused a redistribution of a large portion of Lake Ontario's available planktonic nutrients from the water column to the benthic environment and contributed to decreases in turbidity. [Reference 2-5, Section 6.2]

The impact of alewife on the zooplankton species composition since the early 1970s in Lake Ontario has been significant. Intense planktivory by these fish has structured the community toward small species. Zooplankton are the principal food of juvenile and adult alewife, and alewife were responsible for > 96% of the predation on zooplankton by Lake Ontario fish as late as 1990. Alewife abundance has declined 42% from the early 1980s to the early 1990s, and subtle changes were observed in the zooplankton community coincident with this decline. [Reference 2-5, Section 6.2]

2.2.3 Benthic Communities

One of the most significant changes in the benthic macrofauna of Lake Ontario has been the establishment of two species of *Dreissena*. The exotic zebra mussel (*Dreissena polymorpha*) and quagga mussel (*Dreissena bugensis*) have amplified the effects of reduced nutrient levels by filtering and clarifying the water column throughout Lake Ontario. The zebra mussel was first detected in Lake Ontario in 1989, and by 1991 the quagga mussel was observed co-existing with the zebra mussel. These mussels had colonized western Lake Ontario and the south shore by 1991–1992 and the eastern outlet basin by 1993. South-shore studies between 1992 and 1995 showed that total *Dreissena* biomass had increased and that areas of lake bottom dominated by zebra mussels in 1992 were dominated by quagga mussels in 1995. *Dreissena* mussels are capable of colonizing areas from the waters' edge to depths beyond 400 feet; zebra mussels are primarily found in water less than 10 feet deep. Quagga mussel density has increased to over 18,800 mussels/yd^2 in water 246 feet deep and over 2,000/yd^2 in water 425 feet deep. [Reference 2-5, Section 6.3]

After 1994, benthic macroinvertebrate populations declined in many areas of Lake Ontario. Associated with the dramatic increase in *Dreissena* spp. was a collapse of the larger fingernail clams (*Sphaerium* spp.), likely due to competition with *Dreissena* for food and space. Coincident with the ascent of *Dreissena* spp., numbers of the shallow water amphipod *Gammarus fasciatus* increased, perhaps because they benefited from the structural complexity associated with mussel colonies and energy transfer to the benthos through pseudofecal deposition. Colonization of Lake Ontario by the filter-feeding *Dreissena* spp. has likely decreased crustacean zooplankton production, particularly in nearshore (< 30 m depth) areas if the ecological response is similar to that of Lake Erie, where dreissenid mussels depressed zooplankton production through their impact on pelagic primary production. The nearshore macrobenthos community has undergone further change with the replacement of the gastropod snails (*Amnicola* spp. and *Valvata* spp.) with the exotic New Zealand mud snail (*Potamopyrgus antipodarum*). [Reference 2-5, Section 6.3]

The deepwater scud (*Diporeia*) was historically the dominant benthic invertebrate in most offshore areas of Lake Ontario representing 60–80% of benthic biomass of Lake Ontario. *Diporeia* is an important prey item for alewife, rainbow smelt, slimy sculpin, young lake trout, and lake whitefish. In the Kingston Basin, density of *Diporeia* increased between 1983 and 1989 and reached a seasonal average just over 13,000/m^2 in 1988. After 1990, *Diporeia* density in the Kingston Basin (at depths < 35 m) plummeted to < 4/m^2 by October 1995 and to zero in April 1996. A significant decline in *Diporeia* density between 1972 and 1997 at depths of 12–88 meters was also observed. A zone of low *Diporeia* density (< 4/m^2) encompassing a significant portion of the soft sediment habitat in Lake Ontario currently extends to 26 km offshore and as deep as 160 meters. The diversion of algal production into *Dreissena* tissue and biodeposits may deprive *Diporeia* of food settling from the water column. This reduction of *Diporeia* is expected to have a significant impact on the fish of Lake Ontario that are dependent on these organisms for their growth and survival. [Reference 2-5, Section 6.3]

2.2.4 Fish Communities

2.2.4.1 Historical

The Lake Ontario ecosystem has undergone dramatic change since European colonization, primarily due to human impacts on Lake Ontario and its watershed. The native fish community of Lake Ontario comprised a rich forage base that included coregonids (whitefish family) and sculpins. Atlantic salmon (*Salmo salar*), lake trout (*Salvelinus namaycush*), and burbot (*Lota lota*) were the most abundant offshore predators in Lake Ontario. In nearshore waters, warm water predator species such as yellow perch (*Perca flavescens*), walleye (*Stizostedion vitreum*), northern pike (*Esox lucius*), and lake sturgeon (*Acipenser fulvescens*) were in abundance. Prey species included deepwater ciscoes (*Coregonus* spp.) and sculpins (*Myoxocephalus thompsoni* and *Cottus cognatus*) in offshore areas, and emerald shiner (*Notropis atherinoides*) and spottail shiner (*Notropis hudsonius*) in nearshore areas. Coregonids and salmonids constituted the largest components of the fish population in the Great Lakes, which reflected their oligotrophic character. The earliest records of the Lake Ontario fish community involve the commercial fishery. Historically, the Lake Ontario commercial fishery was based on a variety of species including lake herring, deepwater ciscoes, lake trout, lake whitefish, American eel (*Anguilla rostrata*), walleye, yellow perch, northern pike, and bullheads (*Ictalurus* spp). [Reference 2-5, Section 6.4]

Habitat and water quality degradation, overfishing, and the introduction of exotic species contributed to the decline of the native fish community. By the 1970s, these impacts culminated in the virtual extinction of large piscivores, the reduction or extinction of other native fishes, and proliferation of exotic species. Atlantic salmon, deepwater sculpins, lake trout, burbot, and coregonids had all disappeared or had seriously declined in abundance. Notable changes to the fish community began over 100 years ago with the arrival of several exotic species. Alewife (*Alosa pseudoharengus*), sea lamprey (*Petromyzon marinus*), and rainbow smelt (*Osmerus mordax*) colonized Lake Ontario most likely via migration through the New York State Canal System. Sea lampreys established a reproducing population, and their parasitic feeding habits decimated native lake trout fish stocks until the 1970s when control measures were implemented. Alewife and rainbow smelt proliferated in the virtual absence of predators and became overabundant by the 1960s. Eutrophic conditions in Lake Ontario and abundant phytoplankton perpetuated the population growth of both alewife and smelt. [Reference 2-5, Section 6.4]

Early efforts to stock the Great Lakes with various species of salmon and trout met with little or no success. Renewed stocking efforts began in the 1960s in an attempt to control nuisance levels of alewife and quickly became focused on developing a recreational fishing industry. In the early 1970s, New York State and the Province of Ontario began to establish recreational fisheries and rehabilitate lake trout by accelerating the introductions of lake trout, brown trout (*Salmo trutta*), rainbow trout (*Oncorhynchus mykiss*), chinook salmon (*Oncorhynchus tshawytscha*), coho salmon (*Oncorhynchus kisutch*), and Atlantic salmon. The introductions initially failed to establish fisheries due to high parasitic lamprey induced mortality. In the early 1980s sea lamprey was effectively controlled and the survival of stocked salmonids improved. Hatchery programs in both New York and Ontario were expanded and the number of salmonids stocked rapidly increased during the 1970s and 1980s. [Reference 2-5, Section 6.4]

In the following years, activity in the recreational fishery greatly expanded. Total annual expenditures by anglers in Lake Ontario's recreational fisheries were $53 million (Canadian) for Ontario in 1995 and $71 million (U.S.) for New York in 1996. In the mid-1980s, the state of New York and the province of Ontario agreed to limit stocking to 8 million salmonids annually in response to concerns about the sustainability of the high predator levels, declining alewife, record fishery yields, and perceived risks to the burgeoning recreational fishery. Salmonid consumption of alewives was estimated to exceed supply in 1992. To reduce the risk of an alewife collapse and associated adverse impacts on the recreational fishery, stocking levels were reduced to 4.5 million salmonids in 1996 and have been maintained at between 4 and 5.5 million annually. In 1999, the percentage of the total salmonid stocked by species was 39.2% chinook salmon, 18.8% lake trout, 17.2% rainbow trout, 12.2% brown trout, 7.2% coho salmon, and 5.5% Atlantic salmon. [Reference 2-5, Section 6.4]

In the 1970s and early 1980s, Lake Ontario's offshore fish community was dominated by non-native planktivores (alewife and rainbow smelt) and a native benthivore, slimy sculpin. Data prior to the build-up of predator levels (pre-1985) suggests that alewife and smelt were regulated by intraspecific and interspecific competitive interactions, cannibalism, and weather. The diet of salmonids in Lake Ontario is comprised almost entirely of smelt and alewife. The combination of predation from stocked salmonids and changes in the trophic structure resulting from declines in nutrients and zebra and quagga mussel colonization in Lake Ontario resulted in marked declines in alewife and rainbow smelt by the early 1990s. Compared to the early 1980s, the biomass of prey fish like the alewife and rainbow smelt has been reduced by one-half. The results of midwater trawls combined with acoustical transects conducted by NYSDEC and the Ontario Ministry of Natural Resources in Lake Ontario revealed an 80% reduction in the alewife population between October 1991 and 1994. Dreissenid mediated changes in the trophic structure of Lake Ontario toward a more benthic oriented food web and resultant decreases in planktonic prey upon which alewife feed also affect the alewife population. [Reference 2-5, Section 6.4]

Alewives exert the dominant biotic influence on fish communities in Lake Ontario and are the principal prey of most predatory fish and fish eating birds. Chinook salmon, in particular, rely heavily on alewives in their diet even when alewive numbers are low. A number of changes have been observed in recent years as alewife abundance has declined: lake trout began to successfully reproduce, threespine stickleback abundance increased, lake whitefish populations have increased, populations of other native fish species (yellow perch, emerald shiner, and lake herring) improved. Two native pelagic species, threespine stickleback (*Gasterosteus aculeatus*) and emerald shiner (*Notropis atherinoides*), have recently increased in abundance and may reflect a significant change in the Lake Ontario fish community. It was suggested that the seminal event that allowed these fishes to reproduce successfully was a relaxation of predation on their larvae resulting from the shift of alewife to deeper water. Alewives prey on the pelagic larvae of many fish species. Male threespine sticklebacks establish and defend territories during breeding season and build nests of submerged aquatic vegetation and sand grains with mucus from kidney secretions. Suitable nest sites may be in short supply in some habitats and males nesting in rocky areas had fewer eggs in their nests than males in vegetated areas. An additional factor contributing to increasing abundance of threespine stickleback in Lake Ontario may be an increase in nesting habitat quantity and quality due to the increased growth of macrophyte beds in many littoral areas since dreissenid mediated increases in water clarity. [Reference 2-5, Section 6.4]

Slimy sculpin are native benthic fish that are important to the diet of lake trout. Numbers of slimy sculpins fell sharply in southern Lake Ontario between 1982 and 1984 due to predation by stocked juvenile lake trout. Numbers slowly rose from 1984 to 1991, declined abruptly in 1992, and remained low during 1993–1998. It was hypothesized that the decline of slimy sculpins was due to reductions in productivity brought on by nutrient abatement and to reductions in *Diporeia*, an important prey item, brought on by dreissenid colonization. [Reference 2-5, Section 6.4]

The current Lake Ontario fish community is in a dynamic state, affected by trophic changes triggered by invasive species as well as through manipulation by agency stocking programs. The system is largely composed of a mix of exotic species that have no evolutionary sympatry. Recruitment of dominant predators and the associated top-down influence on fish communities is largely controlled through stocking levels. An imbalance of predators and prey has resulted, with important forage species (alewife and rainbow smelt) at low population levels. As a result, conventional ecological paradigms are difficult to apply, and descriptions of historical fish community structures are not useful for understanding or predicting species interactions or equilibrium states. [Reference 2-5, Section 6.4]

More recent invasions of exotic fish include the European ruffe (*Gymnocephalus cernuus*), blueback herring (*Alosa aestivalis*), and the round goby (*Neogobius melanostomus*). Blueback herring have not become as abundant as had been expected, although they have been found in the Oswego area. Round goby, a predator of *Dreissena*, are established in Rochester, New York, and have spread eastward to the Sodus, New York, area, approximately 30 miles west of Nine Mile Point. Round gobies, which are native to Eastern Europe, were introduced into the St. Claire River in 1990, probably via contaminated ballast water of transoceanic ships. The goby is a bottom-dwelling fish that has great potential for causing impacts on Great Lakes fisheries. Round gobies are thriving in the Great Lakes Basin because they are aggressive, voracious feeders that can forage in total darkness. The round goby takes over prime spawning sites traditionally used by native species, competing with native fish for habitat and changing the balance of the ecosystem. The round goby is already causing problems for other bottom-dwelling Great Lakes native fish like mottled sculpin, logperch, and darters. Goby spawn more often and over a longer period than native fish. Unfortunately, they have shown a rapid expansion of their range through the Great Lakes. No round gobies were collected in impingement samples in 2004 or in previous years at JAFNPP or NMPNS. Another species that resource managers are watching is the invasive species ruffe (*Gymnocephalus cernuus*). Although the ruffe has yet to be found in Lake Ontario, they are rapidly moving east from the Upper Great Lakes and appear to compete with the walleye and yellow perch. The goby and ruffe do not appear to have reached this area of the Great Lakes based on extensive impingement monitoring at JAFNPP. [Reference 2-5, Section 6.4]

2.2.4.2 Nearshore: Lake Ontario

With few exceptions, most Lake Ontario fish spend at least part of their life cycle in the nearshore zone. The resident fish community inhabiting the nearshore zone varies with season, the degree of nutrient enrichment, temperature, and available habitat. Dominant fish species that spend most of their life cycle in the nearshore zone include walleye, smallmouth bass, largemouth bass, northern pike, freshwater drum, yellow perch, white perch, gizzard shad, trout perch, white sucker, various minnows, and several sunfishes (e.g., rock bass, pumpkinseed, bluegill, black crappie). The American eel is an important nearshore fish predator, but is currently at historically low levels of abundance. The lake sturgeon, which inhabits a wide range of water depths, is a formerly common species showing a moderate resurgence in recent years. The alewife, primarily an offshore pelagic species, utilizes the nearshore as spawning and nursery habitat and seasonally can be very abundant in nearshore areas. [Reference 2-5, Section 6.5]

The fish community in the coastal nearshore areas surrounding the main body of Lake Ontario is relatively sparse; therefore, much of the nearshore fish community production comes from major embayments such as the Bay of Quinte and Lake Ontario's relatively shallow Outlet Basin. Here, several species of management interest have shown dramatic changes in abundance in the past decade. The Bay of Quinte and eastern Lake Ontario ecosystems have undergone tremendous change, both gradually since water quality clean-up efforts initiated in the late 1970s, and rapidly following the invasion and proliferation of dreissenid mussels in the early to mid-1990s. The ecosystem change has included increased water clarity, increased levels of submerged aquatic vegetation, and a modified fish community. Smallmouth bass, abundant throughout the 1980s, declined dramatically in the Outlet Basin of Lake Ontario after 1992. The decline appears to be largely due to unfavorable summer water temperatures during the exceptionally cool years of the early 1990s. However, recruitment conditions were especially good in the late 1990s, particularly the warm summers of 1995 and 1998, and smallmouth bass abundance has not shown any significant resurgence. Recent smallmouth bass decline has also been attributed to increased predation by double-crested cormorant. [Reference 2-5, Section 6.5]

Walleye are an important keystone predator of the inshore fish community of eastern Lake Ontario. Walleye have resurged from low levels in the early 1970s and reached record setting high levels in the Bay of Quinte in the early 1990s. The resurgence began as a result of an extremely large year class in 1978 after the winter kill of its larval predators, alewife and white perch, which occurred after the severe winters of 1976–1977 and 1977–1978. In the late 1980s and early 1990s, the walleye population of the Bay of Quinte moved down the bay as spawning runs of alewife, an important prey species for walleye, diminished. Although large walleye have seasonal migrations between the Bay of Quinte and eastern Lake Ontario, this shift, along with the increased abundance of walleye, initiated their dispersion out of the lower Bay of Quinte into eastern Lake Ontario. This was accelerated in the early 1990s by increasing water transparency caused by dreissenid colonization. In the mid-1990s, walleye abundance increased in New York waters of Lake Ontario's eastern basin. This increase, which was also seen in the upper St. Lawrence River, likely reflected the dispersion of the Bay of Quinte stock. Coincident with this decrease, yellow perch abundance increased substantially throughout the Bay of Quinte at a time when the species was decreasing in the eastern basin of Lake Ontario. [Reference 2-5, Section 6.5]

Another important inshore species, yellow perch, were at record-setting high levels in northeastern Lake Ontario in the late 1970s and early 1980s, but declined precipitously in the mid-1980s. Among the many factors associated with these dynamics was a massive winter kill of alewives, significant predators of yellow perch larvae, in the late 1970s followed by a strong rebound in the 1980s. A shift in alewife distribution in the early 1990s boosted yellow perch reproductive success, but it was followed by increased predation by double-crested cormorant that appears responsible for decreasing yellow perch abundance in eastern Lake Ontario in recent years. [Reference 2-5, Section 6.5]

2.2.4.3 Nearshore: Vicinity of Nine Mile Point

The temporal and spatial distribution of fishes in the vicinity of Nine Mile Point were monitored at varying levels of effort from 1969 through 1978 using a variety of gear types including gill nets, trawls, seines, and trap nets. Fish community structure varied seasonally during any given year, changing from a simple system in winter and early spring to a more complex and diverse community in late spring through the fall. Data indicated that the fish community in the Nine Mile Point vicinity was dominated by one or two species with a small number of other species in reduced numbers. Species diversity was highest in the spring due to an inshore movement of a number of species. During summer when alewives were most abundant, diversity was low. Diversity usually increased again in the fall, coinciding with the offshore movement of alewives. [Reference 2-5, Section 6.6]

Seventy-two fish species were collected from 1969 to 1978 in the vicinity of Nine Mile Point. During a typical year, alewives comprised a majority of the total catch, with rainbow smelt, spottail shiners, emerald shiners, centrarchids, yellow perch, and white perch accounting for the majority of the remaining catch. Seasonally, fish were collected in greatest numbers during the spring, coinciding with the shoreward migration of the two most abundant species, alewife and rainbow smelt. Abundances typically decline during the warmer summer months and rise during the fall, corresponding to increased catches of young of the year fish. Abundance patterns based on gill net data generally mimicked the patterns displayed for impingement catches at JAFNPP and NMPNS. [Reference 2-5, Section 6.6]

Yearly gill net catch data for rainbow smelt, white perch, and smallmouth bass in the Nine Mile Point vicinity displayed no significant changes among years 1969–1978. Alewife abundance oscillated, displaying highest numbers in 1974 and 1976 and declining through 1977 and 1978. The yellow perch population declined slightly from 1977 through 1978. Data on gizzard shad indicated a generally increasing population in the Nine Mile Point vicinity through 1975 and a decline during 1977 and 1978. Greatest concentrations were in the vicinity of plant thermal discharges during the fall. Salmonids appeared infrequently in gill net catches through the years and typically reflected stocking intensity for any given year. [Reference 2-5, Section 6.6]

No incidents of cold shock mortality due to plant shutdown at either JAFNPP or NMPNS were reported, nor were any rare, endangered, or threatened fish species collected. Comparison of temporal and spatial abundance based on catch per unit effort data as well as length-frequency distribution, age and growth, fecundity, gonad maturity, and diet analysis between experimental and control areas in the Nine Mile Point vicinity for 1969–1978 revealed no distinct alteration to the normal seasonal life cycle patterns of the nearfield fish community directly attributable to operations at JAFNPP or NMPNS. [Reference 2-5, Section 6.6]

2.3 Groundwater Resources

Four hydrologic units exist below the JAFNPP site: Unlithified Sediments, Oswego Sandstone, Pulaski Formation, and Whetstone Gulf Formation, in descending order. Groundwater is available from an unconfined aquifer and deeper confined aquifers. The unconfined aquifer is composed of glacial till and fill material (Unlithified Sediments) and the upper portion of the Oswego Sandstone beneath the soil. The unconsolidated deposits rest on a permeable fractured zone at the top of the Oswego Sandstone. The Oswego Sandstone formation becomes relatively impermeable within approximately 20 feet. [Reference 2-10, Section 2.2.2]

Within a two-mile radius of Nine Mile Point, the local water table ranges in elevation from 300 feet National Geodetic Vertical Datum (NGVD) in the southeast to the lake water level, approximately 246 feet NGVD, with annual variations of approximately two feet. The normal groundwater table in the plant complex area is approximately 255 feet NGVD. The average gradient is approximately 0.7% to the north-northwest [Reference 2-10, Section 2.2.2]

The transition zone between the Oswego Sandstone and the youngest division of the Pulaski Formation (Pulaski Unit A) is more permeable than the overlying and underlying strata and constitutes the uppermost confined aquifer at the JAFNPP site. Below this zone, another confined zone of relatively high permeability exists in the Pulaski Unit B strata. The Pulaski Unit C zone has a very low permeability and separates the confined Unit B zone of the Pulaski Formation from the underlying Whetstone Gulf Formation. All of these deep aquifers are confined as characterized by artesian pressure. [Reference 2-10, Section 2.2.2]

Groundwater recharge in the JAFNPP site vicinity most likely occurs as a result of infiltration of precipitation and local seepage from ponds and swamps through the unconsolidated deposits and bedrock outcrops. Due to the low permeability of the surficial soils in the vicinity of the site, most of the precipitation runs off toward the Lake, leaving approximately two inches available for recharge annually. The Oswego Sandstone is recharged by seepage from the unconsolidated deposits and local outcrops located to the south and southeast of the JAFNPP site. Recharge of the lower zones of rock beneath the surface occurs through outcrops upgradient to the JAFNPP site, or possibly through fractures. Groundwater flow velocities in the JAFNPP site vicinity are slow due to low hydraulic conductivities. The maximum estimated regional velocity of groundwater in the unconfined aquifer is no more than a few yards annually, based on a gradient of 0.7% and an assumed average permeability of 4×10^{-6} inches per second. [Reference 2-10, Section 2.2.2]

The unconfined water table aquifer is generally of sufficient yield capacity for domestic use only. Within two miles of JAFNPP, groundwater wells yield an estimated 5–8 gpm from the unconsolidated deposits and up to 10 gpm from the lower strata. [Reference 2-10, Section 2.2.2]

Potable water in the area is supplied to residents either through the Scriba Water District, which receives its water from the City of Oswego, or from private wells. Currently, operation of private groundwater wells in Oswego County is not regulated, nor does any agency keep a listing of all groundwater wells in the area. [Reference 2-10, Section 2.2.2] The two nearest public water supplies are located approximately eight and one-half miles from the site and both use water from Lake Ontario. The nearest producing private well known at the time of construction is located about 3,500 feet from the plant location. All known water wells are located up-gradient from the site and would not be affected by changes in the groundwater regime at the site. The possibility of adversely affecting the groundwater resources of existing wells in the area by the operation of a nuclear facility is remote. [Reference 2-4, Section 2.4.2]

JAFNPP is not a direct user of groundwater and has no plans for direct groundwater use in the future. Lake Ontario is the source for cooling and service water, while the Town of Scriba is the source for potable water.

2.4 Critical and Important Terrestrial Habitats

JAFNPP and the associated transmission lines are located within the Erie and Ontario Lake plain eco-region, which is characterized by flat terrain and shallow entrenchments of the primary drainage systems. The eco-region is a combination of level to gently rolling hills and flat lake plain. There are a few areas with broad, low ridges (glacial end moraines) that generally trend parallel to the Lake Ontario shoreline. Natural vegetation communities that occupy this region develop as a function of the soil conditions and slight variations in drainage conditions and patterns. Potential vegetation communities include northern hardwood forest, beech-maple forest, and elm-ash forest. Other important vegetation types include maple-basswood forest, hemlock-northern hardwood forest, oak openings, and pitch pine-heath barrens. [Reference 2-20, Section 2.2.6]

Sixty-six percent of the JAFNPP site is characterized by forest shrub, 21% is open/ grass lands, 10% is wetlands or ponds, and 3% is occupied by the power plant, associated buildings, and other developed land.

No formal wetland delineations or surveys have been conducted for the Nine Mile Point area. However, based on mapping conducted by the USFWS (1982) under the National Wetland

Inventory and surveys conducted by the State of New York, it has been estimated that approximately seven percent of Nine Mile Point is occupied by wetlands. These wetland communities are most likely an outcome of relatively impermeable glacial till soils that allow perched groundwater to lie at or near ground surface seasonally or during years of above average precipitation. [Reference 2-20, Section 2.2.6]

Terrestrial communities in the Nine Mile Point area have been impacted by past land clearing activities associated with military construction and agricultural land use, such as cropland, pasture, and orchards. Much of the land is now in varying stages of plant community succession, reverting from the previous land cover to old field communities and second growth hardwood forests. Current conditions reflect continuing succession of old fields to secondary forests. [Reference 2-20, Section 2.2.6]

Mammals in the Nine Mile Point area include the white-footed mouse (*Peromyscus leucopus*), deer mouse (*P. maniculatus*), woodchuck (*Marmota monax*), meadow jumping mouse (*Zapus hudsonius*), meadow vole (*Microtus pennsylvanicus*), red squirrel (*Tamiasciurus hudsonicus*), raccoon (*Procyon lotor*), and cottontail rabbit (*Sylvilagus floridanus*). Amphibians seen in the area have included multiple types of frogs, such as the wood frog (*Rana sylvatica*) and northern leopard frogs (*R. pipiens*). [Reference 2-20, Section 2.2.6;Reference 2-15, Section 2.7.1]

As part of the Coastal Zone, Lake Ontario has a large array of avian species. This is further compounded by its location on a migratory flight path for many species of birds. As many as 69 species of birds have been observed during seasonal bird counts. [Reference 2-20, Section 2.2.6]

There are three sites in the vicinity of Nine Mile Point which the NYSDEC considers to be significant habitats. Teal Marsh, which is located approximately 3.5 miles west on Lake Ontario, is a 250-acre scrub-shrub and forested wetland separated from Lake Ontario by a narrow barrier beach. Teal Marsh is the largest area of predominately scrub-shrub wetland in the Oswego County coastal area. NYSDEC also considers the nearshore area of Lake Ontario between the Salmon River and the City of Oswego to be a significant habitat. This area is an important non-breeding waterfowl winter concentration area used primarily by diving ducks. Species observed include greater scaup (*Aythya marila*), golden eye (*Bucephala clangula*), merganser (*Mergus merganser*), and, in lesser numbers, canvasback (*Aythya valisineria*) and oldsquaw (*Clangula hyemalis*). There is also a rich shrub fen located approximately four miles south of the Nine Mile Point area that has been identified as a Rare Natural Community. [Reference 2-10, Section 2.3.2]

2.4.1 State-Listed Critical or Important Habitats

State-listed critical or important habitats have been unaffected by current JAFNPP operations. Although no impacts are anticipated during the license renewal term, the New York Natural Heritage Program was contacted (see Attachment A) regarding any state-listed critical or significant habitats within a 50-mile radius of JAFNPP. Critical and important habitats are those areas managed for state-listed threatened and endangered species. Although there are critical and important habitats in Oswego County, there are none located on the JAFNPP site. There is one near-shore area of Lake Ontario (between the Salmon River and the City of Oswego) considered to be an important waterfowl winter concentration area [Reference 2-10, Section 2.3.2].

2.4.2 Federal-Listed Critical or Important Habitats

Although federally-listed threatened and endangered species have been unaffected by current JAFNPP operations, there are seven federally-listed threatened and endangered species that potentially occur in the vicinity of the site as addressed in Section 2.5 below. Critical habitat has been designated for several of these species in portions of the United States, but there are no known critical or significant habitats on the JAFNPP site for any of these species based on consultation with the U.S. Fish and Wildlife Service and the New York State Natural Heritage Program (see Attachment A).

2.5 Threatened or Endangered Species

Four animal species currently protected and one animal species being considered for protection under the Endangered Species Act have geographic ranges that could possibly include the JAFNPP site. Species represented include two reptiles, two birds, and one mammal. These include the bog turtle (*Clemmys muhlenbergii*), massasauga rattlesnake (*Sistrurus catenatus catenatus*), piping plover (*Charadrius melodus*), bald eagle (*Haliaeetus leucocephalus*), and Indiana bat (*Myotis sodalis*). Of these species, the massasauga rattlesnake is under consideration for protection, the piping plover and the Indiana bat are listed as endangered, and the bog turtle and bald eagle are listed as threatened. [Reference 2-16]

Although the species listed above have the potential to occur at the JAFNPP site, it is considered that only the Indiana bat and the bog turtle and transient occurrences by bald eagles and piping plovers could realistically occur at the JAFNPP site.

The Indiana bat is known to occur at hibernacula in Onondaga and Oswego Counties that are located 18.5 and 38 miles from Nine Mile Point. As this would easily fall within the range of the bats' normal travels, there is the possibility that the bats could reside at the site, should the proper bat habitat be present and available [Reference 2-20, Section 2.2.6]. However, there have been no sightings of the Indiana bat at JAFNPP.

The bog turtle has known sites approximately 12 miles from JAFNPP. However, there have been no sightings of the bog turtle at JAFNPP.

The State of New York also protects additional species as endangered, threatened, or as species of special concern. State listed species which could possibly occur at JAFNPP include an additional 46 plant and animal species. Species represented include 5 reptiles, 24 birds, 1 mammal, 7 fish, and 9 plants (in addition to federally listed species) (see Table 2-2). [Reference 2-20, Table 2-6]

As discussed in Section 2.4, critical habitat has not been designated for any state or federally listed threatened and endangered species on the JAFNPP site. Therefore, with the exception of a potential transient occurrence, it is not expected that any state or federally listed species would be found at the JAFNPP site.

Table 2-2
Federal and New York State Threatened and Endangered Species

Scientific Name	Common Name	Federal Status[a]	State Status[b]
Reptiles and Amphibians			
Crotalus horridus	timber rattlesnake	-	T
Ambystoma jeffersonianum	Jefferson salamander	-	SC
Ambystoma laterale	blue-spotted salamander	-	SC
Clemmys guttata	spotted turtle	-	SC
Clemmys insculpta	wood turtle	-	SC
Clemmys muhlenbergii	bog turtle	T	E
Sisturus catenatus catenatus	massasauga rattlesnake	C	E
Birds			
Accipiter cooperli	Cooper's hawk	-	SC
Accipiter striatus	sharp-shinned hawk	-	SC
Ammodramus henslowli	Henslow's sparrow	-	T
Ammodramus savannarum	grasshopper sparrow	-	SC
Aquila chrysaetos	golden eagle	-	E
Asio flammeus	short-eared owl	-	E
Bartramia longicauda	upland sandpiper	-	T
Buteo lineatus	red-shouldered hawk	-	SC
Charadrius melodius	piping plover	E	E
Chlidonias niger	black tern	-	E
Chordeiles minor	common nighthawk	-	SC
Circus cyaneus	northern harrier	-	T
Cistothorus platensis	sedge wren	-	T
Dendroica cerulea	cerulean warbler	-	SC
Eremophila alpestris	horned lark	-	SC
Falco peregrinus	peregrine falcon	-	E
Gavia immer	common loon	-	SC

Table 2-2 (Continued)
Federal and New York State Threatened and Endangered Species

Scientific Name	Common Name	Federal Status[a]	State Status[b]
Haliaeetus leucocephalus	bald eagle	E	-
Ixobrychus exilis	least bittern	-	T
Lanius ludovicianus	loggerhead shrike	-	E
Melanerpes erythrocephalus	red-headed woodpecker	-	SC
Pandion haliaetus	osprey	-	SC
Podilymbus podiceps	pied-billed grebe	-	T
Pooecetes gramineus	vesper sparrow	-	SC
Sterna hirundo	common tern	-	T
Vermivora chrysoptera	golden-winged warbler	-	SC
Mammals			
Myotis leibii	small-footed bat	-	SC
Myotis sodalis	Indiana bat	E	E
Fish			
Acipenser fulvescens	lake sturgeon	-	T
Cottus ricei	spoonhead sculpin	-	E
Erimyzon sucetta	lake chubsucker	-	T
Hideon tergisus	mooneye	-	T
Lythrurus umbratilis	redfish shiner	-	SC
Myoxocephalus thompsoni	deepwater sculpin	-	E
Prosopium cylindraceum	round whitefish	-	E
Plants			
Eleocharis quadrangulata	angled spikerush	-	E
Eleocharis obtuse var. ovata	blunt spikerush	-	E
Lycopodium complanatum	northern running pine	-	E
Polygonum setaceum var interjectum	swamp smartweed	-	E

Table 2-2 (Continued)
Federal and New York State Threatened and Endangered Species

Scientific Name	Common Name	Federal Status[a]	State Status[b]
Polystichum archostichoides	Christmas fern	-	SC
Thelypteris noveboracensis	New York fern	-	SC
Trillium flexipes	nodding trillium	-	E
Trillium sessile	toad-shade	-	E
Trillium spp	trillium	-	SC
C = Candidate E = Endangered SC = Special Concern T = Threatened			

a. Reference 2-7
b. Reference 2-20, Table 2-6

2.6 Regional Demography

2.6.1 Regional Population

The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) presents a population characterization method that is based on two factors: "sparseness" and "proximity" [Reference 2-18, Section C.1.4]. "Sparseness" measures population density and city size within 20 miles of a site and categorizes the demographic information as follows.

Demographic Categories Based on Sparseness

		Category
Most sparse	1.	Less than 40 persons per square mile and no community with 25,000 or more persons within 20 miles
	2.	40 to 60 persons per square mile and no community with 25,000 or more persons within 20 miles
	3.	60 to 120 persons per square mile or less than 60 persons per square mile with at least one community with 25,000 or more persons within 20 miles
Least sparse	4.	Greater than or equal to 120 persons per square mile within 20 miles

Source: Reference 2-18

"Proximity" measures population density and city size within 50 miles and categorizes the demographic information as follows.

Demographic Categories Based on Sparseness

		Category
Not in close proximity	1.	No city with 100,000 or more persons and less than 50 persons per square mile within 50 miles
	2.	No city with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles
	3.	One or more cities with 100,000 or more persons and less than 190 persons per square mile within 50 miles
In close proximity	4.	Greater than or equal to 190 persons per square mile within 50 miles

Source: Reference 2-18

The GEIS then uses the following matrix to rank the population in the vicinity of the plant as low, medium, or high.

GEIS Sparseness and Proximity Matrix					
		Proximity			
		1	2	3	4
Sparseness	1	1.1	1.2	1.3	1.4
	2	2.1	2.2	2.3	2.4
	3	3.1	3.2	3.3	3.4
	4	4.1	4.2	4.3	4.4

Low Population Area

Medium Population Area

High Population Area

Source: Reference 2-18

NRC guidance suggests using the most recent decennial census data. For estimating total population, and minority and low-income populations within a 50-mile area around JAFNPP, Entergy utilized U.S. 2000 census data.

The 2000 census data shows that approximately 109,440 people live within a 20-mile radius of JAFNPP, which equates to a population density of 87 persons per square mile [Reference 2-20, Section 2.2.8.5]. According to the GEIS Sparseness Index, JAFNPP is classified as Category 3 (60 to 120 persons per square mile or less than 60 persons per square mile with at least one community of 25,000 or more persons with 20 miles).

Within a 50-mile radius of JAFNPP, the 2000 census data identified approximately 914,668 people living within a 50-mile radius of JAFNPP, which equates to a density of 117 persons per square mile [Reference 2-20, Section 2.2.8.5]. With a 2000 population of 732,117, the Syracuse MSA is the largest metropolitan area within 50 miles of the site. Syracuse, the largest city in the MSA, had a 2000 population of 147,306 [Reference 2-22]. Since Syracuse is the largest city within 50 miles of the site and it has a total population of well over 100,000, JAFNPP is classified as a Category 3 (one or more cities with 100,000 or more persons and less than 190 persons per square mile within 50 miles) on the GEIS proximity index.

According to the GEIS sparseness and proximity matrix above, JAFNPP has a value of 3.3 and is therefore located in a medium population area.

2.6.1.1 Regional Demography

The area within 50 miles of JAFNPP includes all or portions of ten New York counties (see Table 2-3). According to the 2000 census, the total population of these ten counties was 1,333,599 residents. Within this ten-county area, 914,668 residents live within the 50-mile radius of JAFNPP. By 2034, which is the end of the proposed license renewal period, the total population of the ten New York counties is projected to decline by approximately 6% to a total of 1,251,958 [Reference 2-6].

Table 2-3
County Population - 50-Mile Radius Surrounding JAFNPP

County	2000 Population	2034 Projected Population
Cayuga	81,963	71,362
Jefferson	111,738	111,827
Lewis	26,944	24,376
Madison	69,441	69,078
Oneida	235,469	226,900
Onondaga	458,336	393,623
Ontario	100,224	104,780
Oswego	122,377	122,773
Seneca	33,342	27,026
Wayne	93,765	100,213
Total	**1,333,599**	**1,251,958**

The JAFNPP site is located in an area composed of small suburban and rural communities. Much of the population in Oswego County lives within unincorporated areas. The JAFNPP site is located within the Town of Scriba, which had a 2000 population of 7,331. Other nearby towns in Oswego County include Oswego, located about 5 miles to the southwest, and Fulton, located about 12 miles south of the site. The 2000 populations for Oswego and Fulton were 17,954 and 11,855, respectively.

The largest city within 50 miles of the JAFNPP site is Syracuse, located about 35 miles southeast of the site in Onondaga County. The 2000 population of Syracuse was 147,306, down from 163,860 in 1990 [Reference 2-20, Section 2.2.8.5]. Other major cities in the region include Rochester, located 65 miles southwest of the site; Auburn, located 40 miles to the south; and

Watertown, located 40 miles northeast from JAFNPP. The 2000 populations of these three cities were 219,773, 28,574, and 26,705, respectively [Reference 2-22]. The only Indian reservation within 50 miles of JAFNPP is the Onondaga Indian Reservation, which is located south of Syracuse [Reference 2-17]. The population of the Onondaga Indian Reservation is 1,473 based on 2000 census data.

Estimated total populations and average annual growth rates between each census for Oswego and Onondaga counties, where the majority (95.5%) of JAFNPP employees live is shown in Table 2-4. Average annual growth rates for Oswego County show relatively slow growth of 0.11% for the period 1990 to 2000, while the average annual growth rate for New York during this same period was 0.5%. Only a slight increase in population is expected for Oswego County during the period 2000 through 2034. In Onondaga County, the population declined during the 1990s and the trend is expected to continue through 2034.

Table 2-4
Population Growth in Onondaga and Oswego Counties, 1990–2034

County	1990[a]	2000[a]	2003[a] (estimate)	Average Annual Growth	2034 Projected[b]
Onondaga County, NY	468,973	458,336	460,517	-0.14	393,623
Oswego County, NY	121,771	122,377	123,495	0.11	122,773

a. Reference 2-22
b. Reference 2-6

2.6.2 Minority and Low-Income Populations

2.6.2.1 Background

The NRC typically performs environmental justice analyses utilizing a 50-mile radius around the plant as the environmental "impact site" and the state as the "geographic area" for comparative analysis. Although areas in Ontario, Canada, are within the 50-mile radius, only minority and low-income populations in New York are addressed below.

Entergy used ArcView® geographic information system software to combine U.S. Census Bureau (USCB) TIGER line data with USCB 2000 census data to determine minority and low-income characteristics (at the block-group level) within the 50-mile radius environmental impact site. Entergy included all block groups if any of their area lay within a 50-mile radius of JAFNPP. The 50-mile radius included 758 census block groups.

2.6.2.2 Minority Populations

The NRC procedural guidance for performing environmental assessments and considering environmental issues defines a "minority" population as racial categories American Indian or

Alaskan Native, Asian, Native Hawaiian or Pacific Islander, Black races, other races, more than 2 races, and the aggregate of all minority races. Hispanic ethnicity is also defined as a minority population category [Reference 2-19, page D-8]. The guidance indicates that a minority population exists if either of the two following conditions exists:

- *Exceeds 50 Percent* — the minority population of the environmental impact site exceeds 50 percent, or

- *More than 20 Percentage Points Greater* — the minority population percentage of the environmental impact site is significantly greater (typically at least 20 percentage points) than the minority population percentage in the geographic area chosen for comparative analysis.

NRC guidance calls for use of the most recent USCB decennial census data. Entergy used 2000 census data [Reference 2-22] to determine the percentage of the total population in the State of New York for each of the racial and ethnic minority categories (Table 2-5). This information was then used to calculate minimum thresholds for each minority category. The aggregate minority population percentage was calculated by dividing the non-white racial population by the total population.

Minimum thresholds were calculated by first adding 20% to each of the minority percentage values for the geographic area. The lower of the two NRC conditions for a minority population (exceeds 50% or more than 20% greater than the geographic area) was used as a threshold value. Any block group with a minority percentage that exceeded this value was considered to be a minority population. Minority percentages for New York and the corresponding threshold values for block groups within a 50 mile radius of JAFNPP are shown in Table 2-5. [Reference 2-19]

Entergy divided USCB minority population numbers for each block group by the total population within that block group to obtain the percent of the block group's population that belonged to each minority category. For each of the 758 block groups within a 50 mile radius of JAFNPP, Entergy calculated the percentage of the population in each minority category and compared the result to the state geographic area's minority threshold percentages to determine if a minority population exists. The number of block groups that exceeded minority thresholds is summarized in Tables 2-6 and 2-7. The location of each minority population within a 50 mile radius of JAFNPP is shown in Figures 2-5 through 2-8.

None of the 758 block groups exceed the thresholds for Asian, Native Hawaiian or other Pacific Islander, Other Races, or More Than One Race minority. One American Indian minority population exists in Onondaga County at the Onondaga Indian Reservation located south of Syracuse. Black and Aggregate of Minorities populations occur in 46 of the 758 block groups. These populations are generally clustered in the Syracuse metropolitan area. One Hispanic ethnic minority population also occurs in the Syracuse metropolitan area. [Reference 2-22]

Overall, no minority populations were identified within a 6-mile radius of JAFNPP. The nearest minority population within a 50-mile radius was near Syracuse in central Onondaga County. This area is about 40 miles southeast of JAFNPP. [Reference 2-22]

2.6.2.3 Low-Income Populations

NRC guidance defines "low-income" by using USCB statistical poverty thresholds for the year 1999 [Reference 2-19, Appendix D]. Low-income populations within the 50-mile radius of JAFNPP were identified using information on the number of individuals below the poverty level in the New York geographic area and the 758 census block groups near JAFNPP. The USCB value for the number of individuals below the poverty level in New York is 14.1% (Table 2-5). [Reference 2-22]

A low-income population is considered to be present if

(1) the low-income population of the block group or environmental impact site exceeds 50 percent, or

(2) the percentage of households below the poverty level in a block group is significantly greater (typically at least 20 percentage points) than the low-income population percentage in the geographic area chosen for comparative analysis.

Because no block groups had more than 50% of its individuals below the poverty level, the "greater than 20%" criterion was used to identify low-income populations within the 50-mile radius environmental impact site (Table 2-5). The number and percentage of block groups that exceeded these thresholds are included in Tables 2-6 and 2-7. Based on the "more than 20 percent" criterion, low-income populations exist in 55 of the 758 block groups. The locations of the low-income populations within the 50-mile radius area are shown in Figure 2-9. Forty-six low-income populations occur in the Syracuse area in Central Onondaga County, and three each in Cayuga, Jefferson, and Oswego Counties. [Reference 2-22]

Overall, no low-income populations occur within a 6-mile radius of JAFNPP. The nearest low-income population occurring within a 50-mile radius is in the community of Oswego where three block groups exceeded the minimum thresholds. These populations are located approximately 7–8 miles southwest of JAFNPP. Other low-income populations within 50 miles of JAFNPP were clustered near Syracuse in Onondoga County, near Auburn in Cayuga County, and Watertown in Jefferson County. [Reference 2-22]

Table 2-5
Average Percentage of Minority and Low-Income Individuals in the New York Geographic Area and Threshold Criteria for Identifying Minority and Low-Income Populations at Block Group Level

Area	American Indian/ Alaska Native	Asian	Native Hawaiian or Other Pacific Islander	Black Races	Other Races	More than Two Races	Aggregate of Minority Races	Hispanic Ethnicity	Low-Income Population (Individuals)
New York Geographic Area	0.4	5.5	0.0	15.9	7.1	3.1	32.0	15.1	14.1
Minority and Low-Income Population Thresholds									
Census Block Group	20.4	25.5	20.0	35.9	27.1	23.1	50.0	35.1	34.1

Table 2-6
Number of Block Groups within a 50-Mile Radius of JAFNPP that Exceed Thresholds for Minority and Low-Income Populations

New York County	Number of Block Groups within 50-Mile Radius	American Indian/ Alaska Native	Asian	Native Hawaiian or Other Pacific Islander	Black Races	Other Races	More than Two Races	Aggregate of Minority Races	Hispanic Ethnicity	Low-Income Population (Individuals)
Cayuga	68	0	0	0	1	0	0	1	0	3
Jefferson	69	0	0	0	0	0	0	0	0	3
Lewis	2	0	0	0	0	0	0	0	0	0
Madison	33	0	0	0	0	0	0	0	0	0
Oneida	28	0	0	0	0	0	0	0	0	0
Onondaga	416	1	0	0	45	0	0	45	1	46
Ontario	3	0	0	0	0	0	0	0	0	0
Oswego	69	0	0	0	0	0	0	0	0	3
Seneca	22	0	0	0	0	0	0	0	0	0
Wayne	48	0	0	0	0	0	0	0	0	0
Total	**758**	**1**	**0**	**0**	**46**	**0**	**0**	**46**	**1**	**55**

Table 2-7
Number and Percentage of Census Block Groups within a 50-Mile Radius of JAFNPP that Exceed Thresholds for Minority and Low-Income Populations

Minority and Low-Income Categories	Thresholds (%)	Number of Block Groups that Exceed State Threshold	Percentage of Block Groups that Exceed Threshold
American Indian and Alaskan Native	20.4	1	0.1
Asian	25.5	0	0
Native Hawaiian or other Pacific Islander	20.0	0	0
Black Races	35.9	46	6.0
Other Races	27.1	0	0
More than Two Races	23.1	0	0
Aggregate of Minority Races	50.0	46	6.0
Hispanic Ethnicity	35.1	1	0.1
Low-Income Population	34.1	55	7.2

2.7 Taxes

JAFNPP is assessed annual property taxes by Oswego County, the Town of Scriba, and Mexico Central Schools. Property taxes paid to Oswego County and the Town of Scriba fund such services as transportation, education, public health, and public safety.

The continued availability of JAFNPP and the associated tax base is an important feature in the ability of the Town of Scriba and Oswego County communities to continue to invest in infrastructure and to draw industry and new residents. Table 2-8 shows the percentage of the annual revenues provided by JAFNPP PILOT payments to the Town of Scriba, County of Oswego, and Mexico Central Schools.

Table 2-8
Total Revenues of the Town of Scriba, Oswego County, and the Mexico Central Schools

Year	Total Revenues[a] ($)	JAFNPP PILOT Payments[b] ($)	Percent of Total Revenues
Oswego County			
2002	152,912,700	2,910,800	1.9
2003	156,051,500	2,910,800	1.9
2004	172,488,182	2,910,800	1.7
Town of Scriba			
2002	4,017,300	436,620	10.9
2003	4,861,300	436,620	9.0
2004	4,256,140	436,620	10.3
Mexico Central Schools			
2002	32,428,800	3,929,580	12.1
2003	32,709,395	3,929,580	12.0
2004	34,137,703	3,929,580	11.5

a. Reference 2-9
b. Reference 2-3

In 2004, Entergy paid approximately $7.8 million in taxes for JAFNPP and based on Table 2-9, a minimum of an estimated $38.1 million in taxes will be paid by Entergy for JAFNPP through the original license period. These property taxes, and other local taxes, along with JAFNPP operating payroll and locally purchased goods and services, aid the local economy.

The energy market in the state of New York has been deregulated to encourage the development of competition in the production and sale of electricity. A study performed by the New York State Board of Real Property Services concluded that the value of many power-generating plants is likely to decline in a deregulated market. Therefore, Entergy expects that any future property taxes assessed through the license renewal term should be similar to or may be less than the estimated in lieu payments. [Reference 2-20, Section 2.2.8.6]

Table 2-9
Entergy Estimated Tax Distribution, 2002 - 2011

Fiscal Year	Use Tax	Excise Tax	Oswego County[a]	Town of Scriba[a]	Mexico Central Schools[a]	Other Property Taxes	Total Property Taxes	Total Taxes
2002	$180,571	$76,622	$2,910,800	$436,620	$3,929,580	$17,759	$7,294,759	$7,551,529
2003	$221,023	$78,985	$2,910,800	$436,620	$3,929,580	$18,670	$7,295,670	$7,596,678
2004	$451,340	$68,827	$2,910,800	$436,620	$3,929,580	$19,543	$7,296,543	$7,813,710
2005	$463,704[b]	$58,612[b]	$2,910,800	$436,620	$3,929,580	$20,267	$7,297,267	$7,819,583[b]
2006	ND	ND	$2,910,800	$436,620	$3,929,580	ND	$7,277,000	ND
2007	ND	ND	$2,910,800	$436,620	$3,929,580	ND	$7,277,000	ND
2008	ND	ND	$2,910,800	$436,620	$3,929,580	ND	$7,277,000	ND
2009	ND	ND	$2,910,800	$436,620	$3,929,580	ND	$7,277,000	ND
2010	ND	ND	$2,910,800	$436,620	$3,929,580	ND	$7,277,000	ND
2011	ND	ND	$1,455,400	$218,310	ND	ND	$1,673,710	ND

a. Total estimated tax payments are based on a current Payment-in-Lieu-of-Taxes (PILOT) agreement with the County of Oswego, the Town of Scriba, and the Mexico Central Schools. The PILOT agreement does not extend past June 30, 2011.

b. Through November 2005

ND: No data available.

2.8 Land Use Planning

Land use planning focuses on Oswego and Onondaga counties as these counties represent 95.5% of the total workforce employed at JAFNPP and therefore, would more likely influence land use.

2.8.1 Existing Land Use Trends

The majority of Oswego County is rural in nature, with 55% of land classified as vacant, forested, or used for agriculture (see Table 2-10). Residential uses account for 36% of all land in the county with industrial and commercial activities occupying only 3% of available land. Residential growth has been strongest in towns in southern Oswego County and in the Town of Scriba in northern Oswego County. Oswego County also contains one of the largest areas of wetlands in the state. Commercial and industrial land uses have centered on the cities of Oswego and Fulton and their surrounding areas in adjoining towns. The Town of Scriba is one of the industrial centers of Oswego County, particularly for energy production. In addition to JAFNPP and NMPNS, Sithe Industries operates Independence Station, a 1042 MWe natural gas fueled power plant. The 190-acre site is located approximately 2 miles from JAFNPP. [Reference 2-20, Section 2.2.8.3]

Onondaga County is somewhat more developed than Oswego County, with both residential and commercial land uses more evident in the vicinity of Syracuse. Growth has been steady throughout Onondaga County, except in the county's southern towns, where the lack of infrastructure and public water availability has limited growth. Agriculture remains a significant land use in southern Onondaga County (see Table 2-10). Forests in the southern portion of the county are mostly natural and reforested areas owned by the county or state. [Reference 2-20, Section 2.2.8.3]

Seventeen state parks and one national wildlife refuge are located within a 50-mile radius of JAFNPP. The Montezuma National Wildlife Refuge is located north of Cayuga Lake in Seneca County, approximately 44 miles southwest of JAFNPP. Approximately twenty State Wildlife Management Areas are also located within a 50-mile radius of JAFNPP. [Reference 2-20, Section 2.2.8.3]

In order to accommodate and regulate growth and development, Onondaga and Oswego Counties have developed county-specific comprehensive growth management plans characterizing current conditions and setting standards, regulations, and goals for land use and development. Neither county implements growth control measures that limit residential housing development. Land use planning and zoning regulations are primarily developed by the towns, villages and municipalities located within Oswego and Onondaga Counties, meaning that land use standards may vary across each county. [Reference 2-20, Section 2.2.8.3]

Table 2-10
Land Use in Oswego (1995) and Onondaga (2004) Counties, New York

Land Use	Percent of Total
Oswego County	
Agriculture, forested, and vacant	55
Residential	36
Public	6
Commercial and industrial	3
Onondaga County	
Agriculture, forested, and vacant	51
Residential	29
Public	10
Commercial and industrial	10
SOURCE: Reference 2-20, Table 2-10	

2.8.1 Future Land Use Trends

The town of Scriba is an unincorporated portion of Oswego County. As for all unincorporated land in Oswego County, there are no zoning or land-use restrictions. The town of Scriba does implement site plan review and lot size restrictions on proposed development, either business or residential. [Reference 2-10, Section 2.9]

Oswego County has experienced low-to-moderate population growth and land-use changes in the last 10 years and Onondaga County has experienced a population loss of 2.3% [Reference 2-22].

Taxes paid by JAFNPP contribute to maintaining the tax rates in Oswego County and the Town of Scriba lower than would otherwise be needed to fund the county and local government's current level of public infrastructure and services. This could enhance the area's attractiveness as a place to live and possibly influence overall growth and development trends in the county.

2.9 Housing

As of September 2005, JAFNPP has a permanent staff of approximately 716 employees. The majority of the employees live in Oswego and Onondaga Counties. As shown in Table 3-1, 556 employees live in Oswego County and 127 live in Onondaga County. The remaining employees are divided among seven counties in New York State and one town in Massachusetts.

JAFNPP schedules refueling outages at 24-month intervals. During refueling outages, site employment may increase by as many as 700 to 900 workers for temporary duty (approximately 30 days). Most of these workers are assumed to be located in the same geographic areas as the permanent JAFNPP staff.

Between 1990 and 2000, the total population of the two counties where the majority of JAFNPP employees live, Onondaga and Oswego Counties (Table 2-4), has decreased by 1.7%. In Oswego County the total population increased from 121,771 to 122,377, but decreased in Onondaga County from 468,973 to 458,336. During this same period, the number of housing units increased at a slightly higher pace than the increase in population. In the represented two-county area near JAFNPP, total housing units increased approximately 4% as shown in Table 2-11. Total housing units increased from 48,548 to 52,831 in Oswego County and from 190,878 to 196,633 in Onondaga County. [Reference 2-22]

The vacancy rates in Oswego and Onondaga counties changed little from 1990 to 2000 as shown in Table 2-11. Oswego County had the higher vacancy rate of approximately 13.8% in 2000, an increase of 1.2% since 1990. The vacancy rate in Onondaga County increased from 6.8 to 7.9% over the ten-year period. The larger vacancy rate in Oswego County was likely due to the larger percentage of units in the county which are designated as having seasonal, recreational, and occasional uses. [Reference 2-22]

Median home values increased between 1990 and 2000 as shown in Table 2-11. Values increased 12.3% in Oswego County and 5.2% in Onondaga County. The median monthly rent (contracted) in Oswego County increased 38.7% in the 10-year period, while the increase was lower in Onondaga County (31.6%). [Reference 2-22]

Overall, little discernible change in housing availability has occurred in the two county area near JAFNPP since 1990. Vacancy rates have remained relatively stable and the number of available units has kept pace with the low growth in the area population. Home values and rental rates in the area have remained relatively stable as well. [Reference 2-22]

Table 2-11
Onondaga and Oswego Counties Housing Statistics, 1900–2000

	1990	2000	% Change
Onondaga County			
Total Housing Units	190,878	196,633	2.9
Occupied Units	177,898	181,153	1.8
Vacant Units	12,980	15,480	16.1
Vacancy Rate (%)	6.8	7.9	1.1
Median House Value ($)	81,000	85,400	5.2
Median Rent ($/month)	376	550	31.6
Oswego County			
Total Housing Units	48,548	52,831	8.1
Occupied Units	42,434	45,522	6.8
Vacant Units	6,114	7,309	16.3
Vacancy Rate (%)	12.6	13.8	1.2
Median House Value ($)	65,100	74,200	12.3
Median Rent ($/month)	311	507	38.7

Source: Reference 2-22

2.10 Social Services and Public Facilities

2.10.1 Public Water Supply

JAFNPP does not utilize public water supplies for cooling and service water, but instead uses water from Lake Ontario for plant operations. The plant obtains potable water from the Town of Scriba.

Potable water in the vicinity of the plant is supplied to residents either through the Scriba Water District, which receives its water from the City of Oswego, or from private wells [Reference 2-20, Section 2.2.2]. Private wells supply potable water to approximately 49% of the local population [Reference 2-10, Section 2.8.1]. Public water supply comes from Lake Ontario and from underground aquifers [Reference 2-20, Section 2.2.8.2].

There are three principle groundwater aquifers accessed as a consumptive resource by public water suppliers. These aquifers are the Sand Ridge Aquifer, the Fulton Aquifer, and the Tug Hill Aquifer. In addition, to these developed aquifers, it is believed that substantial groundwater resources could be made available from other local or regional aquifers that have been as of yet largely unused. [Reference 2-20, Section 2.2.8.2]

The five districts in the Town of Scriba obtain their water from the City of Oswego. These are the Broadway Road, Hall Road, North Road, Route 104, and Seneca Hill Districts. The total number of customers in all five districts is 646 residential users with a total consumption of 125,925 gallons per year. There is no available capacity in these districts due to low pressure and lack of storage facilities. The Town of Scriba is currently in the process of consolidating these districts into one town district. [Reference 2-12]

The Onondaga County Water Authority (OCWA) purchases water wholesale from the Metropolitan Water Board (MWB) and then sells it retail to water districts in Oswego and Onondaga Counties. The Oswego County districts include the Fort Brewerton Water District, Fort Brewerton Water Supply District, Corporate Park Water Supply District, Central Square Middle School and Transportation Center Water Supply District, Big Bay Water District, Owen Road Water District, and the Oswego Town Wide Water District. The difference between water districts and water supply districts is that the OCWA leases facilities in water districts and owns facilities in water supply districts. [Reference 2-12]

Most of the MWB's capacity is sold to the OCWA, but by law the MWB must provide 25% of its pipeline capacity to Oswego County. While the MWB is allowed to draw as much as 62.5 million gallons per day (gpd) from Lake Ontario through an intake owned by the City of Oswego, its capacity is 60 million gpd. In 1998, the MWB withdrew an average of over 25 million gpd of which 200,000 gpd was provided to communities in Oswego County. Therefore, the MWB has large excess capacity to support future growth in Oswego County. [Reference 2-20, Section 2.2.8.2]

2.10.2 Transportation

JAFNPP is located on the shore of Lake Ontario in the Town of Scriba in Oswego County. The road structure in the immediate vicinity of JAFNPP is primarily smaller county routes, rather than state or interstate highways.

JAFNPP is accessed from the east by Lake Road, which is a two-lane paved roadway running east of the intersection of County Route 1A and Lakeview Road [Reference 2-20, Section 2.2.8.2]. According to the Oswego County Planning and Community Development Department, the average daily traffic count for County Route 1A from County Route 1 to Lakeview Road was 4,900 vehicles in 1995 [Reference 2-20, Section 2.2.8.2].

Due to the rural nature of JAFNPP's location there is no state level of service determination for the county roads which service JAFNPP and the immediate area. However, a traffic capacity study was conducted for a proposed gas turbine plant which was to be located on Lake Ontario, approximately 2 miles from JAFNPP. Only one intersection in the study area was found to have unacceptable operating conditions during the peak morning traffic flow. This intersection is the eastbound approach on Route 1 to Route 1/Route 1A. In addition to the study completed for the proposed plant, the Oswego County Department of Public Works reviewed traffic patterns for the major roads around the JAFNPP as part of a reconstruction project for Route 1A. The County determined that traffic counts were within acceptable levels. [Reference 2-20, Section 2.2.8.2]

2.11 Meteorological and Air Quality

The climate of New York state is broadly representative of the humid continental type, which prevails in the northeastern U.S., but its diversity is not usually encountered within an area of comparable size. Differences in latitude, character of the topography, and proximity to large bodies of water, such as Lake Ontario, have pronounced effects on the climate. JAFNPP is located in a moist continental climate zone characterized by the dominance from tropical air masses in summer and polar air masses in winter, and the presence of deciduous forest that covers the eastern parts of the U.S. and southern Canada. Seasonal changes between summer and winter are very large, with an average seasonal temperature change of 56°F. Mean or normal daily minimum and maximum temperatures for the Oswego East NWS station from 1971 through 2000 range from 16°F in January to 62°F in July and August, and from 31°F in January to 81°F in July, respectively. Cold winters are caused by polar and arctic air masses moving south. Abundant local precipitation occurs throughout the year, with a typical increase in summer rainfall due to invading tropical air masses. Meteorological records for north central New York (Ithaca area) are generally representative of the Nine Mile Point area. The data from this area indicate that lowest precipitation amounts for the year generally last for about a month or two, typically in January and/or February. Mean or normal monthly temperatures for north central New York range from 12.9°F to 30.1°F in January to 57.2°F to 79.8°F in July and August. The mean annual precipitation for the region is 30.5 inches. Normal monthly precipitation ranges from 0.5 to 6.4 inches in the dry season (January) to 1 to 13 inches in the wet season (July). [Reference 2-20, Section 2.2.4]

Severe thunderstorms with winds exceeding 58 mph and/or with property damage occur on average 2 to 3 days per year. During June through August, the daily occurrence of thunderstorms is approximately one day per month, with a total of 126 thunderstorm and wind damage reports filed for Oswego County from January 1, 1950 to June 30, 2004. Through the last half of the last century, 1950 to 2004, a total of eight tornadoes touched down in Oswego County. Seven of these produced slight or moderate property damage and were categorized in the low intensity range of the Fujita Tornado Scale. [Reference 2-20, Section 2.2.4] The probability of a tornado striking this plant site is estimated to be in the order of 3.12×10^{-3} in a reactor lifetime of 40 years [Reference 2-4, Section 12.4.5].

Wind resources are expressed in terms of wind power classes, ranging from class 1 to class 7. Each class represents a range of mean wind power density or approximate mean wind speed at specified heights above the ground. The wind energy resource for most of the Lake Ontario and Lake Erie shoreline region of New York State, including Oswego County, has good wind power potential. The annual average wind power for this part of the state is rated class 3. Areas designated class 3 or greater are suitable for most wind energy applications, whereas class 2 areas are marginal and class 1 areas are generally not wind-power suitable. [Reference 2-20, Section 2.2.4]

JAFNPP is located in Oswego County, New York, which is part of the Central Air Quality Control Region covered by Region 7 of NYSDEC. With the exception of ozone, this region is designated as being in attainment or as unclassifiable for all criteria pollutants as defined in 40 CFR 81.333. Jefferson County, north of Oswego County, is designated as a nonattainment area for ozone, and classified moderate for the 8-hour and marginal for the 1-hour ozone National Ambient Air Quality Standards. No Prevention of Significant Deterioration Class I areas are located within 62 miles of JAFNPP. [Reference 2-20, Section 2.2.4]

There are two auxiliary boilers, four emergency diesel generators, and two diesel fire pumps located on the JAFNPP site. Emissions from the boilers, generators, and fire pumps are regulated under a Certificate to Operate an Air Contamination Source (7-3556-0020/00012) issued by the NYSDEC. This certificate limits the fuel usage and hours of operation of these emission sources.

2.12 Historic and Archaeological Resources

2.12.1 Federal and State Historic Preservation

The New York State Historic Preservation Office Environmental Review program is a planning process that helps protect New York's historic cultural resources from the potential impacts of projects that are funded, licensed, or approved by state or federal agencies. Under Section 106 of the National Historic Preservation Act and Section 14.09 of the New York State Historic Preservation Act, the State Historical Preservation Office's (SHPO) role in the review process is to ensure that effects or impacts on eligible or listed properties are considered and avoided or mitigated during the project planning process. In addition, the SHPO advises local communities on local preservation environmental reviews, upon request, under the provisions of the State Environmental Quality Review Act. [Reference 2-8]

New York's State Historic Preservation Office (SHPO) helps communities identify, evaluate, preserve, and revitalize their historic, archeological, and cultural resources. The SHPO administers programs authorized by both the National Historic Preservation Act of 1966 and the New York State Historic Preservation Act of 1980. These programs, including the Statewide Historic Resources Survey, the New York State and National Registers of Historic Places, the federal historic rehabilitation tax credit, the Certified Local Government program, the state historic preservation grants program, state and federal environmental review, and a wide range of technical assistance, are provided through a network of teams assigned to territories across the state. The SHPO works with governments, the public, and educational and not-for-profit organizations to raise historic preservation awareness, to instill in New Yorkers a sense of pride in the state's unique history and to encourage heritage tourism and community revitalization. [Reference 2-8]

The New York SHPO is the primary contact for the two historic registers that track New York's historic resources. The National Register of Historic Places is the official federal listing of significant historic, architectural, and archaeological resources. The New York State Register of Historic Places is the list of significant historic and prehistoric resources throughout New York.

The New York SHPO was contacted during the early stages of site construction for information related to any known archeological resources in the vicinity of the JAFNPP site. JAFNPP received certification from the SHPO that the plant would not have a harmful effect on any sites of historical or archaeological importance. [Reference 2-15, Section 2.3] JAFNPP contacted the SHPO in February 2006. The SHPO did not raise any items of concern and asked to be consulted prior to the beginning of any construction on the JAFNPP site.

2.12.2 Historic Era

New York has more than 3,000 historic sites which are listed in or eligible for the National Register of Historic Places (NRHP) [Reference 2-21]. There are seventy-nine NRHP sites in Oswego County. Several of these sites are considered to be historical districts that encompass multiple properties. Forty-three of these NRHP sites are located within 10 miles of JAFNPP (Table 2-12).

New York has 254 sites on the register of National Historic Landmarks (NHL); however, none are included in the 43 properties on the above NRHP list (see Table 2-12) [Reference 2-21]. One NHL site, the NASH (harbor tug) is located in Oswego County. There are no historical or archeological sites in the immediate vicinity of the JAFNPP site based on consultation with the New York State Historic Preservation Office (see Attachment B).

The JAFNPP site is part of what at one time was the Onondaga Indian Nation's eighteenth century tribal land. A series of treaties between 1794 and 1822 between New York Indian tribes and the U.S. government diminished tribal territorial holdings in the State of New York. The present day Onondaga Indian Nation tribal holdings consist of 7,300 acres of land south of Syracuse. [Reference 2-11]

Oswego County where JAFNPP is located is rich in history. Prior to the Civil War, the Underground Railroad was very active throughout Oswego County as a stopping point on the way to Canada for escaped African American men and women who had been enslaved in the southern United States. Many of the properties listed in the NRHP for Oswego County are related to the Abolitionist movement of the 1800s. [Reference 2-14]

Oswego County has also played an important role in the defense of the United States. During the Revolutionary War, it was the furthest frontier border of the colonies and was an important battle front in the War of 1812 [Reference 2-12]. Fort Ontario, which originally played a role in U.S. defense, played a different role at the end of World War II, when it was used as an emergency refugee center for survivors of the Nazi holocaust. This was the only refugee center of its kind on U.S. soil. [Reference 2-1]

The Town of Scriba was created in 1811, although settlers in the area arrived as early as 1798. The location for the first non-Indian settlement was at "Scriba Corners." The earliest business at Scriba Corners was Heil Stone's log tavern, followed in 1819 by a store. [Reference 2-20, Section 2.2.9.1]

The early economy was based on timber harvesting and lumber production. As forests were cut, residents moved to farming, especially dairy and fruit production. The Oswego Canal opened in 1828 and the Syracuse & Oswego Railroad opened in 1848. The canal and railroad precipitated surges in the lumber industry and in agriculture. By 1855 more than half of the county's workers were farmers. However, by the late 1800s the shipping industry in Oswego collapsed, as did agriculture, and farmers began to leave. It took Oswego County 90 years to return to the population level of 1870. By 1900, at least twelve residences had located in the JAFNPP area. The number of farms and homes remained relatively stable until 1955, at which time there were fourteen residences. [Reference 2-20, Section 2.2.9.1]

Table 2-12
Listed or Eligible Historic Locations for the National Register of Historic Places
Oswego County, 10-Mile Radius Surrounding JAFNPP

Resource Name	City
Buckout – Jones Building	Oswego
Edwin W. and Charlotte House	Oswego
John B. and Lydia Edwards House	Oswego
Fort Ontario	Oswego
Franklin Square Historic District	Oswego
Nathan and Clarissa Green House	Oswego
Hunter – Oliphant Block	Oswego
Kingsford House	Oswego
Hamilton and Rhoda Littlefield House	Oswego
Market House	Oswego
John and Harriet McKenzie House	Oswego
Montcalm Park Historic District	Oswego
Oswego Armory	Oswego
Oswego City Hall	Oswego
Oswego City Library	Oswego
Oswego County Courthouse	Oswego
Oswego Theater	Oswego
Oswego West Pierhead Lighthouse	Oswego

Table 2-12
Listed or Eligible Historic Locations for the National Register of Historic Places Oswego County, 10-Mile Radius Surrounding JAFNPP

Resource Name	City
Daniel and Miriam Pease House	Oswego
Pontiac Hotel	Oswego
Richardson-Bates House	Oswego
Riverside Cemetery	Oswego
Sheldon Hall	Oswego
George B. Sloan Estate	Oswego
U.S. Customhouse	Oswego
Walton and Willett Stone Store	Oswego
Woodruff Block	Oswego
Leonard Ames Farmhouse	Mexico
Orson Ames House	Mexico
Peter Chandler House	Mexico
Starr Clark Tin Shop	Mexico
Phineas Davis Farmstead	Mexico
Fowler – Loomis House	Mexico
Hamilton Farmstead	Mexico
Mexico Academy and Central School	Mexico
Mexico Octagon Barn	Mexico
Mexico Railroad Depot	Mexico
Mexico Village Historic District	Mexico
Timothy Skinner House	Mexico
Slack Farmstead	Mexico
Stillman Farmstead	Mexico
Thayer Farmstead	Mexico
Asa and Caroline Wing House	Mexico
SOURCE: Reference 2-21	

2.13 Related Federal Project Activities

During the preparation of this report, Entergy identified the pending license renewal application of NMPNS as an activity that could potentially contribute to the cumulative environmental effects of license renewal at JAFNPP. No additional activities that could contribute to the cumulative environmental impacts of license renewal at JAFNPP were identified.

2.14 References

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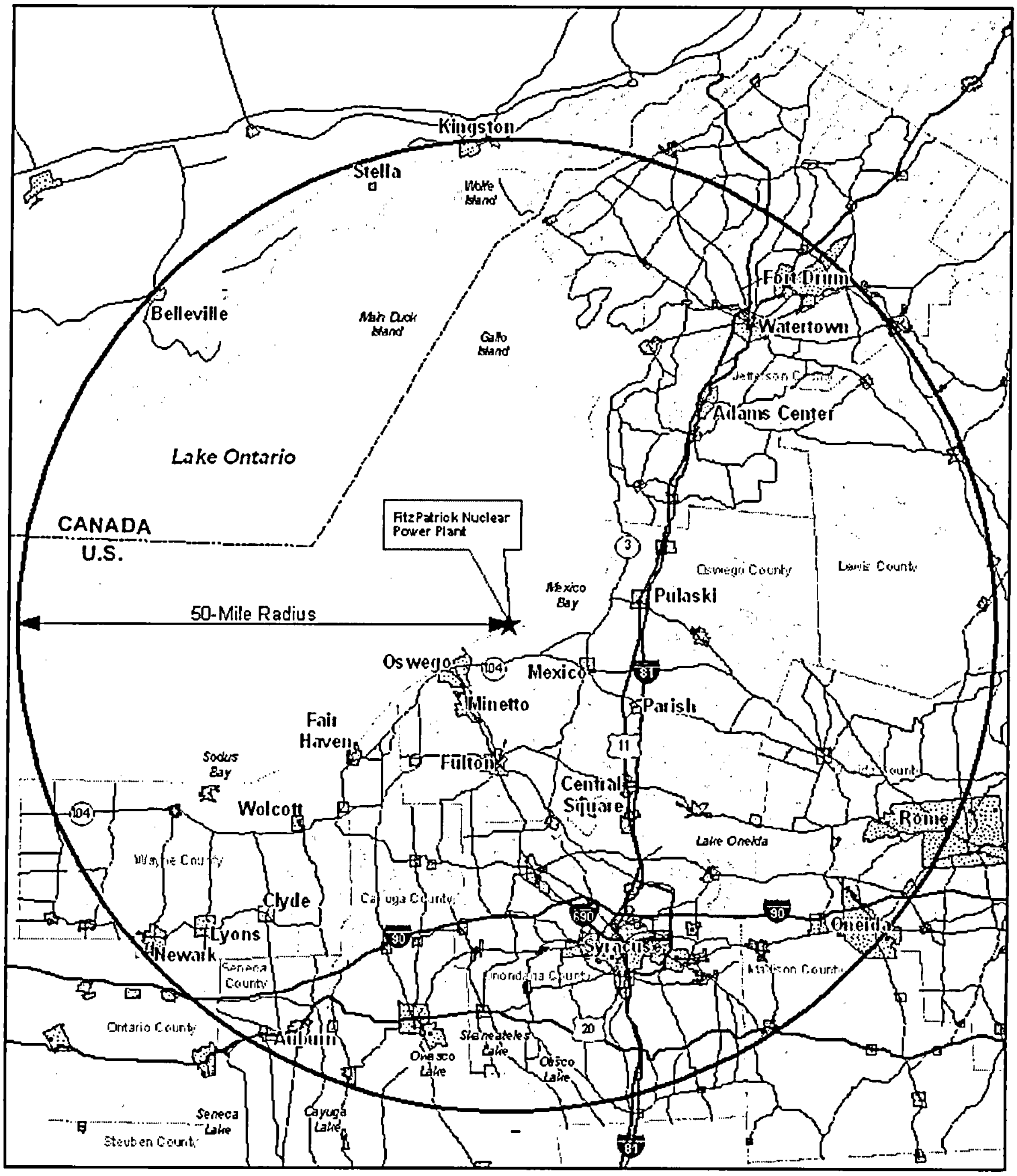

Figure 2-1
Location of JAFNPP

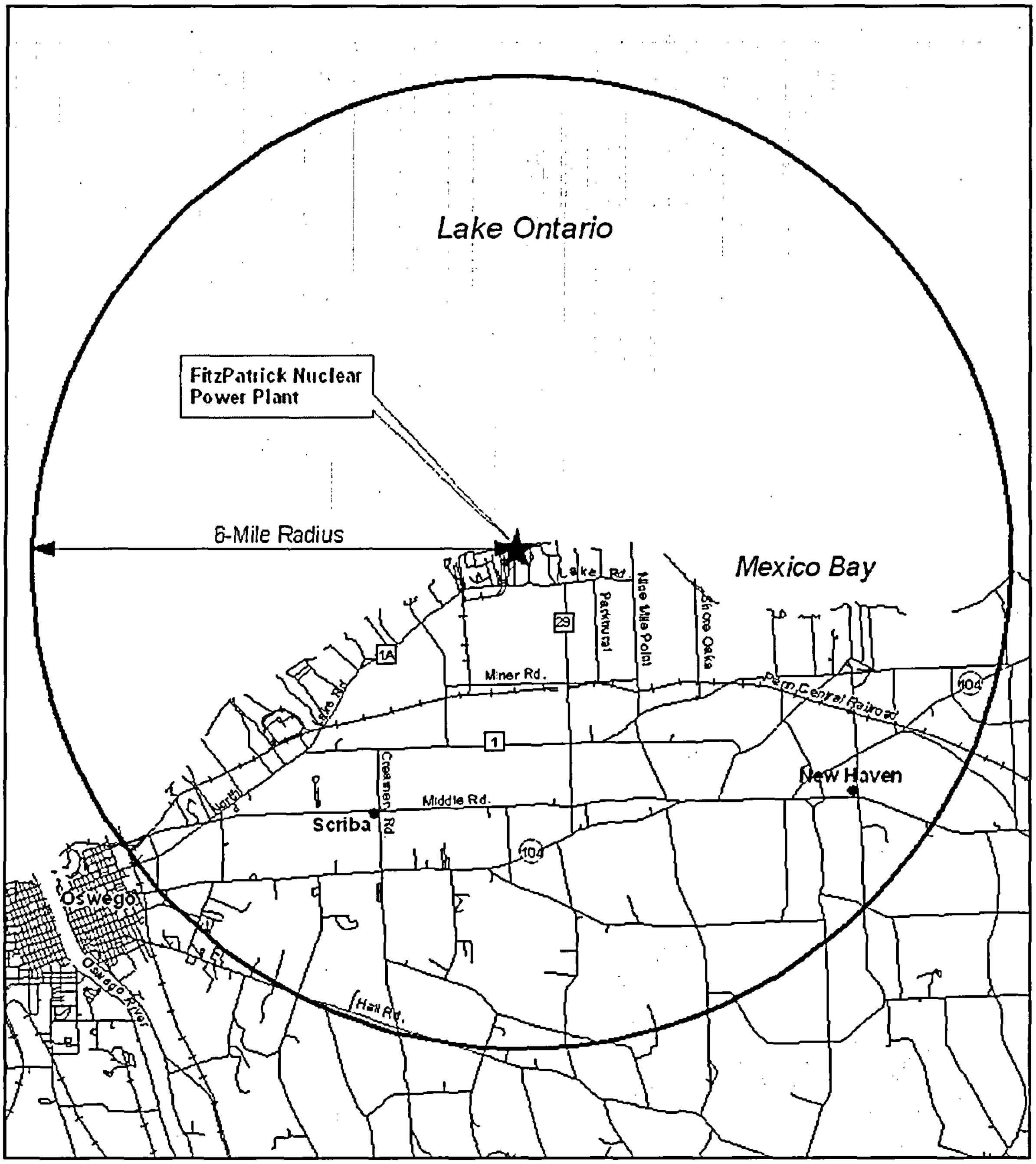

Figure 2-2
General Area Near JAFNPP

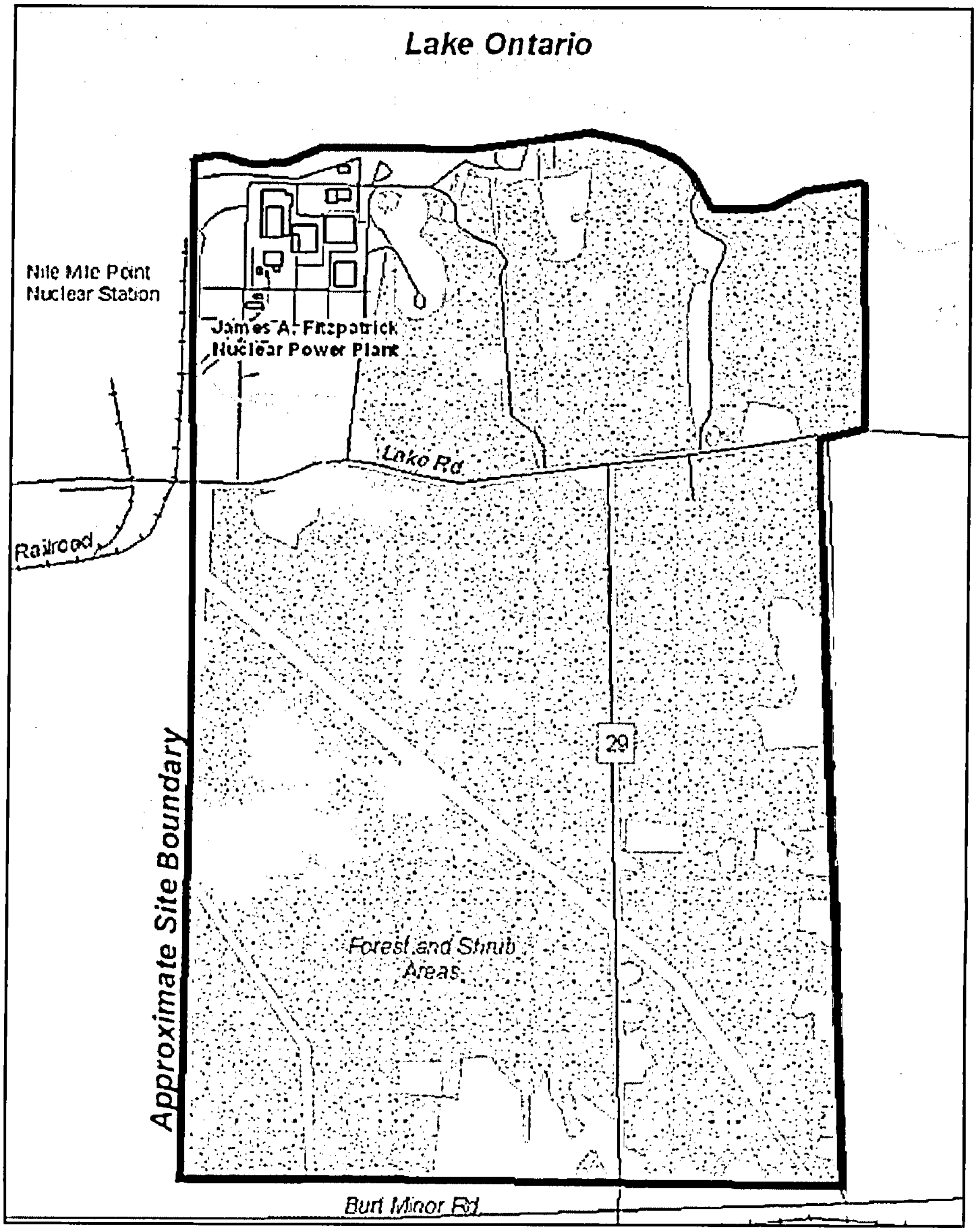

Figure 2-3
Approximate Site Boundary

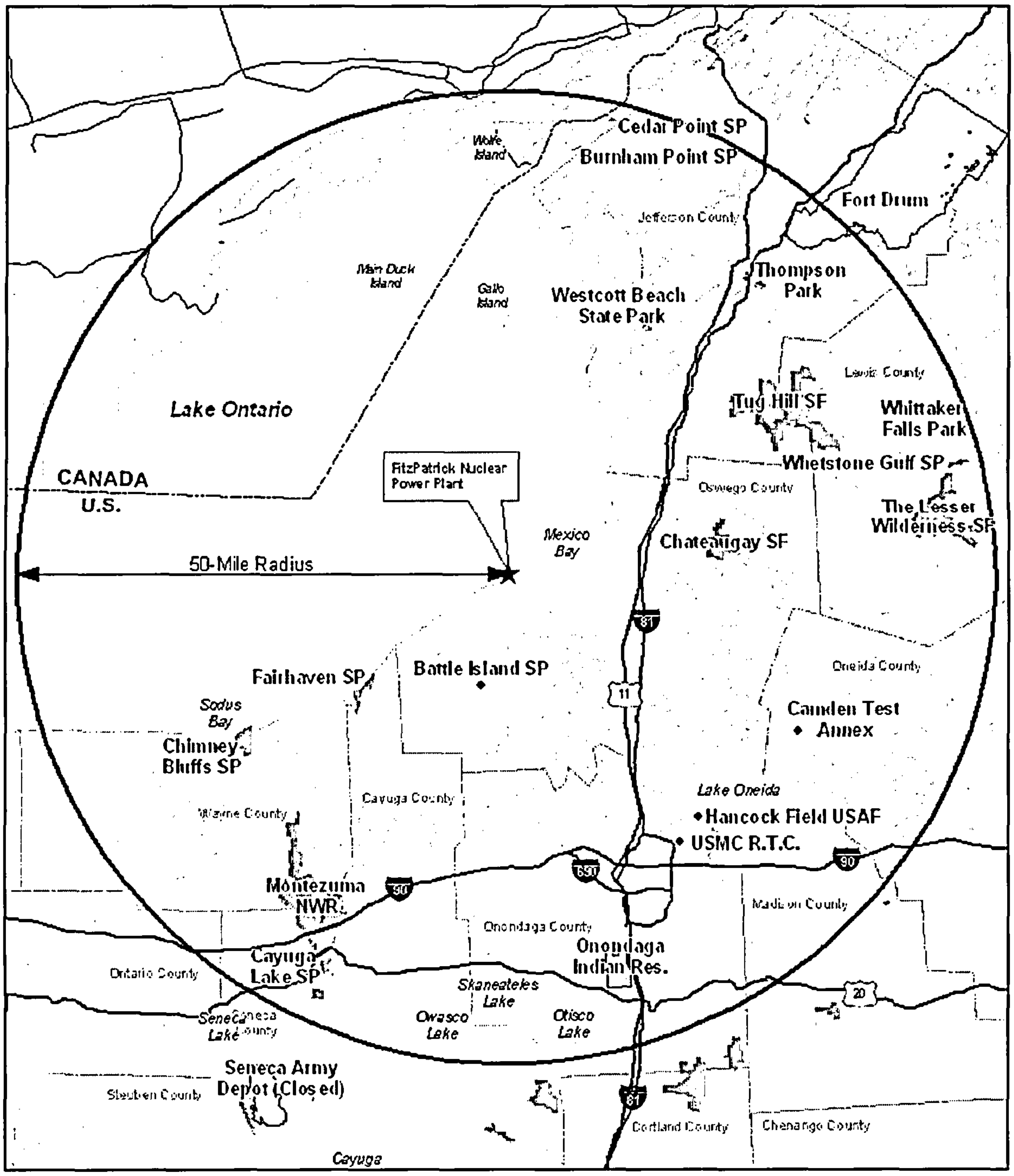

Figure 2-4
Major State and Federal Lands, 50-Mile Radius

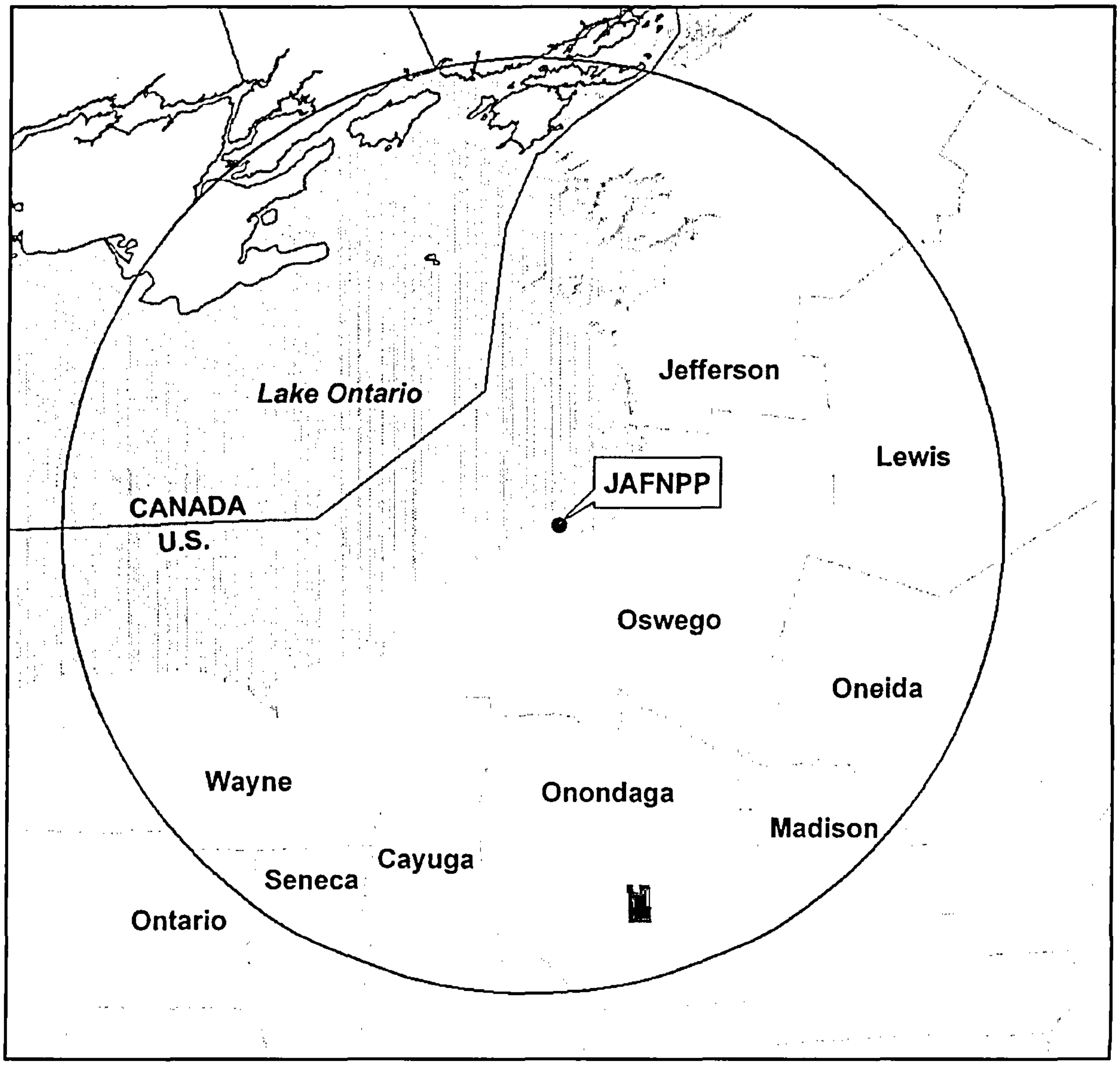

Figure 2-5
American Indian Population Map

Red areas indicate census block groups that meet the definition of a minority population.

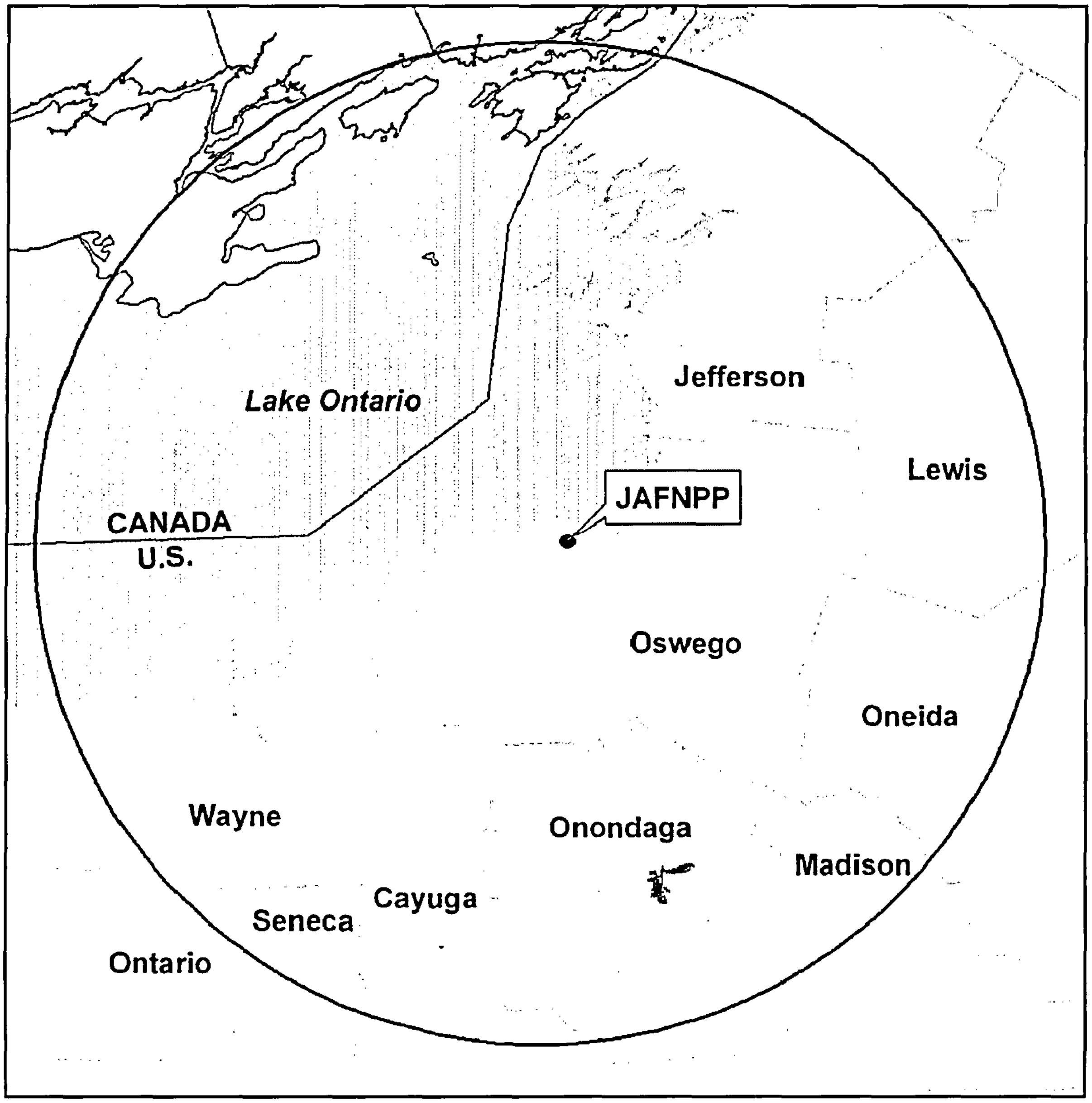

Figure 2-6
Black Races Population Map

Red areas indicate census block groups that meet the definition of a minority population.

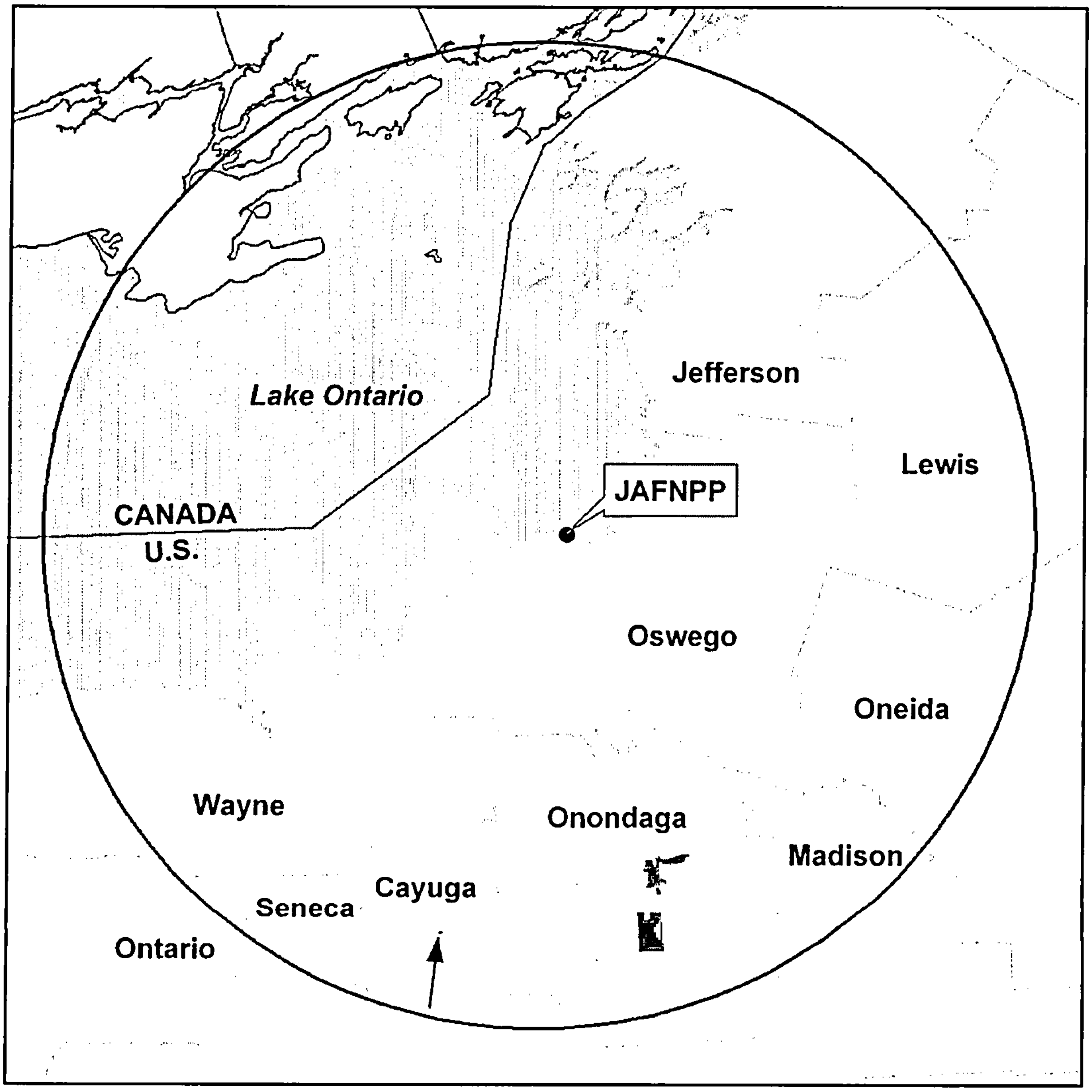

Figure 2-7
Aggregate Minority Population Map

Red areas indicate census block groups that meet the definition of a minority population.

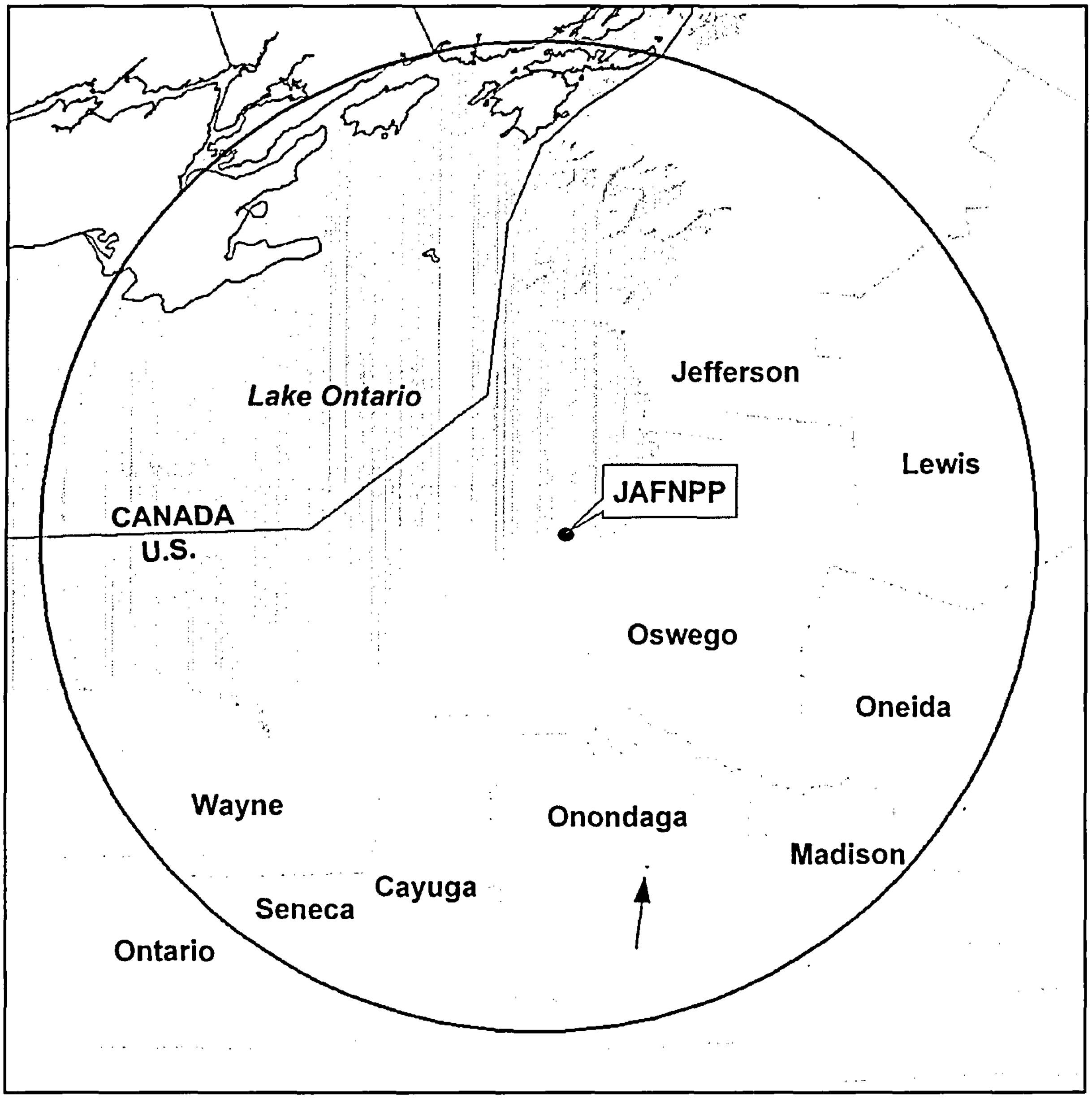

Figure 2-8
Hispanic Ethnicity Population Map

Red areas indicate census block groups that meet the definition of a minority population.

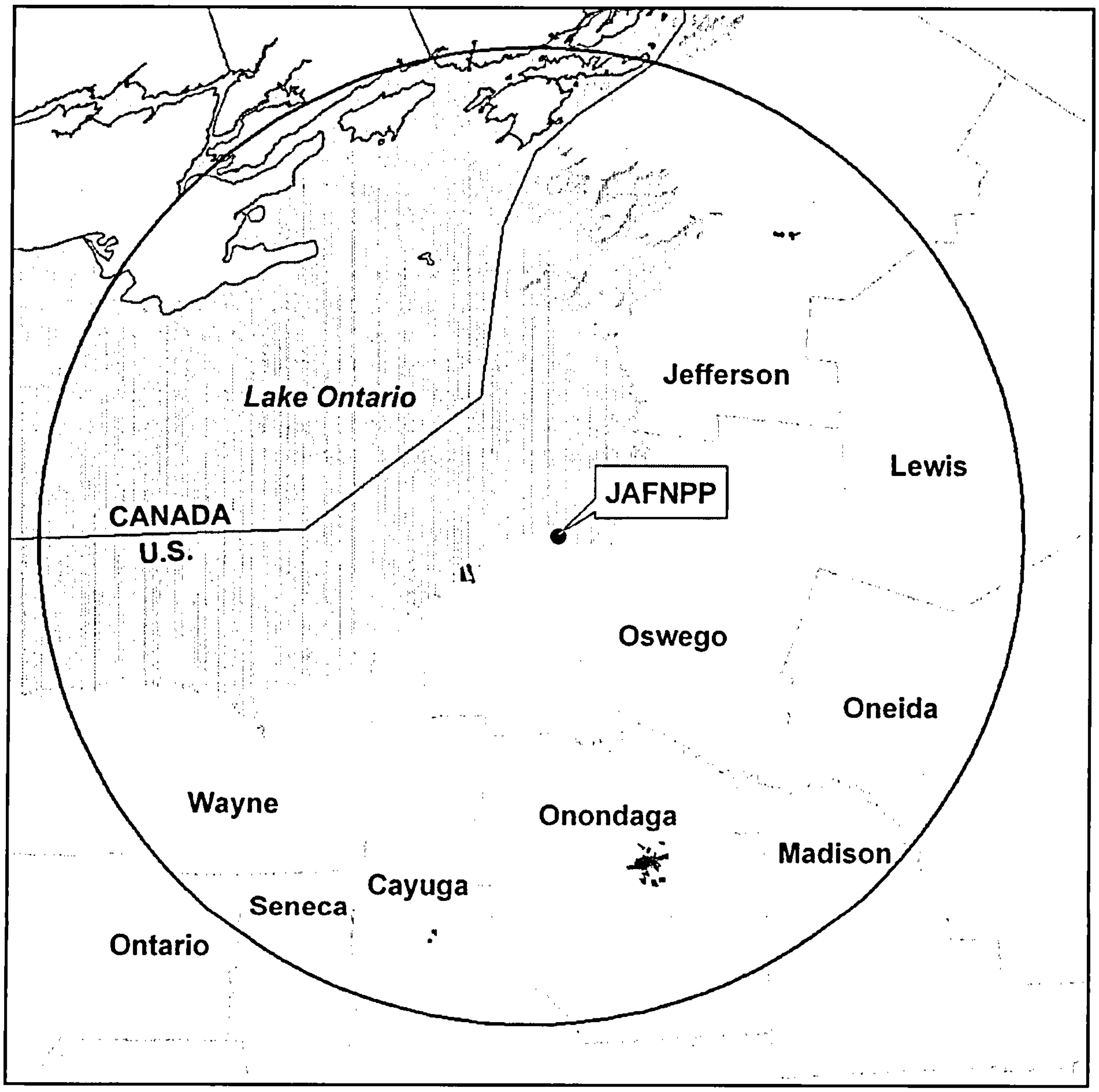

Figure 2-9
Low Income Population Map

Red areas indicate census block groups that meet the definition of a minority population.

3.0 THE PROPOSED ACTION

3.1 Description of the Proposed Action

The proposed action is to renew the facility operating license for JAFNPP for an additional twenty (20) years beyond the expiration of the current operating license. For JAFNPP (Facility Operating License DPR-59), the requested renewal would extend the license expiration date from midnight October 17, 2014, until midnight October 17, 2034.

There are no changes related to license renewal with respect to operation of JAFNPP that would significantly affect the environment during the period of extended operation. The application to renew the operating license of JAFNPP assumes that licensed activities are now conducted, and would continue to be conducted, in accordance with the facility's current licensing bases (e.g., use of low-enriched uranium fuel only). Changes made to the current licensing basis of JAFNPP during the staff review of this application would be made in accordance with the Atomic Energy Act of 1954, as amended, and in accordance with Commission regulations.

3.2 General Plant Information

The principal buildings and structures at JAFNPP consist of the reactor building, turbine building with electrical and heater bays, administration building and control room, radioactive waste building, screenwell-pump-house building with intake and discharge tunnels and structures, diesel generator building, auxiliary boiler building, main stack, Independent Spent Fuel Storage Installation (ISFSI), sewage treatment plant, and interim radwaste storage building [Reference 3-1, Section 12.1]. The reactor and nuclear steam supply system for JAFNPP, along with the mechanical and electrical systems required for the safe operation of JAFNPP, are primarily located in the reactor building. Figure 3-1 shows the general features of JAFNPP and Figure 2-3 shows the site boundary.

3.2.1 Reactor and Containment Systems

The reactor coolant system includes a single cycle, forced circulation, General Electric Boiling Water Reactor producing steam for direct use in the steam turbine [Reference 3-1, Section 1.6.1.3]. The rated thermal output of the unit is 2,536 megawatts-thermal (MWt) [Reference 3-1, Section 1.6.1.3]. The gross electrical output corresponding to 2,536 MWt is approximately 881 megawatts-electric (MWe) [Reference 3-1, Section 1.1]. JAFNPP achieved commercial operation in 1975.

The fuel for the reactor core consists of slightly enriched uranium dioxide pellets contained in sealed Zircaloy-2 tubes which were evacuated, backfilled with helium, and sealed with Zircaloy end plugs welded in each end [Reference 3-1, Section 3.2.4]. The core is designed to permit the energy extraction of 19,000 MWD/T of uranium averaged over the initial core load [Reference 3-1, Section 3.6.5.2].

The primary containment and reactor vessel isolation control systems automatically initiate the closure of isolation valves to close all potential leakage paths for radioactive material to the environs. This action is taken upon indication of a potential breach in the reactor coolant pressure boundary. [Reference 3-1, Section 1.6.2.7]

The reactor building is designed as a low inleakage, elevated release secondary containment system which houses the primary containment system, refueling facilities, and most of the components of the nuclear steam supply system. The secondary containment systems provide secondary containment when the primary containment system is closed and in service, and it provides primary containment when the primary containment system is open, as in refueling. The secondary containment consists of the reactor building, standby gas treatment system, reactor building isolation control system, and the main stack. In the event of a postulated pipe break inside the drywell, or a fuel handling accident, the reactor building is isolated by the reactor building isolation control system to provide a low leakage barrier. The standby gas treatment system is initiated by the same conditions that isolate the reactor building. The standby gas treatment system exhausts air from the reactor building to maintain a reduced pressure within the reactor building relative to the outside atmosphere, treats the air to remove particulates and iodines, and releases the air through the elevated release point, the main stack. [Reference 3-1, Section 1.6.2.8] These safety features function to localize, control, mitigate, and terminate such events to limit exposure levels below applicable dose guidelines.

3.2.2 Cooling and Auxiliary Water Systems

3.2.2.1 Circulating Water System

The circulating water system uses water taken from Lake Ontario. Water passes through trash racks and then through traveling water screens. A major portion (approximately 91%) of the flow is directed to the circulating water pumps which deliver water to the main condenser. A small portion (approximately 9%) of the water is used by the service water pumps. The discharge from the main condenser and from the service water system is returned via the discharge tunnel and diffuser system to the lake. [Reference 3-1, Section 10.6.3]

The trash rack installed in front of the traveling water screens retains pieces of debris larger than 3 1/8 inch. The traveling water screens retain particles 3/8 inch and larger. The screenwell houses three circulating water pumps, each having a rated head of 27 ft Total dynamic head and a rated flow of 120,000 gpm. The pumps are vertical, mixed flow, dry pit type. The pump drivers are open, drip-proof, induction motors rated at 1000 hp, 257 rpm, 4160V, 3 phase, 60 Hz. [Reference 3-1, Section 10.6.3]

At the design circulating water flow of 352,600 gpm through the condenser and at design power on the turbine-generator, the maximum allowable temperature rise through the main condenser is 32.4°F. The design effluent flow rate to the discharge tunnel is 388,600 gpm, including the design service water pumps discharge of 36,000 gpm. [Reference 3-1, Section 10.6.3]

Nine integrated projector housings are installed on top of the intake structure roof symmetrically located at elevation 232'-8" to provide for fish deterrence of the alewives fish species. This system will not reduce or change the flow rates as described. Due to the possibility of ice packs defacing the projector face, the projectors can be removed for the winter months. [Reference 3-1, Section 10.6.3]

3.2.2.2 Screenwell-Pumphouse Building

The screenwell-pumphouse building houses the condenser circulating water, normal service water, emergency service water, RHR service water, and fire protection system supply pumps, as well as water treatment tanks and equipment. The structure is attached to the turbine building on the south side, the radioactive waste building on the east side, and the emergency diesel generator building on the west side. [Reference 3-1, Section 12.3.6]

The circulating water is brought into a large forebay area from the underground intake tunnel. Trash racks, with a movable rake, and traveling screens are provided to filter the water before it passes to the individual pump bays. The circulating water is pumped to the main condenser in the turbine building through a steel tube encased in reinforced concrete and is returned to the discharge side of the screenwell through a reinforced concrete tunnel. The structure is divided into bays to permit the water flow to be controlled by the use of various gates. [Reference 3-1, Section 12.3.6]

3.2.2.3 Intake Structure

The lake water intake structure is a reinforced concrete structure setting on the lake bottom at a distance of approximately 900 ft from the shoreline in approximately 25 ft of water. The main structure is anchored to natural bedrock below the lake bottom by post-tensioned tendons. The main structure is approximately 44 ft diagonally across and 14 ft high, with the top surface being 10 ft below the minimum lake level. On the shoreward side of the main structure, a fan-shaped intake is constructed of precast concrete sections anchored to the bedrock with grouted rock bolts. An intake area of approximately 8 ft by 70 ft is provided with bar racks to prevent entrance of large debris. This results in an intake velocity of approximately 1.6 fps across the intake bar racks. The bars are heated by induction coils to minimize the probability that frazil ice will block the intake by adhering to the bars during circulating water pump operation. A fish deterrence system is installed on top of the intake structure roof (elevation 232' - 8") consisting of nine projector housings to prevent the impingement of alewives. [Reference 3-1, Section 12.3.7]

The intake is a roofed structure which draws water in through side openings protected with rack bars spaced at 1 foot centers to block the entrance of large debris. This results in water being taken at lower levels and prevents the formation of vortices at the surface, thus minimizing the possibility of floating ice being drawn down from the surface. [Reference 3-1, Section 12.3.7]

The formation of frazil ice on the steel bar racks at the intake structure openings is common in northern climates. This kind of ice is formed when meteorological conditions are such that the water is supercooled below its freezing point due to radiation cooling. Under these conditions, frazil ice can form on intake bar racks, or spongy masses of this ice, formed in other parts of the lake and carried past an intake by wind driven currents, can adhere to the bar racks. [Reference 3-1, Section 12.3.7]

There were two frazil ice events during the first thirty years of plant operations. Frazil ice will not form on, or adhere to, racks which are at a temperature which is slightly above the freezing point. To take advantage of this, heating elements were installed in each of the 88 rack bars at the JAFNPP intake. The capacity of these heaters is such as to keep the temperature of the bars at 33°F during periods when no supercooling occurs or above freezing with up to 1°F supercooling. This is an adequate thermal margin to prevent frazil ice, grease ice, or slush buildup on the bars most of the time. Ice build up can occur on the bars because the amount of supercooling can possibly exceed the thermal margin available. In order to prolong heater life, the heaters are normally energized continuously except for maintenance. Stray frazil ice will then be drawn past the intake racks to the screenwell structure where it can be mixed with tempering water from the circulating water discharge chamber. [Reference 3-1, Section 12.3.7]

The heating system has built-in redundancy in that each of the heaters is wired separately. There are 24 eight-conductor cables running from the intake to the screenwell within 8 conduits embedded in the invert of the intake tunnel. In the event of plant service power failure, the emergency diesel generator system will supply power to the heater system. [Reference 3-1, Section 12.3.7]

The deicing heaters are not, however, required for safe shutdown of the plant and therefore are not safety-related. During plant shutdown conditions when the circulating water pumps are not normally operating, the flow velocity of water into the intakes is so low that significant frazil ice is not drawn into the intake. Additionally, the residence time for the water in the intake tunnel is significantly increased, allowing the water to absorb more heat from the ground/earth and melt any ice particles that may have passed the intake structure. Ice that is accreted (built-up) on the trash rack bars will be eroded prior to reaching one foot of head. When the circulating water pumps are operating, the flow of water into the intake may draw in frazil ice which can form under certain meteorological and hydrological conditions. [Reference 3-1, Section 12.3.7]

In the unlikely event that large masses of ice, coming from another area, are drawn to the intake by the intake velocity (1.2 fps at the outer face of the intake) and block the opening to the extent that the main circulators trip out, it is inconceivable that an opening large enough (less than approximately 10% of the total area) to pass the 30,000 gpm required for normal shutdown would not be left. Assuming, however, that this is the case, the screenwell has built-in provisions that make it possible for the flow in the tunnels to be reversed, i.e., the discharge structure consisting of twelve 2 1/2 ft diameter diffuser nozzles would become the intake and the necessary cooling water would be drawn into the system through these openings. These provisions consist of a series of gates that can be positioned in such a way as to reroute the flow. The sequence for establishing reverse flow involves the opening of two gates (one of which is used for tempering operation) which interconnect the intake and discharge chambers of the screenwell, and the closure of five gates which block the normal intake and discharge flow paths. [Reference 3-1, Section 12.3.7]

Neither the intake structure nor the discharge water outlets are in the shipping lanes of the lake; therefore, they do not constitute a hazard to the commercial shipping industry. The low water datum of the lake is El. 244.0. The top of the intake structure is El. 232.8, or 11.2 ft below the low water datum. The top of the discharge water diffusers is El. 223.3, or 20.7 ft below the low water datum. All the above elevations refer to the United States Lake Survey Datum of 1935. Drawings showing the above information were submitted to the United States Corps of Engineers for obtaining a permit to construct these facilities. Permission was granted in July of 1970. In the highly unlikely event an object of unknown size or description did strike and damage the intake structure, water can be circulated into the plant utilizing the discharge tunnel in a manner described above. [Reference 3-1, Section 12.3.7]

3.2.2.4 Intake Tunnel

The intake tunnel, which is designed as a seismic Class I structure, connects to the bottom of the intake structure and extends downward 60 ft into the natural rock and then runs approximately 1150 ft at a slight downward slope to the screenwell-pumphouse structure. The tunnel is a 14 ft D-shaped tunnel, with flat bottom, vertical sides, and a round top. The average velocity within the tunnel is approximately 4.7 fps. The tunnel arch is reinforced with mortared and grouted rock bolts. Hydraulic smoothness is provided by reinforced concrete invert paving and wire mesh reinforced gunite lining on the sidewalls and arch. The transition sections, elbow and vertical shafts are lined with reinforced concrete. [Reference 3-1, Section 12.3.7]

3.2.2.5 Discharge Tunnel

The discharge tunnel starts at the screenwell-pumphouse structure and extends approximately 1,400 ft northward to the junction with the diffuser branch tunnels, which are oriented generally parallel to the shoreline. The alignment of the discharge tunnel with the diffuser branch tunnels is such as to produce an equal division of flow. The main tunnel is a 14 ft high D-shaped structure, and the diffuser branch tunnels are 9 ft wide by 10 ft high with a slight arch. Construction is similar to the intake tunnel. The velocity in the branch tunnels varies from 4.9 fps just downstream from the junction with the main tunnel to 1.6 fps just prior to the end risers. Discharge is through six risers, three on each branch tunnel, with a distance of at least 150 ft between risers. At the top of each riser is a diffuser head consisting of two horizontal discharge nozzles separated by an included angle of 42 degrees. Each nozzle has a diameter of 2.5 ft to produce an exit velocity of 14 fps in the offshore direction. The nozzle center lines are 5 to 6 ft above lake bottom. [Reference 3-1, Section 12.3.7]

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

The radioactive waste systems collect, treat, and dispose of radioactive and potentially radioactive wastes in a controlled and safe manner such that the operational availability of the plant is not limited. Operating procedures for the radioactive waste systems ensure that radioactive wastes are safely processed and discharged from the plant within the limits set forth in 10 CFR 20, 10 CFR 50, the plant's technical specifications, and the Offsite Dose Calculation Manual (ODCM). The radioactive input to the radioactive waste systems is due to activation products resulting from irradiation of the reactor water and impurities therein (principally metallic corrosion products), and fission products resulting from defective fuel cladding or uranium contamination within the reactor coolant system. [Reference 3-1, Section 11.1]

Radioactive wastes resulting from plant operation are classified as liquid, gaseous, and solid. These three major categories of radioactive wastes are defined below [Reference 3-1, Section 11.1].

(a) Liquid radioactive wastes: liquids received directly from portions of the reactor coolant system or liquids which can become contaminated due to contact with liquids from the reactor coolant system.

(b) Gaseous radioactive wastes: gases or airborne particulates vented from reactor and turbine equipment containing radioactive material.

(c) Solid radioactive wastes: solids from the reactor coolant system, solids in contact with reactor coolant system liquids or gases, and solids used in reactor coolant and steam and power conversion system operation or maintenance.

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 reactor building and may later be transferred to dry storage at an onsite interim spent fuel storage installation. JAFNPP also provides for onsite storage of mixed wastes, which contain both radioactive and chemically hazardous materials.

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 under the Resource Conservation and Recovery Act of 1976.

Systems used at JAFNPP to process liquid, gaseous, and solid radioactive wastes are described in the following sections.

3.2.3.1 <u>Liquid Waste Processing Systems and Effluent Controls</u>

The liquid waste processing system collects, holds, treats, processes, and monitors for reuse or disposal of all radioactive liquid wastes. The system is divided into several subsystems so that the liquid wastes from various sources can be segregated and processed separately. Cross connections between the subsystems provide additional flexibility for processing of the wastes by alternate methods. The wastes are collected, treated, and disposed of according to their conductivity and/or radioactivity. [Reference 3-1, Section 11.2.4]

3.2.3.1.1 High Purity Wastes (Waste Collector Subsystem)

The bulk of the liquid wastes come from the reactor coolant, condensate, and feedwater systems. They have low conductivity (less than 10 mho) with variable radioactivity concentrations dependent upon their source. Radioactive and particulate materials are removed from these wastes by the waste filter and waste demineralizer. The waste demineralizer may be supplemented with the fuel pool etched disc filter or filter-demineralizer. Following this treatment and batch sampling, the waste liquid is normally returned to condensate storage tanks for reuse in the plant. Off-standard process effluents such as high conductivity water (greater than 1 mho) or water of high radioactivity concentration (3 x 10^{-3} Ci/ml) are recycled to the waste collector tank. The waste surge tank is also available as a collection tank for system flexibility. When the activity concentration is equal to or less than 5 x 10^{-4} Ci/ml, the liquid can be discharged to the lake. [Reference 3-1, Section 11.2.4.1]

3.2.3.1.2 Low-Purity Wastes (Floor Drain Subsystems)

The usual sources of low-purity liquid wastes are floor drains and drains from the cooling water side of heat exchangers. These wastes usually have conductivities between 100 and 1,000 mhos and generally have low radioactivity concentrations. These liquid wastes are collected in the waste neutralizer tanks and processed through the modular fluidized transfer demineralization and sluice system (MFTDS). [Reference 3-1, Section 11.2.4.2]

3.2.3.1.3 Chemical Wastes (Chemical Waste Subsystem)

The major wastes in this category are the solutions from laboratory drains, personnel decontamination shower drains, and decontamination drains (non-detergent decontamination solutions). Their radioactivity concentrations vary and are substantially affected by the amount of fission product radioactivity present due to fuel leakage. The concentrated waste tank discharges its solid contents to the liner fill area for dewatering and offsite shipment. [Reference 3-1, Section 11.2.4.3]

3.2.3.1.4 Liquid Radioactive Waste Discharge Header

The liquid radioactive waste discharge header receives batch discharge from the waste sample tanks. All liquid radioactive waste effluent discharged to the environs is routed through the liquid radioactive waste discharge header. The header provides controlled discharge to the tunnel through either a low flow (2–25 gpm) discharge path or high flow (20–200 gpm) discharge path. [Reference 3-1, Section 11.2.4.5]

3.2.3.1.5 Turbine Building Service Area Floor Drains

There are three floor drain sumps located in the turbine building. One is in the steam tunnel, one is in the condenser tube withdrawal area, and the third is in the condensate pump area, all at 244 ft-0 inches. Around each of these sumps, collection hubs collect local floor drainage and route the drainage to the sumps. Since these three sumps are potentially radioactive, they are routed to the radwaste system floor drain subsystem. Any oil which does get to the radwaste system will be visually detected by sampling. Before the waste sample tanks are discharged to the lake, a manual radioactivity sample is taken. The three turbine building floor drain sumps normally collect trace quantities of oil which is recovered by resin precoat material in the radwaste system. Spent resin is back-washed into a sludge tank and processed. [Reference 3-1, Section 11.2.4.6]

3.2.3.1.6 Modular Fluidized Transfer Demineralization and Sluice System

The modular fluidized transfer demineralization and sluice system (MFTDS) is a means of filtering radioactive waste that was originally processed by the waste concentrators. The filtration system consists of five vessels in series: charcoal, cation, anion, anion, and mixed bed. A pump is supplied with the assembly. This pump augments the concentrator feed pumps, if necessary, to boost the driving head to overcome total system head loss with the filtration system installed. Electrical requirements are obtained from a 240/480 V receptacle outside hopper room B. The MFTDS assembly is located in the northeast radwaste building elevation 272' east truck bay area in hopper room A. The area is equipped with four-inch floor drains which have sufficient capacity to contain the liquid in the event of leakage from the filtration system. These drains flow to the radwaste floor drain collector tank (20TK-28) and the waste sludge tank (20TK-45) at the 250' elevation and any leakage would be contained inside the radwaste building. [Reference 3-1, Section 11.2.10]

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 ten times the concentration value specified in Appendix B, Table 2, Column 2, to 10 CFR 20.1001–20.2402 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 [Reference 3-2, Section 2.2.1]. The ODCM dose limits during a calendar quarter are 0.015 millisievert (mSv) (1.5 mrem) to the total body and 0.05 mSv (5 mrem) to any organ [Reference 3-2, Section 2.3.1]. 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 [Reference 3-2, Section 2.3.1]. 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

The gaseous radioactive waste system processes and then disposes of the condenser off-gases via the main stack. Non-radioactive gland seal gas and gases from the start-up mechanical pump also are discharged from the stack. [Reference 3-1, Section 11.4.4.1]

During plant operation, condenser off-gas is the major contributor to the activity in the off-gas release. Condenser off-gas entering this system consists of noncondensables from the main condenser. These gases consist of hydrogen and oxygen formed in the reactor by radiolytic decomposition of water, air in-leakage to the turbine-condenser, water vapor, and a negligible volume of fission gases. The most important sources of radioactive gases are activation gases in the reactor coolant and fission gases which leak through the fuel cladding. [Reference 3-1, Section 11.4.4.1]

3.2.3.2.1 Condenser Off-Gas System

In the current configuration, the off-gas system has three possible modes of operation as follows:

(1) Start-up mode: steam jet air ejector (SJAE) off-gas is released to the 24-inch holdup pipe (with a 30-minute holdup time at the nominal flow of 20 scfm) and then to the atmosphere via high efficiency particulate air (HEPA) filters.

(2) Intermediate mode: SJAE off-gas is processed by the recombiner, released to the 24-inch holdup pipe and then released into the atmosphere via HEPA filters.

(3) Normal mode: SJAE off-gas is processed by the recombiner, directed to the charcoal beds in the main stack (by a 2" line bypassing the holdup pipe), and then released to the atmosphere via HEPA filters.

In all three modes, the discharge is through the main stack. [Reference 3-1, Section 11.4.4.2]

During normal operation, the hydrogen and oxygen in the condenser off-gas are recombined prior to passing through (1) a moisture removal process, (2) charcoal beds for retention of Xe and Kr, and (3) HEPA filters for the removal of carbon dust before the off-gas exits through the stack. A 2-inch line transfers the effluent from the recombiner directly to the charcoal beds in the main stack. If the off-gas recombiner is inoperable, the off-gas is routed to the 24-inch holdup pipe before exiting to the main stack where dilution air is provided to reduce the hydrogen concentration to below the limit of 4% hydrogen by volume. The off-gas passes through the drip pot prior to entering the holdup pipe. The drip pot is designed to collect excess moisture and return it to the main condenser. The holdup pipe, by design, drains back to the drip pot so that any moisture in the off-gas effluent condensing in the pipe in the journey to the stack will be returned. [Reference 3-1, Section 11.4.4.2]

The dilution air fans and charcoal beds are located in the base of the stack. The stack design ensures prompt mixing of gas inlet streams at its base, thereby providing prompt dilution of hydrogen and allowing the location of sample points as near the base as possible. The main stack drainage is routed to the reactor building equipment drain sump. [Reference 3-1, Section 11.4.4.2]

3.2.3.2.2 Recombiner System

The recombiner system is an off-gas treatment train that is located in the turbine building. The system receives off-gas from the main condenser air ejectors and continuously recombines the hydrogen and oxygen to form steam. Prior to recombination, the gas mixture is diluted with steam to reduce the hydrogen concentration to less than 7.3% by volume. This dilution is required to maintain the gas mixture below the flammable concentration for hydrogen in a steam environment. [Reference 3-1, Section 11.4.4.2]

During plant operation with hydrogen injection, the non-condensable gas composition in the main condenser will shift from an essentially stoichiometric mixture of hydrogen and oxygen to a hydrogen rich mixture. Accordingly, to maintain normal operation of the off-gas system, oxygen is injected in the steam dilution line upstream of the recombiners. After recombination, the off-gas mixture passes through two in series condensers. The first condenser uses main condensate as the cooling medium while the second uses turbine building closed loop cooling water. This cooling water is chilled by one of the two 100% capacity chillers. This low temperature cooling water is necessary to insure that the off-gas mixture is cooled before it enters the off-gas dryer assembly. The off-gas chiller consists of two separate units. One chiller unit is in continuous service, while the other is in standby. The off-gas dryers reduce the moisture content of the mixture to less than +10°C (50°F) dewpoint to ensure proper operation of the activated charcoal beds. The off-gas dryer consists of two drying towers. One tower is in service, while the other tower is regenerating or in a standby status. During regeneration, the tower is heated to remove moisture absorbed by the dryer desiccant. When regeneration is complete, the tower is in standby until cycled automatically at 12-hour intervals. The off-gas drying towers are contained within an enclosure designed to capture off-gas leakage. Air flow through the enclosure removes the heat generated during desiccant regeneration. [Reference 3-1, Section 11.4.4.2]

During start-up or in the intermediate mode when the charcoal vessels cannot be used (due to either high hydrogen concentration, high moisture content at the recombiner dryer exit, or high charcoal temperature), the off-gas mixture is discharged via the 24" holdup pipe to the stack. In the start-up mode, the holdup piping and system provide approximately 22 minutes of holdup time (at a flow rate of 269 cubic feet per minute (cfm)) for all nuclides prior to being released through HEPA filters 01-107F-1A and B. [Reference 3-1, Section 11.4.4.2]

During the intermediate mode (recombiner in use; charcoal tanks bypassed), the system and holdup piping provides approximately 1.63 hours of holdup time for all nuclides prior to being released through the HEPA filters and exiting through the stack. The holdup pipe is buried five feet below grade to provide shielding and protection of the holdup pipe. [Reference 3-1, Section 11.4.4.2]

During normal operating mode, the 24-inch holdup pipe is bypassed. Holdup time for activation gases is one minute, based on 60 scfm flow through the 2-inch discharge line to the charcoal tanks. Holdup times with the use of activated charcoal beds for Kr and Xe are 4.6 hours and 106.7 hours, respectively. [Reference 3-1, Section 11.4.4.2]

The recombiner system is located adjacent to the SJAEs to reduce the hydrogen as soon as possible and minimize the length of pipe run. The recombiner system has several alarm conditions that can be used to warn the control room operator that the line from the SJAEs to the recombiner or the line downstream of the recombiner has ruptured. If the line upstream of the recombiner should rupture, the hydrogen concentration to the recombiner would be reduced, thus lowering the recombiner effluent temperature which is alarmed. If the line downstream of the recombiner should rupture, the pressure in the recombiner system would be reduced, thus increasing the dilution steam flow to the recombiner, which is also alarmed. Following rupture of either the recombiner intake or discharge piping, the recombiner is automatically isolated on a signal from either the recombiner effluent temperature or the steam flow to the recombiner, thus routing the SJAE off-gas through a bypass line directly to the 24-inch underground pipe. [Reference 3-1, Section 11.4.4.2]

The filters which follow the activated charcoal banks and those which follow the holdup piping are located at the base of the main stack and consist of two parallel sets of full-flow HEPA filters. The filters located in the discharge of the charcoal filters are used during the normal operating mode. They serve to remove carbon dust from the gas before it passes up the stack. The isolated parallel filter provides backup and ensures availability of filtration. A filter catcher is also provided at the filters that follow the 24-inch holdup piping. The filter catcher, located at the filter outlet, serves to collect filter fragments in case of an explosion in the 24-inch holdup piping. The catcher, an internal part of the filter, is composed of fine stainless steel mesh screen and reinforced to withstand an explosion. These filters are not used during normal operating mode. [Reference 3-1, Section 11.4.4.2]

Two air dilution fans are present in the stack. One dilution fan operates continuously while the other fan is in standby. Dilution fans are located in the base of the stack. The flow from the operating stack dilution fan ensures that hydrogen is diluted to less than 4% by volume and allows an isokinetic sample to be taken. To prevent backflow, each dilution fan has a discharge valve that is closed when the fan is not operating. A local flow indicator on each fan indicates when fan volumetric flow rate drops to less than 3,000 cfm. [Reference 3-1, Section 11.4.4.2]

3.2.3.2.3 Off-Gas System Charcoal Filter

The off-gas system charcoal beds are composed of twelve steel vessels in series. The gas flows through the 12 vessels in series, entering at the bottom of each vessel. To assure that the system is performing as intended, gas sampling connections and tubing run to the sample room from the piping connecting the tanks. As the gas passes through the charcoal filter bed, a release re-adsorption process takes place, increasing the holdup time of radioactive Xe and Kr gases. The exit gas from the charcoal filter bed passes through another HEPA filter which prevents the release of any charcoal dust that may carry over from the beds. The gases then pass to the main stack for release. Moisture content of the off-gas is monitored by two moisture analyzers which are located on the off-gas piping between the recombiner unit and the charcoal tanks. [Reference 3-1, Section 11.4.4.2]

3.2.3.2.4 Gland Seal Off-gas System

The gland seal off-gas system collects gases from the gland seal condenser and the mechanical vacuum pump and passes them through holdup piping prior to release to the stack. Gland seal off-gases and gases from the mechanical vacuum pump, used during each start-up, are routed to the stack via the gland seal holdup line which is separate from the condenser off-gas holdup line. The gland seal off-gas system provides a 1.75 minute holdup time for decay of N-16. Operating pressure is atmospheric; hydrogen and oxygen are well below explosive limits. The design pressure is 150 psig. No filters, shutoff valves, or radiation monitors are required. The mechanical vacuum pump is automatically stopped and a discharge line valve closed on main steam line high radiation signal. [Reference 3-1, Section 11.4.4.3]

JAFNPP 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 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 20, Appendix B.

The quantities of gaseous effluents released from JAFNPP 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 (3000 mrem/yr) to the skin [Reference 3-2, Section 3.2.1]. For iodine and particulates with half-lives greater than 8 days, the limit is 15 mSv/yr (1500 mrem/yr) to an organ [Reference 3-2, Section 3.2.1]. 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 [Reference 3-2, Section 3.3.1]. For a calendar year, the limit is 0.1 mGy (10 mrad) for gamma radiation and 0.2 mGy (20 mrad) for beta radiation [Reference 3-2, Section 3.3.1]. 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

The radioactive solid waste processing equipment is located in the Radioactive Waste Building with the exception of the cleanup phase separator tanks which are located in the Reactor Building. Both wet and dry radioactive solid wastes are processed. Wet solid wastes include backwash sludge wastes from the Reactor Water Cleanup System, waste and floor drain filters, the fuel pool filter-demineralizers, spent resins from the waste and condensate demineralizers, and spent media from MFTDS. Dry solid wastes include rags, contaminated clothing, paper, small equipment parts, solid laboratory wastes, etc. [Reference 3-1, Section 11.3.4.1]

The slurry handling facility is divided into three processing subsystems: filter precoat materials, ion exchange resins, and spent media from MFTDS. The purpose of concentrating solid materials is to facilitate off-site disposal. [Reference 3-1, Section 11.3.4.2]

3.2.3.3.1 Precoat Materials

The reactor water cleanup filter-demineralizers discharge the precoat material into one of two phase separator tanks. After the contained solids have settled in the tank, the liquid is decanted to the waste collector tank for subsequent filtration, demineralization, and reuse. After the filters have been backwashed into one of the two phase separator tanks, the tanks are allowed to settle before being pumped to the radioactive waste building for further processing or to the liner fill area for offsite shipment. The waste, floor drain, and fuel pool precoat filters discharge to the waste sludge tank which is located below the filters. After the solids settle from a backwash, the decant liquid is pumped to the floor drain collector or waste collector tank for further processing. When the solids concentration is at an acceptable level in the waste sludge tank, the slurry is pumped to the Liner Fill Area for offsite shipment. [Reference 3-1, Section 11.3.4.2]

3.2.3.3.2 Ion Exchange Resins

All spent resin slurries from radioactive waste and condensate demineralizers are sluiced into a 3,000 gallon spent resin tank for storage. Each bed of the waste and condensate demineralizers contains strongly acidic cation resin and strongly basic anion resin. The spent resins are pumped to the Liner Fill Area for additional processing and offsite processing. All spent media from the liquid radwaste MFTDS are sluiced at a 3,000 gallon spent resin tank for storage. Each vessel (5 total) contains 40 ft3 of the following: activated carbon, cation, anion, and mixed bed. [Reference 3-1, Section 11.3.4.2]

3.2.3.3.3 Miscellaneous Solid Waste System

Currently, contaminated miscellaneous solid wastes such as air filters, rags, paper, small equipment parts, and solid laboratory wastes are normally processed by a vendor. If during plant operation it is determined to perform onsite processing, plant installed equipment will be utilized per vendor or supplier data. All processing will be completed to the extent practicable to allow shipment in accordance with all applicable local, state, and federal regulations. [Reference 3-1, Section 11.3.4.3]

Normally contaminated waste such as demolished piping, equipment, and components from plant radiologically controlled areas are first processed at an onsite decontamination unit. If the material is below the acceptable release limits and shows no further reduction of levels, the material may be returned to use or released from the radiologically controlled area. If the material is not below the release limits and shows no further reduction of levels, it will be taken to a designated Segregation Area and disposed of as radioactive material. If the material is to be reused, it is taken to the storage area if it is within the radiation protection procedural limits for reuse within the radiologically controlled area. [Reference 3-1, Section 11.3.4.3]

There may be instances where it is more economical to send material to a vendor for decontamination. This material may then be processed offsite and/or returned for reuse or disposed of as radioactive waste per the vendor's processes or as regulations may dictate. [Reference 3-1, Section 11.3.4.3]

3.2.4 Transportation of Radioactive Materials

JAFNPP radioactive waste shipments are packaged in accordance with NRC and Department of Transportation (DOT) requirements. The type and quantities of solid radioactive waste generated and shipped at JAFNPP vary from year to year, depending on plant activities. JAFNPP currently transports radioactive waste to either the licensed Barnwell, South Carolina, facility or to a licensed processing facility in Tennessee where the wastes are further processed prior to being sent to the Barnwell facility or the Envirocare facility in Clive, Utah. JAFNPP may also transport material from an offsite processing facility to a disposal site or back to the plant site for reuse or storage.

3.2.5 Nonradioactive Waste Systems

Nonradioactive waste is produced from plant maintenance and cleaning processes. Most of these wastes are from filter backwash, sludges and other wastes, floor and yard drains, and stormwater runoff. Chemical and biocide wastes are typically produced from processes used to control scale and corrosion, and to clean and defoul the condenser. Waste liquids are typically combined with cooling water discharges in accordance with SPDES Permit requirements. Sanitary wastewater from the facility flows to an onsite sewage treatment plant prior to discharge to Lake Ontario and is regulated by JAFNPP's SPDES Permit #NY-0020109 issued from the New York State Department of Environmental Conservation.

Nonradioactive gaseous effluents result from operation of the oil-fired boilers used to heat the plant and from testing of the emergency diesel generators. Discharge of regulated pollutants is minimized by limiting fuel usage and hours of operation and is within New York State air quality standards. Nonradioactive gaseous effluents at JAFNPP are regulated under a Certificate to Operate an Air Contamination Source (7-3556-0020/00012) issued by the NYSDEC.

3.2.6 Maintenance, Inspection and Refueling Activities

Various programs and activities currently exist at JAFNPP to 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 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, including the Structures Monitoring Program; 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. Certain program activities are performed during the operation of the unit, while others are performed during scheduled refueling outages.

3.2.7 Power Transmission Systems

A single circuit 345-kilovolt (kV) transmission line, approximately 70 miles in length, was constructed for the purposes of connecting the JAFNPP to the New York Power Pool transmission grid. This line runs southeasterly from the plant 345-kV switchyard to the Edic

Substation located near Utica, NY (Figure 3-2). The New York Power Authority (NYPA) has owned and operated the transmission line since it was constructed in the early 1970s. A 400-ft wide Right-of-Way (ROW) was acquired by NYPA for the Edic 345-kV transmission line, although a width of only 150 feet, totaling 1273 acres, was actually cleared for the line [Reference 3-6, Section 3.7]. The remaining ROW was acquired for the possible construction of additional transmission lines [Reference 3-6, Section 3.7]. The Edic transmission line was constructed with steel self-supporting towers spaced about 1,200 feet apart [Reference 3-6, Section 3.7]. When the ROW was acquired, about 65% of the ROW passed through forests, 29% through agricultural lands, and 6% through wetlands [Reference 3-6, Section 8.2.1]. Construction of the line had a low impact on wildlife and land uses in the area. Most of ROW land remains in private ownership and it is used for a variety of compatible purposes [Reference 3-6, Section 3.7].

A short 345-kV transmission line was also constructed between JAFNPP and the NMPNS facility. This line, approximately 4,900 feet in length, runs southward from the plant's 345-kV switchyard to the National Grid Scriba Substation where it connects to the 345-kV transmission system (Figure 3-2). The two 345-kV lines for JAFNPP have transmission capacity in excess of the JAFNPP generating unit, so either line can be out of service without curtailing the output from the plant. Both lines exceed the requirements of the National Electric Safety Code for heavy loading districts, Grade B. [Reference 3-1, Section 8.3.1.2]

In addition to the two 345-kV transmission lines for outgoing electricity, offsite power is provided to JAFNPP by two single circuit 115-kV transmission lines connected to the plant's 115-kV bus. One transmission line runs southward from the site and connects to the National Grid 115-kV transmission line that extends to the Lighthouse Hill Hydroelectric Station located about 26 miles east of JAFNPP (Figure 3-2). In addition to being a hydroelectric generating station and an integral part of the National Grid 115-kV system, the Lighthouse Hill facility also serves as the switchyard for several other hydroelectric facilities in the area. The other JAFNPP 115-kV line is approximately 3,700 ft long and is connected to the 115-kV bus at NMPNS Unit-1 (Figure 3-2). The 115-kV bus at NMPNS Unit-1 is also connected via a 115-kV transmission line to the South Oswego Substation. [Reference 3-1, Section 8.3.2.4]

Ownership of the four JAFNPP transmission lines is as follows.

- Edic substation 345-kV transmission line

  From 345-kV switchyard to approximately the site property line, JAFNPP owns the line. From the JAFNPP property line to the Edic Substation, NYPA owns the line.

- Scriba substation 345-kV transmission line

  From 345-kV switchyard to approximately the site property line, JAFNPP owns the line. From the JAFNPP property line to the Scriba Substation, NYPA owns the line.

- Lighthouse Hill Hydroelectric Station 115-kV transmission line

  From 115-kV Switchyard to approximately the site property line, JAFNPP owns the line. From the JAFNPP property line to the Lighthouse Hill Hydroelectric Station, National Grid owns the line.

- NMPNS Unit-1 115-kV transmission line

  From 115-kV switchyard to approximately the site property line, JAFNPP owns the line. From the JAFNPP property line to the NMPNS Unit-1 115-kV bus, NMPNS owns the line.

For the two 345-kV transmission line ROWs, NYPA uses a vegetation management plan approved by the New York State Public Service Commission [Reference 3-5]. NYPA uses an Integrated Vegetation Management computer application which employs geographic information system technology [Reference 3-3]. The application utilizes a balance of cultural, physical, biological, and chemical tactics to control tall growing tree species and to enhance the abundance of lower growing desirable vegetation [Reference 3-3]. Field inventories are conducted annually for the ROW scheduled for clearing the following year. The inventories and treatment recommendations are reviewed and approved by the NYPA forestry staff. The majority of clearing is performed using mechanical methods [Reference 3-4]. Herbicide applications are individually applied to selected plant species by licensed contractors, and a safe buffer is maintained around wetlands and wells and springs that are used for residential water supplies [Reference 3-4]. Areas where herbicides are used are posted with information regarding the chemicals used and when they were applied. Herbicides are not applied on NYPA ROWs using aerial application methods [Reference 3-4].

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 plant aging could preclude certain JAFNPP 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 JAFNPP license renewal application. This evaluation did not identify the need for refurbishment of structures or components related to license renewal.

Routine replacement of certain components during the period of extended operation is expected to occur within the bounds of normal plant maintenance. Modifications to improve operation of plant systems, structures, or components are reviewed for environmental impact by station personnel during the planning stage for the modification. These reviews are controlled by site procedures.

3.4 Programs and Activities for Managing the Effects of Aging

The programs for managing aging of systems and equipment at JAFNPP are described in the body of the JAFNPP license renewal application. The evaluation of structures and components required by 10 CFR 54.21 identified some new inspection activities necessary to continue operation of JAFNPP during the additional 20 years beyond the initial license term. These activities are described in the body of the JAFNPP 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 or modest modifications of existing programs.

3.5 Employment

The non-outage work force at JAFNPP consists of approximately 716 persons. Table 3-1 shows employee residences by county, state, and city. The GEIS estimated that an additional 60 employees would be necessary for operation during the period of extended operation. Since there will not be significant new aging management programs added at JAFNPP, Entergy believes that it will be able to manage the necessary programs with existing staff. Therefore, 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. Depending on the scope of these outages, an additional 700 to 900 workers are typically on site. 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 JAFNPP.

Table 3-1
Employee Residence Information, JAFNPP, September 2005

County, State and City	Employees (Entergy and Baseline Contractors)
Cayuga County	**11**
Auburn	2
Cato	4
Martville	1
Sterling	4
Cortland County	**1**
Homer	1
Jefferson County	**10**
Adams	1
Brownsville	1
Dexter	1
Evan Mills	1
Henderson Harbor	1
Mannsville	1
Rodman	1
Watertown	2
Woodville	1
Monroe County	**1**
Rochester	1
Oneida County	**6**
Blossvale	1
Camden	3
Taberg	1
Westdale	1

Table 3-1
Employee Residence Information, JAFNPP, September 2005

County, State and City	Employees (Entergy and Baseline Contractors)
Onondaga County	**127**
Baldwinsville	54
Bridgeport	1
Camillus	1
Cicero	4
Clay	6
Fayetteville	2
Liverpool	39
Manlius	2
Memphis	1
North Syracuse	3
Skaneateles	2
Syracuse	12
Oswego County	**556**
Altmar	5
Brewerton	3
Central Square	2
Cleveland	1
Constantia	1
Fulton	56
Hannibal	4
Hastings	4
Lacona	4
Lycoming	10
Mexico	75
Minetto	3

Table 3-1
Employee Residence Information, JAFNPP, September 2005

County, State and City	Employees (Entergy and Baseline Contractors)
New Haven	1
Oswego	320
Parish	11
Pennellville	6
Phoenix	4
Pulaski	32
Richland	2
Sandy Creek	4
West Monroe	1
Williamstown	7
Otsego County	**1**
Westford	1
Wayne County	**2**
Clyde	1
North Rose	1
Barnstable County (Massachusetts)	**1**
West Falmouth	1
TOTAL EMPLOYEES	**716**

3.6 References

3-1 Entergy Nuclear James A. FitzPatrick, James A. FitzPatrick Nuclear Power Plant Final Safety Analysis Report.

3-2 Entergy Nuclear James A. FitzPatrick, James A. FitzPatrick Nuclear Power Plant, DVP-01.02, Offsite Dose Calculation Manual, Revision 9, September 2004.

3-3 ESRI, Energy Currents, Fall 2004.

3-4 New York Power Authority, from Charles I. Lipsky, PE, White Plains, NY, to Douglas Harrison, James A. FitzPatrick Nuclear Power Plant, Lycoming, NY, letter (with four attachments) dated April 17, 2006.

3-5 New York Power Authority, Personal communication with Mr. Peter Muench, Transmission Superintendent, NYPA, Clark Energy Center, Marcy, NY, 2006.

3-6 U.S. Atomic Energy Commission, *Final Environmental Statement Related to the* Operation of James A. FitzPatrick Nuclear Power Plant, Docket No. 50-333, United States Atomic Energy Commission, Directorate of Licensing, March 1973.

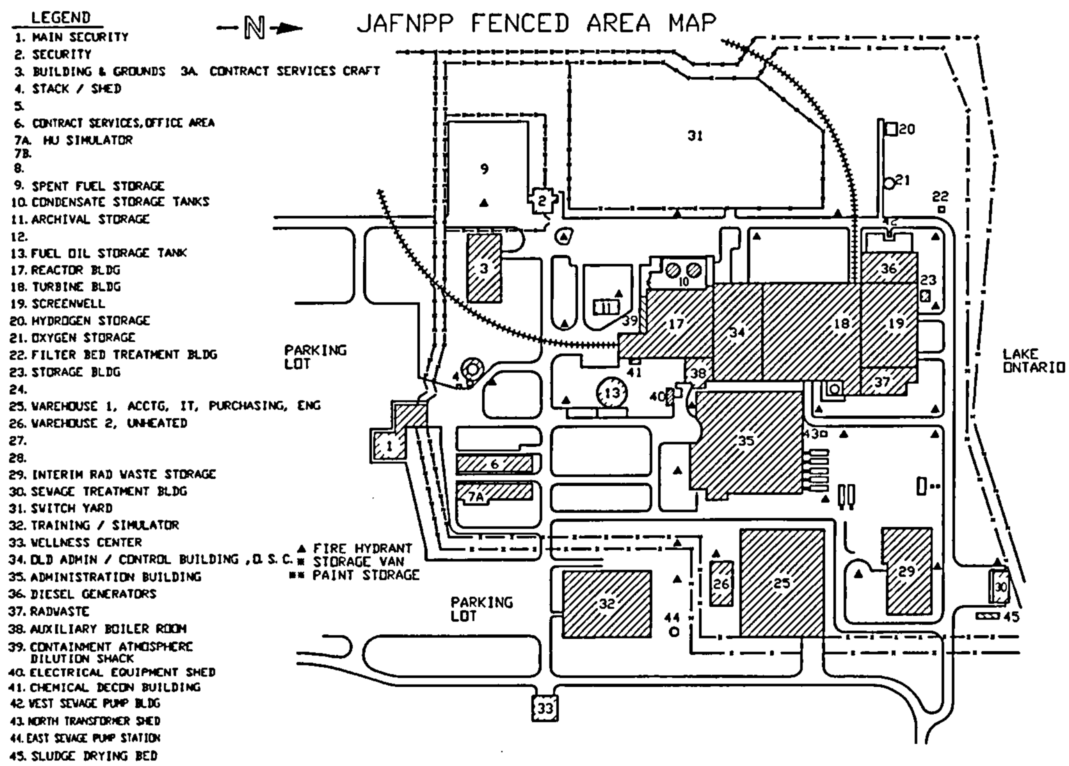

Figure 3-1
JAFNPP Plant Features

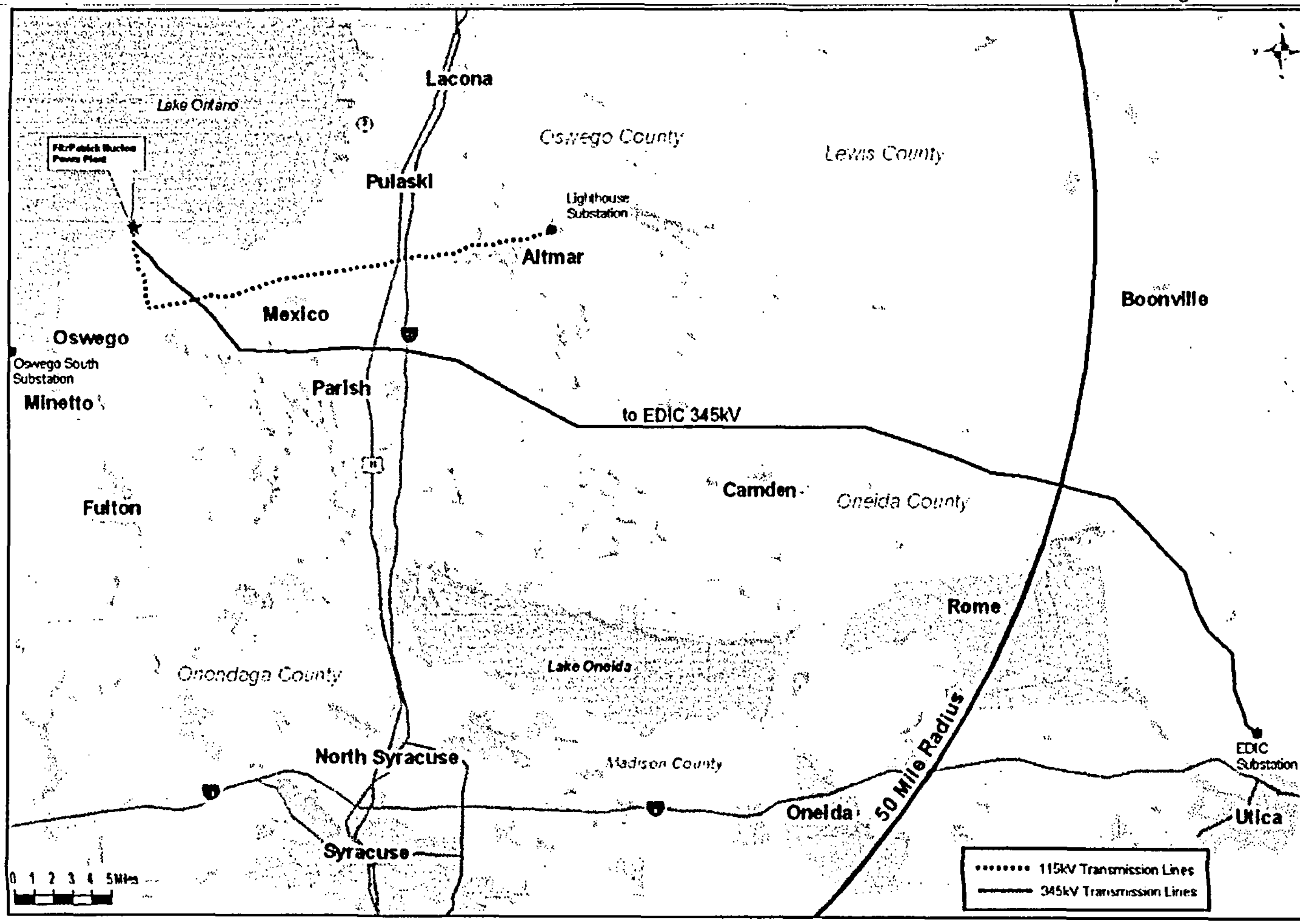

Figure 3-2
JAFNPP Transmission Lines

4.0 ENVIRONMENTAL CONSEQUENCES OF THE 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 51, Appendix B, Table B-1) as described in the GEIS [Reference 4-6]. An applicant may reference the generic findings or GEIS analyses for Category 1 issues.

Category 1 License Renewal Issues

Entergy has determined that, of the 69 Category 1 issues, 12 are not applicable to JAFNPP 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 19 issues and provides a brief explanation of why they are not applicable to JAFNPP. Table 4-2 lists the 50 Category 1 issues applicable to JAFNPP. Entergy reviewed the NRC findings on these 50 issues and identified no new and significant information that would invalidate the findings for JAFNPP. Therefore, Entergy adopts by reference the NRC findings for these Category 1 issues.

Table 4-1
Category 1 Issues Not Applicable to JAFNPP

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 salinity gradients	JAFNPP does not discharge to an estuary.
Aquatic Ecology (for All Plants)	
Refurbishment	No refurbishment activities planned.
Aquatic Ecology (for Plants with Cooling Tower-Based Heat Dissipation Systems)	
Entrainment of fish and shellfish in early life stages	JAFNPP is a once through cooling system and does not utilize cooling towers.
Impingement of fish and shellfish	JAFNPP is a once through cooling system and does not utilize cooling towers.
Heat Shock	JAFNPP is a once through cooling system and does not utilize cooling towers.
Ground-water Use and Quality	
Impacts of refurbishment on ground-water use and quality	No refurbishment activities planned.
Ground-water use conflicts (potable and service water; plants that use <100 gpm)	JAFNPP does not utilize groundwater.
Ground-water quality degradation (Ranney Wells)	JAFNPP does not have or use Ranney wells.
Ground-water quality degradation (saltwater intrusion)	JAFNPP is located on a freshwater body.
Ground-water quality degradation (cooling ponds in salt marshes)	JAFNPP does not have or use cooling ponds.
Human Health	
Radiation exposures to the public during refurbishment	No refurbishment activities planned.
Occupational radiation exposures during refurbishment	No refurbishment activities planned.
Terrestrial Resources	
Cooling pond impacts on terrestrial resources	JAFNPP is a once through cooling system and does not utilize cooling towers.
Bird collisions with cooling towers	JAFNPP is a once through cooling system and does not utilize cooling towers.

Table 4-1 (Continued)
Category 1 Issues Not Applicable to JAFNPP

Cooling tower impacts on crops and ornamental vegetation	JAFNPP is a once through cooling system and does not utilize cooling towers.
Cooling tower impacts on native plants	JAFNPP is a once through cooling system and does not utilize cooling towers.
Socioeconomics	
Aesthetic impacts (refurbishment)	No refurbishment activities planned.

Table 4-2
Category 1 Issues Applicable to JAFNPP

Surface Water Quality, Hydrology, and Use (for all plants)
Altered thermal stratification of lakes
Water use conflicts (plants with once-through cooling systems)
Altered current patterns at intake and discharge structures
Temperature effects on sediment transport capacity
Scouring caused by discharged cooling water
Eutrophication
Discharge of chlorine or other biocides
Discharge of sanitary wastes and minor chemical spills
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
Premature emergence of aquatic insects
Gas supersaturation (gas bubble disease)

Table 4-2 (Continued)
Category 1 Issues Applicable to JAFNPP

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
Power line right-of-way management (cutting and herbicide application)
Bird collision with power lines
Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)
Floodplains and wetland on power line right of way
Air Quality
Air quality effects of transmission lines
Land Use
Land Use (license renewal period)
Power line right-of-way
Human Health
Microbiological organisms (occupational 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)
Postulated Accidents
Design basis accidents

**Table 4-2 (Continued)
Category 1 Issues Applicable to JAFNPP**

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 JAFNPP does not have. In addition, some Category 2 issues (4) apply only to refurbishment activities. If the issue does not apply to JAFNPP, the section explains the basis.

For the 11 Category 2 issues applicable to JAFNPP, 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 JAFNPP 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 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 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 51, 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 and environmental justice are found in Sections 4.1 through 4.22. The format for the review of the Category 2 issues 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, are presented.

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

- *Background*: for issues applicable to JAFNPP, a background excerpt from the applicable section of the GEIS is provided. 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 JAFNPP.

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

- *Conclusion*: for issues applicable to JAFNPP, the conclusion of the analysis is presented 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 instream 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

JAFNPP does not have or use cooling ponds or cooling towers. JAFNPP has a once through cooling system utilizing makeup water from Lake Ontario. Therefore, this issue is not applicable to JAFNPP and 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 Clean Water Act 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 effects of entrainment on aquatic resources were considered by NRC at the time of original licensing and are periodically reconsidered by EPA or state water quality permitting agencies in the development of NPDES permits and 316(b) demonstrations. 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. [Reference 4-6, Section 4.2.2.1.2]

4.2.5 Analysis of Environmental Impact

316(b) Determination

Section 51.53(c)(3)(ii)(B) does not require an impact assessment of the proposed action at JAFNPP on fish and shellfish resources resulting from entrainment, if a Clean Water Act 316(b) determination is available. JAFNPP operates a state-of-the-art fish deterrence system (FDS) that is installed at the offshore intake structure from April to October of each year as required by Additional Requirement 9 to the SPDES Permit (provided in Attachment C). The high frequency/ high amplitude acoustic FDS has been determined by the NYDSEC to be Best Technology Available (BTA) for reducing both entrainment and impingement impacts as discussed in a March 1, 1996, letter from the NYSDEC to the NYPA (provided in Attachment C). This BTA determination was included in SPDES Permit NY-0020109 issued on July 16, 1997, and is included in the current SPDES Permit issued August 1, 2001, as outlined in the SPDES Permit Fact Sheet (provided in Attachment C).

Operational Measures and Technological Design Features

In addition to the BTA determination, additional operational measures and technological design features also exist at JAFNPP to further minimize the already small entrainment impacts. Operational measures include intake flow reductions, including those resulting from pump differentials, maintenance outages, and recirculation of heated condenser flow that is used to temper the incoming ambient Lake Ontario water during the winter. The primary technological design feature is the submerged, mid-water, shore-facing intake located 900 feet offshore in Lake Ontario.

Ecological Studies

In the late 1960s, ecological studies in the vicinity of Nine Mile Point began to evaluate potential effects of power station operations at JAFNPP and NMPNS on the aquatic ecosystems. These studies are discussed in the JAFNPP Proposal for Information Collection to address compliance with the Clean Water Act 316(b) Phase II Regulations [Reference 4-1] that was submitted to the NYSDEC on January 25, 2006. The entrainment losses incurred at Nine Mile Point, in comparison with the standing stock of lake fish species, are small and unlikely to adversely affect the fish community in the lake. This same conclusion was reached in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Supplement 24 - Nine Mile Point Nuclear Station, Units 1 and 2 - Final Report (NUREG-1437, Supplement 24). [Reference 4-9, Section 4.1.1]

4.2.6 Conclusion

JAFNPP operates a state of the art fish deterrence system (FDS) installed at the offshore intake structure, which has been accepted by NYSDEC as Best Technology Available (BTA) for reducing impingement mortality and entrainment impacts. In addition, extensive studies have been conducted at JAFNPP and NMPNS on the potential impact of cooling water withdrawals from Lake Ontario on indigenous communities of fish. Over 30 years of monitoring data collected at the plants support the conclusion that JAFNPP has not had an adverse impact on fish populations. Entergy, therefore, concludes that any impact on these populations from entrainment of larval fish during the license renewal period would be SMALL and does not warrant mitigation.

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 125, or equivalent state permits and supporting documentation. If the applicant can not 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 and 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 once-through power plants, particularly where restoration of anadromous fish may be affected. Impingement is an intake-related effect that is considered by EPA or state water quality permitting agencies in the development of NPDES permits and 316(b) determinations. 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. [Reference 4-6, Section 4.2.2.1.3]

4.3.5 Analysis of Environmental Impact

316(b) Determination

Section 51.53(c)(3)(ii)(B) does not require an impact assessment of the proposed action at JAFNPP on fish and shellfish resources resulting from impingement, if a Clean Water Act 316(b) determination is available. JAFNPP operates a state-of-the-art fish deterrence system (FDS) that is installed at the offshore intake structure from April to October of each year as required by Additional Requirement 9 to the SPDES Permit (provided in Attachment C). The high frequency/ high amplitude acoustic FDS has been determined by the NYDSEC to be Best Technology Available (BTA) for reducing both entrainment and impingement impacts as discussed in a March 1, 1996 letter from the NYSDEC to the NYPA (provided in Attachment C). This BTA determination was included in SPDES Permit NY-0020109 issued on July 16, 1997 and is included in the current SPDES Permit issued August 1, 2001 as outlined in the SPDES Permit Fact Sheet (provided in Attachment C).

Operational Measures and Technological Design Features

In addition to the BTA determination, additional operational measures and technological design features also exist at JAFNPP to further minimize the already small impingement impacts. Operational measures include intake flow reductions, including those resulting from pump differentials, maintenance outages, and recirculation of heated condenser flow that is used to temper the incoming ambient Lake Ontario water during the winter. The primary technological design feature is the submerged, mid-water, shore-facing intake located 900 feet offshore in Lake Ontario.

Ecological Studies

Impingement studies have been conducted annually at JAFNPP from 1975 through 1997 and again in 2004 to evaluate potential effects of power station operations on the aquatic ecosystems. These studies are discussed in the JAFNPP Proposal for Information Collection to address compliance with the Clean Water Act 316(b) Phase II Regulations that was submitted to the NYSDEC on January 25, 2006 [Reference 4-1]. Based on the results of these studies, there have been no long-term trends in fish population abundance due to the impingement process at JAFNPP. Impingement losses incurred at JAFNPP, in comparison with the standing stock of lake fish species, are small and unlikely to adversely affect the fish community in the lake. This same conclusion was reached in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Supplement 24 - Nine Mile Point Nuclear Station, Units 1 and 2 - Final Report (NUREG-1437, Supplement 24). [Reference 4-9, Section 4.1.2]

4.3.6 Conclusion

JAFNPP operates a state of the art fish deterrence system (FDS) installed at the offshore intake structure, which has been accepted by NYSDEC as Best Technology Available (BTA) for reducing impingement mortality and entrainment impacts. In addition, extensive studies have been conducted at JAFNPP on the potential impact of cooling water withdrawals from Lake Ontario on indigenous communities of fish. Years of monitoring data collected at the plant support the conclusion that JAFNPP has not had an adverse impact on fish populations. Entergy, therefore, concludes that any impact on these populations from impingement of fish during the license renewal period would be SMALL and does not warrant mitigation.

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(a) determinations and variance in accordance with 40 CFR 125, or equivalent state permits and supporting documentation. If the applicant can not 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. [Reference 4-6, Section 4.2.2.1.4]

4.4.5 Analysis of Environmental Impact

NRC made impacts on fish and shellfish resources resulting from heat shock a Category 2 issue 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 [Reference 4-6, Section 4.2.2.1.4]. Information to be ascertained includes (1) type of cooling system (whether once-through or cooling pond), and (2) evidence of a CWA Section 316(a) variance or equivalent state documentation.

As Section 3.2.2 describes, JAFNPP has a once-through heat dissipation system that uses water from Lake Ontario for condenser cooling. As discussed below, Entergy also has a Section 316(a) variance for JAFNPP discharges.

Section 316(a) of the CWA establishes a process whereby a discharger can demonstrate that established thermal discharge limitations are more stringent than necessary to protect a balanced indigenous population of fish and wildlife and obtain facility-specific thermal discharge limits (33 USC 1326). This 316(a) demonstration was established by JAFNPP's former owner, New York Power Authority, accepted by the NYSDEC, and used in determining facility-specific SPDES discharge temperature limits [Reference 4-4]. This Section 316(a) demonstration, based on pre-operational and post-operational engineering, hydrological, and ecological data, concluded that the thermal effluent from JAFNPP would not result in long-term impacts to the fish and wildlife populations of Lake Ontario.

In issuing and renewing the Station's SPDES permits since that time, the NYSDEC determined that thermal discharges from JAFNPP were sufficiently protective of the aquatic ecosystem of Lake Ontario to satisfy alternative thermal effluent limitations under Section 316(a) of the CWA. This determination by the NYSDEC has been incorporated into Part 1, Condition 8 of the SPDES Permit (provided in Attachment C) which states:

The thermal discharge from this facility shall assure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife in and on Lake Ontario. In this regard, the Department has approved the permittee's request for alternative effluent limitations pursuant to Section 316(a) of the Clean Water Act. The effluent limitations on page 2 of this permit reflect this approval. The water temperature at the surface of Lake Ontario shall not be raised more than three Fahrenheit degrees over the temperature that existed before the addition of heat of artificial origin except in a mixing zone consisting of an area of 35 acres from the point of discharge, this temperature may be exceeded.

As identified in Table 9-1 of this ER, the SPDES Permit for discharges at JAFNPP will expire on August 1, 2006. In accordance with SPDES regulations, JAFNPP filed the SPDES Permit renewal application 180 days prior to the current permit's expiration date on January 24, 2006. Therefore, the current SPDES Permit and its Section 316(a) variance remain in effect. For this reason, Entergy concludes that impacts to fish and shellfish from heat shock are SMALL and warrant no additional mitigation.

4.4.6 Conclusion

As noted previously, Entergy has submitted a timely application for renewal of the JAFNPP SPDES Permit. The current SPDES Permit and its Section 316(a) variance therefore remain in effect. For this reason, Entergy concludes that impacts to fish and shellfish from heat shock are SMALL and warrant no additional mitigation.

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, Subpart A, Appendix 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

There are no pumpable groundwater wells at the JAFNPP site. Drinking water is supplied by the Town of Scriba and cooling and service water is taken from Lake Ontario. Therefore, this issue is not applicable to JAFNPP 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 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.

4.6.4 Analysis of Environmental Impact

JAFNPP does not have or use cooling towers. JAFNPP is a once through cooling system utilizing makeup water from Lake Ontario. Therefore, this issue is not applicable to JAFNPP and 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, Subpart A, Appendix 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 onsite) 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

JAFNPP does not have or utilize Ranney wells. As discussed in Section 4.5.4, drinking water is supplied by the Town of Scriba and cooling and service water is taken from Lake Ontario. Therefore, this issue is not applicable to JAFNPP 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, Subpart A, Appendix 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

JAFNPP does not have or utilize cooling ponds. JAFNPP is a once-through cooling system. Therefore, this issue is not applicable to JAFNPP 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, Subpart A, Appendix 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, no refurbishment activities are required for JAFNPP license renewal. Therefore this issue is not applicable to JAFNPP and no 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 Findings 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 [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

It is not possible to reach a conclusion about the significance of potential impacts to threatened and endangered species at this time 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. [Reference 4-6, Section 3.9]

4.10.5 Analysis of Environmental Impacts

As discussed in Section 3.3, Entergy has no plans to conduct refurbishment or construction activities at JAFNPP 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.

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

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

As stated in Section 2.5, there are 4 federally listed animal species which may occur in the vicinity of JAFNPP. None of these species has actually been seen or reported as occurring at the JAFNPP site. Of the 4 species, only two, the Indiana Bat and the bog turtle, has the potential for more than a transitory visit. However, there have been no sightings of the Indiana bat or the bog turtle at JAFNPP.

Entergy is not aware of any potential concerns regarding threatened or endangered species which could occur due to the continued operation of JAFNPP. Furthermore, station operations are not expected to be altered over the license renewal period and any maintenance activities necessary to support license renewal would be limited to previously disturbed areas on-site. Also, no expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal. Therefore, no adverse impacts to threatened or endangered terrestrial species from current or future operations are anticipated.

4.10.6 Conclusion

There are no major refurbishment activities required for license renewal at JAFNPP. Therefore, there will be no impact to threatened and endangered species from refurbishment activities.

The continued operation of JAFNPP is not expected to impact any endangered, threatened, or rare species which may exist on or pass through the site. Any 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. Therefore, Entergy concludes that impacts to threatened or endangered species from license renewal would be SMALL and does not warrant further mitigation.

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, Subpart A, Appendix 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

As discussed in Section 3.3, Entergy has no plans for refurbishment related to license renewal at JAFNPP. Therefore, this issue is not applicable to JAFNPP 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 Analysis of Environmental Impact

JAFNPP does not discharge to a small river. Therefore, this issue is not applicable to JAFNPP and analysis is not required.

4.13 Electromagnetic Fields—Acute Effects

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. [Reference 4-6, Sections 4.5.4 and 4.5.4.1]

4.13.5 Analysis of Environmental Impact

The NRC made the impact of electric shock from transmission lines a Category 2 issue because without a review of each plant's transmission line conformance with the National Electrical Safety Code® (NESC®) criteria, which specifies minimum vertical clearances to the ground for electric wires to limit electrostatic effects, the NRC could not determine the significance of the electrical shock potential. The regulation at 10 CFR 51.53(c)(3)(ii)(H) does not define the phrase "transmission line," but in the GEIS, the NRC indicates that transmission lines use voltages of about 115/138 kilovolts (kV) and higher, and that, in contrast, distribution lines use voltages below the 115/138 kV level [Reference 4-6, Sections 2.2.7 and 4.5.1]. The GEIS also specifies that the transmission lines of concern are located between the plant switchyard and the connection to the existing transmission system (or grid). Information to be ascertained includes (1) change in line use and voltage since last analysis; (2) conformance with NESC® (1981)

standards; and (3) the potential change in land use along the transmission lines since the initial NEPA review.

As described in Section 3.2.7, two single-circuit 345 kV lines exiting the switchyard connect JAFNPP to the transmission grid. One line, approximately 68 miles in length, connects to the transmission system at NYPA's Edic Substation. The other line, approximately 4900 feet in length, connects to the transmission system at the National Grid Scriba Substation located on the NMPNS site. Although JAFNPP owns the lines within the site property boundary, lines exiting the property boundary are owned and maintained by NYPA. These two lines were evaluated concerning adherence to the NESC® steady-state limit.

As stated above, the NESC® specifies minimum vertical clearances to the ground for electric lines. For electric lines operating at voltages exceeding 98kV alternating current (AC) to ground, the clearance provided must limit the steady-state current due to electrostatic effects to 5 milliamperes (mA) if the largest anticipated vehicle were short-circuited to ground. The largest vehicle anticipated under JAFNPP 345 kV lines is a 65-foot long tractor-trailer, with a height of 13.5 feet, parked along a roadway. The 5 mA design standard limits electric fields within the ROW to 7-8 kV/meter.

According to the NYPA Transmission Engineering Department [Reference 4-3], the two 345-kV transmission lines at JAFNPP are operated and maintained in a manner consistent with the design criteria listed in NUREG-1437, Section 4.5.4.1. Specifically, these lines meet a more stringent induced shock standard than the 5 mA design criterion of NESC® (1981).

The State of New York Public Service Commission (NYPSC) requires that transmission lines in New York be designed so that the short-circuit current to ground, produced from the largest anticipated vehicle or object, is limited to less than 4.5 mA. This allows no more than 7.0 kV/meter electric field levels on the ROWs. In 1991, NYPA demonstrated to the NYPSC that its transmission lines, including the two 345-kV lines associated with JAFNPP, do not exceed safety levels of 6.5 kV/meter for electric fields or 4.5 mA for induced shocks [Reference 4-3].

Nuisance shocks are further controlled through NYPA's annual routine inspection of ROWs for land intrusion, along with its program of informing landowners about induced shock hazards and assisting them with grounding any metallic structures in or near a ROW.

4.13.6 Conclusion

Entergy's assessment concludes that electric shock is of SMALL significance for the JAFNPP 345-kV transmission lines. The lines are operated within their original design specifications, the ROWs are routinely monitored for any land use changes, and NYPA has demonstrated that the 345-kV transmission lines meet the NESC® (1981) requirements for preventing induced shock hazards. Due to the small significance of the issue, mitigation measures such as installing warning signs at road crossings or increasing clearances are not warranted.

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... 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. [Reference 4-6, 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 that: "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 that: "If additional workers are not anticipated there will be no impact on housing and no further analysis is required."

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

The JAFNPP site currently has approximately 716 full-time workers during normal plant operations. The majority of these employees live within a two-county area adjacent to the plant. As discussed in Section 2.9 of this ER, little discernible change in housing availability has occurred in the two-county area near JAFNPP since 1990. Vacancy rates have remained relatively stable and the number of available units has kept pace with or exceeded the low growth in the area population.

4.14.6 Conclusion

As noted in Section 3.3, there are no major refurbishment activities required for JAFNPP license renewal. Additionally, Entergy does not anticipate a need for additional full time workers during the license renewal period. Therefore, Entergy concludes that impacts to the housing availability from plant-related population growth and plant demand would be SMALL and mitigation would not be warranted.

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)]

... [T]he applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.

4.15.4 Public Water Supply—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. [Reference 4-6, Section 3.7.4.5]

4.15.5 Analysis of Environmental Impact

As noted in Section 3.3, there are no major refurbishment activities required for JAFNPP license renewal. Therefore, there will be no impact to public utilities from refurbishment activities. In addition, Entergy does not anticipate a need for additional workers during the period of extended operation. Therefore, there will be no impact to public utilities from additional plant workers living in the two county area near the plant.

Entergy obtains cooling and process water for JAFNPP from Lake Ontario. Potable water is purchased from the Town of Scriba. As there is no anticipated need for additional workers at the plant for the extended period of operation, there should be no additional impact from the amount of potable water used at JAFNPP.

4.15.6 Conclusion

License renewal operations will not cause any appreciable increased demand on the public water supply system. As noted in Section 3.3, there are no major refurbishment activities required for license renewal at JAFNPP. Entergy also does not anticipate that additional workers will be employed during the period of extended operations.

Both public and private water systems in the region appear to be adequate to provide the capacity and meet the demand of residential and industrial customers in the area. Therefore, impacts to public water supplies will continue to be SMALL and no evaluation of mitigation measures is 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 major refurbishment activities required for JAFNPP license renewal. Therefore this issue is not applicable to JAFNPP and no analysis is required.

4.17 <u>Offsite Land Use—Refurbishment</u>

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...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 major refurbishment activities required for JAFNPP license renewal. Therefore this issue is not applicable to JAFNPP and no analysis is required.

4.18 <u>Offsite Land Use—License Renewal Term</u>

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...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 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." Therefore, the discussion will be limited to the land use changes that may result from tax payments made by the plant to local governments.

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 are 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. Also, 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. [Reference 4-6, 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.

Population-Driven Land Use Changes

Entergy agrees with the GEIS conclusion that new population-driven land use changes at JAFNPP during the license renewal term will be SMALL [Reference 4-6, Section 4.7.4.2]. Entergy does not anticipate that additional workers will be employed at JAFNPP during the period of extended operations. Therefore, there will be no adverse impact to the offsite land use from plant-related population growth.

Tax-Driven Land Use Changes

JAFNPP is assessed annual property taxes by Oswego County, the Town of Scriba, and Mexico Central Schools. Property taxes paid to Oswego County and the Town of Scriba fund such services as transportation, education, public health, and public safety.

Entergy has entered into an agreement with Oswego County, the Town of Scriba, and the Mexico Central Schools regarding property taxes paid to those entities for JAFNPP. The agreement stipulates that Entergy, instead of paying property taxes for JAFNPP based on the assessed value of the plant, will make standardized annual payments in lieu of taxes to the taxing entities.

Because (1) Entergy does not anticipate that additional workers will be employed at JAFNPP during the license renewal period, and (2) Entergy does not anticipate major refurbishment or construction during this period, and therefore does not anticipate any increase in the assessed value of JAFNPP during the license renewal period, it can be concluded that the net impact of plant-related population increases is likely to be SMALL.

4.18.6 Conclusion

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

In addition, the impact to tax-driven land use changes from the continued payment of property taxes at JAFNPP is expected to be SMALL and no mitigation is required.

4.19 Transportation

4.19.1 Description of Issue

Public services, Transportation

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

SMALL, MODERATE, or LARGE. Transportation impacts (level of service) of highway traffic generated during plant refurbishment and during the term of the renewed license are generally expected to be of small significance. However, the increase in traffic associated with additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites. 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 the proposed project on local transportation during periods of license renewal refurbishment activities and during the term of the renewed license.

4.19.4 Background

Impacts to transportation during the license renewal term would be similar to those experienced during current operations and would be driven mainly by the workers involved in current plant operations.

Based on past and projected impacts at the case study sites, 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 forecast, 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. [Reference 4-6, Section 4.7.3.2]

4.19.5 Analysis of Environmental Impact

In 2000, a capacity analysis of area intersections was performed as a part of an application for a proposed gas turbine plant to be located on Lake Ontario. This analysis showed that the intersections reviewed were acceptable, with the exception of the Route 1 eastbound approach to Route 1/Route 1A during the morning rush hour. [Reference 4-9, Section 2.2.8.2]

The Oswego County Department of Public Works also completed a study of traffic patterns in the JAFNPP vicinity as part of a construction project involving Route 1A. As a result of this study, the County determined that traffic counts were of an acceptable level. [Reference 4-9, Section 2.2.8.2]

4.19.6 Conclusion

As noted in Section 3.3, there are no major refurbishment activities required for JAFNPP license renewal. As noted in Section 3.5, there are no expected increases in the total number of employees that will be on-site during the period of extended operation. In addition, the County has determined that traffic counts were of an acceptable level. Therefore, impacts on local traffic will be SMALL and no mitigation measures are 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 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 occur at any site unless new facilities or service roads are constructed or new transmission lines are established.

However, the identification of historic resources and determination of possible impact 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. [Reference 4-6, Section 3.7.7]

4.20.5 Analysis of Environmental Impact

As discussed in Section 2.12, the New York SHPO was contacted during the early stages of site construction for information related to any known archaeological resources in the vicinity of the JAFNPP site. JAFNPP received certification from the SHPO that the plant would not have a harmful effect on any sites of historical or archaeological importance. [Reference 4-5, Section 2.3]

JAFNPP consulted with the New York SHPO in February 2006. The SHPO reviewed the proposed project for its potential effects on archaeologically and historically sensitive areas and determined that no prehistoric or historic resources would be affected by the project (see Attachment B).

In addition, no refurbishment activities have been identified to support continued operation of JAFNPP beyond the end of the existing operating license. Therefore, there will be no impact on historic or archeological properties from refurbishment activities.

JAFNPP operations are not expected to be altered over the license renewal period and any maintenance activities necessary to support license renewal would be limited to previously disturbed areas on-site. Also, no expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

Entergy has procedural administrative controls in place to ensure that environmental reviews are conducted prior to engaging in additional construction or operational activities that may result in an environmental impact at the site. This includes activities involving disturbance of previously undisturbed surface or subsurface land areas. For these type surface or subsurface activities, the controls listed below would be implemented, as appropriate. [Reference 4-2]

> In accordance with the National Historic Preservation Act, any cultural resources in the area must not be disturbed until prior authorization is obtained from the State Historic Preservation Office, and if applicable, the NRC as set forth in the site's Cultural Resource Protection Plan. This would also apply to archaeological, historical or other cultural resources that may be inadvertently uncovered during excavation activities. [Reference 4-2]

4.20.6 Conclusion

As noted in Section 3.3, there are no major refurbishment activities required for license renewal at JAFNPP. In addition, based on consultation with the New York SHPO (see Attachment B), no prehistoric or historic resources would be affected by operation of the plant during the license renewal period. Entergy also has procedural administrative controls in place to ensure that environmental reviews are conducted prior to engaging in additional construction or operational activities that may result in an environmental impact at the site, including impacts related to historic and archaeological resources. Therefore, the potential impact of continued operation of JAFNPP during the period of the renewed license on historic or archeological resources will be SMALL and evaluation of mitigation measures is 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. [Reference 4-6, Section 5.5.2.5]

4.21.5 Analysis of Environmental Impact

The method used to perform the Severe Accident Mitigation Alternative (SAMA) analysis was based on the handbook used by the NRC to analyze benefits and costs of its regulatory activities [Reference 4-7].

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) Establish the Baseline Impacts of a Severe Accident

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 and a present worth discount rate of 7%).

- 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%.

- 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%).

- 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 and 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 Attachment E 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;

- SAMA analyses for other BWR plants, including the evolutionary General Electric Advanced Boiling Water Reactor (ABWR) design;

- NRC and industry documentation discussing potential plant improvements;
- JAFNPP Individual Plant Examination (IPE) of internal and external events reports and their updates (in both reports, several enhancements related to severe accident insights were recommended and implemented); and
- JAFNPP PSA model risk significant contributors.

(3) Phase I—Preliminary Screening

Potential SAMA candidates were screened out if they modified features not applicable to JAFNPP, if they had already been implemented at JAFNPP, 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 or SAMDA analysis was used. These estimates were used for comparison against an

estimated benefit at JAFNPP since they were developed in the past and no credit was taken for inflation when applying them to JAFNPP. In addition, several of them were developed from SAMDA analysis (i.e., during the design phase of the plant), and therefore, did not consider the additional costs associated with performing design modifications to an existing plant (i.e., reduced efficiency, minimizing dose, disposal of contaminated material, etc.)

- 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) <u>Sensitivity Analyses</u>

Two sensitivity analyses were conducted to gauge the impact of key assumptions upon the analysis. One sensitivity analysis was to investigate the sensitivity of assuming a 28-year period for remaining plant life. The other sensitivity analysis was to investigate the sensitivity of each analysis case to the discount rate of 3%.

The SAMA analysis for JAFNPP is presented in the following sections. Attachment E.1 and Attachment E.2 provide a more detailed discussion of the process presented above.

4.21.5.1 Establish the Baseline Impacts of a Severe Accident

A baseline was established to enable estimation of the risk reductions attributable to implementation of potential SAMA candidates. This severe accident risk was estimated using the JAFNPP PSA model and the MACCS2 consequence analysis software code. The PSA model used for the SAMA analysis (JAFNPP Revision 2, October 2004) is an internal events risk model.

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

The PSA model (Level 1 and Level 2) used for the SAMA analysis was the most recent internal events risk model for JAFNPP (JAFNPP Revision 2). This model is an updated version of the model used in the 1991 IPE and reflects the JAFNPP configuration and design as of December 2003. It uses component failure and unavailability data as of December 2002, and resolves all findings and observations from the industry peer review of the model conducted in December 1997. The JAFNPP model adopts the small event tree / large fault tree approach and uses 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 3.83. This analysis is presented in Section E.1.1 of Attachment E.

The JAFNPP 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 IPEEE model was reviewed and used for SAMA analysis. The seismic, high wind and external flooding analyses determined that the plant is adequately designed to protect against the effects of these natural events. The seismic portion of the IPEEE was completed in conjunction with the Seismic Qualification Utility Group (SQUG) program. JAFNPP performed a NRC seismic margin methodology 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 JAFNPP 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.

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 JAFNPP PSA model, 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 Section E.1.5 of Attachment E.

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 analysis was used to establish the maximum benefit that a SAMA could achieve if it eliminated all risk due to JAFNPP at-power internal events.

Off-Site Exposure Costs

The Level 3 baseline analysis resulted in an annual off-site exposure risk of 1.63 person Rem. 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 [Reference 4-7]. This monetary equivalent was then discounted to present value using the formula from the same source:

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

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).

Using a 20-year license renewal period, a 7% discount rate, assuming F_A is zero, and the baseline CDF of 2.74E-06/year resulted in the monetary equivalent value of $35,087. 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 $3,340. This value was discounted in the same manner as the public health risks in accordance with the following equation:

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

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 $35,948. 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 [Reference 4-7]. 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

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

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 F_A is zero, the bounding monetary value of the immediate dose associated with JAFNPP's accident risk is

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

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

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

For the baseline CDF, 2.74 x 10^{-6}/year,

$$W_{IO} = \$195.$$

Long Term Dose

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

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 JAFNPP's accident risk is

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

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

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

For the CDF for the baseline, 2.74 x 10^{-6}/year,

$$W_{LTO} = \$848.$$

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

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

where

AOE = on-site exposure avoided.

The bounding value for occupational exposure (AOE_B) is

$$AOE_B = W_{IO} + W_{LTO} = \$195 + \$848 = \$1{,}043.$$

The resulting monetary equivalent of $1,043 is presented in Table 4-3.

<u>On-Site Economic Costs</u>

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 [Reference 4-7] 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,

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

$$PV_{CD} = \$1.08 \times 10^9$$

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

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

where,

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

Based upon the values previously assumed,

$$U_{CD} = \$1.16 \times 10^{10}$$

Replacement Power Costs

Replacement power costs were estimated in accordance with the Regulatory Analysis Technical Evaluation Handbook [Reference 4-7]. 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:

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

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 $\$1.2 \times 10^8$ 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 [Reference 4-7] for discount rates between 5% and 10% only.

Based upon the values previously assumed:

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

$$PV_{RP} = \$9.73 \times 10^8$$

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

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

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,

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

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

$$AOSC = \Delta F(U_{CD} + U_{RP}) = \Delta F(\$1.16 \times 10^{10} + \$7.89 \times 10^9)$$

$$AOSC = \Delta F(\$1.95 \times 10^{10})$$

where

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

For the baseline CDF, 2.74×10^{-6}/year,

$$AOSC = \$53{,}469$$

The resulting monetary equivalent of $53,469 is presented in Table 4-3.

Table 4-3
Estimated Present Dollar Value Equivalent of Internal Events CDF at JAFNPP

Parameter	Present Dollar Value ($)
Off-site population dose	35,087
Off-site economic costs	35,948
On-site dose	1,043
On-site economic costs	53,469
Total	125,547

4.21.5.2 Identify SAMA Candidates

Based on a review of industry documents, an initial list of SAMA candidates was identified. Since JAFNPP is a General Electric (GE) nuclear power reactor, considerable attention was paid to the SAMA candidates from SAMA analyses for other GE plants. Attachment E lists 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 JAFNPP IPE and IPEEE. Several enhancements from the JAFNPP IPE and IPEEE related to severe accident insights were recommended and implemented. These enhancements were included in the comprehensive list of SAMA candidates and were verified to have been implemented during preliminary screening.

The JAFNPP Revision 2 PSA model was used to identify plant-specific modifications for inclusion in the comprehensive list 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 Table E.1-2 and Table E.1-6 of Attachment E. The comprehensive list contained a total of 293 SAMA candidates. 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)

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at JAFNPP. Potential SAMA candidates were screened out if they modified features not applicable to JAFNPP or if they had already been implemented at JAFNPP. 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, 230 of the 293 initial SAMA candidates were eliminated, leaving 63 SAMA candidates for further analysis. The list of 293 original SAMA candidates and applicable screening criterion is 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 implementation. 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.2-1 of Attachment E.

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 the Phase II analysis of SAMA 040 in Table E.2-1). 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 [Reference 4-7] 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

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 and seismic events) could lead to potentially significant risk contributions. To account for the risk contribution from external events and uncertainties, the cost of SAMA implementation was compared with a benefit value estimated by applying a multiplier of 16 to the internal events estimated benefit. This value is defined as an upper bound estimated benefit. This treatment accounts for the impact of external events and uncertainty associated with the internal events. The basis for this multiplier is discussed in the following paragraphs.

The JAFNPP 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 1×10^{-6}/year. 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 seismic margin assessment was performed for the seismic portion of the JAFNPP IPEEE. Thus, no CDF sequences were quantified as part of the IPEEE seismic risk analysis. The limiting values for the high confidence of low probability of failure were 0.22g peak ground acceleration from failure of the electric bay block walls. The review level earthquake is 0.3g. No potential vulnerabilities were identified. As seismic events are not dominant contributors to external event risk and all outliers have been addressed, further cost-beneficial seismic improvements are not expected and seismic events are considered negligible in estimation of the external events multiplier.

The EPRI Fire PRA Implementation Guide was followed for the JAFNPP IPEEE fire analysis. The EPRI Fire Induced Vulnerability Evaluation 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.1-12) is approximately 2.56×10^5 per reactor-year. However, a more realistic fire CDF may be closer to a factor of three less than this value due to conservatisms in the IPEEE fire analysis.

Conservatisms in the IPEEE fire analysis methods 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.

- The peer review process for fire analyses is less well developed than for internal events PSAs. For example, no industry process, such as NEI 00-02, exists for the structured peer review of a fire PSA.

Plant-specific conservative assumptions in the JAFNPP IPEEE fire analysis include the following.

- Heat and combustion products from a fire within a zone were assumed to be confined within the zone. Heat loss through water curtains 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 tunnel trays (Zones CT-1 and CT-2) 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.

- Cable trays above panels in the relay room (Zone RR-1) were assumed to be damaged despite successful fire suppression.

- Recovery was not credited for fires in the turbine building electric bays (Zones SW-1 and SW-2).

- Although changes to administrative procedures have been implemented to reduce the probability of a transient combustible fire forming a hot gas layer in the cable spreading room (Zone CS-1), credit was not taken for these changes in the IPEEE fire analysis. Zone CS-1 is the zone with the largest contribution to fire CDF.

The IPEEE fire CDF value, reduced by a factor of three, is 8.53×10^{6} per year, which is three times higher than the internal events CDF. This justifies use of a multiplier of three on the averted cost estimates (for internal events) to represent the additional SAMA benefits from external events. The upper bound estimated benefit is intended to account for both the internal and external events impacts with uncertainty. CDF uncertainty estimates resulted in a factor of 3.83 (Table E.1-3). Since 4 x 3.83 = 15.32, a multiplier of 16 would be reasonable to account for both internal and external events impacts with uncertainty.

Use of an upper bound estimated benefit is considered appropriate because of the inherent conservatism in the external events modeling approach and conservative assumptions in benefit modeling of individual SAMA candidates. In addition, not all potential enhancements would be impacted by an external event. In some cases an external event would only impose partial failure of systems or trains. Therefore, using 16 times the internal events estimated benefit to account for internal and external events with uncertainty is appropriate.

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 and SAMDA analyses. In particular, these cost-estimates were derived from the following major sources:

- GE ABWR SAMDA Analysis
- Peach Bottom SAMA Analysis
- Quad Cities SAMA Analysis
- ANO-2 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. In addition, several of the implementation cost estimates were originally developed for SAMDA analyses (i.e., during the design phase of the plant), and therefore, do not capture the additional costs associated with performing design modifications to existing plants (i.e., reduced efficiency, minimizing dose, disposal of contaminated material, etc.).

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. Nonetheless, the cost of SAMA candidates 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 63 Phase II SAMA candidates is presented in Table E.2-1 of Attachment E.

4.21.5.5 Sensitivity Analyses

Two sensitivity analyses were conducted to gauge the impact of key assumptions upon the analysis. The main factors affecting present worth are the extended plant life and the discount rate. 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 28-year period for remaining plant life (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 28 years remaining until end of facility life to investigate the impact on each analysis case.

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 7.0% used in the base case analyses is conservative relative to corporate practices; nonetheless, a lower discount rate of 3.0% was assumed in this case to investigate the impact on each analysis case.

The benefits estimated for each of these sensitivities are presented in Table E.2-2 of Attachment E.

4.21.6 Conclusion

This analysis addressed 293 SAMA candidates for mitigating severe accident impacts. Phase I screening eliminated 230 SAMA candidates from further consideration, based on either inapplicability to JAFNPP's design, or features that had already been incorporated into JAFNPP's current design, procedures and/or programs. During the Phase II cost benefit evaluation of the remaining 63 SAMA candidates, an additional 58 SAMA candidates were eliminated because their cost was expected to exceed their benefit and were therefore determined not to be cost beneficial.

Five Phase II SAMA candidates (i.e. 26, 30, 36, 61, and 62), presented in Table 4-4, were found to be potentially cost beneficial for mitigating the consequences of a severe accident for JAFNPP. Sensitivity studies indicated that the results of the analysis would not change for the conditions analyzed.

- A plant modification was recommended to provide additional DC battery capacity to ensure longer battery capability during the station blackout event, which would extend HPCI/RCIC operability and allow more time for AC power recovery (SAMA candidate 26).

- A plant modification was recommended to provide 16-hour SBO injection to improve capability to cope with longer SBO scenarios (SAMA candidate 30).

- A plant modification was recommended to extend SBO provisions to extend DC power availability during the SBO event, which would extend HPCI/RCIC operability and allow more time for AC power recovery (SAMA candidate 36).

- A plant procedural development was recommended to allow use of use a portable power supply for battery chargers. This procedure would improve the availability of the DC power system (SAMA candidate 61).

- A plant procedural development was recommended to open the doors of the EDG buildings upon receipt of a high temperature alarm. This procedure would improve the reliability of the EDGs following high temperatures in the EDG buildings (SAMA candidate 62).

SAMA candidates 26, 30, and 36 would extend HPCI/RCIC operability and allow more time for AC power recovery. Therefore, implementation of one of the three SAMAs may reduce the CDF contribution from this scenario enough that the other two are no longer cost-beneficial.

The above SAMA candidates do not relate to adequately managing the effects of aging during the period of extended operation.

Table 4-4
Final SAMAs

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost
026	Provide additional DC battery capacity.	SAMA would ensure longer battery capability during an SBO, which would extend HPCI/RCIC operability and allow more time for AC power recovery.	39.0%	43.74%	$52,365	$837,840	$500,000
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 7 hours to 24 hours during SBO scenarios to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $500,000 by engineering judgment.						
030	2.i. Provide 16 hour SBO injection.	SAMA includes improved capability to cope with longer SBO scenarios.	39.0%	43.74%	$52,365	$837,840	$500,000
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 7 hours to 24 hours during SBO scenarios to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $500,000 by engineering judgment.						
036	10.e. Extended SBO provisions.	SAMA would extend DC power availability in an SBO, which would extend HPCI/RCIC operability and allow more time for AC power recovery.	39.0%	43.74%	$52,365	$837,840	$500,000
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 7 hours to 24 hours during SBO scenarios to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $500,000 by engineering judgment.						

Table 4-4
Final SAMAs

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost
061	Develop a procedure to use a portable power supply for battery chargers.	This SAMA would improve the availability of the DC power system.	3.49%	0.39%	$2,113	$33,808	$10,000
	Basis for Conclusion: The CDF contribution due to loss of DC battery chargers 71BC-1A and 71BC-1B was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $10,000 by engineering judgment						
062	Develop a procedure to open the doors of the EDG buildings upon receipt of a high temperature alarm.	This SAMA would improve the reliability of the EDGs following high temperatures in the EDG buildings.	21.15%	24.28%	$28,975	$463,600	$10,000
	Basis for Conclusion: The probability of EDG run failures was reduced by a factor of three to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $10,000 by engineering judgment.						

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 51.

4.22.4 Background

The following background information is from the 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 Attachment 4, "NRR Procedures for Environmental Justice Reviews," to NRR Office Letter No. 906, Revision 2, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues," September 21, 1999. NRR Office Letter No. 906 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 Letter No. 906, Revision 2 [Reference 4-8] 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 JAFNPP license. 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 JAFNPP license. 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 JAFNPP license.

4.23 References

4-1 Entergy Nuclear FitzPatrick, LLC, Proposal for Information Collection to Address Compliance with the Clean Water Act, §316(b) Phase II Regulations at James A. FitzPatrick Nuclear Power Plant, (SPDES Permit No. NY 0020109), Lycoming, New York, January 31, 2006.

4-2 Entergy Nuclear, Nuclear Management Manual Procedure EN-EV-115, Environmental Reviews and Evaluations, April 10, 2006.

4-3 New York Power Authority, from Charles I. Lipsky, PE, White Plains, NY to Douglas Harrison, James A. FitzPatrick Nuclear Power Plant, Lycoming, NY, letter (with four attachments) dated April 17, 2006.

4-4 Power Authority of the State of New York, James A. FitzPatrick Nuclear Power Plant, 316(a) Demonstration Submission, Permit No. NY0020109, 1976.

4-5 U.S. Atomic Energy Commission, Final Environmental Statement Related to the Operation of James A. FitzPatrick Nuclear Power Plant, Docket No. 50-333, United States Atomic Energy Commission, Directorate of Licensing, March 1973.

4-6 U.S. Nuclear Regulatory Commission, Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), Volumes 1 and 2, NUREG-1437, Washington, DC, 1996.

4-7 U.S. Nuclear Regulatory Commission, Regulatory Analysis Technical Evaluation Handbook, NUREG/BR-0184, Washington, DC, January 1997.

4-8 U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, NRR Office Letter No.906, Revision 2, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues," dated September 21, 1999.

4-9 U.S. Nuclear Regulatory Commission, Generic Environmental Impact Statement for License Renewal of Nuclear Plants, NUREG-1437, Supplement 24, Regarding Nine Mile Point Nuclear Station, Units 1 and 2, Final Report, Office of Nuclear Reactor Regulation, Washington, DC, May 2006.

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. Section 4 presents the NRC definitions of MODERATE and LARGE impacts.

Entergy reviewed SEISs associated with other license renewal applications to determine if there were new issues identified for those plants that may be applicable to JAFNPP. In addition, some regulatory agencies were consulted regarding new and significant information. However, 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 JAFNPP license renewal include the following:

- Review of documents related to environmental issues at JAFNPP.
- 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.

As a result of this assessment, Entergy is aware of no new and significant information regarding the environmental impacts of JAFNPP license renewal.

6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 License Renewal Impacts

Entergy has reviewed the environmental impacts of renewing the JAFNPP operating license and has concluded that all impacts would be SMALL and would not require mitigation. This environmental report documents the basis for Entergy's conclusion. Section 4 incorporates by reference NRC findings for the 50 Category 1 issues that apply to JAFNPP (and for the 2 "NA" issues for which NRC came to no generic conclusion), all of which have 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 impacts that JAFNPP 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 of 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, Regulatory Guide 4.2 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" [Reference 6-2].

As described in Section 6.1 and as 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 that mitigate the environmental impacts of plant operations are adequate. 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 JAFNPP

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.** JAFNPP is equipped with a once through cooling system that utilizes make-up water from Lake Ontario. The Station does 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.** JAFNPP FDS accepted as BTA by NYSDEC, operational measures and intake structure feature further minimize entrainment, and biological studies indicate small impacts to fish populations.
Impingement of fish and shellfish 10 CFR 51.53(c)(3)(ii)(B)	**SMALL.** JAFNPP FDS accepted as BTA by NYSDEC, operational measures and intake structure feature further minimize impingement, and biological studies indicate small impacts to fish populations.
Heat shock 10 CFR 51.53(c)(3)(ii)(B)	**SMALL.** NYSDEC determined that thermal discharges from JAFNPP were sufficiently protective of the aquatic ecosystem of Lake Ontario to satisfy alternative thermal effluent limitations under Section 316(a) of the CWA (refer to Part 1, Condition 8 of the SPDES Permit provided in Attachment C).
Ground-water Use and Quality	
Groundwater use conflicts (plants using >100 gpm of ground-water) 10 CFR 51.53(c)(3)(ii)(C)	**NONE.** There are no pumpable groundwater wells at the JAFNPP site. Drinking water is supplied by the Town of Scriba and service water is taken from Lake Ontario. 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.** JAFNPP does not have or use cooling towers. The Station obtains cooling water from Lake Ontario and potable water from the Town of Scriba. Consideration of mitigation is not required.
Groundwater use conflicts (Ranney Wells) 10 CFR 51.53(c)(3)(ii)(C)	**NONE.** JAFNPP does not have or use Ranney wells. Consideration of mitigation is not required.
Degradation of groundwater quality 10 CFR 51.53(c)(3)(ii)(D)	**NONE.** JAFNPP does not have or utilize cooling ponds. The Station is equipped with a once-through cooling system. Consideration of mitigation is not required.

Table 6-1
Environmental Impacts Related to License Renewal at JAFNPP

Issue	Environmental Impact
Terrestrial Resources	
Refurbishment impacts on terrestrial resources 10 CFR 51.53(c)(3)(ii)(E)	**NONE.** No major refurbishment activities 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 major refurbishment activities identified. No threatened or endangered species impacted by continued operations of JAFNPP. Consideration of mitigation is not required.
Air Quality	
Air quality during refurbishment 10 CFR 51.53(c)(3)(ii)(F)	**NONE.** No major refurbishment activities identified. Consideration of mitigation is not required.
Human Health	
Microbiological (Thermophilic) Organisms 10 CFR 51.53(c)(3)(ii)(G)	**NONE.** JAFNPP does not discharge to a small river. Consideration of mitigation is not required.
Electromagnetic fields – Acute effects 10 CFR 51.53(c)(3)(ii)(H)	**SMALL.** Transmission lines meet the NESC® recommendations for preventing electric shock from induced currents. Consideration of mitigation is not warranted.
Socioeconomics	
Housing impacts 10 CFR 51.53(c)(3)(ii)(I)	**SMALL.** No major refurbishment activities identified. Entergy does not anticipate an increase in employment during period of extended operation. Therefore, there no additional impacts to housing are expected due to continued operations of JAFNPP. Consideration of mitigation is not required.
Public utilities: public water supply availability 10 CFR 51.53(c)(3)(ii)(I)	**SMALL.** No major refurbishment activities identified and no additional workers anticipated during the period of extended operation. Public water systems near JAFNPP have adequate system capacity to meet demand of residential and industrial customers in the area. Consideration of mitigation is not required.
Education impacts from refurbishment 10 CFR 51.53(c)(3)(ii)(I)	**NONE.** No major refurbishment activities identified. Consideration of mitigation is not required.

Table 6-1
Environmental Impacts Related to License Renewal at JAFNPP

Issue	Environmental Impact
Offsite land use (effects of refurbishment activities) 10 CFR 51.53(c)(3)(ii)(I)	**NONE.** No major refurbishment activities identified. Consideration of mitigation is not required.
Offsite land use (effects of license renewal) 10 CFR 51.53(c)(3)(ii)(I)	**SMALL.** Area around JAFNPP has pre-established land patterns of development and has public services and regulatory controls in place to support and guide development. No additional workers anticipated during the period of extended operation. Consideration of mitigation is not required.
Local transportation impacts 10 CFR 51.53(c)(3)(ii)(J)	**SMALL.** No major refurbishment activities identified and no increases in total number of employees during the period of extended operation. Consideration of mitigation is not required.
Historic and archaeological properties 10 CFR 51.53(c)(3)(ii)(K)	**SMALL.** No major refurbishment activities identified and no archaeologically and historically sensitive areas present on-site. Consideration of mitigation is not required.
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. Consideration of mitigation is not required.

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 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 51, and information specific to JAFNPP.

This review and analysis did not identify any significant adverse environmental impacts associated with the continued operation of JAFNPP. 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 JAFNPP 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 Irreversible or Irretrievable Resource Commitments

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 JAFNPP 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; and
- materials used for the normal industrial operations of JAFNPP that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

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

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 JAFNPP site has remained relatively constant since the Station began operating in 1975. The Final Environmental Statement Related to the Operation of James A. FitzPatrick Nuclear Power Plant 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 JAFNPP [Reference 6-1, Section 8.3]. The period of extended operation will not change 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). However, extending operations will not adversely affect the long-term uses of the site.

There are no major refurbishment activities or changes in operation of JAFNPP 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

6-1 U.S. Atomic Energy Commission, Final Environmental Statement Related to the Operation of James A. FitzPatrick Nuclear Power Plant, Docket No. 50-333, United States Atomic Energy Commission, Directorate of Licensing, March 1973.

6-2 U.S. Nuclear Regulatory Commission, Supplement 1 to Regulatory Guide 4.2, Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses, September 2000.

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. In addition, this review addresses the environmental consequences of taking no action [Reference 7-1, Section 8.2]. For license renewal, there are only two alternatives that meet the purpose of the requirement: not renew the operating license or renew the operating license. The alternatives are discussed below.

7.2 Proposed Action

JAFNPP operated at a 2003 capacity factor of 96.4% (non-outage year) and is rated at approximately 881 MWe. The proposed action is to renew the operating license for JAFNPP which would provide the opportunity for Entergy to continue to operate JAFNPP through the period of extended operation.

The review of the environmental impacts required by 10 CFR 51.53(c)(3)(ii) is provided in Section 4 of this ER. Based on this review, Entergy concludes that there would be no adverse impact to the environment from the continued operation of JAFNPP through the period of extended operation.

7.3 No-Action Alternative

The "no-action alternative" to the proposed action is not to renew the operating license for JAFNPP. In this alternative, it is expected that JAFNPP will continue to operate up to the end of the existing operating license, at which time plant operation would cease and decommissioning would begin. In an "obligation to serve" the regulated environment, a decision not to seek a renewal license would necessitate the replacement of approximately 881 MWe with other sources of generation. The environmental impacts of the no-action alternative would be:

- the environmental impacts from decommissioning the JAFNPP unit, and
- the environmental impacts from a replacement power source.

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

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 [Reference 7-1, 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 JAFNPP until the current license expires, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of an example reactor (the "reference" boiling-water reactor is the 1,155 MWe Washington Public Power Supply System's Columbia Nuclear Power Plant). This is a substantially larger plant than JAFNPP and, therefore, bounds decommissioning activities that Entergy would conduct at JAFNPP.

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 [Reference 7-2] 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 have to decommission JAFNPP; license renewal would only postpone decommissioning for 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 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 [Reference 7-1, Section 8.4] and in the decommissioning GEIS [Reference 7-2, 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

Nuclear power plants are commonly 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 8.1.1). Entergy did not consider coal-fired generation at the JAFNPP site since it was concluded that there was not enough land to build a 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. JAFNPP is situated on approximately 702 acres and is rated at approximately 881 MWe. Therefore for an 881 MWe plant, it would take approximately 1,498 acres of land.

- Natural gas-fired generation at the JAFNPP site and at an alternate site (Section 8.1.2)

- Nuclear generation at the JAFNPP site and at an alternate site (Section 8.1.3).

These alternatives are presented (Sections 8.1.1, 8.1.2, and 8.1.3, respectively) as if such plants were constructed at the JAFNPP site (natural gas-fired and advanced light water reactor 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 JAFNPP site.

The potential for using imported power is discussed in Section 8.1.4. 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 Canadian province. In addition, there is no assurance that the capacity or energy would be available.

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" [Reference 7-1, Section 8.1]. Accordingly, the following alternatives were not considered as reasonable replacement power.

- wind
- solar
- hydropower
- geothermal
- wood energy

- municipal solid waste
- other biomass-derived fuels
- oil
- fuel cells
- delayed retirement
- utility-sponsored conservation
- 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, 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 JAFNPP.

- Low capacity factors

  Some of the technologies identified above (wind, solar, and hydroelectric) are not capable of producing the nearly 881 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 unlikely resources.

- Geographic availability of the resource

  Some of the technologies are not feasible because there is no feasible location in the Entergy service area.

- Emerging technology

  Some of the technologies has not been proven as reliable and cost effective replacements of 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.

7.6 References

7-1 U.S. Nuclear Regulatory Commission, NUREG-1437, Generic Environmental Statement for License Renewal of Nuclear Power Plants, Final Report, May 1996.

7-2 U.S. Nuclear Regulatory Commission, 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, November 2002.

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 881 MWe of base-load generation. Alternatives that do not meet the goal are not considered in detail.
- The time frame for the needed generation is 2014 through 2034.
- Purchased power is not considered a reasonable alternative because there is no assurance that the capacity or energy would be available. See Section 8.1.4.
- The annual capacity factor of JAFNPP in 2003 (non-outage year) was 96.4%. The capacity factor is targeted to remain at or near this value throughout the plant's operating life.

8.1 Comparison of Environmental Impacts for Reasonable Alternatives

Each year the Energy Information Administration (EIA), a component of the U.S. Department of Energy (DOE), issues an Annual Energy Outlook. In its Annual Energy Outlook 2005 with Projections to 2025, EIA projects that combined-cycle or combustion turbine technology fueled by natural gas is likely to account for approximately 60% of new electric generating capacity between the years 2005 and 2025 [Reference 8-17]. Coal-fired plants are projected by EIA to account for approximately 35% of new capacity during this period [Reference 8-17]. Both technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet base load requirements. Coal-fired plants are generally used to meet base load requirements. Renewable energy sources, primarily wind, biomass gasification, and municipal solid waste units are projected by EIA to account for the remaining 5% of capacity additions. EIA's projections are based on the assumption that providers of new generating capacity will seek to minimize cost while meeting applicable environmental requirements. Combined-cycle plants are projected by EIA to have the lowest generation cost in 2005 and 2020 followed by coal-fired plants and then wind generation [Reference 8-17].

EIA projects that oil-fired generation will decrease in the U.S. through 2025 because of rising fuel costs and lower efficiencies. EIA's projections are based on the assumption that providers of new generating capacity will seek to minimize cost while meeting applicable environmental requirements. The cost of new oil-fired generation is not expected to be competitive with that of coal and natural gas. EIA also projects that new nuclear power plants will not account for any new generation capacity in the United States during the 2005 to 2025 time period because natural gas and coal-fired plants are projected to be more economical [Reference 8-17]. In spite of this projection, since 1997, the NRC has certified three new standard designs for nuclear power plants under the procedures in 10 CFR 52, Subpart B. Therefore, a new nuclear plant alternative for replacing power generated by JAFNPP is considered in Section 8.1.3. The submission to the NRC of these three applications for certification indicates continuing interest in the possibility of licensing new nuclear power plants.

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" [Reference 8-21, Section 8.1]. Below is a discussion of the supply side alternative energy technologies that Entergy could utilize if the license for JAFNPP is not renewed. These alternatives are within the range of alternatives capable of meeting the goal of approximately 881 MWe as base-load generation (replacement power for JAFNPP).

Based on discussion above, conventional coal-fired, oil and natural gas-fired combined cycle and advanced light water reactor are currently available conventional base-load technologies considered to replace JAFNPP generation upon its termination of operation.

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 JAFNPP site, with the exception of a coal-fired unit).

As described below, the continued operation of JAFNPP for the period of extended operation would result in less environmental impact than that of the replacement power that could be obtained from other reasonable generating sources.

8.1.1 Coal-Fired Generation

NRC has 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 816 MWe of coal-fired generation capacity [Reference 8-24, Section 8.2.1]. Entergy has reviewed the NRC analysis and believes it to be sound. Although the V. C. Summer analysis understates the impacts of replacing the approximately 881 MWe at JAFNPP by 7%, Entergy believes these differences are insignificant. In defining the JAFNPP coal-fired alternative, Entergy has used site-specific input and has scaled from the NRC analysis, where appropriate.

Tables 8-1 through 8-3 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 [Reference 8-19]. The coal-fired alternative that Entergy has defined would be located at an alternative site.

8.1.1.1 <u>Once-Through Cooling System</u>

The overall impacts at an alternate greenfield site of the coal-fired generating system using a once-through cooling system is discussed below. The magnitude of impacts for the alternate site will depend on the location of the particular site selected. JAFNPP currently uses a once-through system. Therefore, for the purposes of comparison with an alternative site, it is assumed that the replacement coal-fired plant sited at an alternate site also would also use a once-through cooling system.

The environmental impacts of building a coal-fired generation facility with a once- through cooling system at an alternate site are summarized in Table 8-4.

8.1.1.1.1 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 816 MWe plant utilized in this analysis, it would take approximately 1,387 acres of land. This would amount to 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 offsite in an undetermined coal-mining area to supply coal for the plant. In the GEIS, the staff 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 [Reference 8-21, Section 8.3.9]. Therefore, for the 816 MWe plant utilized in this analysis, it would take approximately 17,952 acres of land. Partially offsetting this offsite land use would be the elimination of the need for uranium mining and processing to supply fuel for JAFNPP. In the GEIS, the staff estimated that approximately one acre per MWe would be affected for mining and processing the uranium during the operating life of a nuclear power plant [Reference 8-21, Section 8.3.12]. Therefore, for the 816 MWe plant utilized in this analysis, it would take approximately 816 acres of land.

The impact of a coal-fired generating unit with a once-through cooling system on land use located at an alternate site is considered as MODERATE to LARGE.

8.1.1.1.2 Ecology

Constructing a coal-fired plant at an alternate site would alter ecological resources because of the need to convert roughly 1,387 acres of land at the site to industrial use for plant, coal storage, and ash and scrubber sludge disposal. However, some of this land might 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.

Once-through cooling water withdrawal and discharge could have adverse aquatic resource impacts. If needed, construction and maintenance of an electric power transmission line and a rail spur would have ecological impacts. 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.

8.1.1.1.3 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 permit. The impact on the surface water would depend on the volume of water needed for makeup, the discharge volume and the characteristics of the receiving body of water. 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: Groundwater impacts would depend on the site characteristics, including the amount of groundwater available. 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.

8.1.1.1.4 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 (SOx), nitrogen oxides (NOx), 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 8-2).

- Oxides of sulfur = 2,514 tons per year
- Oxides of nitrogen = 591 tons per year
- Carbon monoxide = 591 tons per year
- Particulates:
    - Total suspended particulates = 84 tons per year
    - PM10 (particulates having a diameter of less than 10 microns) = 19 tons per year

The acid rain requirements of the Clean Air Act amendments capped the nation's SOx emissions from power plants. Under the Clean Air Act amendments, each company with fossil-fuel-fired units was allocated SOx allowances. To be in compliance with the Act, the companies must hold enough allowances to cover their annual SOx emissions. Entergy would have to purchase allowances to cover its SOx emissions.

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, SOx emission allowances, NOx emission offsets, low NOx 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 impacts would be clearly noticeable, but would not destabilize air quality in the area.

8.1.1.1.5 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 2,362,375 tons of coal having an ash content of 7.11%. After combustion, 99.9% of this ash (approximately 167,797 tons per year) would be collected and disposed of at either an onsite or offsite landfill. In addition, approximately 136,995 tons of scrubber waste would be disposed of each year (based on annual calcium hydroxide usage of approximately 46,241 tons). Entergy estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 161 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 8-3 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; the impacts of increased waste disposal would be clearly noticeable, but would not destabilize any important resource and further mitigation would be unwarranted.

8.1.1.1.6 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 [Reference 8-21, Section 8.3.9]. 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 [Reference 8-6].

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.

8.1.1.1.7 Socioeconomics

Based on Table 8.1 of the GEIS, construction of the coal-fired alternative would take approximately 1 year per 200 MWe rating. 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. Therefore, for the 816 MWe plant utilized in this analysis, it would take approximately four years to construct the plant with the workforce ranging from approximately 979 to 2,040 workers.

Communities around the new site would have to absorb the impacts of a large, temporary work force (up to approximately 2,040 workers at the peak of construction) and a permanent work force of approximately 0.2 workers per MWe based on Table 8.1 of the GEIS or approximately 163 workers for the 816 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 work force 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. Barge delivery of coal and lime/limestone would have SMALL socioeconomic impacts.

8.1.1.1.8 Aesthetics

At an alternate site, there would be an aesthetic impact from the buildings and exhaust stacks. This impact could be LARGE if a greenfield site is used. 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 short duration of the noise reduces the impact. 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 offsite. 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.

8.1.1.1.9 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 archeological resource impacts can generally be effectively managed and as such are considered SMALL.

Table 8-1
Coal-Fired Alternative Emission Control Characteristics

Characteristic	Basis
Unit size = 408 MW ISO rating net[a]	Chosen as equal to JAFNPP unit.
Unit size = 430 MW ISO rating gross[a]	Chosen as equal to JAFNPP unit.
Number of units = 2	
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxide emissions [Reference 8-19, Table 1.1-3]
Fuel type = bituminous, pulverized coal	Typical for coal used in New York [Reference 8-3, Table 4]
Fuel heating value = 13,117 Btu/lb	2000 value for coal used in New York [Reference 8-3, Table 4]
Fuel ash content by weight = 7.11%	2000 value for coal used in New York [Reference 8-3, Table 22]
Fuel sulfur content by weight = 1.12%	2000 value for coal used in New York [Reference 8-3, 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 [Reference 8-19, Table 1.1-3]
Heat rate = 10,200 Btu/kWh	Typical for coal-fired, single-cycle steam turbines [Reference 8-4, 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 [Reference 8-19, Table 1.1-2]
Particulate control = fabric filters (baghouse - 99.9% removal efficiency)	Best available for minimizing particulate emissions [Reference 8-19, pp. 1.1-6 and 1.1-7]
SO_x control = Wet scrubber – lime (95% removal efficiency)	Best available for minimizing SO_x emissions [Reference 8-19, 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 [Reference 8-4 page 109].

Table 8-2
Air Emissions from Coal-Fired Alternative

Parameter	Calculation	Result
Annual coal consumption	$\frac{816\text{ MW}}{\text{unit}} \times \frac{10{,}200\text{ Btu}}{\text{kW x hr}} \times \frac{1{,}000\text{ kW}}{\text{MW}} \times \frac{\text{lb}}{13{,}117\text{ Btu}} \times \frac{24\text{hr}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times 0.85$	2,362,375 tons of coal per year
SO_x [a, b]	$\frac{2{,}362{,}375\text{ tons}}{\text{yr}} \times \frac{1.12\%\text{ x }38\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{100-95}{100}$	2,514 tons SO_x per year
NO_x [b, c]	$\frac{2{,}362{,}375\text{ tons}}{\text{yr}} \times \frac{10\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{100-95}{100}$	591 tons NO_x per year
CO [b]	$\frac{2{,}362{,}375\text{ tons}}{\text{yr}} \times \frac{0.5\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}}$	591 tons CO per year
TSP [d]	$\frac{2{,}362{,}375\text{ tons}}{\text{yr}} \times \frac{7.11\%\text{ x }10\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{100-99.9}{100}$	84 tons TSP per year
PM_{10} [d]	$\frac{2{,}362{,}375\text{ tons}}{\text{yr}} \times \frac{7.11\%\text{ x }2.3\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{100-99.9}{100}$	19 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. Reference 8-19, Table 1.1-1
b. Reference 8-19, Table 1.1-3
c. Reference 8-19, Table 1.1-2
d. Reference 8-19, Table 1.1-4

Table 8-3
Solid Waste from Coal-Fired Alternative

Parameter	Calculation	Result
Annual SO_x generated[a]	$\frac{2{,}362{,}375 \text{ tons Coal}}{\text{yr}} \times \frac{1.12 \text{ tons}}{100 \text{tons Coal}} \times \frac{64.1 \text{ tons } SO_2}{32.1 \text{ tons S}}$	52,835 tons of SO_x per year
Annual SO_x removed	$\frac{52{,}835 \text{ tons } SO_2}{\text{yr}} \times \frac{95}{100}$	50,193 tons of SO_x per year
Annual ash generated	$\frac{2{,}362{,}375 \text{ tons Coal}}{\text{yr}} \times \frac{7.11 \text{ tons ash}}{100 \text{ tons Coal}} \times \frac{99.9}{100}$	167,797 tons of ash per year
Annual lime consumption[b]	$\frac{52{,}835 \text{ tons } SO_2}{\text{yr}} \times \frac{56.1 \text{ tons CaO}}{64.1 \text{ tons } SO_2}$	46,241 tons of CaO per year
Calcium sulfate[c]	$\frac{50{,}193 \text{ tons } SO_2}{\text{yr}} \times \frac{172 \text{ tons } CaSO_4 \bullet 2H_2O}{64.1 \text{ tons } SO_2}$	134,683 tons of $CaSO_4 \cdot 2H_2O$ per year
Annual scrubber waste[d]	$\frac{46{,}241 \text{ tons CaO}}{\text{yr}} \times \frac{100-95}{100} \times 134{,}683 \text{ tons } CaSO_4 \bullet 2H_2O$	136,995 tons of scrubber waste per year
Total volume of scrubber waste[e]	$\frac{136{,}995 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2000 \text{ lb}}{\text{ton}} \times \frac{\text{ft}^3}{144.8 \text{ lb}}$	75,687,845 ft^3 of scrubber waste
Total volume of ash[f]	$\frac{167{,}797 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2000 \text{ lb}}{\text{ton}} \times \frac{\text{ft}^3}{100 \text{ lb}}$	134,237,600 ft^3 of ash
Total volume of solid waste	$75{,}687{,}845 \text{ ft}^3 + 134{,}237{,}600 \text{ ft}^3$	209,925,445 ft^3 of solid waste
Waste pile area (acres)	$\frac{209{,}925{,}445 \text{ ft}^3}{30 \text{ ft}} \times \frac{\text{acre}}{43{,}560 \text{ ft}^2}$	161 acre of solid waste
Waste pile area (ft x ft square)	$\sqrt{209{,}925{,}445 \text{ft}^3/30 \text{ ft}}$	2,645 feet by feet square of solid waste

Based on annual coal consumption of 2,362,375 tons per year (see Table 8-2).

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/ft3.
f. Density of coal bottom ash is 100 lb/ft^3 [Reference 8-5].

Table 8-4
Summary of Environmental Impacts from Coal-Fired Generation Using Once-Through Cooling at an Alternate Greenfield Site

Impact Category	Impact	Comments
Land Use	MODERATE to LARGE	Approximately 1,387 acres, including transmission lines and rail line for coal delivery.
Ecology	MODERATE to LARGE	Impact will depend on ecology of site.
Surface Water Use and Quality	SMALL to MODERATE	Impact will depend on volume and other characteristics of receiving water.
Groundwater Use and Quality	SMALL to LARGE	Impact will depend on site characteristics and availability of groundwater.
Air Quality	MODERATE	SO_x – 2,514 tons/yr – allowances required NO_x – 591 tons/yr – allowances required Particulate – 84 tons/yr (filterable) – 19 tons/yr (unfilterable) Carbon monoxide – 591 tons/yr Trace amounts of mercury, arsenic, chromium, beryllium, and selenium
Waste	MODERATE	Total waste volume would be estimated around 304,792 tons/yr of ash and scrubber sludge.
Human Health	SMALL	Impacts considered minor.
Socioeconomics	SMALL to LARGE	Communities would have to absorb impacts of a large, temporary workforce (up to approximately 2,040 workers at the peak of construction) and a permanent work force of approximately 163 workers. Impacts at a rural site would be larger. Transportation-related impacts associated with commuting construction workers would be site dependent.

Table 8-4 (Continued)
Summary of Environmental Impacts from Coal-Fired Generation Using Once-Through Cooling at an Alternate Greenfield Site

Impact Category	Impact	Comments
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.

8.1.1.2 <u>Closed-Cycle Cooling System</u>

The environmental impacts of constructing a coal-fired generation system at an alternate greenfield site using closed-cycle cooling are similar to the impacts for a coal-fired plant using a once-through cooling system. However, there are some environmental differences between the closed-cycle and once-through cooling systems. Table 8-5 summarizes the incremental differences.

Table 8-5
Summary of Environmental Impacts from Coal-Fired Generation Using Closed-Cycle Cooling at an Alternate Greenfield Site

Impact Category	Comments
Land Use	25 to 30 additional acres required for cooling towers and associated infrastructure.
Ecology	Impact would depend on ecology at the site. Additional impact to terrestrial biota from cooling tower drift. Reduced impact to aquatic ecology.
Surface Water Use and Quality	Discharge of cooling tower blowdown containing dissolved solids. Discharge would be regulated. Decreased water withdrawal and less thermal load on receiving body of water. Consumptive use of water due to evaporation.
Groundwater Use and Quality	No change.
Air Quality	No change.
Waste	No change.
Human Health	No change.
Socioeconomics	No change.
Aesthetics	Introduction of cooling towers and associated plume. Natural draft towers could be up to 520 feet high. Mechanical draft towers could be up to 100 feet high and also have an associated noise impact.
Historic and Archaeological Resources	No change.

8.1.2 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 8-6 presents the basic gas-fired alternative characteristics and Table 8-7 presents emission estimates.

NRC has evaluated gas-fired generation alternatives in each of the plant-specific Supplements to the GEIS. For the V. C. Summer pressurized water reactor the NRC analyzed 816 MWe of gas-fired generation capacity [Reference 8-24, Section 8.2.2]. Entergy has reviewed the NRC analysis and believes it to be sound. Although the V. C. Summer analysis understates the impacts of replacing the approximately 881 MWe at JAFNPP by 7%, Entergy believes these differences are insignificant. In defining the JAFNPP coal-fired alternative, Entergy has used site-specific input and has scaled from the NRC analysis, where appropriate.

Although air emissions from the gas-fired unit would be substantially smaller than from the coal-fired unit, human health effects associated with such emissions would be of concern.

8.1.2.1 Once-Through Cooling System

The overall impacts of the natural-gas-generating system with a once-through cooling system located at the JAFNPP site or an alternate site are summarized in Table 8-8 and discussed in the following sections. The magnitude of impacts at an alternate site will depend on the location of the particular site selected.

8.1.2.1.1 Land Use

For siting at JAFNPP, existing facilities and infrastructure would be used to the extent practicable, limiting the amount of new construction that would be required. Specifically, it was assumed that the natural gas-fired replacement plant alternative would use the once-through cooling system, switchyard, offices, and transmission line right(s)-of-way. The GEIS estimated that 110 acres are needed for a 1,000 MWe natural gas-fired facility [Reference 8-21, Section 8.3.10]. Scaling down for the 816 MWe facility considered by Entergy would indicate a somewhat smaller land requirement (90 acres). Operation of a new gas-fired facility at the JAFNPP site would require the construction of approximately 25 miles of pipeline [Reference 8-25, Section 8.2.2.1]. It is estimated that this pipeline would require approximately 230 acres for an easement [Reference 8-25, Section 8.2.2.1]. The onsite facilities would represent expansion of an existing industrial land use, and JAFNPP expects there would be little or no adverse-impact on land uses adjacent to the site.

For construction at an alternate site, the full land requirement of 110 acres for a natural gas-fired facility would be necessary because no existing infrastructure would be available. Additional land could be impacted by construction of a transmission line and natural gas pipelines to serve the plant. The gas line requirements at an alternate site would depend on the characteristics and location of the alternate site.

Regardless of where the natural gas-fired plant is built, additional land would be required for natural gas wells and collection stations. Partially offsetting these offsite land requirements would be the elimination of the need for uranium mining to supply fuel for JAFNPP. In the GEIS the NRC estimated that approximately 1,000 acres would be affected for mining the uranium and processing it during the operating life of a nuclear power plant [Reference 8-21, Section 8.3.12].

Overall, the land-use impacts of constructing the natural gas-fired alternative at the JAFNPP site are considered SMALL to MODERATE. The land-use impacts of siting the natural gas-fired alternative at an alternate site would depend on the chosen site, but are characterized as SMALL to LARGE.

8.1.2.1.2 Ecology

Siting gas-fired generation at the existing JAFNPP site would have MODERATE ecological impacts because the facility would be constructed partly on previously disturbed areas and would disturb relatively little acreage at the site. However, significant habitat would be disturbed by approximately 25 miles of pipeline construction. Ecological impacts could be reduced by using the existing intake and discharge system. Past operational monitoring of the effects of the cooling system at JAFNPP has not shown significant negative impacts to the Lake Ontario ecology, and this would be expected to remain unchanged.

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. The connection to a gas pipeline located approximately 25 miles from the JAFNPP site is a site-specific factor that would make the gas-fired alternative's ecological impacts larger than those of license renewal. Therefore, in this case, the appropriate characterization of gas-fired generation ecological impacts is MODERATE.

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.

8.1.2.1.3 Water Use and Quality

Surface Water: The plant would use the existing JAFNPP intake and discharge structures as part of the once-through cooling system. Therefore, water quality impacts would continue to 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. Surface water impacts would remain SMALL; the impacts would not be detectable or be so minor that they would not noticeably alter important attributes of the resource.

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 to MODERATE.

Groundwater: As discussed in Section 2.3, JAFNPP does not have onsite pumpable groundwater wells. Potable water is supplied by the Town of Scriba and cooling water is taken from Lake Ontario. Therefore, groundwater impacts would be SMALL; the impacts would be so minor that they would not noticeably alter important resources.

For alternative 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 and LARGE.

8.1.2.1.4 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 gas-fired alternative emissions to be as follows (from Table 8-7).

- Sulfur oxides = 85 tons per year
- Oxides of nitrogen = 272 tons per year
- Carbon monoxide = 57 tons per year
- Filterable Particulates = 47 tons per year (all particulates are PM_{10})

Regional air quality and Clean Air Act requirements are also 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 at JAFNPP would noticeably alter local air quality, but would not destabilize regional resources. 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 nonattainment 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.

8.1.2.1.5 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 be limited to typical office wastes. This impact would be SMALL; waste generation impacts would be so minor that they would not noticeably alter important resource attributes.

Siting the facility at an alternate greenfield site would not alter the waste generation; therefore, the impacts would continue to be SMALL.

8.1.2.1.6 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 8.1.1.1 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; that is, human health effects would not be detectable or would be so minor that they would neither destabilize nor noticeably alter important attributes of the resource.

Siting of the facility at an alternate greenfield site would not alter the possible human health effects. Therefore, the impacts would be SMALL.

8.1.2.1.7 Socioeconomics

Construction of a natural gas-fired plant would take approximately two years. Peak employment would be approximately 1,200 workers [Reference 8-21, Section 8.3.10]. It is assumed that gas-fired construction would take place while JAFNPP continues operation, with completion of the replacement plant at the time that the nuclear plant would halt operations. During construction, the communities surrounding the JAFNPP site would experience demands on housing and public services that could have SMALL impacts. These impacts would be tempered by construction workers commuting to the site from other parts of Oswego and Onondaga Counties. After construction, the communities would be impacted by job loss. The current JFNPP workforce (716 workers) would decline through a decommissioning period to a minimal maintenance size. The natural gas-fired plant would introduce a replacement tax base at JAFNPP, or an alternate greenfield site, and approximately 50 new permanent jobs. Impacts in Oswego and Onondaga Counties resulting from the decommissioning of JAFNPP may be offset by potential job opportunities in the Syracuse area.

In the GEIS [Reference 8-21, Section 8.3.10], the staff concluded that socioeconomic impacts from constructing a natural gas-fired plant would not be very noticeable and that the small operational workforce would have the smallest socioeconomic impacts of any nonrenewable technology. Compared to the coal-fired and nuclear alternatives, the smaller size of the construction work force, the shorter construction time frame, and the smaller size of the operations work force would mitigate socioeconomic impacts. For these reasons, natural gas-fired generation socioeconomic impacts associated with construction and operation of a natural gas-fired power plant would be MODERATE for siting at JAFNPP. Depending on other growth in the area, socioeconomic effects could be noticed, but they would not destabilize any important socioeconomic attribute.

Socioeconomic impacts of constructing and operating the representative natural gas-fired alternative at a greenfield site in upstate New York would be highly location dependent. Not considering impacts from terminating JAFNPP operations, community impacts resulting from location of the representative natural gas-fired plant in areas within reasonable distance to large population centers (i.e., Syracuse), would likely be small, with moderate impacts possible in more rural areas [Reference 8-8, Section 7.3.2]. However, communities in Oswego County in particular would experience losses in both employment and tax revenues due to JAFNPP closure, assuming the natural gas-fired alternative plant is constructed outside the area. Considered in combination with JAFNPP, overall socioeconomic impacts of the natural gas-fired alternative at a greenfield site would likely range from MODERATE to LARGE.

Transportation impacts associated with construction and operating personnel commuting to the plant site would depend on the population density and transportation infrastructure in the vicinity of the site. The impacts can be classified as MODERATE for siting at JAFNPP or at an alternate greenfield site.

8.1.2.1.8 Aesthetics

The turbine buildings and exhaust stacks would be visible during daylight hours from offsite. The gas pipeline compressors would also be visible. However, development of the representative natural gas-fired plant at the JAFNPP site would represent an incremental addition to an existing plant with similar characteristics, and a forest buffer provides a visual screen to residential developments bordering the site. Overall, the aesthetic impacts from development of a natural gas-fired plant at the JAFNPP site would be SMALL.

At an alternate greenfield site, the buildings and the associated transmission line and gas pipeline compressors would be visible offsite. The visual impact of a new transmission line would be especially significant. Aesthetic impacts could be mitigated if the plant were located in an industrial area adjacent to other power plants. Overall, the aesthetic impacts associated with an alternate greenfield site are categorized as MODERATE to LARGE. The greatest contributor to this categorization is the aesthetic impact of the new transmission line.

Natural gas generation would introduce mechanical sources of noise that would be audible offsite. 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 include the use of outside loudspeaker 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 JAFNPP site are considered to be SMALL.

At an alternate site, these noise impacts would be SMALL to LARGE depending on the site.

8.1.2.1.9 Historic and Archaeological Resources

At both JAFNPP and an alternate greenfield site, a cultural resource inventory would likely be needed for any onsite property that has not been previously surveyed. Other lands, if any, that are acquired to support the plant would also likely need an inventory of field cultural resources, identification and recording of existing historic and archaeological resources, and possible mitigation of adverse effects from subsequent ground disturbing actions related to physical expansion of the plant site.

Before construction at JAFNPP or an alternate greenfield site, studies would likely be needed to identify, evaluate, and address mitigation of the potential impacts of new plant construction on cultural resources. The studies would likely be needed for all areas of potential disturbance at the proposed plant site and along associated corridors where new construction would occur (e.g., roads, transmission and pipeline corridors, or other rights-of-way). Impacts to cultural resources can be effectively managed under current laws and regulations and kept SMALL.

Table 8-6
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 and a 143 MW Heat Recovery Boiler	Calculated based on 4% onsite power
Number of units = 2	
Fuel type = natural gas	Assumed
Fuel heating value = 1,019 Btu/ft^3	2000 value for gas used in New York [Reference 8-3, Table 14]
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available [Reference 8-20, Table 3.1-2a]
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_x emissions [Reference 8-20, Table 3.1 Database]
Fuel NO_x content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas-fired units with water injection [Reference 8-20, Table 3.1 Database]
Fuel CO content = 0.0023 lb/MMBtu	Typical for large SCR-controlled gas-fired units [Reference 8-20, Table 3.1]
Heat rate = 8,200 Btu/kWh	Typical for combined cycle gas-fired turbines [Reference 8-4, 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
SCR = selective catalytic reduction

a. The difference between "net" and "gross" is electricity consumed by auxiliary equipment and environmental control devices [Reference 8-4, page 109].

Table 8-7
Air Emissions from Gas-Fired Alternative

Parameter	Calculation	Result
Annual gas consumption	$\frac{816\text{ MW}}{\text{unit}} \times \frac{8{,}200\text{ Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\text{ kW}}{\text{MW}} \times 0.85 \times \frac{\text{ft}^3}{1{,}019\text{ Btu}} \times \frac{24\text{ hr}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}}$	48,893,695,000 ft^3 per year
Annual Btu input	$\frac{48{,}893{,}695{,}000\text{ ft}^3}{\text{yr}} \times \frac{1{,}019\text{ Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\text{Btu}}$	49,822,675 MMBtu per year
SO_x [a]	$\frac{0.0034\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{49{,}822{,}675\text{ MMBtu}}{\text{yr}}$	85 tons SO_x per year
NO_x [b]	$\frac{0.0109\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{49{,}822{,}675\text{ MMBtu}}{\text{yr}}$	272 tons NO_x per year
CO [b]	$\frac{0.0023\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{49{,}822{,}675\text{ MMBtu}}{\text{yr}}$	57 tons CO per year
TSP [a]	$\frac{0.0019\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{49{,}822{,}675\text{ MMBtu}}{\text{yr}}$	47 tons filterable TSP per year
PM_{10} [a]	$\frac{47\text{ tons TSP}}{\text{yr}}$	47 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. Reference 8-20, Table 3.1-2a
b. Reference 8-20, Table 3.1-1

Table 8-8
Summary of Environmental Impacts from Gas-Fired Generation Using Once-Through Cooling at JAFNPP and Alternate Greenfield Site

Impact Category	JAFNPP Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Land Use	SMALL to MODERATE	~110 acres for power block, offices, roads & parking areas. Use existing infrastructure to minimize new land requirements. Additional land impacts for construction of underground gas pipeline.	SMALL to LARGE	Land use requirement higher due to need for developing infrastructure. Total impact would depend on whether the alternate site is previously disturbed.
Ecology	MODERATE	Constructed on land within JAFNPP site. Possible significant 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.
Surface Water Use and Quality	SMALL	Uses existing intake and discharge structures.	SMALL to MODERATE	Impact depends on volume and characteristics of receiving water body.
Groundwater Use and Quality	SMALL	JAFNPP does not use onsite groundwater.	SMALL to LARGE	Impacts dependent on site characteristics, including amount of groundwater available.
Air Quality	MODERATE	Primarily NO_x. Impacts could be noticeable but not destabilizing.	MODERATE	Same impacts as JAFNPP site.
Waste	SMALL	Small amount of ash produced.	SMALL	Same impacts as JAFNPP site.
Human Health	SMALL	Impacts considered minor.	SMALL	Same impacts as JAFNPP site.
Socioeconomics	SMALL to MODERATE	Additional workers during construction period, followed by reduction from current JAFNPP workforce.	MODERATE to LARGE	Construction impacts would be relocated. Community near JAFNPP would still experience workforce reduction.

Table 8-8 (Continued)
Summary of Environmental Impacts from Gas-Fired Generation Using Once-Through Cooling at JAFNPP and Alternate Greenfield Site

Impact Category	JAFNPP Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Aesthetics	SMALL	Visual impact of stacks and equipment would be noticeable, but not as significant as coal option.	SMALL to LARGE	Significance of impacts would depend on the characteristics of the alternate site. The gas-fired alternative at an alternate site could require transmission lines with attendant aesthetic impacts.
Historic and Archaeological Resources	SMALL	Any potential impacts can likely be effectively managed.	SMALL	Any potential impacts can likely be effectively managed.

8.1.2.2 Closed-Cycle Cooling System

The environmental impacts of constructing a natural-gas-fired generation system at the JAFNPP site and an alternate site using a closed-cycle cooling system are similar to the impacts for a natural-gas-fired plant using once-through cooling. However, there are some environmental differences between the closed-cycle and once-through cooling systems. Table 8-9 summarizes the incremental differences.

Table 8-9
Summary of Environmental Impacts from Gas-Fired Generation Using Closed Cycle Cooling at JAFNPP and Alternate Greenfield Site

Impact Category	Comments
Land Use	*25 to 30 additional acres required for cooling towers and* associated infrastructure.
Ecology	Impact would depend on ecology at the site. Additional impact to terrestrial biota from cooling tower drift. Reduced impact to aquatic ecology.

**Table 8-9 (Continued)
Summary of Environmental Impacts from Gas-Fired Generation
Using Closed Cycle Cooling at JAFNPP and Alternate Greenfield Site**

Impact Category	Comments
Surface Water Use and Quality	Discharge of cooling tower blowdown containing dissolved solids. Discharge would be regulated. Decrease water withdrawal and less thermal load on receiving body of water. Consumptive use of water due to evaporation.
Groundwater Use and Quality	No change.
Air Quality	No change.
Waste	No change.
Human Health	No change.
Socioeconomics	No change.
Aesthetics	Introduction of cooling towers and associated plume. Possible noise impact from operation of cooling towers.
Historic and Archaeological Resources	No change.

8.1.3 Nuclear Power Generation

Since 1997, the NRC has certified three new standard designs for nuclear power plants under 10 CFR 52, Subpart B. These designs are the U.S. Advanced Boiling Water Reactor (10 CFR 52, Appendix A), the System 80+ Design (10 CFR 52, Appendix B), and the AP600 Design (10 CFR 52, Appendix C). All of these plants are light-water reactors. Although no applications for a construction permit or a combined license based on these certified designs have been submitted to NRC, the submission of the design certification applications indicates continuing interest in the possibility of licensing new nuclear power plants. 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 cooling is considered in this section. It was assumed that the new nuclear plant would have a 40-year lifetime [Reference 8-23, Section 8.2.3].

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 and would need to be adjusted to reflect replacement of JAFNPP, which has a capacity of approximately 881 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 the NRC's findings on NEPA issues for license renewal of nuclear power plants in Table B-1 of 10 CFR 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 [Reference 8-23, Section 8.2.3].

8.1.3.1 Once-Through Cooling System

The environmental impacts of constructing a nuclear power plant at the existing JAFNPP site or at an alternate greenfield site using once-through cooling are summarized in Table 8-10.

Table 8-10
Summary of Environmental Impacts from Nuclear Power Generation Using Once-Through Cooling at JAFNPP Site and at an Alternate Greenfield Site

Impact Category	JAFNPP Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Land Use	MODERATE	Requires approximately 500 to 1000 acres for the plant and 1000 acres for uranium mining.	MODERATE TO LARGE	Same impacts as JAFNPP site, plus the potential need for land for transmission line(s). Overall, the impacts would depend on whether the alternate site is previously disturbed.
Ecology	SMALL TO MODERATE	Uses undeveloped areas at current JAFNPP site. Potential habitat loss and fragmentation; reduced productivity and biological diversity.	MODERATE TO LARGE	Impact depends on location and ecology of the site, surface water body used for intake and discharge, and transmission line route; potential habitat loss and fragmentation; reduced productivity and biological diversity.
Surface Water Use and Quality	SMALL	Uses existing once-through cooling system.	SMALL TO MODERATE	Impacts would depend on the volume of water withdrawn and discharged and the characteristics of the surface water sources.

**Table 8-10 (Continued)
Summary of Environmental Impacts from Nuclear Power Generation
Using Once-Through Cooling at JAFNPP Site and at an Alternate Greenfield Site**

Impact Category	JAFNPP Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Groundwater Use and Quality	SMALL	No groundwater used at JAFNPP site.	SMALL TO MODERATE	Impacts would depend on the volume of water withdrawn and discharged, and the characteristics of the groundwater source.
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.	SMALL	Same impacts as JAFNPP site.
Waste	SMALL	Waste impacts for an operating nuclear power plant are set out in 10 CFR 51, Appendix B, Table B-1. Debris would be generated and removed during construction.	SMALL	Same impacts as JAFNPP site.
Human Health	SMALL	Human health impacts for an operating nuclear power plant are set out in 10 CFR 51, Appendix B, Table B-1.	SMALL	Same impacts as JAFNPP site.

Table 8-10 (Continued)
Summary of Environmental Impacts from Nuclear Power Generation Using Once-Through Cooling at JAFNPP Site and at an Alternate Greenfield Site

Impact Category	JAFNPP Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Socioeconomics	SMALL TO MODERATE	During construction, impacts would be MODERATE, with up to 2500 workers during peak period of the five-year construction period. During operation, employment levels would be similar to those for JAFNPP. Overall, socioeconomic impacts from operation are SMALL.	SMALL TO LARGE	The characteristics of the construction period and operation at an alternate site would be similar to those at JAFNPP. Socioeconomic impacts to the local community would depend on the characteristics of the alternate site and might vary from SMALL to LARGE.
Socioeconomics (Transportation)	SMALL TO LARGE	Transportation impacts associated with construction workers could be MODERATE to LARGE. Transportation impacts of commuting workers during operations would be SMALL.	SMALL TO LARGE	Transportation impacts associated with construction workers could be MODERATE to LARGE. Transportation impacts of commuting workers during operations would be SMALL.
Aesthetics	SMALL TO MODERATE	No exhaust stacks or cooling towers would be needed. Daytime visual impact could be mitigated by landscaping and appropriate color selection for buildings. Visual impact at night could be mitigated by reduced use of lighting and appropriate shielding. Noise impacts would be relatively small and could be mitigated.	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	Any potential impacts can likely be effectively managed.	SMALL	Same impacts as JAFNPP site.

8.1.3.1.1 Land Use

The existing facilities and infrastructure at the JAFNPP site would be used to the extent practicable, limiting the amount of new construction that would be required. Specifically, the replacement nuclear power plant would use the existing transmission facilities, roads, parking areas, office buildings, and the existing cooling system. According to the GEIS, a light-water reactor requires approximately 500 to 1,000 acres excluding transmission lines (these estimates are not scaled to any particular facility size). Much of the land that would be used has been previously disturbed. The JAFNPP site consists of approximately 702 acres and should be adequate to support a new nuclear facility. There would be no net change in land needed for uranium mining because land needed to supply the new nuclear plant would offset the land needed to supply uranium for fueling the existing reactor JAFNPP. Overall, the impact of a replacement nuclear generating plant on land use at the existing JAFNPP site is characterized as MODERATE.

Land-use requirements at an alternate greenfield site would be similar to siting at the JAFNPP plus the possible need for land to support 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. Depending particularly on transmission line routing, siting a new nuclear plant at an alternate greenfield site would result in MODERATE to LARGE land-use impacts.

8.1.3.1.2 Ecology

Locating a replacement nuclear power plant at the JAFNPP site would alter ecological resources because of construction, and because of the need to convert currently unused land to industrial use. In total, impacts could include habitat degradation, fragmentation, or loss as a result of construction activities and conversion of land to industrial use. Ecological communities may experience reduced productivity and biological diversity from disturbing previously intact land. Overall, the ecological impacts of the nuclear alternative at the JAFNPP site are considered SMALL to MODERATE.

At an alternate site, there would be construction impacts and new incremental operational impacts. Even assuming siting at a previously disturbed area, the impacts may alter the ecology. Impacts could include (1) habitat degradation, habitat fragmentation, or habitat loss; (2) reduced ecosystem productivity; and (3) reduced biological diversity. Construction and maintenance of transmission lines, a rail spur, or a barge offloading facility could result in the same types of ecological impacts. Use of makeup cooling water from a nearby surface water body could have adverse aquatic resource impacts. Overall, the impacts of the nuclear alternative at an alternate site would be MODERATE to LARGE. [Reference 8-25, Section 8.2.3.1]

8.1.3.1.3 Water Use and Quality

<u>Surface Water</u>: A replacement nuclear power plant located at the JAFNPP site is assumed to use the existing once-through cooling system, with cooling water supplied by Lake Ontario. Potable water would continue to be provided by the Town of Scriba. Therefore, surface water impacts would be similar to the existing JAFNPP and classified as SMALL.

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. [Reference 8-25, Section 8.2.3.1]

Groundwater: No groundwater is currently used for operation of JAFNPP. It is unlikely that groundwater would be used for an alternative nuclear power plant sited at JAFNPP. Use of groundwater for a nuclear power plant sited at an alternate site is a possibility. Any groundwater withdrawal would require a permit from the local permitting authority. Overall, the impacts of the nuclear alternative at the JAFNPP site would be SMALL. The impacts of the nuclear alternative at an alternate site would be SMALL to MODERATE.

8.1.3.1.4 Air Quality

Construction of a new nuclear plant at the JAFNPP site or an alternate 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. An operating nuclear plant would have minor air emissions associated with diesel generators and other minor intermittent sources. These emissions would be regulated by the NYSDEC. Overall, emissions and associated impacts to air quality of a nuclear plant at either the JAFNPP site or an alternate site are considered SMALL.

8.1.3.1.5 Waste

The waste impacts associated with operation of a nuclear power plant are listed in Table B-1 of 10 CFR 51 Subpart A, Appendix B. Construction-related debris would be generated during construction activities and removed to an appropriate disposal site. Overall, waste impacts of a new nuclear plant at either the JAFNPP site or an alternate site are considered SMALL.

8.1.3.1.6 Human Health

Human health impacts for an operating nuclear power plant are identified in 10 CFR 51 Subpart A, Appendix B, Table B-1. Overall, human health impacts of a new nuclear plant at either the JAFNPP site or an alternate site are considered SMALL.

8.1.3.1.7 Socioeconomics

For a 1,000 MWe reactor, it was assumed that the construction period would be 5 years and the peak workforce would be 2500. It was also assumed that construction would take place while the existing nuclear unit continues operation and would be completed by the time JAFNPP permanently cease operations. Since JAFNPP's current reactor is rated at approximately 881 MWe, construction period and peak workforce may be less, but impacts are expected to be consistent with that of the 1,000 MWe reactor.

For a facility constructed at the JAFNPP site, construction workers would be in addition to the employees that currently work at the site. Surrounding communities would experience significant, but not destabilizing, demands on housing and public services. After construction, the communities would be impacted by the loss of the construction jobs. In total, the socioeconomic impacts during the construction period for the nuclear alternative at the JAFNPP site are considered MODERATE.

At an unnamed alternate site, the construction impacts could be smaller or larger than those at the JAFNPP site, depending on how close the site is to a vital economic center. These impacts are considered to be SMALL to LARGE depending on the site.

The replacement nuclear unit is assumed to have an operating work force comparable to the 716 workers currently working at JAFNPP. The replacement nuclear unit would provide a new tax base to offset the loss of tax base associated with decommissioning of JAFNPP. For all of these reasons, the appropriate characterization of socioeconomic impacts for operating a new nuclear power plant constructed at JAFNPP is considered SMALL.

The impacts of operating the nuclear alternative at an unnamed alternate site could be smaller or larger than those at the JAFNPP 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 five-year construction period, up to approximately 2,500 construction workers could be working at the site, in addition to the 716 workers currently working at JAFNPP. 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 JAFNPP and are considered SMALL.

Transportation-related impacts associated with commuting construction workers at an alternate greenfield 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 to MODERATE. [Reference 8-25, Section 8.2.3.1]

8.1.3.1.8 Aesthetics

The nuclear alternative would result in aesthetic impacts. Visual impacts would result from several structures, including, most prominently, the containment building. The replacement nuclear unit would also likely be visible at night because of outside lighting. Visual impact at night could be mitigated by reduced use of lighting and appropriate use of shielding. Overall, the visual aesthetic impacts of the nuclear unit alternative at the JAFNPP site are considered MODERATE.

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. Light from the plant would be detectable offsite but could 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 [Reference 8-23, Section 8.2.3.1].

Nuclear generation would introduce mechanical sources of noise from plant operation. The noise sources are both continuous and intermittent. Continuous sources include the mechanical equipment associated with normal plant operations. Intermittent sources include the use of outside loudspeakers and the commuting of plant employees. At the JAFNPP site, the plant operation noises would be similar to existing noise levels from operating the plant. The noise impacts of the nuclear alternative at JAFNPP are considered to be SMALL.

At an alternate site, these noise impacts would be SMALL to LARGE, depending on the site.

8.1.3.1.9 Historic and Archeological Resources

At both the JAFNPP site and an alternate greenfield site, a cultural resource inventory would likely be needed for any onsite property that has not been previously surveyed. Other lands, if any, that are acquired to support the plant would also likely need an inventory of field cultural resources, identification and recording of existing historic and archaeological resources, and possible mitigation of adverse effects from subsequent ground-disturbing actions related to physical expansion of the plant site.

Before construction at the JAFNPP site or an alternate greenfield site, studies would likely be needed to identify, evaluate, and address mitigation of the potential impacts of new plant construction on cultural resources. The studies would likely be needed for all 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.

8.1.3.2 Closed-Cycle Cooling System

The environmental impacts of constructing a nuclear power plant that uses closed-cycle cooling system with a cooling tower at an alternate site are similar to the impacts for a nuclear power plant using a once-through cooling system. However, there are some differences in the environmental impacts between the closed-cycle and once-through cooling systems. Table 8-11 summarizes the incremental differences.

Table 8-11
Summary of Environmental Impacts from Nuclear Power Generation Using Closed-Cycle Cooling at Alternate Greenfield Site

Impact Category	Comments
Land Use	25 to 30 acres land required because cooling towers and associated infrastructure are needed.
Ecology	Impacts would depend on ecology at the site. Additional impact to terrestrial ecology from cooling tower drift. Reduced impact to aquatic ecology.
Surface Water Use and Quality	Discharge of cooling tower blowdown containing dissolved solids. Discharge would be regulated by the State of New York. Decreased water withdrawal and less thermal load on receiving body of water. Consumptive use of water due to evaporation from cooling towers.
Groundwater Use and Quality	No change.
Air Quality	No change.
Waste	No change.
Human Health	No change.
Socioeconomics	No change.
Aesthetics	Introduction of cooling towers and associated plume. Natural draft towers could be up to 520 feet in height. Mechanical draft towers could be up to 100 feet in height and also have an associated noise impact.
Historic and Archaeological Resources	No change.

8.1.4 Purchased Electrical Power

"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. If available, purchased power from other sources could potentially obviate the need to renew the JAFNPP license. The New York State Energy Plan is designed to promote competition in energy supply markets by facilitating participation by non-utility suppliers. A regulatory structure is in place to appropriately anticipate and meet electricity demands, and the New York Independent System Operator (NYISO) anticipates that adequate supplies of electricity will be available to meet anticipated future demands through at least 2021 [Reference 8-25, Section 8.2.4].

In theory, purchased power is a feasible alternative to JAFNPP license renewal. There is no assurance, however, that sufficient capacity or energy would be available during the entire time frame of 2014 through 2034 to replace the approximately 881 MWe of 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 48.9 billion kWh in year 2005 and then gradually decrease to 24.4 billion kWh in year 2020 [Reference 8-16]. On balance, it appears unlikely that electricity imported from Canada or Mexico would be able to replace the JAFNPP generating capacity.

If power to replace JAFNPP capacity were to be purchased from sources within the U.S. or a foreign country, the generating technology would likely be one of those described in this SEIS and in the GEIS (probably coal, natural gas, or nuclear). The description of the environmental impacts of other technologies in Chapter 8 of the GEIS is representative of the purchased power alternative to renewal of the JAFNPP Operating License. Thus, the environmental impacts of purchased power would still occur but would be located elsewhere within the region, nation or another country. For these reasons, Entergy does not believe that purchasing power to make up for the generation at JAFNPP is a meaningful alternative that requires independent analysis.

8.2 Alternatives 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 881 MWe of electricity as a base-load supply using these technologies is not technologically feasible.

8.2.1 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. [Reference 8-25, 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) [Reference 8-2] with a narrow band of Class 3 or 4 along the shore of Lake Ontario. Wind turbines are economical in wind power Classes 4 through 7 (average wind speeds of 16 to 20 mph) [Reference 8-11]. Wind turbines typically operate at a 25- to 35-percent capacity factor, compared to 80 to 95 percent for a base-load plant [Reference 8-9]. 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 JAFNPP and the functionality is not equivalent.

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 [Reference 8-1]. 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 [Reference 8-10]. 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. Also, many of the best quality wind sites are on ridges and hilltops that could have greater archeological sensitivity than surrounding areas. For these reasons development of large-scale, land-based wind power facilities are likely to not only be costly, but could have MODERATE to LARGE impacts on aesthetics, archaeological resources, land use, and terrestrial ecology.

The offshore wind speeds in Lake Ontario 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 of JAFNPP. 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 JAFNPP. The environmental impacts of a large-scale wind farm are described in the GEIS [Reference 8-21, 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.

8.2.2 Solar

Solar technologies use the sun's energy and light to provide heat, cooling, light, hot water, and electricity for homes, businesses, and industry. Solar power technologies, both photovoltaic (PV) and thermal, cannot currently compete with conventional fossil-fueled technologies in grid-connected applications due to higher capital costs per kilowatt of capacity. The average capacity factor of PV cells is about 25%, and the capacity factor for solar thermal systems is about 25–40%. These capacity factors are low because solar power is an intermittent resource, providing power when the sun is strong, whereas JAFNPP provides constant base-load power. Solar technologies simply cannot make up for the capacity from JAFNPP during the night and in overcast conditions. [Reference 8-25, Section 8.2.5.3]

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 1 MWe generated, over 12,000 acres would be required to replace the approximately 881 MWe produced by JAFNPP. There is not enough land for either type of solar electric system at the existing JAFNPP site and both would have LARGE environmental impacts at an alternate site.

The construction impacts would be similar to those associated with a large wind farm as discussed in Section 8.2.1. 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.

8.2.3 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 summer peak capacity. If all this capacity were developed, it would be enough to replace the 881 MWe generating capacity of JAFNPP. However, 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 [Reference 8-15].

The GEIS estimated that land requirements for hydroelectric power are approximately 1 million acres per 1,000 MWe. Replacement of the JAFNPP generating capacity would therefore require flooding a substantial amount of land (881,000 acres). Due to the large land-use and related environmental and ecological resource impacts associated with siting hydroelectric facilities large enough to replace JAFNPP, it can be concluded that local hydropower alone is not a feasible alternative to the renewal of the JAFNPP Operating License on its own. Any attempts to site hydroelectric facilities large enough to replace JAFNPP would result in LARGE environmental impacts.

8.2.4 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. [Reference 8-22, Section 8.2.4.4] A study commissioned by NYSERDA and the DOE, completed in 1996, found that there is some potential for geothermal electric power production in western upstate New York, but high cost inhibits its development [Reference 8-25, Section 8.2.5.5]. Therefore, geothermal energy is not a feasible alternative to renewal of the JAFNPP Operating License.

8.2.5 Wood Energy

The use of wood waste to generate electricity is largely limited to those states with significant wood resources, such as California, Maine, Georgia, Minnesota, Oregon, Washington, and Michigan. Electric power is generated in these states by the pulp, paper, and paperboard industries, which consume wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem. [Reference 8-25, Section 8.2.5.6]

A wood-burning facility can provide base-load power and operate with an average annual capacity factor of around 70 to 80 percent and with 20 to 25 percent efficiency [Reference 8-21, Section 8.3.6]. The fuels required are variable and site-specific. A significant barrier to the use of wood waste to generate electricity is the high delivered-fuel cost and high construction cost per MWe of generating capacity. The larger wood-waste power plants are only 40 to 50 MWe in capacity. Estimates in the GEIS suggest that the overall level of construction impact per megawatt 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. Like coal-fired plants, wood-waste plants require large areas for fuel storage and processing and involve the same type of combustion equipment. [Reference 8-25, Section 8.2.5.6]

Due to 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 high inefficiency, wood waste is not a feasible alternative to renewing the JAFNPP Operating License.

8.2.6 Municipal Solid Waste

Municipal waste combustors incinerate the waste and use the resultant heat to generate steam, hot water, or electricity. Municipal waste combustors use three basic types of technologies: mass burn, modular, and refuse-derived fuel [Reference 8-14]. Mass-burning technologies are most commonly used in the U.S. This group of technologies process raw municipal solid waste as is, with little or no sizing, shredding, or separation before combustion.

Growth in the municipal waste combustion industry slowed dramatically during the 1990s after rapid growth during the 1980s. The slower growth was due to three primary factors: (1) the Tax Reform Act of 1986, which made capital intensive projects such as municipal waste combustion facilities more expensive relative to less capital intensive waste disposal alternative such as landfills; (2) the 1994 Supreme Court decision (C&A Carbone, Inc. v. Town of Clarkstown), which struck down local flow control ordinances that required waste to be delivered to specific municipal waste-combustion facilities rather than landfills that may have had lower fees; and (3) increasingly stringent environmental regulations that increased the capital cost necessary to construct and maintain municipal waste-combustion facilities [Reference 8-14].

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. The use of landfills as a waste disposal option is likely to increase in the near term; however, it is unlikely that many landfills will begin converting waste to energy because of unfavorable economics, particularly with electricity prices declining.

Municipal solid-waste combustors generate an ash residue that is buried in landfills. The ash residue is composed of bottom ash and fly ash. Bottom ash refers to that portion of the unburned waste that falls to the bottom of the grate or furnace. Fly ash represents the small particles that rise from the furnace during the combustion process. Fly ash is generally removed from flue-gases using fabric filters and/or scrubbers [Reference 8-14].

Currently there are approximately 89 waste-to-energy plants operating in the U.S. These plants generate approximately 2,500 MWe, or an average of approximately 28 MWe per plant [Reference 8-7], much smaller than needed to replace the approximately 881 MWe at JAFNPP.

There are only a small number of waste-to-energy plants due to the need for specialized waste separation and handling equipment for municipal solid waste [Reference 8-21, Section 8.3.7]. Furthermore, estimates in the GEIS suggest that the overall level of construction impact from a waste-fired plant should be approximately the same as that for a coal-fired plant. Additionally, waste-fired plants have the same or greater operational impacts (including impacts on the aquatic environment, air, and waste disposal). Some of these impacts would be moderate, but still larger than the environmental effects of license renewal of JAFNPP. Therefore, municipal solid-waste combustors would not be a feasible alternative to renewal of the JAFNPP operating license, particularly at the scale required.

8.2.7 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) [Reference 8-22, Section 8.2.4.7]. 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 JAFNPP. For these reasons, such fuels do not offer a feasible alternative to JAFNPP license renewal. In addition, these systems have LARGE impacts on land use.

8.2.8 Oil

EIA projects that oil-fired plants will account for very little of the new generation capacity in the U.S. through the year 2020 because of higher fuel costs and lower efficiencies [Reference 8-13]. Oil-fired operation is more expensive than nuclear or coal-fired operation. Future increases in oil prices are expected to make oil-fired generation increasingly more expensive than coal-fired generation. The high cost of oil has prompted a steady decline in its' use for electricity generation. Increasing domestic concerns over oil security will only exacerbate the move away from oil-fired electricity generation. Therefore, oil-fired generation by itself is not considered a feasible alternative to the renewal of the JAFNPP Operating License.

8.2.9 Fuel Cells

Fuel cells work without combustion and its environmental side effects. Power is produced electrochemically by passing a hydrogen-rich fuel over an anode, passing air over a cathode, and separating the two by an electrolyte. The only by-products are heat, water, and carbon dioxide. Hydrogen fuel can come from a variety of hydrocarbon resources by subjecting them to steam under pressure. Natural gas is typically used as the source of hydrogen. [Reference 8-25, Section 8.2.5.9]

Phosphoric acid fuel cells are generally considered first-generation technology. These fuel cells are commercially available at cost of approximately $4,500 per kW of installed capacity [Reference 8-12]. Higher temperature second-generation fuel cells achieve higher fuel-to-electricity and thermal efficiencies. The higher temperatures contribute to improved efficiencies and give the second-generation fuel cells the capability to generate steam for cogeneration and combined-cycle operations.

The U.S. Department of Energy has launched a major initiative, the Solid State Energy Conversion Alliance, to bring about dramatic reductions in fuel cell costs. The goal is to cut costs to as low as $400 per kilowatt by 2010, which would make fuel cells competitive for virtually every type of power application [Reference 8-12]. For comparison, the installed capacity cost for a natural gas-fired, combined-cycle plant is about $456 per kW [Reference 8-13]. However, at the present time, fuel cells are not economically or technologically competitive with other alternatives for base-load electricity generation. Fuels cells are, consequently, not a feasible alternative to renewal of the JAFNPP OL.

8.2.10 Delayed Retirement

Even without retiring any generating units, Entergy expects to require additional capacity 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.

NYISO load and capacity projections assume that nuclear generating units in the state will cease operation upon expiration of their current operating licenses, but do not acknowledge retirement of any non-nuclear generating units in the State from 2005 through 2021 [Reference 8-8, Section 7.2.3.2]. Therefore, any such retirements that do occur in this period would merely act to further increase projected demand.

JAFNPP would be required, in part, to offset any actual retirements that occur. Delayed retirement of other Entergy generating units would not provide a replacement of the power supplied by JAFNPP and would not be a feasible alternative to JAFNPP license renewal.

8.2.11 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". It is neither single, nor discrete, nor is it a source of generation [Reference 8-22, Section 8.2.4.12].

Demand side management resource strategies aimed at increasing energy efficiency on the customer side of the electric meter generally fall under the following categories.

- Energy efficiency-selecting equipment that will perform the same work with less energy input.
- Load response-customers who agree to respond to utility requests to reduce use during times of utility peak demand.
- Load management, which encourages customers to reduce their loads during peak times of day and peak season through the use of time-of-use rates, seasonal rates, and interruptible contracts; or direct load control, in which a utility interrupts power supply to customer equipment.

Typically, demand side management induced load reductions are acknowledged in load forecasts. Therefore they cannot be used as credits to offset the power generated by JAFNPP. As a practical matter, it would be impossible to increase those energy savings by an additional 881 MWe to replace the JAFNPP generating capability, particularly in upstate New York, which represents a relatively small fraction of electrical load in the State [Reference 8-25, Section 8.2.5.11].

The environmental impacts of an energy conservation program would be SMALL, but the potential to displace the entire generation at JAFNPP solely with conservation is not realistic. Although it is recognized that energy conservation is promoted and increases in energy efficiency occur as a normal result of replacing older equipment with modern equipment, the conservation option by itself is not considered a reasonable replacement for the JAFNPP OL renewal alternative.

8.2.12 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 [Reference 8-21, Section 8.1]. Consistent with the NRC determination, Entergy has not evaluated mixes of generating sources.

8.3 Proposed Action vs. No Action

The proposed action is the renewal of the operating license of the James A. FitzPatrick Nuclear Power Plant. The specific review of the eleven 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 JAFNPP through the period of extended operation.

The no-action alternative to the proposed action is the decision not to pursue renewal of the operating license for JAFNPP. The environmental impacts of the no-action alternative would be the impacts associated with the construction and operation of the type of replacement power utilized. In effect, the net environmental impacts would be transferred from the continued operation of JAFNPP 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 JAFNPP site. Therefore, the no-action alternative would have no net environmental benefits.

The environmental impacts associated with the proposed action (the continued operation of JAFNPP) were compared to the environmental impacts from the no-action alternative (the construction and operation of other reasonable sources of electric generation). Entergy believes this comparison shows that the continued operation of JAFNPP would produce fewer significant environmental impacts than the no-action alternative. There are significant differences in the impacts to air quality and land use between the proposed action and the reasonable alternative generation sources.

In addition, there would be adverse socioeconomic impacts (including local unemployment, loss of local property tax revenue, and higher energy costs) to the area around JAFNPP from the decision not to pursue 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" [Reference 8-18]. The renewal of the JAFNPP operating license is consistent with these goals.

8.4 Summary

The proposed action is the renewal of the JAFNPP operating license. The proposed action would provide the continued availability of approximately 881 MWe of base-load power generation through 2034.

Carbon dioxide emissions are a major contributor to anthropogenic greenhouse gas emissions and climate change. These emissions results 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 Voluntary Reporting of Greenhouse Gas Emission, Fuel and Energy Emission Coefficients, *below is a comparison of the CO_2 content of various fuels.*

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

Below are estimates of CO_2 emissions that would result if other fuel technologies were utilized to supply the approximately 881 MWe of electricity that is currently being generated by JAFNPP. The technologies, fuels, and production efficiencies shown are based upon "greenfield plants" that have recently been permitted as having "Best Available Control Technology" under the New *Source Review Permit program. In addition, estimates are also based on a 92% capacity factor,* which is what Entergy's northeast nuclear fleet achieved overall during 2004.

Technology	Fuel	Heat Rate (Btu/KWh)	Electricity (MWH/yr)	CO_2 Emissions (metric tons/yr)
Pulverized coal	Bituminous coal	9,928	7,100,155	6,564,348
Pulverized coal	Subbituminous coal	9,700	7,100,155	6,644,772
Combined cycle gas turbine	Natural gas	6,814	7,100,155	2,569,803

The environmental impacts of the continued operation of JAFNPP, providing approximately 881 MWe of base-load power generation through 2034, are superior to impacts associated with the best case among reasonable alternatives. The continued operation of JAFNPP would create significantly less environmental impact than the construction and operation of new base-load generation capacity.

Finally, the continued operation of JAFNPP will have a significant positive economic impact on the communities surrounding the station.

8.5 References

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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."

9.2 Environmental Permits

Table 9-1 provides a list of the environmental permits held by JAFNPP 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. Table 9-2 lists environmental consultations related to the renewal of the JAFNPP operating license.

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 [Reference 9-3]. JAFNPP, located in Oswego County, is within the New York coastal zone. Concurrent with submitting the "Applicant's Environmental Report—Operating License Renewal Stage" to the NRC, JAFNPP submitted a copy of the license renewal application to the New York Department of State Coastal Zone Management Program in fulfillment of the regulatory requirement for submitting a copy of the coastal zone consistency certification to the appropriate state agency (see Attachment D).

9.4 Water Quality (401) Certification

Federal Clean Water Act, 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 Clean Water Act requirements (33 USC 1341). The New York State Department of Environmental Conservation

(NYSDEC) issued a Section 401 State Water Quality Certification for JAFNPP on June 1, 1973 (provided in Attachment C). The NRC has indicated in its Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) that issuance of a National Pollutant Discharge Elimination System (NPDES) permit implies continued certification by the state [Reference 9-2, Section 4.2.1.1]. The U.S. Environmental Protection Agency granted New York State authority to issue NPDES permits under its own program, the New York State Pollutant Discharge Elimination System (SPDES). JAFNPP is applying to the NRC for a license renewal to continue plant operations. Attachment C to this environmental report contains the SPDES permit that authorizes plant discharges at JAFNPP. Consistent with the GEIS, JAFNPP is providing the copy of its SPDES permit as evidence of state water quality (401) certification.

NYSDEC has taken the position [Reference 9-1] 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. JAFNPP plans to submit a Joint Application for Permit for the water quality certification in April 2007 based on conversation with the NYSDEC. Before NYSDEC can issue the water quality certification, it must satisfy the requirements of both the State Environmental Quality Review Act (SEQRA) 6 New York Code of Rules and Regulations Part 617 and the Uniform Procedures Act (6 NYCRR Part 621). The SEQRA process includes a Coastal Zone Consistency Review.

As identified in Table 9-1, the SPDES permit for discharges at JAFNPP will expire on August 1, 2006. In accordance with the New York State Administrative Procedures Act, JAFNPP filed the SPDES permit renewal application 180 days prior to the current permit's expiration date on January 24, 2006.

9.5 Environmental Permits—Discussion of Compliance

JAFNPP has an excellent record of compliance with its environmental permits, including monitoring, reporting, and operating within specified limits. Station personnel are primarily responsible for monitoring and ensuring that JAFNPP complies with its environmental permits and applicable regulations. Sampling results are submitted to the appropriate agency.

Potable water for the JAFNPP site is supplied by the Town of Scriba. Sanitary wastewaters at JAFNPP are treated on-site in a wastewater treatment plant regulated under SPDES Permit NY-0020109.

Entergy has measures in place to ensure that environmentally sensitive areas are adequately protected during site operations and project planning. These measures include an environmental evaluation checklist and also established controls and methods for evaluating potential environmental affects from plant operations and project planning. Planned projects or changes in plant operations are required to undergo an environmental review and evaluation prior to implementation, with appropriate permits obtained or modified as necessary.

Table 9-1
JAFNPP Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
DOT	49 CFR 107, Subpart G	Hazardous Materials Certificate of Registration	060704551044MN	June 30, 2006	Radioactive and hazardous materials shipments.
NRC	Atomic Energy Act, 10 CFR 50	License to operate	DPR-59	October 17, 2014	Operation of JAFNPP.
NYSDEC	6 NYCRR Part 201	Certificate to Operate an Air Contamination Source	7-3556-0020/00012	Not Applicable	Operation of air emission sources (diesel generators and boilers).
NYSDEC	6 NYCRR Part 372	Hazardous Waste Generator Identification	NYD000765073	Not Applicable	Hazardous waste generation
NYSDEC	6 NYCRR Part 675	Water Withdrawal Registration	NYGLWR-4004	November 20, 2006	Withdraw water from Lake Ontario.
NYSDEC	6 NYCRR Part 596	Hazardous Substance Bulk Storage Registration Certificate	7-000117	August 16, 2006	Onsite bulk storage of hazardous substances.
NYSDEC	6 NYCRR Part 750	State Pollutant Discharge Elimination System (SPDES) Permit	NY-0020109	August 1, 2006	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 612	Petroleum Bulk Storage Registration Certificate	7-140600	November 20, 2010	Onsite bulk storage of petroleum products.
NYSDEC	6 NYCRR Part 373	Hazardous Waste Part 373 Permit	7-3556-0020/0004-0	Not Applicable	Accumulation and temporary storage onsite of mixed waste for >90 days.

Table 9-1 (Continued)
JAFNPP Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NYSDEC	6 NYCRR Part 325	Pesticide Application Business Registration	79632	July 31, 2008	Pesticide application.
CVDEM	Title 44, Code of Virginia, Chapter 3.3, Section 44-146.30	Application for Registration to Transport Hazardous Radioactive Materials	EF-S0083107	August 31, 2007	Transportation of radioactive waste into the Commonwealth of Virginia
SCDHEC	Act No.429 of 1980, South Carolina Radioactive Waste Transportation and Disposal Act	South Carolina Radioactive Waste Transport Permit	0031-31-06	December 31, 2006	Transportation of radioactive waste into the State of South Carolina
TDEC	Tennessee Department of Environment and Conservation Regulations	Tennessee Radioactive Waste-License-for-Delivery	T-NY003-L06	12/31/2006	Shipment of radioactive material into Tennessee to a disposal/processing facility

CVDEM: Commonwealth of Virginia (Department of Emergency Management)
DOT: U.S. Department of Transportation
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)

Table 9-2
Environmental Consultations Related to License Renewal

Agency	Authority	Activity Covered
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 (16 USC 1636)	Requires federal agency issuing a license to consult with USFWS.
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 Service 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. Based on its review of the proposed activity, the state must concur with or object to the applicant's certification.
New York State Department of Environmental Conservation	Clean Water Act, Section 401 (33 USC 1341)	Requires New York certification that discharge would comply with CWA standards

9.6 References

9-1 New York State Department of Environmental Conservation, Memorandum from K. Merchant, New York State Department of Environmental Conservation to NYSDEC RG&E Ginna Group, dated September 17, 2002.

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9-3 U.S. Nuclear Regulatory Commission, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues," NRR Office Instruction No. LIC-203, Revision 1, May 24, 2004.

Attachment A

Threatened and Endangered Species Correspondence

- T.A. Sullivan, Entergy Nuclear Fitzpatrick, to David Stilwell, U.S. Fish and Wildlife Service, February 9, 2006.
- D.A. Stilwell, U.S. Fish and Wildlife Service, to T.A. Sullivan, Entergy Nuclear Fitzpatrick, May 19, 2006.
- T.A. Sullivan, Entergy Nuclear Fitzpatrick, to David VanLuven, New York Natural Heritage Program, February 9, 2006.
- Nicholas Conrad, New York Natural Heritage Program, to T.A. Sullivan, Entergy Nuclear Fitzpatrick, March 30, 2006.

Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
James A. Fitzpatrick NPP
P.O. Box 110
Lycoming, NY 13093
Tel 315 349 6024 Fax 315 349 6480

T.A. Sullivan
Site Vice President - JAF

February 9, 2006
JAFP-06-0025

Mr. David Stillwell
Field Supervisor
U.S. Fish and Wildlife Service
New York Field Office
3817 Luker Road
Cortland, NY 13045

RE: Entergy Nuclear Fitzpatrick, LLC
James A. Fitzpatrick Nuclear Power Plant
License Renewal Application

Dear Mr. Stillwell:

Entergy Nuclear Fitzpatrick, LLC (Entergy) is preparing an application to the US Nuclear Regulatory Commission (NRC) to renew the operating license for the James A. Fitzpatrick Nuclear Power Plant (JAFNPP) which is located within the Town of Scriba, County of Oswego, New York. The exact location of the site is latitude 43°31'23" and longitude 76°23'55". JAFNPP is a 702 acre site of which 22 acres has been developed for Station. The Station elevation is 270 feet to 310 feet one mile away at its extremity. JAFNPP is located immediately adjacent to the Nine Mile Point Nuclear Station. The current license for the Plant expires in October 2014. If the application is approved by the NRC, then Entergy will have the option to continue operating the JAFNPP for an additional 20 years.

As part of the license renewal process, the NRC requires the license applicants to "assess the impact of the proposed action." This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the Station during the license renewal period (an additional 20 years). Based on Entergy's preliminary assessment, the continued operation of JAFNPP is not expected to adversely affect the environment within the vicinity of the Station. Entergy has no plans to alter current operations over the license renewal period and any maintenance activities necessary to support license renewal would be limited to previously disturbed areas on-site. Finally, no expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts to threatened or endangered species, or other species of interest, in the vicinity of the Station (see attached map) during the license renewal period. JAFNPP is in the Southeast corner of the USGS 7.5 minute quad map named West of Texas, map number 43076-E4. After your review, we would appreciate your office sending a letter detailing any concerns you may have or confirmation that no concerns exist. Entergy will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the JAFNPP license renewal application.

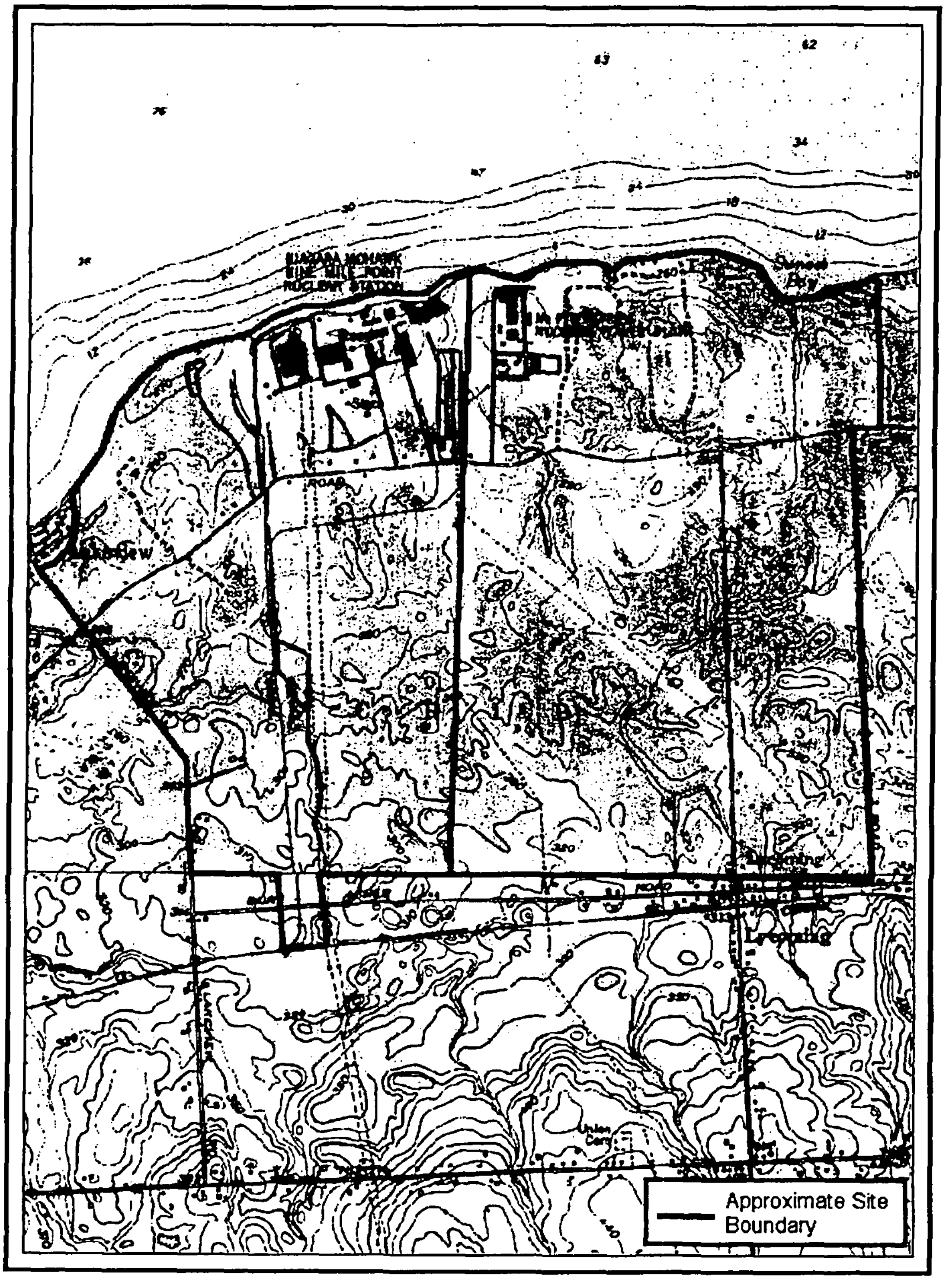
If you have questions or need additional information, please feel free to call me at (315) 349-6004.

Kindest regards,

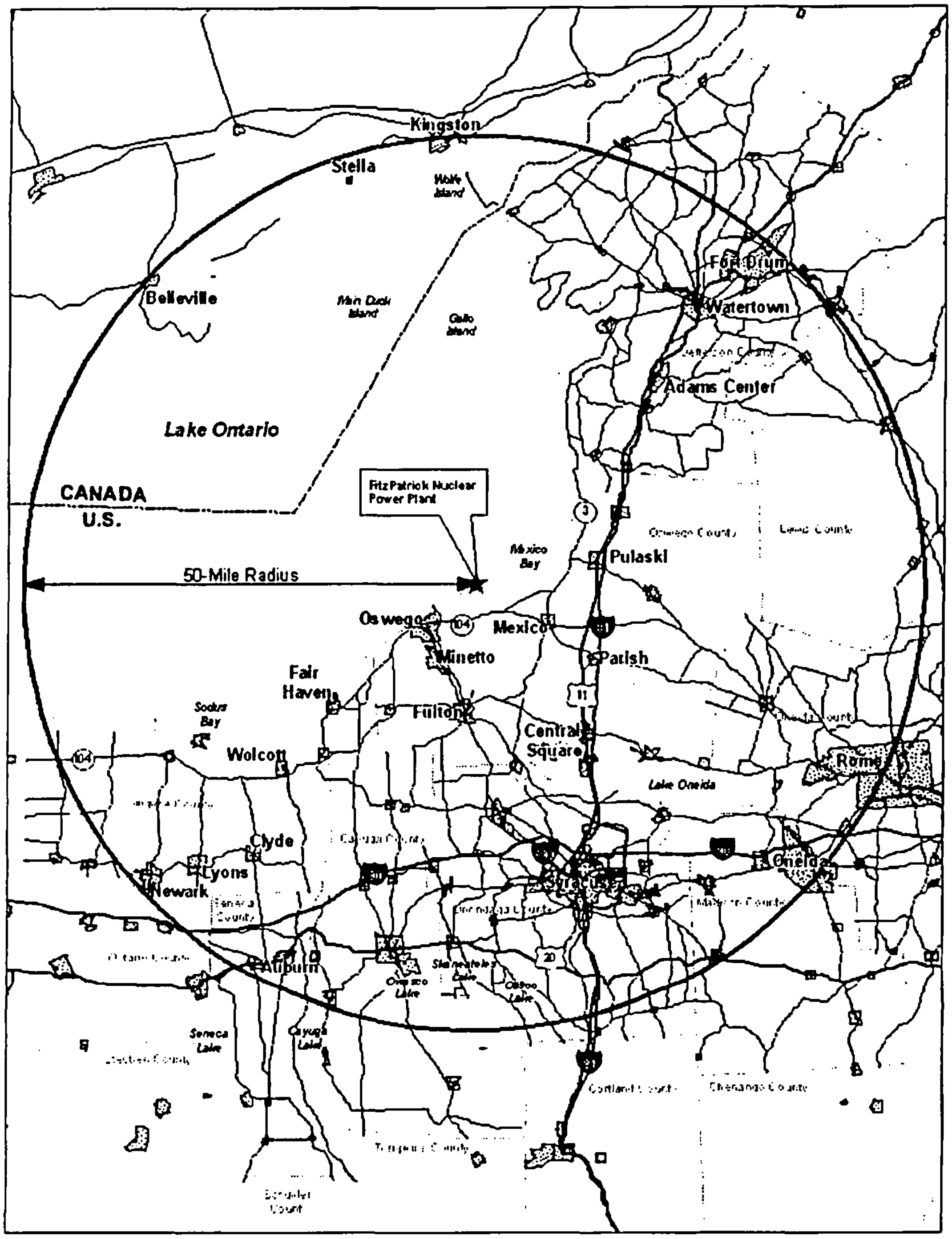
T. A. Sullivan
Site Vice President
James A. Fitzpatrick Nuclear Power Plant

Attachments

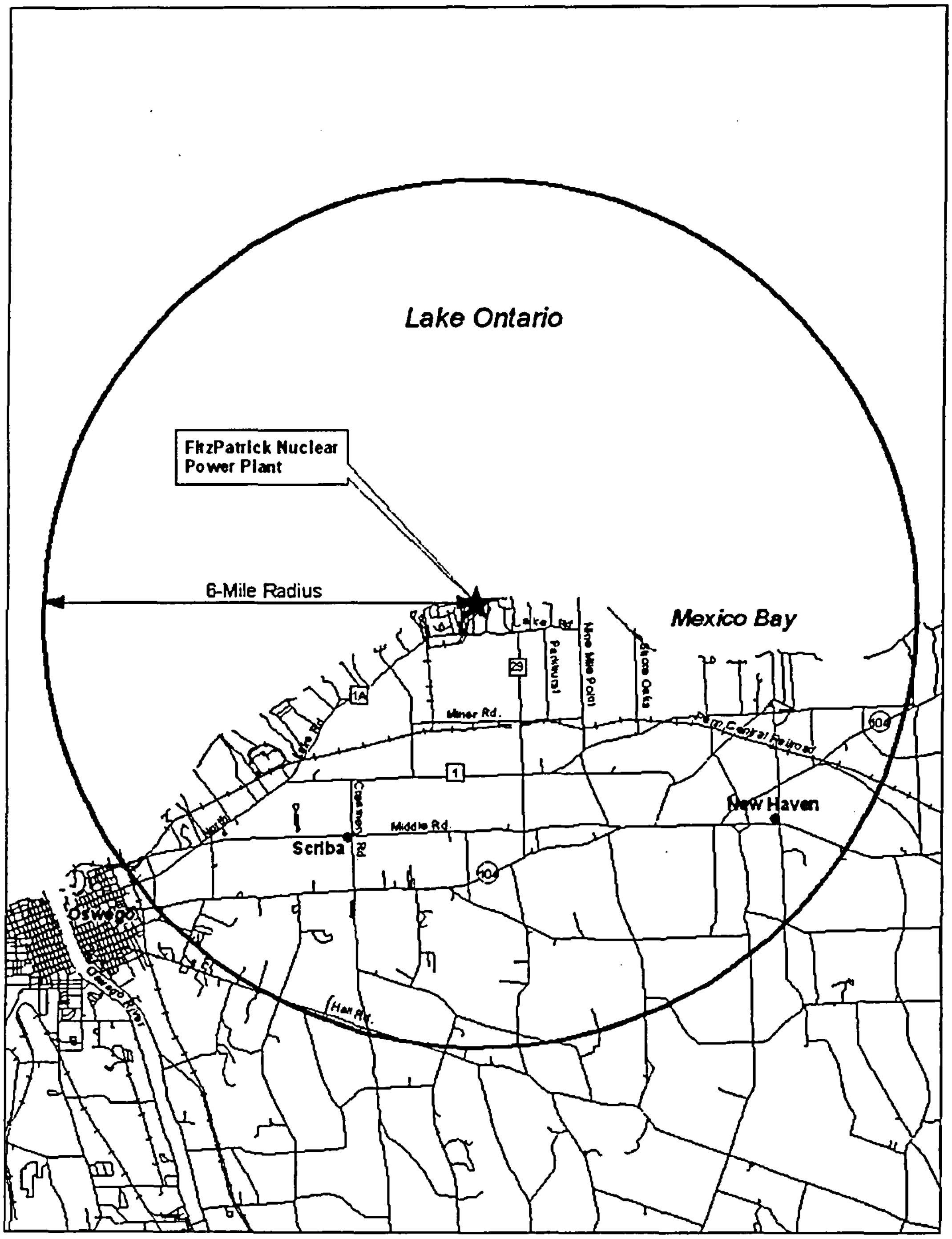
cc: Rick Buckley, Entergy
Doug Harrison, Entergy
Mike Rodgers, Entergy



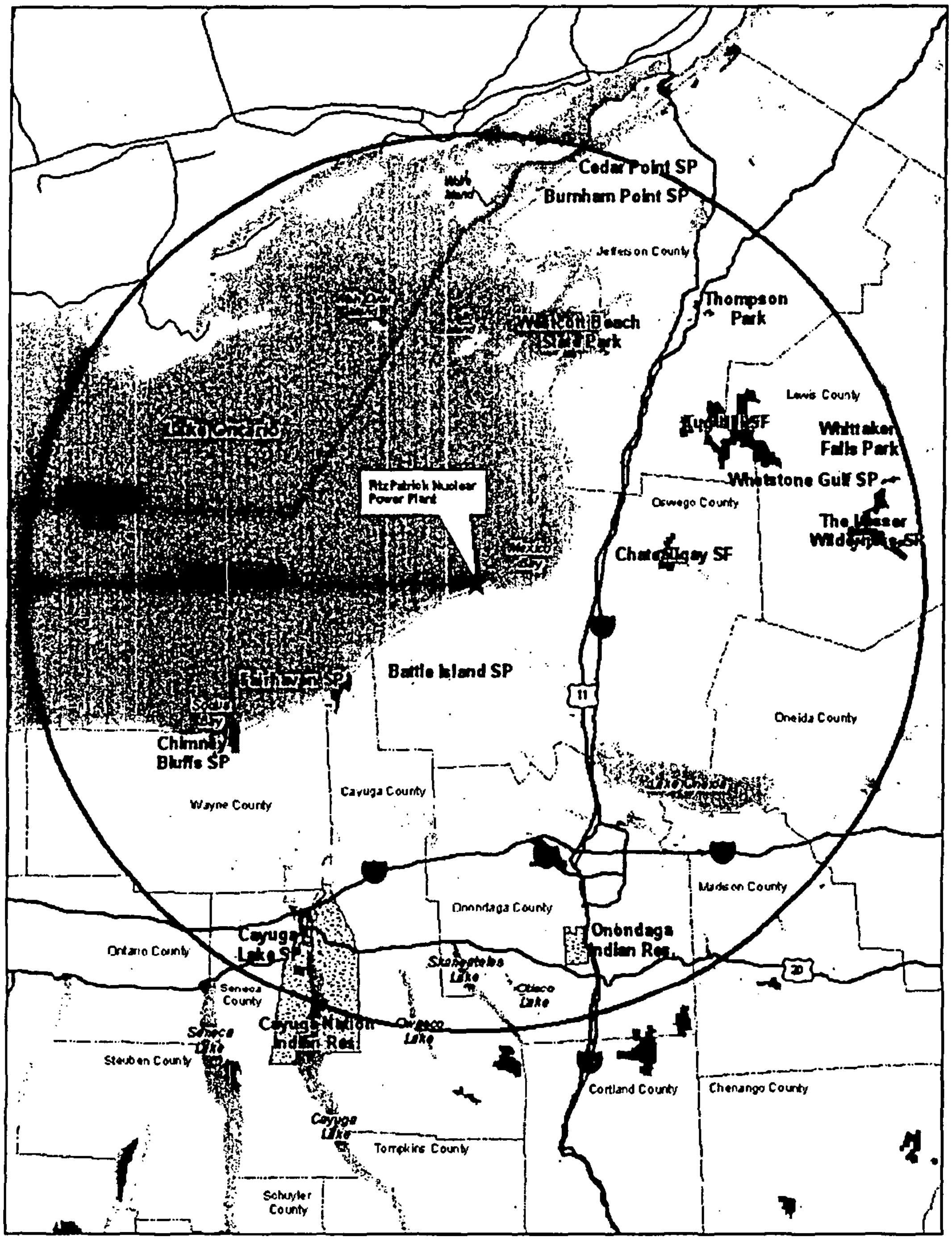
TOPOGRAPHICAL MAP OF AREA SURROUNDING JAFNPP



JAFNPP Figure 2-1
Location of JAFNPP



JAFNPP Figure 2-2
General Area of JAFNPP



JAFNPP Figure 2-4
State and Federal Lands – 50-mile Radius

United States Department of the Interior

FISH AND WILDLIFE SERVICE
3817 Luker Road
Cortland, NY 13045

May 19, 2006

Mr. T.A. Sullivan
Site Vice President
James A. Fitzpatrick Nuclear Power Plant
P.O. Box 110
Lycoming, NY 13093

Dear Mr. Sullivan:

This responds to your February 9, 2006, letter requesting information on the presence of endangered or threatened species within the vicinity of the James A. Fitzpatrick Nuclear Power Plant (JAFNPP) located in the Town of Scriba, Oswego County, New York. We understand that Entergy Nuclear Fitzpatrick, LLC, is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for the JAFNPP. Federal agencies, such as the NRC, have responsibilities under Section 7(a)(2) of the Endangered Species Act of 1973 (ESA) (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.*) to consult with the U.S. Fish and Wildlife Service (Service) regarding projects that may affect Federally-listed species or "critical habitat," and confer with the Service regarding projects that may affect Federally-proposed species or proposed "critical habitat."

There is potential for the Federally- and State-listed endangered Indiana bat (*Myotis sodalis*) to occur within the proposed project area, which is within 11 miles of known roosts and approximately 39 miles from a known hibernaculum in Onondaga County. In addition, there is potential for the Federally-listed threatened and State-listed endangered bog turtle (*Clemmys muhlenbergii*) to occur within the proposed project area, which is approximately 12 miles from known bog turtle sites. Please visit our website* for more information on Indiana bats and bog turtles.

Except for the potential for Indiana bat, bog turtle, and occasional transient individuals, no other Federally-listed or proposed endangered or threatened species under our jurisdiction are known to exist in the project area. In addition, no habitat in the project area is currently designated or proposed "critical habitat" in accordance with provisions of the ESA. Should project plans change, or if additional information on listed or proposed species or critical habitat becomes available, this determination may be reconsidered. The most recent compilation of Federally-listed and proposed endangered and threatened species in New York* is available for your information. Until the proposed project is complete, we recommend that you check our website* every 90 days from the date of this letter to ensure that listed species presence/absence information for the proposed project is current.

The above comments pertaining to endangered species under our jurisdiction are provided as technical assistance pursuant to the ESA. This response does not preclude additional Service comments under other legislation.

As stated above, the Indiana bat and bog turtle are listed as endangered by the State of New York. Any additional information regarding the project and its potential to impact the Indiana bat or bog turtle should be coordinated with both this office and with the New York State Department of Environmental Conservation (NYSDEC). The NYSDEC contact for the Endangered Species Program is Mr. Peter Nye, Endangered Species Unit, 625 Broadway, Albany, NY 12233 (telephone: [518] 402-8859).

For additional information on fish and wildlife resources or State-listed species, we suggest you contact the appropriate NYSDEC regional office(s)* and the New York Natural Heritage Program Information Services.*

Since wetlands, ponds, and/or streams may be present, you may want to utilize the National Wetlands Inventory (NWI) maps* as an initial screening tool. However, they may or may not be available for the project area. Please note that while the NWI maps are reasonably accurate, they should not be used in lieu of field surveys for determining the presence of wetlands or delineating wetland boundaries for Federal regulatory purposes. Online information on the NWI program and digital data can be downloaded from Wetlands Mapper, http://wetlands.fws.gov/mapper_tool.htm.

Work in certain waters of the United States, including wetlands and streams, may require a permit from the U.S. Army Corps of Engineers (Corps). If a permit is required, in reviewing the application pursuant to the Fish and Wildlife Coordination Act, the Service may concur, with or without recommending additional permit conditions, or recommend denial of the permit depending upon potential adverse impacts on fish and wildlife resources associated with project construction or implementation. The need for a Corps permit may be determined by contacting the appropriate Corps office(s).*

Thank you for your time. If you require additional information please contact Robyn Niver at (607) 753-9334. Future correspondence with us on this project should reference project file 60676.

Sincerely,

Anne L. Secord

for David A. Stilwell
Field Supervisor

*Additional information referred to above may be found on our website at: http://www.fws.gov/northeast/nyfo/es/section7.htm

cc: NYSDEC, Syracuse, NY (Attn: Env. Permits)
NYSDEC, Albany, NY (Endangered Species; Attn: P. Nye)
NYSDEC, Albany, NY (Natural Heritage)

Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
James A. Fitzpatrick NPP
P.O. Box 110
Lycoming, NY 13093
Tel 315 349 6024 Fax 315 349 6480

T.A. Sullivan
Site Vice President - JAF

February 9, 2006
JAFP-06-0024

Mr. David VanLuven, Director
New York Natural Heritage Program
625 Broadway, 5th Floor
Albany, NY 12233-4757

RE: Entergy Nuclear Fitzpatrick, LLC
James A. Fitzpatrick Nuclear Power Plant
License Renewal Application

Dear Mr. VanLuven:

Entergy Nuclear Fitzpatrick, LLC (Entergy) is preparing an application to the US Nuclear Regulatory Commission (NRC) to renew the operating license for the James A. Fitzpatrick Nuclear Power Plant (JAFNPP) which is located within the Town of Scriba, County of Oswego, New York. The exact location of the site is latitude 43°31'23" and longitude 76°23'55". JAFNPP is located immediately adjacent to the Nine Mile Point Nuclear Station. The current license for the Plant expires in October 2014. If the application is approved by the NRC, then Entergy will have the option to continue operating the JAFNPP for an additional 20 years.

As part of the license renewal process, the NRC requires the license applicants to "assess the impact of the proposed action." This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the Station during the license renewal period (an additional 20 years). Based on Entergy's preliminary assessment, the continued operation of JAFNPP is not expected to adversely affect the environment within the vicinity of the Station. Entergy has no plans to alter current operations over the license renewal period and any maintenance activities necessary to support license renewal would be limited to previously disturbed areas on-site. Finally, no expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts to threatened or endangered flora or natural communities in the vicinity of the Station (see attached map) during the license renewal period. After your review, we would appreciate your office sending a letter detailing any concerns you may have or confirmation that no concerns exist. Entergy will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the JAFNPP license renewal application.

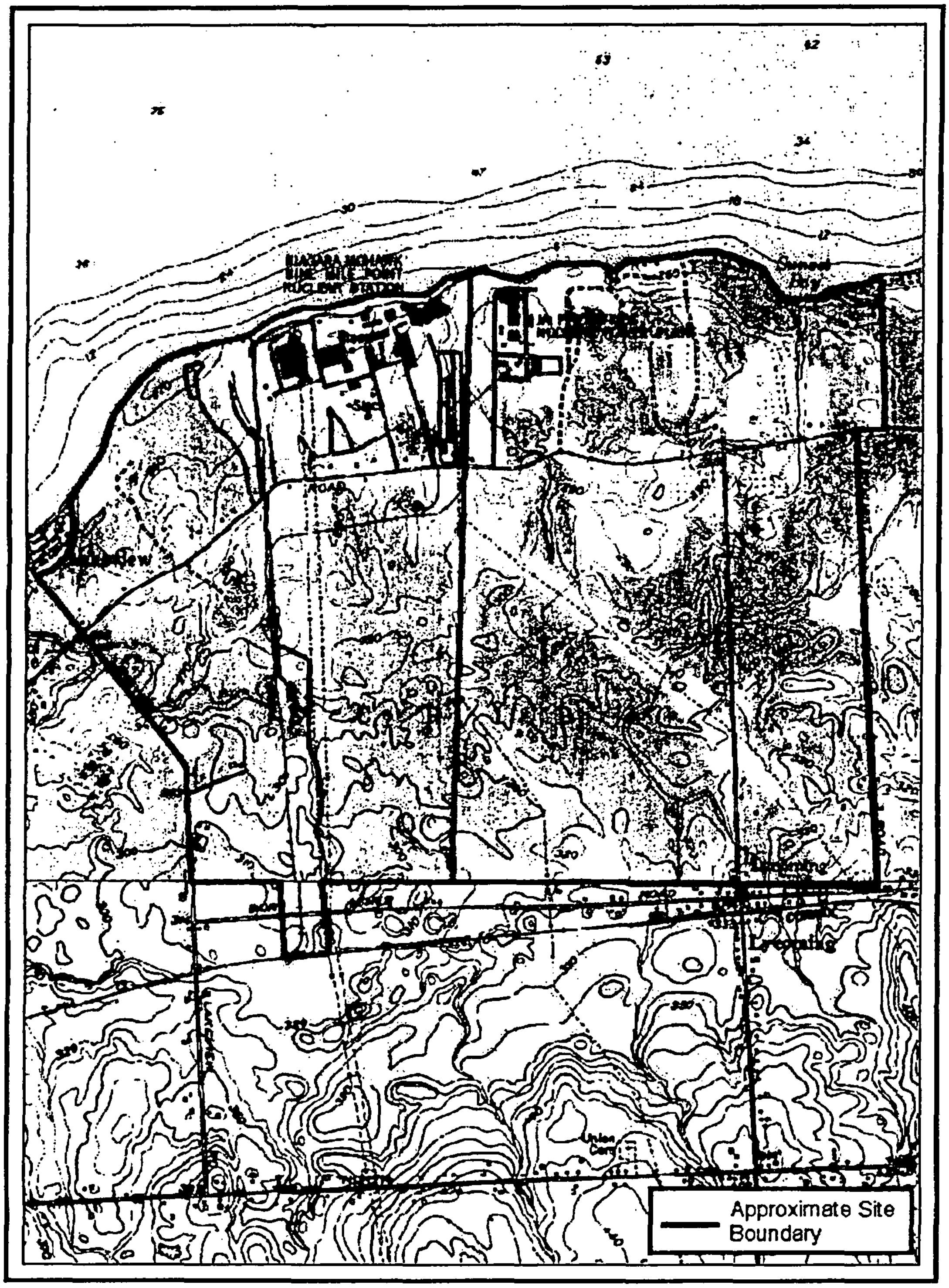
If you have questions or need additional information, please feel free to call me at (315) 349-6004.

Kindest regards,

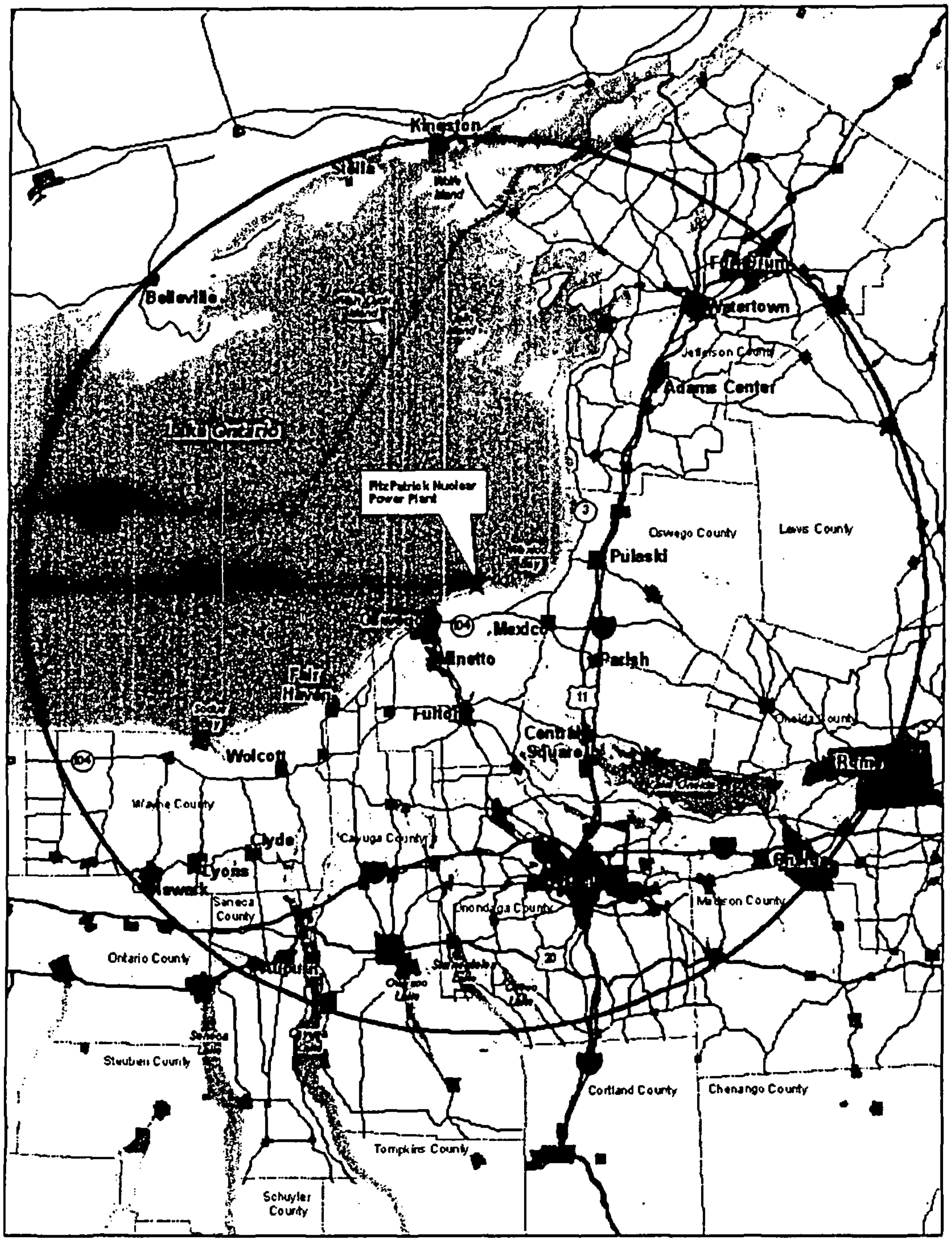
T. A. Sullivan
Site Vice President
James A. Fitzpatrick Nuclear Power Plant

Attachment

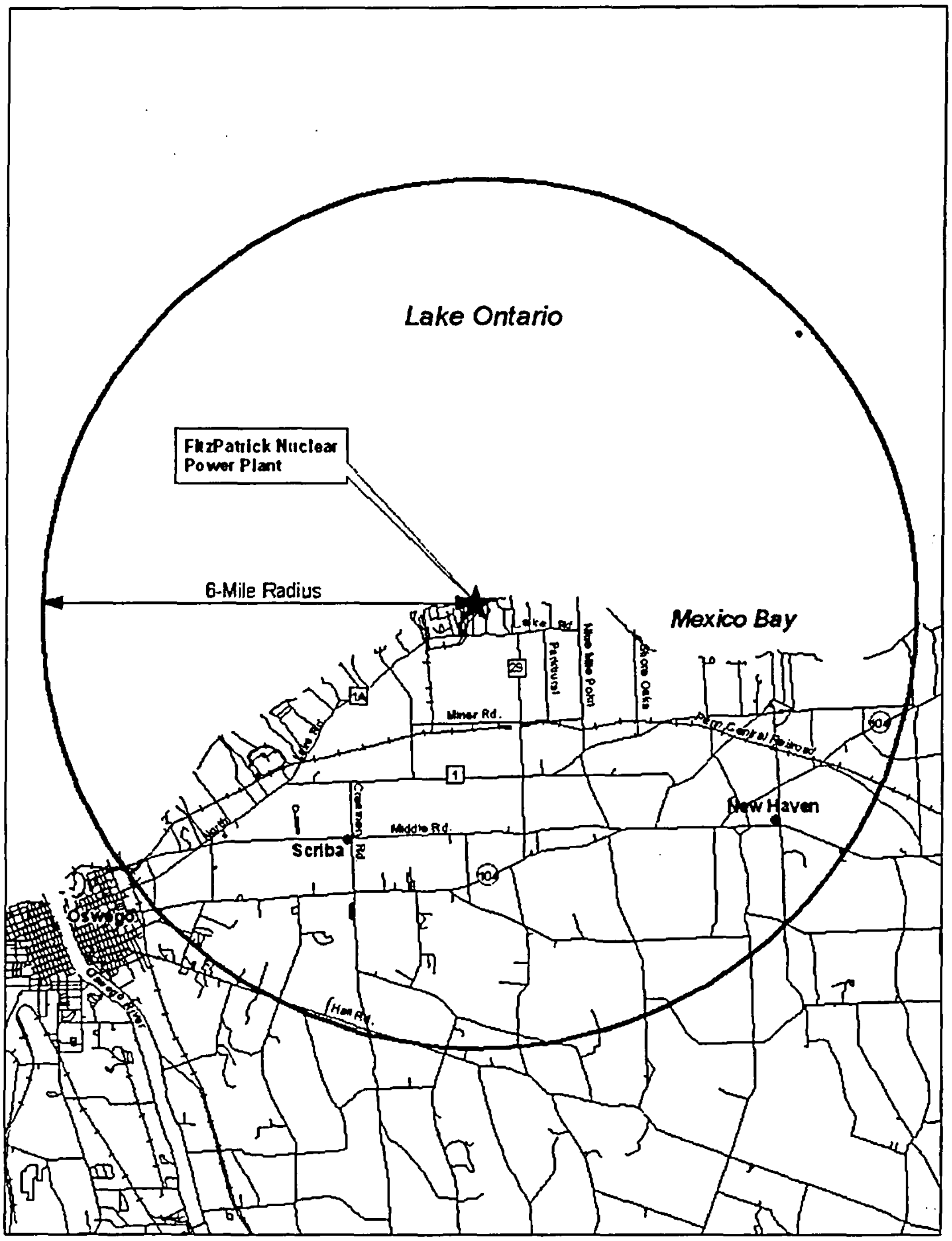
cc: Rick Buckley, Entergy
Doug Harrison, Entergy
Mike Rodgers, Entergy



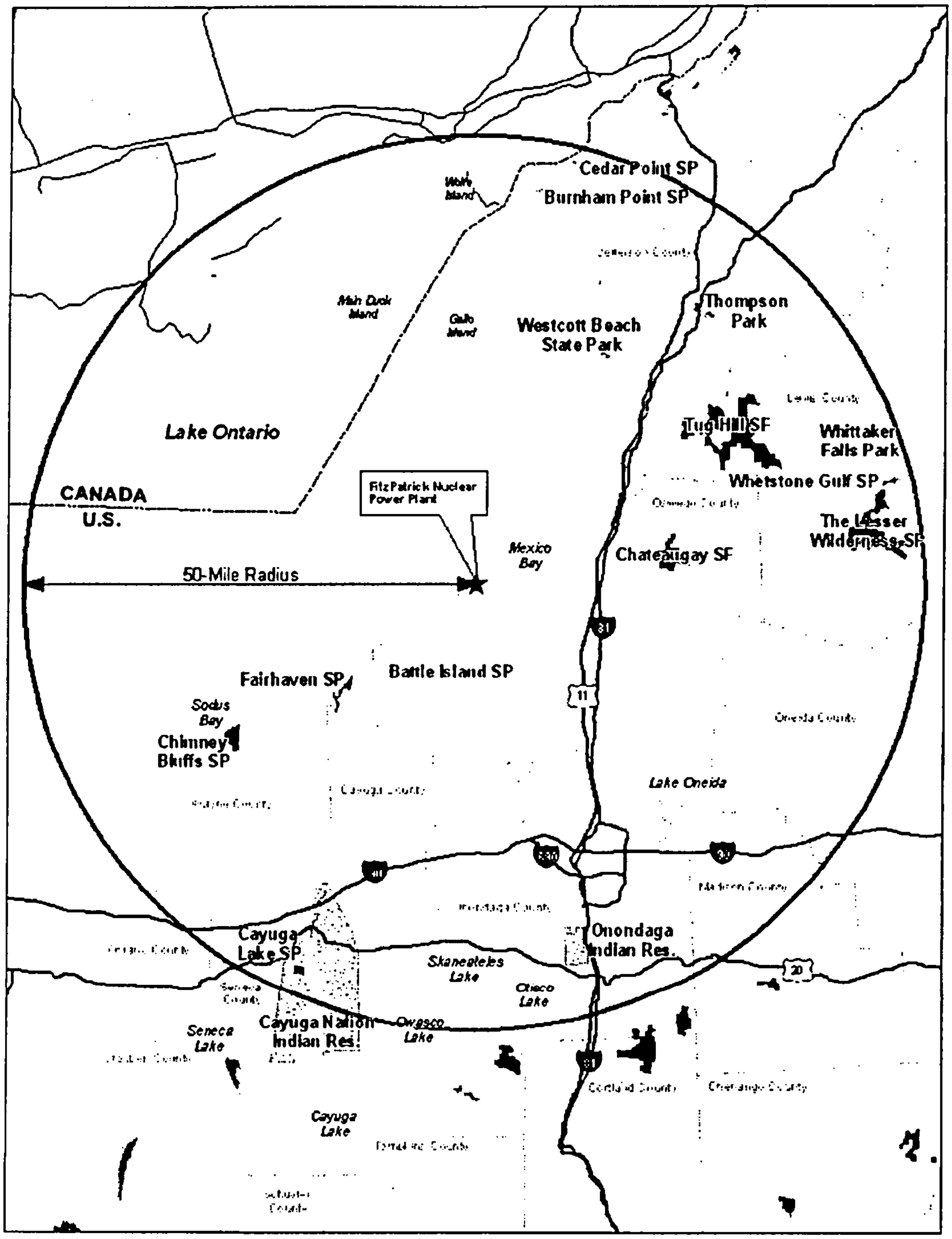
TOPOGRAPHICAL MAP OF AREA SURROUNDING JAFNPP



JAFNPP Figure 2-1
Location of JAFNPP



JAFNPP Figure 2-2
General Area of JAFNPP



JAFNPP Figure 2-4
State and Federal Lands – 50-mile Radius

New York State Department of Environmental Conservation
Division of Fish, Wildlife & Marine Resources
New York Natural Heritage Program
625 Broadway, 5th floor, Albany, New York 12233-4757
Phone: (518) 402-8935 • FAX: (518) 402-8925
Website: www.dec.state.ny.

Denise M. Sheehan
Commissioner

March 30, 2006

T A Sullivan
Entergy Nuclear Northeast
PO Box 110
Lycoming, NY 13093

Dear Mr. Sullivan:

In response to your recent request, we have reviewed the New York Natural Heritage Program database with respect to an Environmental Assessment for the proposed Permit Renewing for the operation license for the James A Fiitzpatrick Nuclear Power Plant, site as indicated on the map you provided, located the Town of Scribna, Oswego County.

Enclosed is a report of rare or state-listed animals and plants, significant natural communities, and other significant habitats, which our databases indicate occur, or may occur, on your site or in the immediate vicinity of your site. The information contained in this report is considered sensitive and may not be released to the public without permission from the New York Natural Heritage Program.

The presence of rare species may result in this project requiring additional permits, permit conditions, or review. For further guidance, and for information regarding other permits that may be required under state law for regulated areas or activities (e.g., regulated wetlands), please contact the appropriate NYS DEC Regional Office, Division of Environmental Permits, at the enclosed address.

For most sites, comprehensive field surveys have not been conducted; the enclosed report Ponly includes records from our databases. We cannot provide a definitive statement on presence or absence of all rare or state-listed species or significant natural communities. This information should not be substituted for on-site surveys that may be required for environmental impact assessment.

Our databases are continually growing as records are added and updated. If this proposed project is still under development one year from now, we recommend that you contact us again so that we may update this response with the most current information.

Sincerely,

Nicholas Conrad JP

Nicholas Conrad, Information Services
NY Natural Heritage Program

Enc.
cc: Reg. 7, Wildlife Mgr.
Reg. 7, Fisheries Mgr.

Natural Heritage Report on Rare Species and Ecological Communities

NY Natural Heritage Program, NYS DEC, 625 Broadway, 5th Floor,
Albany, NY 12233-4757
(518) 402-8935

~This report contains SENSITIVE information that may not be released to the public without permission from the NY Natural Heritage Program.
~Refer to the User's Guide for explanations of codes, ranks and fields.
~Location maps for certain species and communities may not be provided if 1) the species is vulnerable to disturbance, 2) the location and/or extent is not precisely known, and/or 3) the location and/or extent is too large to display.

Natural Heritage Report on Rare Species and Ecological Communities

OTHER

Waterfowl Winter Concentration Area

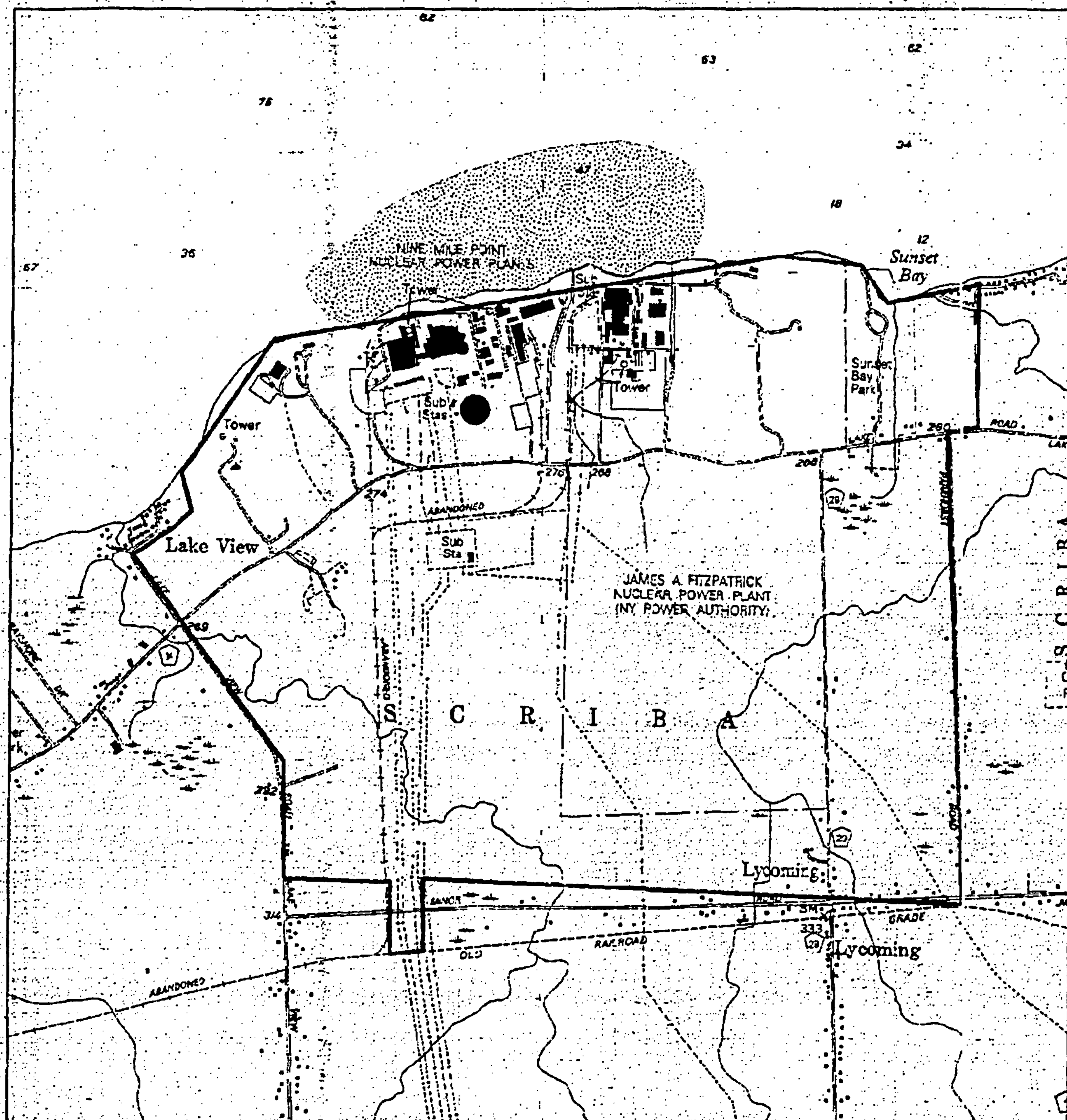
				Office Use
NY Legal Status:	Unlisted	**NYS Rank:**	S3S4; Vulnerable	6678
Federal Listing:		**Global Rank:**	GNR; Not ranked	S
Last Report:	1992-01-08	**EO Rank:**	Extant	

County: New York State Waters, Oswego
Town: Ny State Waters, Scriba
Location: Lake Ontario Scriba, Nine Mile Point Discharge Area
Directions: The concentration area is in east. Lake Ontario, just off shore of the nine mile point nuclear power station, Oswego County.
General Quality and Habitat: A discharge area for warm water from the power plant and station. The warmest water is discharged on the west end of the area and from there it spreads east. The water is 80+ degrees F at the point of discharge.

1 Records Processed

Natural Heritage Map of Rare Species and Ecological Communities

Prepared March 22, 2006 by NY Natural Heritage Program, NYS DEC, Albany, New York



Project Site

NY Natural Heritage Program Database Records*

Plant

Animal

Community

Animal Concentration Area

0 0.25 0.5 1 Miles

*The locations that are displayed are considered sensitive and cannot be released to the public without permission.

N

Attachment B

Historical and Archaeological Properties Correspondence

- T.A. Sullivan, Entergy Nuclear Fitzpatrick, to Bernadette Castro, New York State Office of Parks, Recreation and Historic Preservation, February 9, 2006.
- Nancy Herter, New York State Office of Parks, Recreation and Historic Preservation, to T.A. Sullivan, Entergy Nuclear Fitzpatrick, April 27, 2006.

Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
James A. Fitzpatrick NPP
P.O. Box 110
Lycoming, NY 13093
Tel 315 349 6024 Fax 315 349 6480

T.A. Sullivan
Site Vice President - JAF

February 9, 2006
JAFP-06-0026

Ms. Bernadette Castro, Commissioner
State Historic Preservation Officer
New York State Office of Parks, Recreation and Historic Preservation
Historic Preservation Field Services Bureau
Peebles Island
PO Box 189
Waterford, NY 12188-0189

RE: Entergy Nuclear Fitzpatrick, LLC
James A. Fitzpatrick Nuclear Power Plant
License Renewal Application

Dear Ms. Castro:

Entergy Nuclear Fitzpatrick, LLC (Entergy) is preparing an application to the US Nuclear Regulatory Commission (NRC) to renew the operating license for the James A. Fitzpatrick Nuclear Power Plant (JAFNPP). The current license for the Station expires in October 2014. If the application is approved by the NRC, then Entergy will have the <u>option</u> to continue operating the JAFNPP for an additional 20 years.

As part of the license renewal process, the NRC requires the license applicants to "assess the impact of the proposed action." This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the Station during the license renewal period (an additional 20 years). Based on Entergy's preliminary assessment, the continued operation of JAFNPP is not expected to adversely affect the environment within the vicinity of the Station. Entergy has no plans to alter current operations over the license renewal period and any maintenance activities necessary to support license renewal would be limited to previously disturbed areas on-site. Finally, no expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts to archeological or historic resources in the vicinity of the Station (see attached map and photographs) during the license renewal period. After your review, we would appreciate your office sending a letter detailing any concerns you may have or confirmation that no concerns exist. Entergy will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the JAFNPP license renewal application.

Ms. Bernadette Castro
February 9, 2006
Page 2

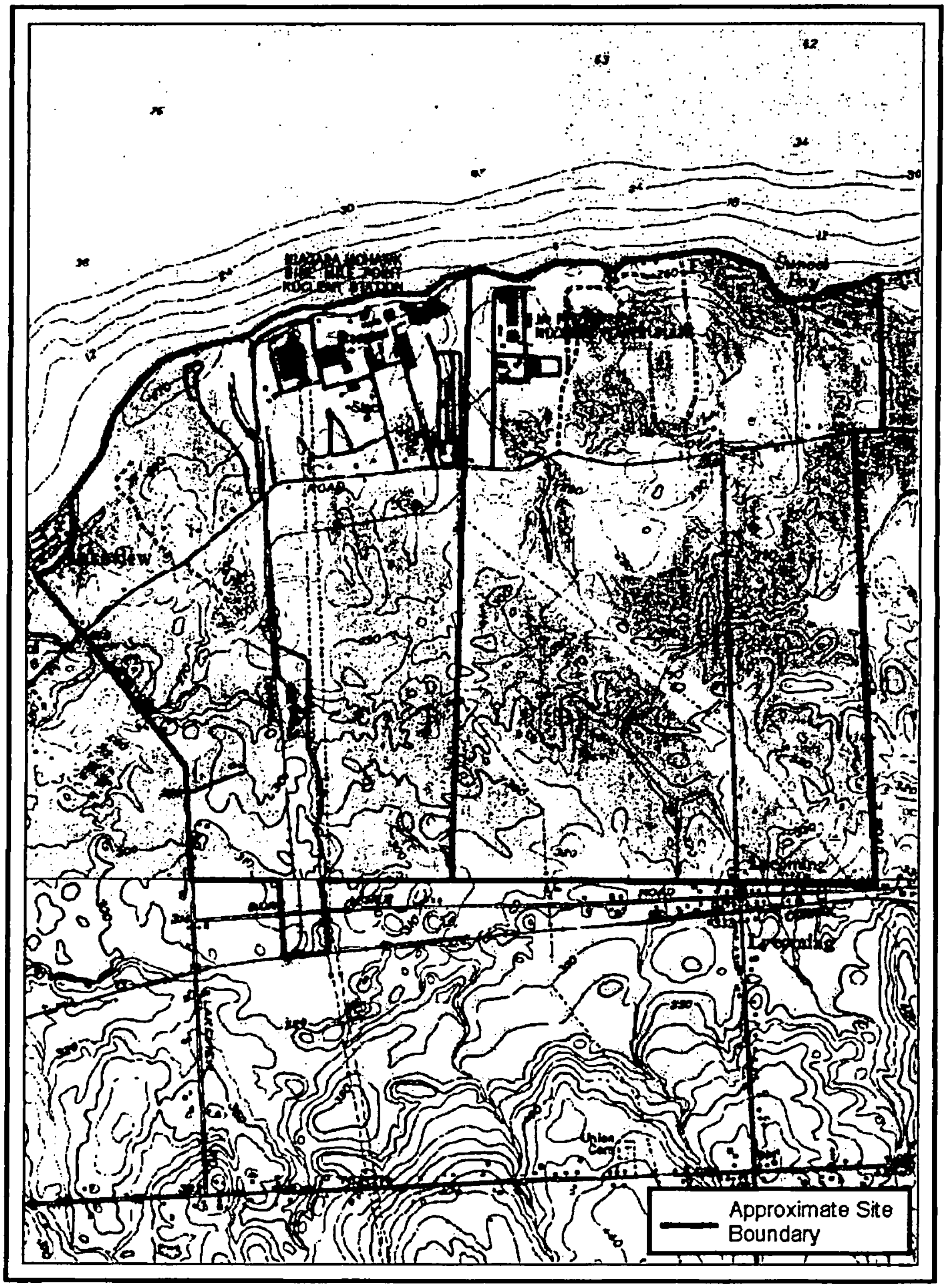
If you have questions or need additional information, please feel free to call me (315) 349-6004.

Kindest regards,

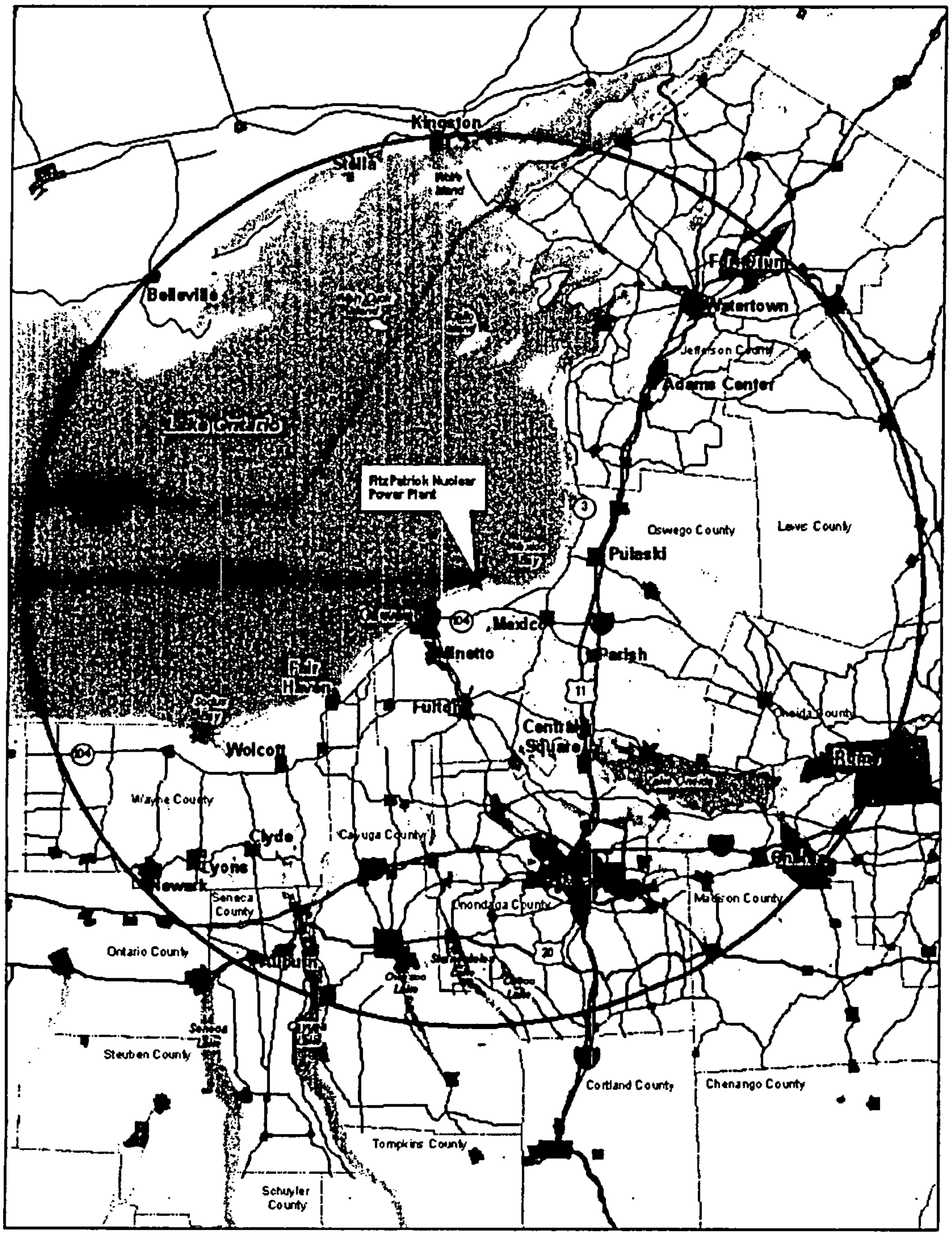
T. A. Sullivan
Site Vice President
James A. Fitzpatrick Nuclear Power Plant

Attachments

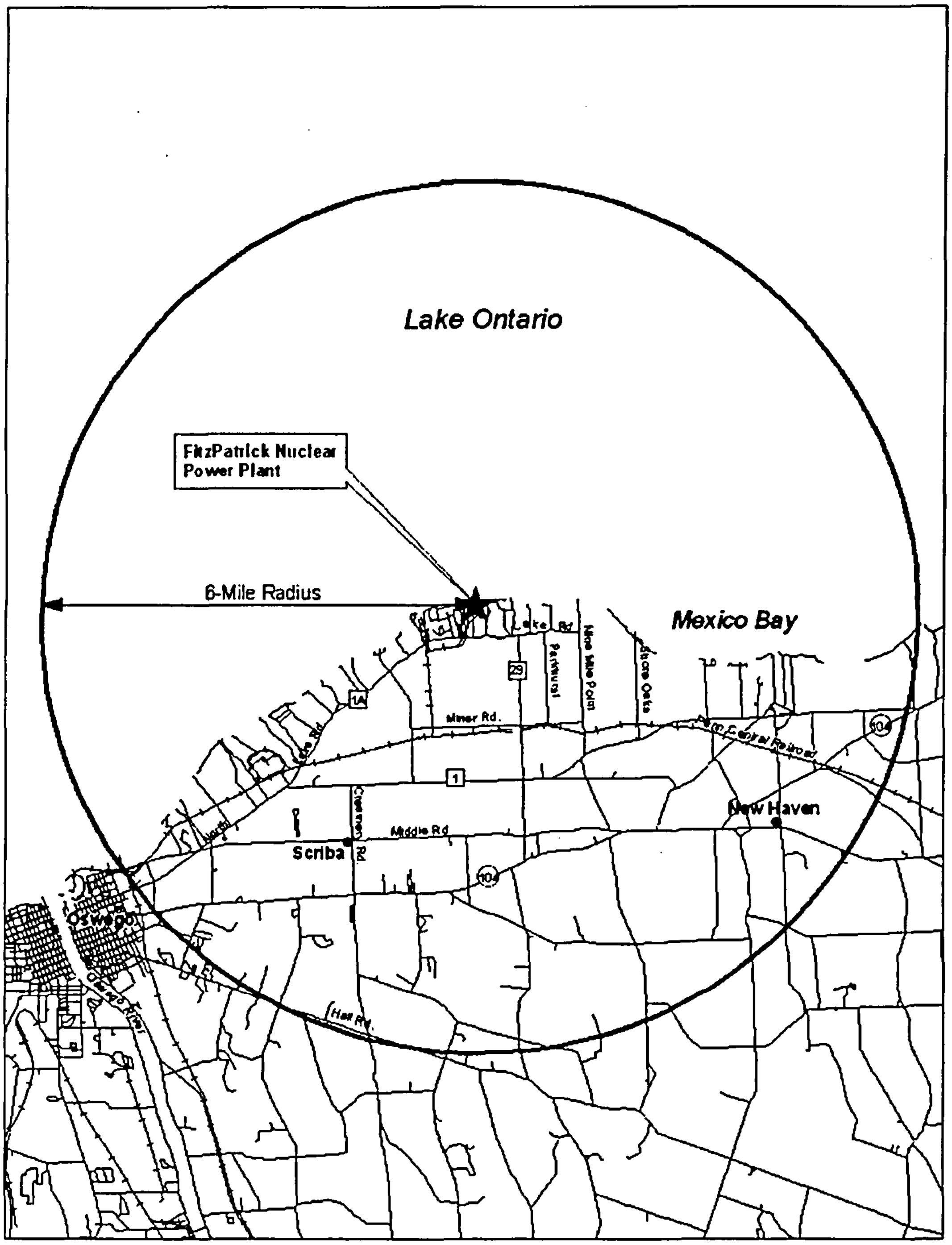
cc: Rick Buckley, Entergy
Doug Harrison, Entergy
Mike Rodgers, Entergy



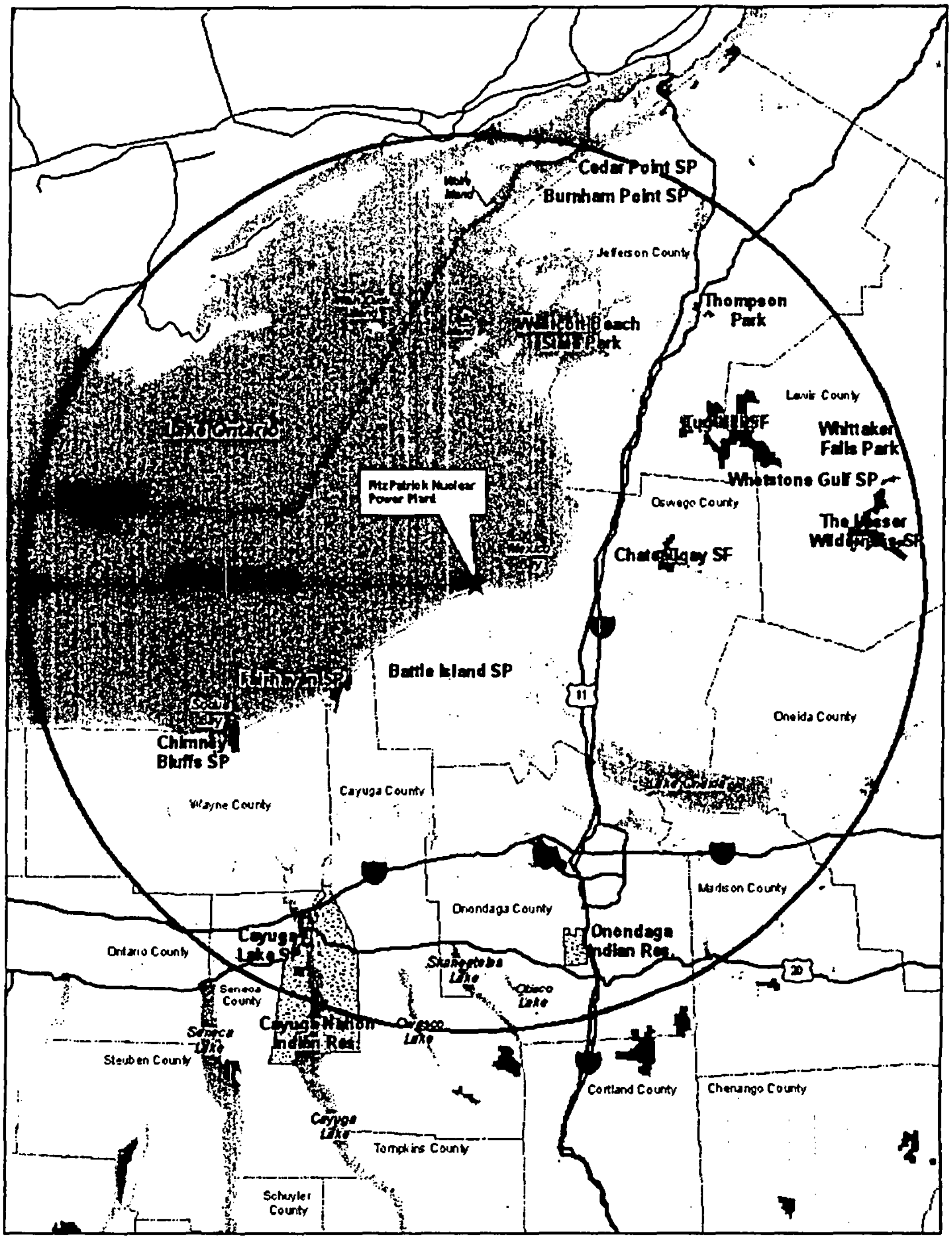
TOPOGRAPHICAL MAP OF AREA SURROUNDING JAFNPP



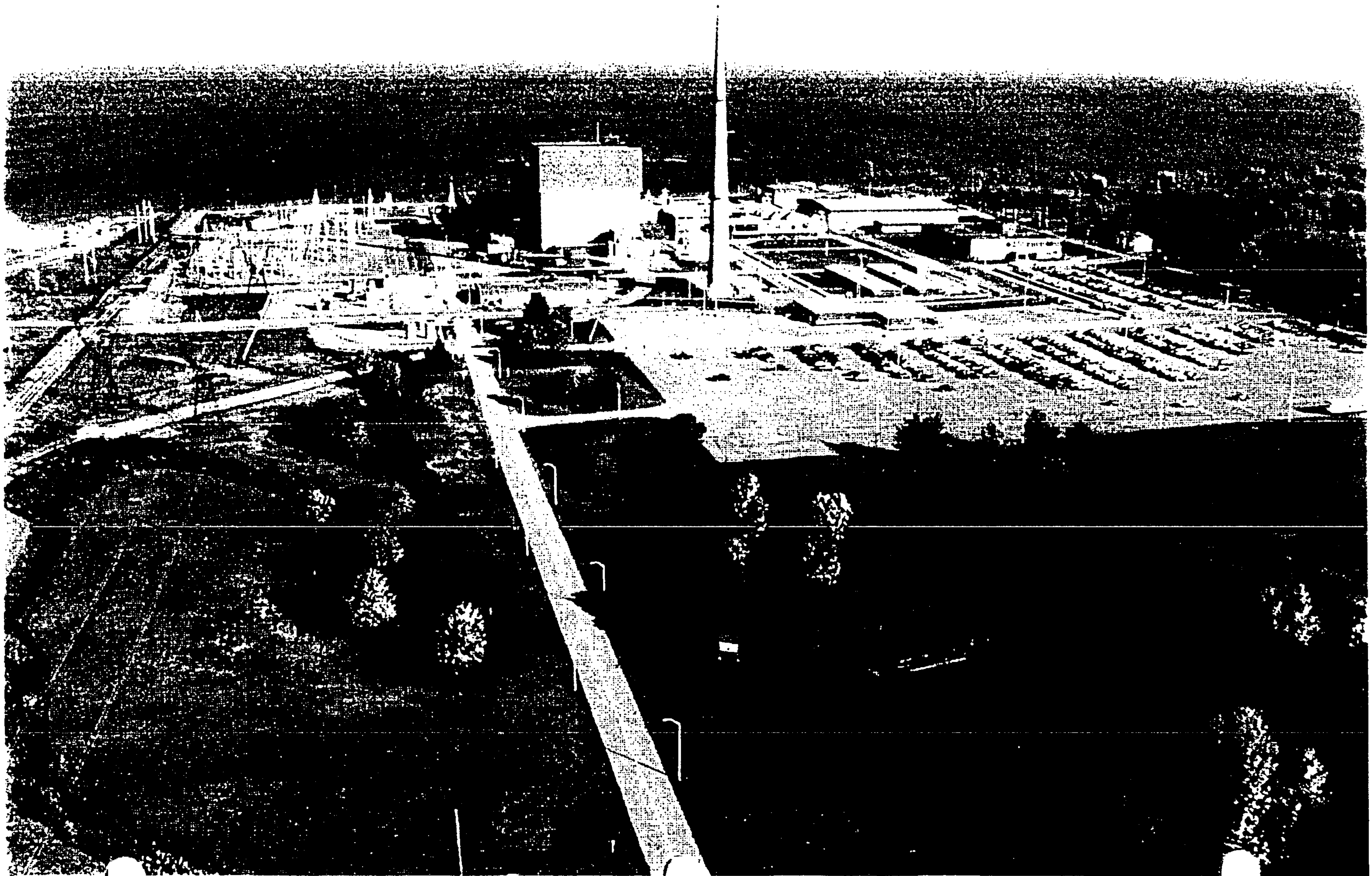
JAFNPP Figure 2-1
Location of JAFNPP



JAFNPP Figure 2-2
General Area of JAFNPP



JAFNPP Figure 2-4
State and Federal Lands – 50-mile Radius



New York State Office of Parks, Recreation and Historic Preservation
Historic Preservation Field Services Bureau
Peebles Island Resource Center, PO Box 189, Waterford, NY 12188-0189 (Mail)
Delaware Avenue, Cohoes 12047 (Delivery) (518) 237-8643

PROJECT REVIEW COVER FORM

Please complete this form and attach it to the top of any and all information submitted to this office for review. Accurate and complete forms will assist this office in the timely processing and response to your request.

This information relates to a previously submitted project. ☐ If you have checked this box and noted the previous Project Review (PR) number assigned by this office you do not need to continue unless any of the required information below has changed.

PROJECT NUMBER ____PR________

COUNTY ____________________

2. This is a new project. ☒ If you have checked this box you will need to complete ALL of the following information.

Project Name James A. FitzPatrick Nuclear Power Plant Licence Renewal Project

Location 268 Lake Rd. East, P.O. Box 110

You MUST include street number, street name and/or County, State or Interstate route number if applicable

City/Town/Village Lycoming, NY 13093

List the correct municipality in which your project is being undertaken. If in a hamlet you must also provide the name of the town.

County Oswego County

If your undertaking* covers multiple communities/counties please attach a list defining all municipalities/counties included.

TYPE OF REVIEW REQUIRED/REQUESTED (Please answer both questions)

A. Does this action involve a permit approval or funding, now or ultimately from any other governmental agency?

☐ No ☒ Yes

If Yes, list agency name(s) and permit(s)/approval(s)

Agency involved	Type of permit/approval	State	Federal
Nuclear Regulatory Commission	License Renewal Amendment	☐	☒
NYS Dept. of Environmental Conservation	Clean Water Act	☒	☒
NYS Dept. of State	Coastal Zone Mgmt. Consistency Certification	☒	☒

B. Have you consulted the NYSHPO web site at **http://nysparks.com to determine the preliminary presence or absence of previously identified cultural resources within or adjacent to the project area? If yes: ☒ Yes ☐ No

Was the project site wholly or partially included within an identified archeologically sensitive area? ☐ Yes ☒ No

Does the project site involve or is it substantially contiguous to a property listed or recommended for listing in the NY State or National Registers of Historic Places? ☐ Yes ☒ No

CONTACT PERSON FOR PROJECT

Name Rick Plasse Title Licensing Engineer

Firm/Agency Entergy Nuclear Operations, Inc

Address 268 Lake Rd. East PO Box 110 City Lycoming STATE NY Zip 13093

Phone (315) 349-6793 Fax (315) 349-6363 E-Mail RPLASSE@ENTERGY.COM

**http://nysparks.com then select HISTORIC PRESERVATION then select On Line Resources

NEW YORK STATE
Bernadette Castro
Commissioner

New York State Office of Parks, Recreation and Historic Preservation
Historic Preservation Field Services Bureau
Peebles Island, PO Box 189, Waterford, New York 12188-0189

518-237 8643

April 27, 2006

T.A. Sullivan
James A. Fitzpatrick, NPP
P.O. Box 110
Lycoming, NY 13093

Dear Mr. Sullivan:

RE: NRC
James A. Fitzpatrick Nuclear Power Plant/
License Renewal Application
Town of Scriba, Oswego County
06PR0982

Thank you for requesting the comments of the State Historic Preservation Office (SHPO). The SHPO has reviewed your letter of February 9, 2006 in accordance with Section 106 of the National Historic Preservation Act of 1966, as amended. Based on this review, the SHPO considers the project area sensitive for archaeological resources. Therefore, it is recommended that the SHPO be consulted prior to the undertaking of construction projects within the license renewal area.

If you have any questions, I can be reached at ext. 3280.

Sincerely,

Nancy Herter

Historic Preservation Program Specialist

Jill Borchu, Entergy (*faxed this day to 508-830-8699*)

Attachment C

Clean Water Act Documentation

- SPDES Permit NY 002 0109
- SPDES Permit NY 002 0109 Fact Sheet
- BTA Determination Letter from Paul J. Kolakowski, New York State Department of Environmental Conservation to Dr. Dennis J. Dunning, New York Power Authority, dated March 1, 1996
- 401 Certification Letter from Terence P. Curran, New York State Department of Environmental Conservation to Mr. Asa George, Power Authority of the State of New York, dated June 1, 1973

ENTERGY NUCLEAR OPERATIONS, INC.
JAMES A. FITZPATRICK NUCLEAR POWER PLANT
CERTIFICATES AND PERMITS

STATE POLLUTANT DISCHARGE ELIMINATION SYSTEM (SPDES) PERMIT
CP-04.03

Permit expires: August 1, 2006

Issued by: New York State Department of Environmental Conservation

Responsible person: Mike Rodgers, Environmental Engineer
JAF Chemistry and Environmental Department

CONTROLLED COPY 04

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION

State Pollutant Discharge Elimination System (SPDES)
DISCHARGE PERMIT

Special Conditions (Part 1)

First3.90

Industrial Code:	4911	SPDES Number:	NY- 0020109
Discharge Class (CL):	03	DEC Number:	7-3556-00020/00001
Toxic Class (TX):	N	Effective Date (EDP):	08/01/01
Major Drainage Basin:	03	Expiration Date (ExDP):	08/01/06
Sub Drainage Basin:	03	Modification Dates:	12/18/01
Water Index Number:	O	Attachment(s):	General Conditions (Part II) Date: 11/90
Compact Area:	GLC		

This SPDES permit is issued in compliance with Title 8 of Article 17 of the Environmental Conservation Law of New York State and in compliance with the Clean Water Act, as amended, (33 U.S.C. §1251 et.seq.)(hereinafter referred to as "the Act").

PERMITTEE NAME AND ADDRESS

Name: **Entergy Nuclear Fitzpatrick, LLC** Attention: **Michael Rodgers, P.E.**
Street: **P.O. Box 110**
City: **Lycoming** State: **NY** Zip Code: **13093**

is authorized to discharge from the facility described below:

FACILITY NAME AND ADDRESS

Name: **Entergy Nuclear Fitzpatrick, LLC**
Location (C,T,V): **Scriba** County: **Oswego**
Facility Address: **Lake Road East**
City: **Lycoming** State: **NY** Zip Code: **13093**
NYTM -E: NYTM - N:
From Outfall No.: **001** at Latitude: **43 ° 31 ' 37 "** & Longitude: **76 ° 23 ' 49 "**
into receiving waters known as: **Lake Ontario** Class: **A-Special**
and; (list other Outfalls, Receiving Waters & Water Classifications) **002-005 Lake Ontario Class A-Special**
012-026 Lake Ontario Class A-Special

in accordance with the effluent limitations, monitoring requirements and other conditions set forth in Special Conditions (Part I) and General Conditions (Part II) of this permit.

DISCHARGE MONITORING REPORT (DMR) MAILING ADDRESS

Mailing Name: **Entergy Nuclear Fitzpatrick, LLC**
Street: **P.O. Box 110**
City: **Lycoming** State: **NY** Zip Code: **13093**
Responsible Official or Agent: **T.A. Sullivan** Phone: **(315)349-3840**

This permit and the authorization to discharge shall expire on midnight of the expiration date shown above and the permittee shall not discharge after the expiration date unless this permit has been renewed, or extended pursuant to law. To be authorized to discharge beyond the expiration date, the permittee shall apply for permit renewal not less than 180 days prior to the expiration date shown above.

DISTRIBUTION:

Bureau of Water Permits
Region 7 Water
USEPA, region II
Oswego Co. Health Dept
Great Lakes Comm.
file

Permit Administrator:	
Address: Barry Barrow, NYSDEC Region 7 615 Erie Boulevard West, Syracuse, NY 13404	
Signature: Barry Barrow	Date: 3/25/02

91-20-2a (1/89)

EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning EDM

and lasting until 08/01/06

the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg.	Daily Max.	Units	Minimum Monitoring Requirements Measurement Frequency	Sample Type
001 - Circulating Cooling Water, Service Water & Intake Screen Backwash					
Flow[a]	Monitor	Monitor	MGD	Continuous	Pump Log
Discharge Temperature	Monitor	112	°F	Continuous	Recorder
Intake-Discharge Temperature Difference[b,c]	Monitor	32.4	°F	Continuous	Recorder
Net Addition of Heat[b]	Monitor	$6.00x10^9$	BTU/hr.	Daily	Calculated
pH (Range)	6.0-9.0		SU	Weekly	Grab
Boron	NA	1	mg/l	Quarterly	Grab
Oil & Grease	NA	15	mg/l	Monthly	Grab
Chlorine, Total Residual[h]	NA	0.2	mg/l	Once per Treatment	Grab
001-a Clarifier Blowdown					
Solids, Suspended (Net)	30	50	mg/l	Weekly	Grab
Oil & Grease	NA	15	mg/l	Annual	Grab
001-b Anthracite Filter Backwash					
Oil & Grease	NA	15	mg/l	Annual	Grab
Solids, Suspended (Net)	30	50	mg/l	Weekly	Grab
001-c Waste Neutralization Tank Discharge					
Oil & Grease	NA	15	mg/l	Annual	Grab
Solids, Suspended	30	50	mg/l	Batch	Grab
pH (Range)	6.0-9.0		SU	Batch	Grab
001-d Clearwell Overflow (Monitoring not required)					
001-e Low Conductivity Waste Sample Tank					
Solids, Suspended	30	50	mg/l	Batch	Grab
pH (Range)	6.0-9.0		SU	Batch	Grab
Conductivity	NA	Monitor	µmhmos/cm	e	Grab
001-f Borated Water					
Flow	NA	Monitor	gpm	Monthly	Instantaneous
Boron	NA	Monitor	mg/l	Monthly	Grab

EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning EDM
and lasting until 08/01/06
the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg.	Discharge Limitations Daily Max.	Units	Minimum Monitoring Requirements Measurement Frequency	Minimum Monitoring Requirements Sample Type
001-h, 001J, 001K Service Water and Emergency Diesel Generator Non-Contact Cooling Water					
Flow	Monitor	Monitor	MGD	Continuous	Pump Log
Chlorine, Total Residual	NA	0.2	mg/l	Once every 12 hrs. during period of Chlorination	Grab[f]
pH (Range)	6.0-9.0		SU	Daily	Grab[f]
001-I Reverse Osmosis					
pH (Range)	6.0-9.0		SU	Monthly	Grab
002 - Combined Stormwater[g]					
Flow	Monitor	Monitor	MGD	Quarterly	Calculated
Oil & Grease	NA	15	mg/l	Quarterly	Grab
002A - Oil/Water Separator (Auxiliary Boiler Floor Drainage and Boiler Blowdown)[g]					
Solids, Suspended	30	50	mg/l	2/month	Grab
Oil & Grease	Monitor	15	mg/l	2/month	Grab
pH (Range)	6.0-9.0		SU	2/month	Grab
012 Sanitary Wastes (See page 5)					
013 - 025 Sanitary Wastes (Monitoring Not Required)					
026 - Diesel Generation Oil/Water Separator					
Flow	Monitor	Monitor	GPD	Each Occur.	Estimate
Solids, Suspended	30	50	mg/l	Batch	Grab
Oil & Grease	NA	15	mg/l	Batch	Grab
pH (Range)	6.0-9.0		SU	Batch	Grab

Footnotes

[a]Monitoring Requirement Only

[b]The discharge intake temperature difference and net rate of addition of heat to the receiving water may exceed the limitations by 5% due to thermodynamic fluctuations or malfunctions in the process steam cycle. In no case shall these limitations be exceeded more than 5 calendar days in any calendar month and in no event more than 10% of the time during the calendar year.

EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning EDM
and lasting until 08/01/06

the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg.	Daily Max.	Units	Minimum Monitoring Requirements Measurement Frequency	Sample Type
003 Storm Water Runoff[9]					
Uncontaminated Runoff (No Monitoring Required)					
004 Storm Water Runoff[9]					
Uncontaminated Runoff (No Monitoring Required)					
005 Storm Water Runoff & Sedimentation Containment Pond[9]					
Flow	NA	Monitor	GPD	Quarterly	Calculated
Oil & Grease	NA	15	mg/l	Quarterly	Grab
005A Sedimentation Containment Pond					
Flow	NA	Monitoring	GPD	Batch	Calculated
Solids, Suspended	NA	50	mg/l	Batch	Grab
Settleable Solids	NA	0.3	ml/l	Batch	Grab

[c]During those periods when intake water tempering occurs, the intake temperature shall be monitored and reported before tempering and at the condenser inlet. The discharge intake temperature difference limit shall be based on intake temperature at the condenser inlet.

[e]If conductivity is equal to or less than 10μmhos/cm, then the pH limit is 4.0 - 9.0 (range). Monitoring is only required when pH range is exceeded.

[f]Grab sample to be taken in the discharge canal at the discharge point from the service water and Emergency Diesel Generator Non-Contact Cooling Water system. Samples obtained from Outfall 001H will be reported as representative results for 001K and 001J.

[g]In addition to general stormwater, outfalls 002, 003, 004 and 005 include uncontaminated water from roof leaders, condensate for non-contact air conditioning units, sprinklers, fire protection headers, and hydrant flushing. Water used in Fire Protection System Testing may be chlorinated at the end of testing to enable residual chlorine to remain in system to prevent biofouling. Roads and Parking areas contributory to these outfalls shall be periodically swept to reduce solids content of runoff.

[h]Chlorine addition to main condenser limited to two hours/day not to exceed 9 hours per week during daylight hours only.

EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning EDM: 07/16/97 and lasting until 08/01/01 the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

LIMITATIONS APPLY: [X] All Year [ ] Seasonal from ________ to ________

Outfall Number 012

EFFLUENT LIMITATIONS

[X] Flow	30 day arithmetic mean	60000	[ ] MGD	[X] GPD	
[X] BOD, 5 - Day(4)	30 day arithmetic mean	30	mg/l and		lbs/day(1)
[X] BOD, 5 - Day(4)	7 day arithmetic mean	45	mg/l and		lbs/day
[ ] UOD(2)			mg/l and		lbs/day
[X] Solids, Suspended	30 day arithmetic mean	30	mg/l and		lbs/day(1)
[X] Solids, Suspended	7 day arithmetic mean	45	mg/l and		lbs/day

[X] Effluent disinfection required: [X] All Year [ ] Seasonal from ________ to ________

[X] Coliform, Fecal	30 day geometric mean shall not exceed 200/100 ml		
[X] Coliform, Fecal	7 day geometric mean shall not exceed 400/100 ml		
[X] Chlorine, Total Residual	Daily Maximum	2.0	mg/l
[X] pH	Range	6.0 to 9.0	SU
[X] Solids, Settleable	Daily Maximum	0.1	ml/l
[ ]		mg/l as	
[ ]			
[ ]			
[ ]			
[ ]			
[ ]			

MONITORING REQUIREMENTS

Parameter	Frequency	Sample Type	Sample Location Influent	Sample Location Effluent
[X] Flow, [ ] MGD [X] GPD	Monthly	Instantaneous		X
[X] BOD, 5 - Day, mg/l	Monthly	Grab		X
[X] Solids, Suspended, mg/l	Monthly	Grab		X
[X] Coliform, Fecal, No./100 ml(3)	Monthly	Grab		X
[ ] Nitrogen, TKN (as N), mg/l				
[ ] Ammonia (as NH_3), mg/l				
[X] pH, SU (standard units)	Monthly	Grab		X
[X] Solids, Settleable, ml/l	Monthly	Grab		X
[X] Chlorine, Total Residual, mg/l(3)	Monthly	Grab		X
[ ] Phosphorus, Total (as P), mg/l				
[ ] Temperature, Deg.___				
[ ]				
[ ]				
[ ]				

NOTES:
(1) and effluent value shall not exceed ____ % and ___ % of influent values for BOD_5 & TSS respectively.
(2) Ultimate Oxygen Demand shall be computed as follows:
UOD = 1 ½ x $CBOD_5$ + 4 ½ x TKN (Total Kjeldahl Nitrogen)
(3) Monitoring of these parameters is only required during the period when disinfection is required.
(4) Monitoring shall be conducted at the same time as introduction of drain downs from the station boilers.

DEFINITIONS OF DAILY AVERAGE AND DAILY MAXIMUM

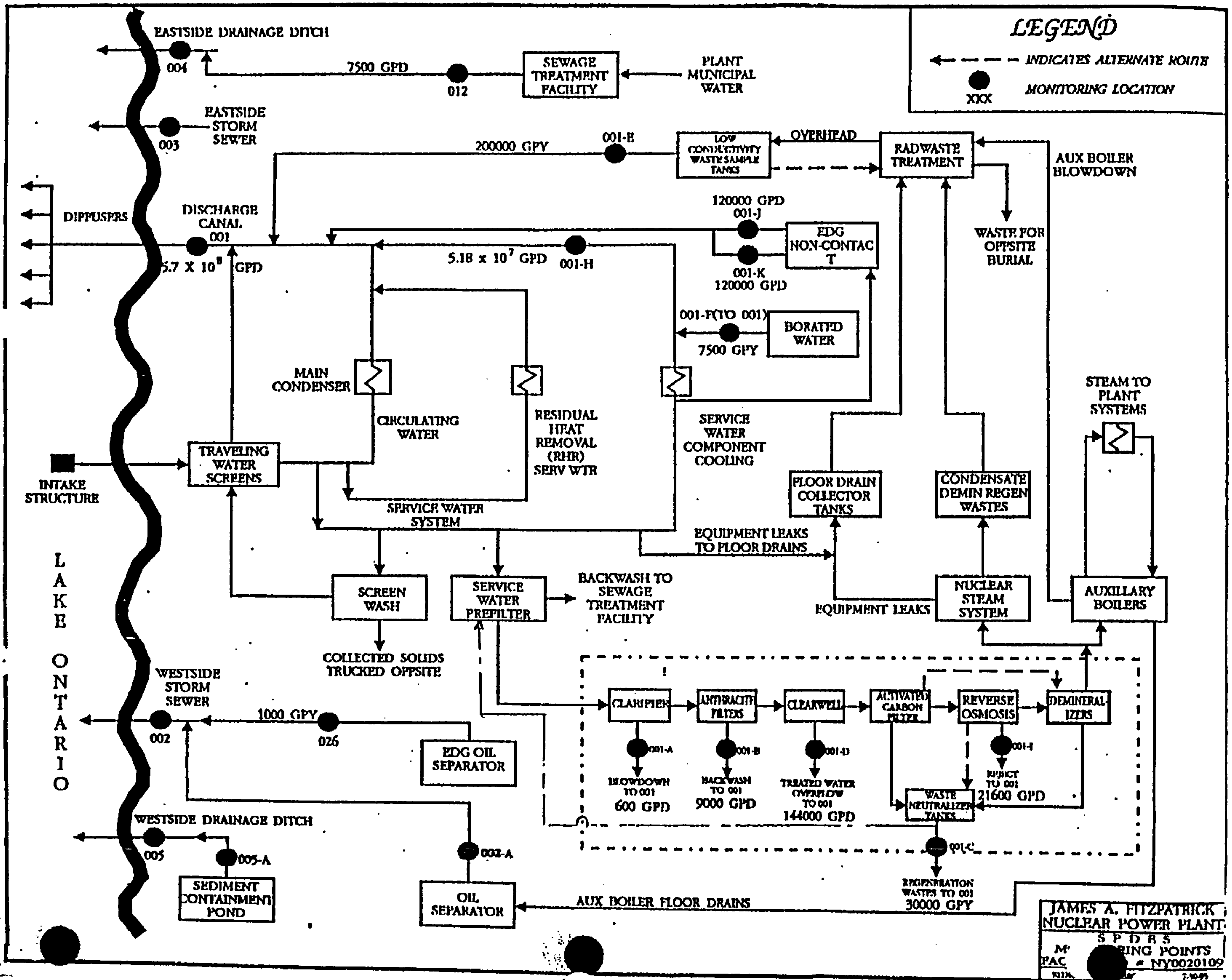
The daily average discharge is the total discharge by weight or in other appropriate units as specified herein, during a calendar month divided by the number of days in the month that the production or commercial facility was operating. Where less than daily sampling is required by this permit, the daily average discharge shall be determined by the summation of all the measured daily discharges in appropriate units as specified herein divided by the number of days during the calendar month when measurements were made.

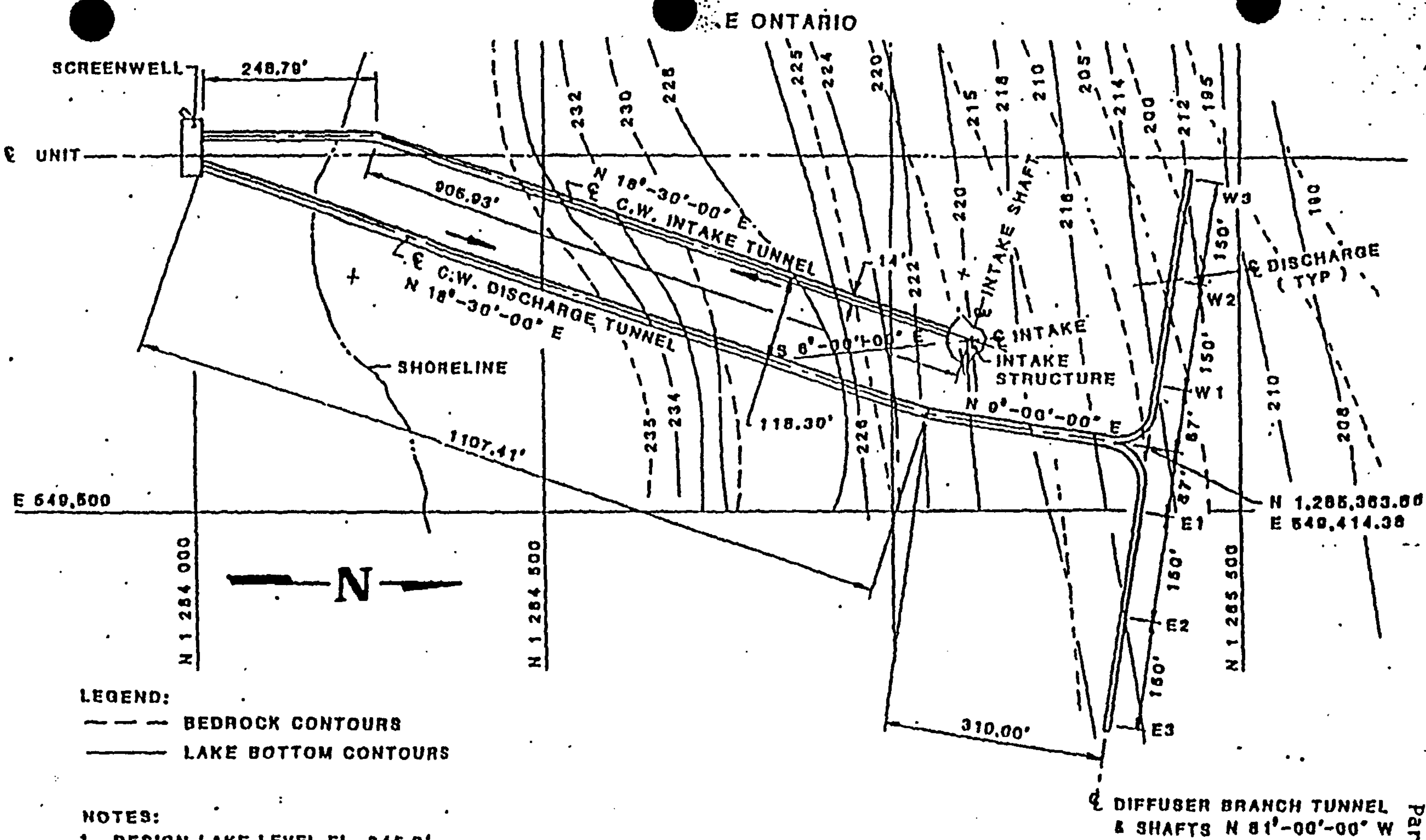
The daily maximum discharge means the total discharge by weight or in other appropriate units as specified herein, during any calendar day.

MONITORING LOCATIONS

The permittee shall take samples and measurements, to comply with the monitoring requirements specified in this permit, at the location(s) indicated below: (Show sampling locations and outfalls with sketch or flow diagram as appropriate)

EXHIBIT 3


LEGEND
INDICATES ALTERNATE ROUTE
XXX MONITORING LOCATION
EASTSIDE DRAINAGE DITCH
004
7500 GPD
012
SEWAGE TREATMENT FACILITY
PLANT MUNICIPAL WATER
EASTSIDE STORM SEWER
003
200000 GPY
001-E
LOW CONDUCTIVITY WASTE SAMPLE TANKS
OVERHEAD
RADWASTE TREATMENT
AUX BOILER BLOWDOWN
DIFFUSERS
DISCHARGE CANAL 001
5.7 X 10^8 GPD
120000 GPD 001-J
EDG NON-CONTACT
001-K 120000 GPD
WASTE FOR OFFSITE BURIAL
5.18 x 10^7 GPD
001-H
001-F(TO 001)
7500 GPY
BORATED WATER
MAIN CONDENSER
CIRCULATING WATER
RESIDUAL HEAT REMOVAL (RHR) SERV WTR
SERVICE WATER COMPONENT COOLING
STEAM TO PLANT SYSTEMS
INTAKE STRUCTURE
TRAVELING WATER SCREENS
FLOOR DRAIN COLLECTOR TANKS
CONDENSATE DEMIN REGEN WASTES
SERVICE WATER SYSTEM
EQUIPMENT LEAKS TO FLOOR DRAINS
L A K E O N T A R I O
SCREEN WASH
SERVICE WATER PREFILTER
BACKWASH TO SEWAGE TREATMENT FACILITY
EQUIPMENT LEAKS
NUCLEAR STEAM SYSTEM
AUXILLARY BOILERS
COLLECTED SOLIDS TRUCKED OFFSITE
WESTSIDE STORM SEWER
002
1000 GPY
026
EDG OIL SEPARATOR
CLARIFIER
ANTHRACITE FILTERS
CLEARWELL
ACTIVATED CARBON FILTER
REVERSE OSMOSIS
DEMINERAL-IZERS
001-A
BLOWDOWN TO 001
600 GPD
001-B
BACKWASH TO 001
9000 GPD
001-D
TREATED WATER OVERFLOW TO 001
144000 GPD
WASTE NEUTRALIZER TANKS
001-I
REJECT TO 001
21600 GPD
WESTSIDE DRAINAGE DITCH
005
005-A
SEDIMENT CONTAINMENT POND
002-A
OIL SEPARATOR
001-C
REGENERATION WASTES TO 001
30000 GPY
AUX BOILER FLOOR DRAINS
JAMES A. FITZPATRICK NUCLEAR POWER PLANT
SPDES
NY0020109



NOTES:

1. DESIGN LAKE LEVEL EL. 245.0'
2. ELEVATIONS REFER TO U.S. LAKE SURVEY DATUM 1935. TO CONVERT TO INTERNATIONAL GREAT LAKES DATUM 1955 SUBTRACT 1.2 FT.

WATER INTAKE AND DISCHARGE ARRANGEMENT
JAMES A. FITZPATRICK NUCLEAR POWER PLANT

ADDITIONAL REQUIREMENTS

1. There shall be no discharge of auxiliary boiler chemical cleaning wastes and other metal cleaning wastewaters.

2. No chemicals shall be added to the intake water of the anthracite filter or to the anthracite filter backwash without prior application to NYSDEC for their use. Chemicals identified in the 12/12/95 renewal application are approved for use as specified.

3. In regards to general condition #11.5, items c and d shall be reported semiannually to NYSDEC offices in Syracuse.

4. The permittee shall submit on a quarterly basis a report to the Department's offices in Albany and Syracuse by the 18th of the month next following the end of the period:

   a. Daily minimum, average, and maximum station electrical output shall be determined and logged.

   b. Daily minimum, average, and maximum water use shall be directly or indirectly measured or calculated and logged.

   c. Daily minimum, average, and maximum intake and discharge temperatures shall be logged.

   d. Measurements in a, b, and c shall be taken on an hourly basis.

5. There shall be no discharge of PCB's.

6. A copy of all reports pertaining to environmental impacts on water which the applicant submits to any federal, state or local agency, shall also be submitted to the Department of Environmental Conservation offices in Syracuse and Albany. The permittee shall also notify the Department within one week after from the time of submission to the Nuclear Regulatory Commission of any requested change in the environmental technical specifications which could effect the requirements of this permit.

7. Radioactivity: Concentrations of radioactivity in the effluent are subject to the requirements of the United States Nuclear Regulatory Commission License Conditions.

8. The thermal discharge from this facility shall assure the protection and propagation of a balanced indigenous population of shellfish, fish and wildlife in an on Lake Ontario. In this regard, the Department has approved the permittee's request for alternative effluent limitations pursuant to Section 316(a) of the Clean Water Act. The effluent limitations on page 2 of this permit reflect this approval. The water temperature at the surface of Lake Ontario shall not be raised more than three Fahrenheit degrees over the temperature that existed before the addition of heat of artificial origin except in a mixing zone consisting of an area of 35 acres from the point of discharge, this temperature may be exceeded.

9. The JAF fish deterrent system shall be de-winterized and made fully operational by the first week of April of each year. Failure to complete the de-winterization of the system in this timeframe beyond the reasonable control of the permittee shall not constitute a violation of the permit. A delay in installation beyond April 15 of any year shall be fully explained in documentation to the department by that date, and shall include a projected date when installation will be completed. Upon de-winterization each year, all nine integrated projection assemblies (IPAs), must be fully functional. However, each year between April and October, the system will be deemed operational as long as five or more IPAs are operating and producing a sound pressure level equal to or greater than 190 dB/uPa at 1 meter from the source, provided that no more than two non-operating IPAs are in adjacent locations. Winterization of the fish deterrent system shall occur each October except during years with a refueling outage scheduled for October. In this case, the system shall be winterized in September. (This is based upon the fact that during refueling outages the circulating water system will not be operating and therefore the likelihood of fish impingement is greatly reduced). The current refueling outage schedule has an outage occurring every other October beginning with October 2002.

10. **Impingement Monitoring** - The permittee shall conduct a one year program to determine the numbers and total weights by species of aquatic organisms impinged on all intake traveling screens. This program may be performed concurrently with the fish deterrent effectiveness program described above, but in any case must be completed before the end of the fourth year of this permit.

a. Collection shall be made seventy-eight (78) days per year, provided however, that the circulating water system is in operation. When collection days coincide with zero water circulation, collections need not be taken. Collections shall be made on randomly selected dates that coincide with collection dates at Nine Mile Point Nuclear Station:

Month	Number of Sample Days
January	4
February	4
March	4
April	16
May	20
June	4
July	4
August	6
September	4
October	4
November	4
December	4

b. Collections shall be conducted for a minimum period of 24 hours with the beginning of the 24-hour period selected and held constant by the permittee for all collections. The collection period shall be no longer than 26 hours. The impingement collection shall be calculated and reported on a 24-hour basis.

c. Traveling screens shall be washed for at least 15 minutes prior to the 24-hour collection.

d. Individual length (cm) and weight (g) measurements shall be made on white perch, smallmouth bass, yellow perch, alewife, rainbow smelt, each species of salmonid, and other abundant species to adequately characterize the size distribution for each 24-hour collection. No fewer than 25 individuals shall be measured unless fewer than 25 individuals occur in the collection.

e. Electrical output, temperature of intake and discharge water, and operation of circulating water pumps shall be recorded on a daily basis and tabulated as previously provided in the Annual Report, Appendix B, Station Operating Conditions at James A. FitzPatrick Nuclear Power Plant. The period of record shall be from the date of the last reported operating conditions in the SPDES Biological Monitoring Report through the year covered by this impingement report.

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f. The impingement report shall include figures and complete description of the cooling water intake system including trash racks, traveling screen type, size mesh, and standard operating procedures; screen washwater discharge sluice configuration and disposition of screen washing, and the nature and estimated quantity of debris collected during impingement sampling from the intake screens.

12. Biological specimens may be required to be submitted to NYSDEC upon request.

13. The permittee shall submit written notification that shall include detailed descriptions and appropriate figures to the DEC Chief, Bureau of Environmental Protection, Regional Supervisor for Natural Resources and Regional Engineer at least 60 days in advance of any change which results in the alteration of the permitted operation, location, design, construction or capacity of the cooling water intake structure. The permittee shall submit, with its written notification, a demonstration that the change reflects the best technology currently available for

minimizing adverse environmental impact. Prior DEC approval is required before initiating such change. Substantial changes may require an application for a permit modification.

14. The permittee shall provide access to the FitzPatrick site, at any time, to representatives of the Department subject to site security regulations, to access the environmental impact of the operation of this facility and to review any sampling program, methodology and the gathering and reporting of any data.

15. The permit application must list all the corrosion/scale inhibitors or biocidal-type compounds used by the permittee. If use of new biocide/cooling water additives is intended, application must be made prior to use.

16. Discharge from diesel room must pass through an oil/water separator and meet limits specified for outfall 026.

SPECIAL CONDITIONS - BEST MANAGEMENT PRACTICES

1. The permittee shall develop and implement a Best Management Practices (BMP) plan, within one year of EDP to prevent, or minimize the potential for, release of significant amounts of toxic or hazardous pollutants to the waters of the State through plant site runoff; spillage and leaks; sludge or waste disposal; and storm water discharges including, but not limited to, drainage from raw material storage. Completed BMP plans shall be submitted to the Regional Water Engineer within six months of EDP.

2. The permittee shall review all facility components or systems (including material storage areas; in-plant transfer, process and material handling areas; loading and unloading operations; storm water, erosion, and sediment control measures; process emergency control systems; and sludge and waste disposal areas) where toxic or hazardous pollutants are used, manufactured, stored or handled to evaluate the potential for the release of significant amounts of such pollutants to the waters of the State. In performing such an evaluation, the permittee shall consider such factors as the probability of equipment failure or improper operation, cross-contamination of storm water by process materials, settlement of facility air emissions, the effects of natural phenomena such as freezing temperatures and precipitation, fires, and the facility's history of spills and leaks. For hazardous pollutants, the list of reportable quantities as defined in 40 CFR, Part 117 may be used as a guide in determining significant amounts of releases. For toxic pollutants, the relative toxicity of the pollutant shall be considered in determining the significance of potential releases.

   The review shall address all substances present at the facility that are listed as toxic pollutants under Section 307(a)(1) of the Clean Water Act or as hazardous pollutants under Section 311 of the Act or that are identified as Chemicals of Concern by the Industrial Chemical Survey.

3. Whenever the potential for a significant release of toxic or hazardous pollutants to State waters is determined to be present, the permittee shall identify Best Management Practices that have been established to minimize such potential releases. Where BMPs are inadequate or absent, appropriate BMPs shall be established. In selecting appropriate BMPs, the permittee shall consider typical industry practices such as spill reporting procedures, risk identification and assessment, employee training, inspections and records, preventive maintenance, good housekeeping, materials compatibility and security. In addition, the permittee may consider structural measures (such as secondary containment and erosion/sediment control devices and practices) where appropriate.

4. Development of the BMP plan shall include sampling of waste stream segments for the purpose of toxic "hot spot"* identification. The economic achievability of technology-based end-of-pipe treatment will not be considered until plant site "hot spot" sources have been identified, contained, removed or minimized through the imposition of site specific BMPs or application of internal facility treatment technology.

5. The BMP plan shall be documented in narrative form and shall include any necessary plot plans, drawings or maps. Other documents already prepared for the facility such as a Safety Manual or a Spill Prevention, Control and Countermeasure (SPCC) plan may be used as part of the plan and may be incorporated by reference. USEPA guidance for development of storm water elements of the BMP is available in the September 1992 manual "Storm Water Management for Industrial Activities," USEPA Office of Water Publication EPA 832-R-92-006 (available from NTIS, (703)487-4650, order number PB 92235969). A copy of the BMP plan shall be maintained at the facility and shall be available to authorized Department representatives upon request. As a minimum, the plan shall include the following BMP's:

a.	BMP Committee	e.	Inspections and Records	i.	Security
b.	Reporting of BMP Incidents	f.	Preventive Maintenance	j.	Spill prevention & response
c.	Risk Identification & Assessment	g.	Good Housekeeping	k.	Erosion & sediment control
d.	Employee Training	h.	Materials Compatibility	l.	Management of runoff

6. The BMP plan shall be modified whenever changes at the facility materially increase the potential for significant releases of toxic or hazardous pollutants or where actual releases indicate the plan is inadequate.

* A "hot spot" is a segment of an industrial facility; including but not limited to soil, equipment, material storage areas, sewer lines etc.; which contributes elevated levels of problem pollutants to the wastewater and/or storm water collection system of that facility. For the purposes of this definition, problem pollutants are substances for which end of pipe treatment to meet a water quality or technology requirement may, considering the results of wastestream segment sampling, be deemed unreasonable. For the purposes of this definition, an elevated level is a concentration or mass loading of the pollutant in question which is sufficiently higher than the end of pipe concentration of the same pollutant so as to allow for an economically justifiable removal and/or isolation of the segment and/or B.A.T. treatment of wastewaters emanating from the segment.

RECORDING, REPORTING AND ADDITIONAL MONITORING REQUIREMENTS

a) The permittee shall also refer to the General Conditions (Part II) of this permit for additional information concerning monitoring and reporting requirements and conditions.

b) The monitoring information required by this permit shall be summarized, signed and retained for a period of three years from the date of the sampling for subsequent inspection by the Department or its designated agent. **Also;**

[X] (if box is checked) monitoring information required by this permit shall be summarized and reported by submitting completed and signed Discharge Monitoring Report (DMR) forms for each 1 month reporting period to the locations specified below. Blank forms are available at the Department's Albany office listed below. The first reporting period begins on the effective date of this permit and the reports will be due no later than the 28th day of the month following the end of each reporting period.

Send the **original** (top sheet) of each DMR page to:

Department of Environmental Conservation
Division of Water
Bureau of Watershed Compliance Programs
50 Wolf Road
Albany, New York 12233-3506

Phone: (518) 457-3790

Send the *first copy* (second sheet) of each DMR page to:

Department of Environmental Conservation
Regional Water Engineer
Region 7
615 Erie Boulevard West
Syracuse, New York 13204-2400

Oswego County Health Dept.
70 Bunner Street
Oswego, NY 13126

c) A monthly "Wastewater Facility Operation Report..." (form 92-15-7) shall be submitted (if box is checked) to the [X] Regional Water Engineer and/or [ ] County Health Department or Environmental Control Agency listed above.

d) **Noncompliance** with the provisions of this permit shall be reported to the Department as prescribed in the attached General Conditions (Part II).

e) Monitoring must be conducted according to test procedures approved under 40 CFR Part 136, unless other test procedures have been specified in this permit.

f) If the permittee monitors any pollutant more frequently than required by this permit, using test procedures approved under 40 CFR Part 136 or as specified in this permit, the results of this monitoring shall be included in the calculations and recording on the Discharge Monitoring Reports.

g) Calculations for all limitations which require averaging of measurements shall utilize an arithmetic mean unless otherwise specified in this permit.

h) Unless otherwise specified, all information recorded on the Discharge Monitoring Report shall be based upon measurements and sampling carried out during the most recently completed reporting period.

i) Any laboratory test or sample analysis required by this permit for which the State Commissioner of Health issues certificates of approval pursuant to section five hundred two of the Public Health Law shall be conducted by a laboratory which has been issued a certificate of approval. Inquiries regarding laboratory certification should be sent to the Environmental Laboratory Accreditation Program, New York State Health Department Center for Laboratories and Research, Division of Environmental Sciences, The Nelson A. Rockefeller State Plaza, Albany, New York 12201.

Combined (7/91)

SPDES No.: NY 002 0109

Part 1, Attachment #: 1

EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning Aug. 01, 1996

and lasting until Aug. 01, 2001

the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall(s) 001

Special Conditions

The combined treatment program for zebra mussel control, submitted by letter application dated January 17, 1991 to Dept. of Environmental Conservation (R-7), is approved with the following conditions:

1. The treatments checked below are approved for the indicated time periods. Specific conditions for each approved treatment are included on the following pages.

	Months of Treatment
☐ Chlorine	
☐ Bromine - Chlorine	
☒ Betz Clam-Trol CT-1	4 Treatments Per Year

2. A maximum of 4 individual zebra mussel control treatments are permitted per year. A minimum 45 day period must separate each individual treatment (for example: chlorine followed by Clam-Trol).

3. All permit conditions that apply to a single treatment such as discharge limits, duration of treatment, special monitoring requirements, detoxification, caged fish studies, etc. apply to each individual treatment in the combined program.

Clam-Trol (7/91)

SPDES No.: NY 002 0109

Part 1, Attachment #: 2

EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

ng the period beginning Aug. 01, 1996

and lasting until Aug. 01, 2001

the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg.	Discharge Limitations Daily Max.	Units	Minimum Monitoring Requirements Measurement Frequency	Minimum Monitoring Requirements Sample Type
Outfall(s) 001					
Betz Clam-Trol CT-1 (whole product)	N/A	0.2	mg/l	Duration of chemical application & discharge	Multiple Grab*

* For purpose of this authorization, multiple grab is defined as individual grab samples collected at three hour intervals during the duration of chemical addition and discharge.

Special Conditions

etz Clam-Trol CT-1 program for zebra mussel control, application submitted by letter application dated Jan. 17, 1992. ept. of Environmental Conservation (R-7), is approved with the following conditions:

1. The effluent concentrations at the discharge shall not exceed 10 ug/l (ppb) of quaternary ammonium compounds and 6 ug/l (ppb) of dodecylguanidine hydrochloride. For Betz Clam-Trol CT-1, these limitations will be achieved by limiting effluent whole product concentrations.
2. Clam-Trol CT-1 detoxification with bentonite clay or other Department approved adsorption medium is required for all affected discharge waste streams throughout the treatment period.
3. Each individual zebra mussel control treatment is limited to a maximum of 24 hours duration.
4. Treatments for zebra mussel control shall be limited to a maximum of four treatments annually. Treatments shall be separated by at least 45 days.
5. Caged fish studies are required to be conducted during the discharge of the molluscicide. Sample study protocols are available from the Department's Division of Fish and Wildlife. Specific caged fish study protocols must be approved by the Department prior to commencement of the zebra mussel control program.
6. Records of product dosage concentration, effluent flow and effluent concentration of product during addition and discharge must be maintained. The flow shall be measured at the frequency specified for flow elsewhere in this permit or at the frequency of the parameter specified above, whichever is more frequent.
7. The Regional Water Engineer shall be notified not less than 48 hours before initiation of a zebra mussel control program.
8. Reports describing caged fish studies shall be sent to New York State Department of Environmental Conservation, Division of Fish and Wildlife, Standards and Criteria Unit - Room 530, 50 Wolf Road, Albany, New York 12233-4756, within 60 days following each individual zebra mussel control treatment.
9. Reports describing the results of the effectiveness of the zebra mussel control program and the effluent analyses for Betz Clam-Trol CT-1 shall be submitted to the Regional Water Engineer, NYSDEC, within 60 days following each chemical eatment.
10. This permit modification is issued based on the best environmental and aquatic toxicity information available at this time. This authorization is subject to modification or revocation any time new information becomes available which justifies such modification or revocation.

SPDES PERMIT FACT SHEET

Prepared by: Paul Kolakowski Date: 12/31/99

Company: Power Authority of the State of New York Permit No.: NY 002 0109

Location: James A. Fitzpatrick Nuclear Power Plant Industrial Code No.: 4911

Industrial Segment: Steam Electric Power Generation Part No.: 423

Type of Processing & Production Rate:

Nuclear powered steam-electric power generating facility (850 MW).

Basis for Technology Effluent Limitations:

BCT, BAT, WQ, Part 704.

PARAMETER	BASIS FOR PERMIT CONDITION
Outfall No.: 001; Circulating Cooling Water	Discharge; Nominal Flow: 5.7×10^8 GPD
Temperature	Part 704
pH	BCT
Boron	BAT/BPJ
Oil and Grease	BAT/BPJ
Outfall No.: 001a; Clarifier Blowdown	Discharge; Nominal Flow: 600 GPD
Solids, Suspended (Net)	BCT
Oil & Grease	BCT
Outfall No.: 001b; Anthracite Filter Backwash	Discharge; Nominal Flow: 9000 GPD
Solids, Suspended (Net)	BCT
Oil & Grease	BCT
Outfall No.: 001c; Waste Neutralization Tank Discharge	Disc.;Nominal Flow: 800000 GPD
Solids, Suspended	BCT
Oil & Grease	BCT
pH	BCT
Outfall No.: 001d; Clearwell Overflow	Discharge; Nominal Flow: 144000 GPD
No Monitoring Required	
Outfall No.: 001e; Low Conductivity Waste Sample Tank	Disc.; Nominal Flow: 225000 GPD
Solids, Suspended	BCT
Oil & Grease	BCT
Conductivity	-
pH	BCT

Outfall No.: 001f; Borated Water Discharge; Nominal Flow: 7500 GPY
Boron Monitor

Outfall No.: 001g; Floor Drain Sample Tank Discharge; Nominal Flow: 7500 GPY
Solids, Suspended BCT
Oil & Grease BCT
pH BCT

Outfall No.: 001h, 001j, 001k; Service Water Discharge; Nominal Flow: 51.84x10⁶ GPD
Total Residual Chlorine BPJ
pH BCT

Outfall No.: 001i; Reverse Osmosis Discharge; Nominal Flow: 21600 GPD
pH BCT

Outfall No.: 002; Stormwater Runoff (Non Contaminated) In Combination with Outfall 002a

Outfall No.: 002A; Oil Water Separator
Oil & Grease BCT

Outfall No.: 003; Stormwater Runoff Discharge; Nominal Flow: Variable

Outfall No.: 004; Stormwater Runoff Discharge; Nominal Flow: Variable

Outfall No.: 005; Stormwwater Runoff Discharge; Nominal Flow: Variable
Oil & Grease BCT
pH BCT

Outfall No.: 005A; Sedimentation Containment Pond Discharge; Nominal Flow: Variable
Oil & Grease BCT

Outfall No.: 012; Sanitary Waste Discharge; Nominal Flow: 60000 GPD
Flow
BOD^5 - 30 Day BCT
BOD^5 - 7 Day BCT
Suspended Solids - 30 Day BCT
Suspended Solids - 7 Day BCT
Total Residual Chlorine BPJ
Settleable Solids BCT
pH BCT

Outfall No.: 026; Diesel Oil/Water Separator Discharge; Nominal Flow: 1010 Gal/Year
Solids, Suspended BCT
pH BCT
Oil & Grease BCT

FITZPATRICK NUCLEAR GENERATING STATION

SPDES PERMIT FACT SHEET

The biological monitoring and mitigation required in this SPDES permit are consistent with the policies and requirements embodied in the ECL, in particular Sections 1-0101.1, 1.0101.2, 1-0101.3.b.,c.,e.; 8-0109.1; 11-0303, 11-0107.1, 11-0535.2, 11-1301.1.2, 11-1301.1.b, 11-1301.4, 11-1321; 17-ff. and the rules thereunder, specifically 6NYCRR704.5. Additionally, the requirements are consistent with the Clean Water Act in particular Section 316.

This facility has conducted monitoring of fish and invertebrates impinged on the intake traveling screens since the station began operation in 1976. Throughout that period impingement abundance has varied due to station operational schedules, the ebb and flow of lake wide abundance and distribution of aquatic organisms and the interaction of these two factors, among others. Estimated numbers of fishes impinged ranged from an annual high of over 4 million to fewer than 8,000 fish each year. The alewife has been the dominant species, comprising an overall estimated 77% of the fish impinged through this period.

The susceptibility alewives to impingement at this facility, the alewife's delicate nature, and the fact that this species demonstrates a strong fright response to high frequency/high amplitude sound led to development of a behavioral system based on this observation that has proven to be highly effective in reducing their impingement. Tests of a prototype system indicates that a reduction in impingement of onshore-migrant alewives of between 80 and 87 % can be achieved. Based in part on the demonstrated performance of the fish deterrent system with alewives, and the fact that such a large percentage of the fish impinged here are alewives, the fish deterrent system was determined to be the Best Technology Available to mitigate fish impingement impacts at this intake.

Alewife early life stages also dominate entrainment abundance estimates at this facility, and therefore an assessment of the responsiveness of larval life stages of alewives (clupeids) to the fish deterrent system is included in this permit. While the small larvae entrained at FitzPatrick have weak swimming abilities, the long distance at which larger alewives respond to acoustic energy makes it reasonable to hypothesize that larvae may respond far enough away from the intake to avoid being overwhelmed by intake currents. The protracted late June through August entrainment period for alewife larvae makes a behavioral based mitigative strategy preferable to consideration of outages or flow reductions in achieving best technology available with respect to entrainment mitigation.

The fish deterrent system that had been tested during the previous permit will be reconfigured during this installation in order to reduce costs; long range narrow beam transducers will be eliminated from the system. This permit includes requirements to test this reconfigured system to insure that mitigative performance is not less than that achievable by a system that includes both broad and narrow beam transducers.

The 20-year impingement data base at this facility was felt adequate to support a transition to a long-term monitoring program at a less intensive level of effort, and therefore requires a one year impingement program during the five year permit period.

er01/fitz6292

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
STATE POLLUTANT DISCHARGE ELIMINATION SYSTEM (SPDES)
DISCHARGE PERMIT

GENERAL CONDITIONS
(PART II)

1. GENERAL PROVISIONS

a. This permit, or a true copy, shall be kept readily available for reference at the wastewater treatment facility.

b. A determination has been made on the basis of a submitted application, plans, or other available information, that compliance with the specified permit provisions will reasonably protect classified water use and assure compliance with applicable water quality standards. Satisfaction of permit provisions notwithstanding, if operation pursuant to the permit causes or contributes to a condition in contravention of State water quality standards, or if the Department determines, on the basis of notice provided by the permittee and any related investigation, inspection or sampling, that a modification of the permit is necessary to prevent impairment of the best use of the waters or to assure maintenance of water quality standards or compliance with other provisions of ECL Article 17, or the Act, the Department may require such a modification and may require abatement action to be taken by the permittee and may also prohibit the noticed act until the permit has been modified.

c. All discharges authorized by this permit shall be consistent with the terms and conditions of this permit. Facility expansion or other modifications, production increases, product changes, product process modifications, and wastewater collection, treatment and disposal system changes which will result in new or increased discharges of pollutants into the waters of the state must be reported by submission of a new SPDES application, in which case the permit may be modified accordingly. The discharge of any pollutant, not identified and authorized, or the discharge of any pollutant more frequently than, or at a level in excess of, that identified and authorized by this permit shall constitute a violation of the terms and conditions of this permit. Facility modifications, process modifications, or production decreases which result in decreased discharges of pollutants must be reported by submission of written notice to the permit-issuing authority, in which case the permit-issuing authority may require the permittee to submit a new SPDES application.

d. The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

e. If the discharge(s) permitted herein originate within the jurisdiction of an interstate water pollution control agency, then the permitted discharge(s) must also comply with any applicable effluent standards or water quality standards promulgated by that interstate agency.

f. The permittee must comply with all terms and conditions of this permit. Any permit noncompliance constitutes a violation of the Environmental Conservation Law and the Clean Water Act and is grounds for: enforcement action; for permit suspension, revocation and modification; and for denial of a permit renewal application.

g. Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Department, the permittee shall promptly submit such facts or information.

h. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

i. The permittee shall comply with effluent standards or prohibitions established under section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that establish these standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

j. The Clean Water Act provides that any person who violates a permit condition implementing sections 301, 302, 306, 307, 308, 318, or 405 of the Clean Water Act is subject to a civil penalty not to exceed $25,000 per day of such violations. Any person who willfully or negligently violates permit conditions implementing sections 301, 302, 306, 307, or 308 of the Clean Water Act is subject to a fine of not less than $5,000 nor more than $50,000 per day of violation, or by imprisonment for not more than three years, or both.

k. The filing of a request by the permittee for a permit modification, revocation, transfer, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

l. The permittee shall furnish to the Department, within a reasonable time, any information which the Department may request to determine whether cause exists for modifying, suspending, or revoking this permit, or to determine compliance with this permit. The permittee shall also furnish to the Department, upon request, copies of records required to be kept by this permit.

m. Nothing in this permit relieves the permittee from a requirement to obtain other permits required by law, including, but not limited to:

(1) an air contamination source permit/certification under 6NYCRR Part 201;

(2) a waste transporter permit under 6NYCRR Part 364; or

(3) a radioactive waste discharge permit under 6NYCRR Part 380.

2. SPECIAL REPORTING REQUIREMENTS FOR EXISTING MANUFACTURING, COMMERCIAL, MINING, AND SILVICULTURAL DISCHARGERS

All existing manufacturing, commercial, mining and silvicultural dischargers must notify the Department as soon as they know or have reason to believe:

a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not specifically controlled in the permit, pursuant to General Provision 1 (c) herein. For the purposes of this section, recurrent accidental or unintentional spills or releases shall be considered to be a discharge on a frequent basis.

b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

(1) 500 micrograms/liter;

(2) 1.0 milligram/liter for antimony;

(3) five times the maximum concentration value reported for that pollutant in the permit application in accordance with 40 CFR §122.21(g)(7); or

(4) the level established by the Department in accordance with 40 CFR §122.44(f).

c. That they have begun or expect to begin to use, or manufacture as an intermediate or final product or by-product, any toxic pollutant which was not reported in the permit application under 40 CFR §122.21(g)(9) and which is being or may be discharged to waters of the state.

3. EXCLUSIONS

a. The issuance of this permit by the Department and the receipt thereof by the Applicant does not supersede, revoke or rescind an order or modification thereof on consent or determination by the Commissioner issued heretofore by the Department or any of the terms, conditions or requirements contained in such order or modification thereof unless specifically intended by said order.

b. The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations; nor does it obviate the necessity of obtaining the assent of any other jurisdiction as required by law for the discharge authorized.

c. This permit does not authorize or approve the construction of any onshore or offshore physical structures or facilities or the undertaking of any work in any navigable waters.

d. Oil and hazardous substance liability: The imposition of responsibilities upon, or the institution of any legal action against the permittee under Section 311 of the Clean Water Act shall be in conformance with regulations promulgated pursuant to Section 311 governing the applicability of Section 311 of the Clean Water Act to discharges from facilities with NPDES permits.

4. MODIFICATION, SUSPENSION, REVOCATION

a. If the permittee fails or refuses to comply with any requirement in this permit, such noncompliance shall constitute a violation of the permit for which the Commissioner may modify, suspend, or revoke the permit after notice and opportunity for hearing and take direct enforcement action pursuant to law. When, at any time during or prior to a period for compliance, the permittee announces or otherwise lets it be known, or the Commissioner on reasonable cause determines, that the permittee will not make the requisite efforts to achieve compliance with an interim or final requirement, the Commissioner may modify, suspend or revoke the permit and take direct enforcement action pursuant to law, without waiting for expiration of the period for compliance with such requirements.

b. After notice and opportunity for a hearing, the Department may modify, suspend or revoke this permit in whole or in part during its term for cause including, but not limited to, the following:

(1) violation of any provision of this permit; or

(2) obtaining this permit by misrepresentation or failure to disclose fully all relevant facts at any time; or materially false or inaccurate statements or information in the application or the permit; or

(3) a change in any physical circumstances, requirements or criteria applicable to discharges,including, but not limited to:

(i) standards for construction or operation of the discharging facility;

(ii) the characteristics of the waters into which such discharge is made;

(iii) the water quality criteria applicable to such is made;

(iv) the classification of such waters; or

(v) effluent limitations or other requirements applicable pursuant to the Act or State Law.

(4) a determination that the permitted activity endangers human health or the environment and can only be regulated to acceptable levels by permit modification, a suspension, or revocation.

(5) violation of any order of the Commissioner or provision of ECL or regulation promulgated thereunder, which is related to the permitted activity.

(6) Newely discovered material information or material change in environmental conditions, relevant technology or applicable law or regulations since the issuance of this permit.

c. If any applicable toxic effluent standard or prohibition (including any schedule of compliance specified in such effluent standard or prohibition) is promulgated under section 307(a) of the Clean Water Act for a toxic pollutant and that a standard or prohibition is more stringent than any limitation on the pollutant in the permit, the Department shall institute proceedings to modify the permit in order to achieve conformance with the toxic effluent standard or prohibition and in conformance with ECL 17-0809.

REPORTING NONCOMPLIANCE

a. Anticipated noncompliance. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

b. Twenty-four hour reporting. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written noncompliance report shall also be provided within five (5) days of the time the permittee becomes aware of the circumstances. The written noncompliance report shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent the noncompliance and its reoccurrence.

(1) The following shall be included as information which must be reported within 24 hours under paragraph (b) above:

(i) any unanticipated bypass which violates any effluent limitation in the permit;

(ii) any upset which violates any effluent limitation in the permit;

(iii) violation of a maximum daily discharge limitation for any of the pollutants listed by the Department in the permit to be reported within 24 hours.

(iv) any unusual situation, caused by a deviation from normal operation or experience (e.g. upsets, bypasses, inoperative treatment process units, spills or illegal chemical discharges or releases to the collection system) which create a potentially hazardous condition.

(v) any dry weather overflow(s).

(2) The Department may waive the written report on a case-by-case basis if the oral report has been received within 24 hours.

(3) Reports required by this section shall be filed with the Department's regional office having jurisdiction over the permitted facility. During weekends, oral noncompliance reports, required by this paragraph, may be made at (518) 457-7362.

c. Other noncompliance. The permittee shall report all instances of noncompliance not otherwise required to be reported under this section or other sections of this permit, with each submitted copy of its Discharge Monitoring Reports until such noncompliance ceases. Such noncompliance reports shall contain the information listed in paragraph (b) of this section.

d. Duty to mitigate. The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment.

6. INSPECTION AND ENTRY

The permittee shall allow the Commissioner of the Department, the EPA Regional Administrator, the County Health Department, or their authorized representatives, upon the presentation of credentials and other documents as may be required by law, to:

a. enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

b. have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit, including records maintained for purposes of operation and maintenance;

c. inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit;

d. sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the Clean Water Act or Environmental Conservation Law, any substances or parameters at any location; and

e. enter upon the property of any contributor of wastewater to the system under authority of the permittee's Sewer Use Ordinance (municipalities) or Regulations.

7. TRANSFER OF PERMIT

a. A permit is transferable only with prior written approval of the Department.

b. To transfer a permit to a new owner or operator, written application must be made to the Department. Application for Permit Transfer forms can be obtained from, and must be submitted to, the appropriate regional office of the Department's Division of Regulatory Affairs.

c. In order for operation of the facility to continue without interruption, application must be made at least 30 days in advance of the transfer.

d. If, when the ownership or operation is transferred, the volume or composition of the facility discharge will be altered, a new application for permit may be required.

8. PERMIT RENEWAL

a. Any permittee who wishes to continue to discharge after the expiration date of a permit shall apply for renewal of its permit no later than 180 days prior to the permit's expiration date (unless permission for a later date has been granted by the Department) by submitting any forms, fees, or supplemental information which may be required by the Department. Upon request, the Department shall provide the permittee with specific information concerning the forms, fees, and supplemental information required.

b. When a permittee has made timely and sufficient application for the renewal of a permit or a new permit with reference to any activity of a continuing nature, the existing permit does not expire until the application has been finally determined by the Department, and, in case the application is denied or the terms of the new permit limited, until the last day for seeking review of the Department order or a later date fixed by order of the reviewing court, provided that this subdivision shall not affect any valid Department action then in effect summarily suspending such permit.

c. A municipality applying for a permit (renewal) shall submit evidence that it is enforcing an up-to-date enacted Sewer Use Ordinance which was approved by the Department.

d. A municipality applying for a permit (renewal) shall have an approved method of residuals disposal in compliance with Part 6-NYCRR 360 and 364.

e. A municipality receiving industrial waste shall submit evidence that it is operating (or implementing) its industrial pretreatment program in accordance with Part 6 NYCRR 651.53(f).

SPECIAL PROVISIONS - NEW OR MODIFIED DISPOSAL SYSTEMS OR SERVICE AREAS

a. Prior to construction of any new or modified waste disposal system or modification of a facility or service area generating wastewater which could alter the design volume of, or the method or effect of treatment or disposing of the sewage, industrial waste or other wastes, from an existing waste disposal system, the Permittee shall submit to the Department or its designated field office for review, an approvable engineering report, plans, and specifications which have been prepared by a person or firm licensed to practice Professional Engineering in the State of New York.

b. The construction of the above new or modified disposal system shall not start until the Permittee receives written approval of the system from the Department or its designated field office.

c. The construction of the above new or modified disposal system shall be under the general supervision of a person or firm licensed to practice Professional Engineering in New York State. Upon completion of construction, that person or firm shall certify to the Department or its designated field office that the system has been fully completed in accordance with the approved engineering report, plans and specifications, permit and letter of approval; and the permittee shall receive written acceptance of such certificate from the Department or designated field agency prior to commencing discharge.

d. The Department and its designated field offices review wastewater disposal system reports, plans, and specifications for treatment process capability only, and approval by either office does not constitute approval of the system's structural integrity.

10. MONITORING, RECORDING, AND REPORTING

10.1 GENERAL

a. The permittee shall comply with all recording, reporting, monitoring and sampling requirements specified in this permit and such other additional terms, provisions, requirements or conditions that the Department may deem to be reasonably necessary to achieve the purposes of the Environmental Conservation Law, Article 17, the Act, or rules and regulations adopted pursuant thereto.

b. Samples and measurements taken to meet the monitoring requirements specified in this permit shall be representative of the quantity and character of the monitored discharges. Composite samples shall be composed of a minimum of 8 grab samples, collected over the specified collection period, either at a constant sample volume for a constant flow interval or at a flow-proportioned sample volume for a constant time interval, unless otherwise specified in Part I of this permit. For GC/MS Volatile Organic Analysis (VOA), aliquots must be combined in the laboratory immediately before analysis. At least 4 (rather than 8) aliquots or grab samples should be collected over the specified collection period. Grab sample means a single sample, taken over a period not exceeding 15 minutes.

c. Accessable sampling locations must be provided and maintained. New sampling locations shall be provided if existing locations are deemed unsuitable by the Department or its designated field agency.

d. Actual measured values of all positive analytical results obtained above the Practical Quantitation Limit (PQL)[1] for all monitored parameters shall be recorded and reported, as required by this permit; except, where parameters are limited in this permit to values below the PQL, actual measured values for all positive analytical results above the Method Detection Limit (MDL)[2] shall be reported.

1 Practical Quantitation Limit (PQL) is the lowest level that can be measured within specified limits of precision and accuracy during routine laboratory operations on most effluent matrices.

2 Method Detection Limit (MDL) is the level at which the analytical procedure referenced is capable of determining with a 99% probability that the substance is present. This value is determined in distilled water with no interfering substances present. The precision at this level is +/- 100%.

e. The permittee shall periodically calibrate and perform manufacturer's recommended maintenance procedures on all monitoring and analytical instrumentation to insure accuracy of measurements. Verification of maintenance shall be logged into the daily record book(s) of the facility. The permittee shall notify the Department's regional office immediately if any required instrumentation becomes inoperable. In addition, the permittee shall verify the accuracy of their measuring equipment to the Department's Regional Office annually.

f. The Clean Water Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit, shall upon conviction, be punished by a fine of not more than $10,000, or by imprisonment for not more than 2 years per violation or by both. If a conviction of such person is for a violation committed after a first conviction of such person under this paragraph, punishment shall be a fine of not more than $20,000 per day of violation, or by imprisonment of not more than 4 years, or by both.

10.2 SIGNATORIES AND CERTIFICATION

a. All reports required by this permit shall be signed as follows:

(1) for a corporation: by a responsible corporate officer. For the purposes of this section, a responsible corporate officer means:

(i) a president, secretary, treasurer, or a vice president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making function for the corporation, or

(ii) the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

(2) for a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or

(3) for a municipality, state, federal, or other public agency: by either a principal or executive officer or ranking elected official. For purposes of this section, a principal executive officer of a federal agency includes: (i) the chief executive officer of the agency, or (ii) a senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency; or

(4) a duly authorized representative of the person described in items (1), (2), or (3). A person is a duly authorized representative only if:

(i) the authorization is made in writing by a person described in paragraph (a)(1), (2), or (3) of this section;

(ii) the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity such as the position of plant manager, operator of a well or well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company. (A duly authorized representative may thus be either a named individual or any individual occupying a named position); and

(iii) the written authorization is submitted to the Department.

b. Changes to authorization: If an authorization under subparagraph (a)(4) of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of subparagrapph (a)(4) of this section must be submitted to the Department prior to or together with any reports, information, or applications to be signed by an authorized representative.

c. Certification: Any person signing a report shall make the following certification:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision, in accordance with a system, designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the permit or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment for knowing violations."

d. The Clean Water Act provides that any person who knowingly makes any material false statement, representation, or certification in any application, record, report, plan, or other document filed or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance shall, upon conviction, be punished by a fine of not more than $10,000, or by imprisonment for not more than 2 years, or by both. If a conviction of such person is for a violation committed after a first conviction of such person under this paragraph, punishment shall be a fine of not more than $20,000 per day of violation, or by imprisonment of not more than 4 years, or by both.

10.3 RECORDING OF MONITORING ACTIVITIES AND RESULTS

a. The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of the sample, measurement, report or application. This period may be extended by request of the Department at any time.

b. Records of monitoring information shall include:

(1) the date, exact place, and time of sampling or measurements;

(2) the individual(s) who performed the sampling or measurements;

(3) the date(s) analyses were performed;

(4) the individual(s) who performed the analyses;

(5) the analytical techniques or methods used; and

(6) the results of such analyses.

10.4 TEST AND ANALYTICAL PROCEDURES

a. Monitoring and analysis must be conducted using test procedures promulgated, pursuant to 40 CFR Part 136, except:

(1) should the Department require the use of a particular test procedure, such test procedure will be specified in Part I of this permit.

(2) should the permittee desire to use a test method not approved herein, prior Department approval is required, pursuant to paragraph (b) of this section.

b. Application for approval of test procedures shall be made to the Department's Regional Permit Administrator (see Part 1, page 1 for address), and shall contain:

(1) the name and address of the applicant or the responsible person making the discharge, the DEC permit number and applicable SPDES identification number of the existing or pending permit, name of the permit issuing agency name and telephone number of applicant's contact person;

(2) the names of the pollutants or parameters for which an alternate testing procedure is being requested, and the monitoring location(s) at which each testing procedure will be utilized;

(3) justification for using test procedures, other than those approved in paragraph (a) of this section; and

(4) a detailed description of the alternate procedure, together with:

(i) references to published studies, if any, of the applicability of the alternate test procedure to the effluent in question;

(ii) information on known interferences, if any; and

(5) a comparability study, using both approved and the proposed methods. The study shall consist of 8 replicates of 3 samples from a well mixed waste stream for each outfall if less than 5 outfalls are involved, or from 5 outfalls if 5 or more outfalls are involved. Four (4) replicates from each of the samples must be analyzed using a method approved in paragraph (a) of this section, and four of the replicates of each sample must be analyzed using the proposed method. This results in 24 analyses per outfall up to a maximum of 120 analyses per permit. A statistical analysis of the data must be submitted that shall include, as a minimum:

(i) calculated statistical mean and standard deviation;

(ii) a test for outliers at the mean ± 3 standard deviations level. Where an outlier is detected, an additional sample must be collected and 8 replicates of the sample must be analyzed as specified above;

(iii) a plot distribution with frequency counts and histogram;

(iv) a test for equality among with-in sample standard deviation;

(v) a check for equality of pooled with-in sample variance with an F-Test;

(vi) a t-Test to determine equality of method means; and

copies of all data generated in the study.

Additional information can be obtained by contacting the Bureau of Technical Services & Research (NYSDEC, 50 Wolf Road, Albany, New York 12233 - 3502).

11. DISPOSAL SYSTEM OPERATION AND QUALITY CONTROL

11.1 GENERAL

a. The disposal system shall not receive or be committed to receive wastes beyond its design capacity as to volume and character of wastes treated, nor shall the system be materially altered as to: type, degree, or capacity of treatment provided; disposal of treated effluent; or treatment and disposal of separated scum, liquids, solids or combination thereof resulting from the treatment process without written approval of the Department of Environmental Conservation or its designated field office.

b. The permittee shall, at all times, properly operate and maintain all facilities and systems of treatment and control (or related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance also includes as a minimum, the following: 1) A preventive/corrective maintenance program. 2) A site specific action orientated operation and maintenance manual for routine use, training new operators, adequate laboratory controls and appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems which are installed by a permittee only when the operation is necessary to achieve compliance with the conditions of the permit.

c. When required under Title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York (6NYCRR 650), sufficient personnel meeting qualifications for operators of sewage treatment works as required therein and additional maintenance personnel shall be employed to satisfactorily operate and maintain the treatment works.

d. The permittee shall not discharge floating solids or visible foam.

11.2 BYPASS

a. Definitions:

(1) "Bypass" means the intentional or unintentional diversion of waste stream(s) around any portion of a treatment facility for the purpose or having the effect of reducing the degree of treatment intended for the bypassed portion of the treatment facility.

(2) "Severe property damage" means substantial damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which would not reasonably be expected to occur in the absence of a bypass. Severe property damange does not mean economic loss caused by delays in production.

b. Bypass not exceeding limitations:

The permittee may allow any bypass to occur which does not cause effluent limitations to be violated, but only if it also is for essential maintenance, repair or replacement to assure efficient and proper operation. These bypasses are not subject to the provisions of pargraph (c) and (d) of this section, provided that written notice is submitted prior to bypass (if anticipated) or as soon as possible after bypass (if unanticipated), and no public health hazard is created by the bypass.

c. Notice:

(1) Anticipated bypass - If the permittee knows in advance of the need for a bypass, it shall submit prior written notice, at least forty five (45) days before the date of the bypass.

(2) Unanticipated bypass - The permittee shall submit notice of an unanticipated bypass as required in Section 5, paragraph b. of this Part (24 hour notice).

d. Prohibition of bypass:

(1) Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless:

(i) bypass was unavoidable to prevent loss of life, personal injury, public health hazard, or severe property damage;

(ii) there were no feasible alternatives to the bypass such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal period of equipment downtime. This condition is not satisfied if adequate backup equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance or if designed and installed backup equipment which could have prevented or mitigated the impact of the bypass is not operating during the bypass; and

(iii) the permittee submitted notices as required under paragraph (c) of this section and, excepting emergency conditions, the proposed bypass was accepted by the Department.

11.3 UPSET

a. Definition:

"Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

b. Effect of an upset:

An upset constitutes an affirmative defense to an action brought for noncompliance with such permit effluent limitations if the requirements of paragraph (c) of this section are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

c. Conditions necessary for a demonstration of upset:

A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operation logs, or other relevant evidence that:

(1) an upset occurred and that the permittee can identify the cause(s) of the upset;

(2) the permitted facility was at the time being properly operated; and

(3) the permittee submitted notice of the upset as required in Section 5, paragraph b of this part (24 hour notice).

(4) the permittee complied with any remedial measures required under Section 5, paragraph d of this part.

d. Burden of proof:

In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

11.4 SPECIAL CONDITION - DISPOSAL SYSTEMS WITH SEPTIC TANKS

If a septic tank is installed as part of the disposal system, it shall be inspected by the permittee or his agent for scum and sludge accumulation at intervals not to exceed one year's duration, and such accumulation will be removed before the depth of either exceeds one-fourth (1/4) of the liquid depth so that no settleable solids or scum will leave in the septic tank effluent. Such accumulation shall be disposed of in an approved manner.

11.5 SLUDGE DISPOSAL

The storage or disposal of collected screenings, sludges, other solids, or precipitates separated from the permitted discharges and/or intake or supply water by the permittee shall be done in such a manner as to prevent creation of nuisance conditions or entry of such materials into classified waters or their tributaries, and in a manner approved by the Department. Any live fish, shellfish, or other animals collected or trapped as a result of intake water screening or treatment should be returned to their water body habitat. The permittee shall maintain records of disposal on all effluent screenings, sludges and other solids associated with the discharge(s) herein described. The following data shall be compiled and reported to the Department or its designated field office upon request:

a. the sources of the materials to be disposed of;

b. the approximate volumes, weights, water content and (if other than sewage sludge) chemical composition;

c. the method by which they were removed and transported, including the name and permit number of the waste transporter; and

d. their final disposal locations.

12. CONDITIONS APPLICABLE TO A PUBLICLY OWNED TREATMENT WORKS (POTW)

12.1 GENERAL

a. All POTWs must provide adequate notice to the Department of the following:

(1) any new introduction of pollutants into the POTW from an indirect discharger which would be subject to sections 301 or 306 of the Clean Water Act if it were directly discharging those pollutants; and

(2) any substantial change in the volume or character of pollutants being introduced into that POTW by a source introducing pollutants into the POTW at the time of issuance of the permit.

(3) For purposes of this paragraph, adequate notice shall include information on:

(i) the quality and quantity of effluent introduced into the POTW; and

(ii) any anticipated impact of the change on the quantity or quality of effluent to be discharged from the POTW.

b. Dry weather overflows are prohibited. The occurance of any dry weather overflow constitutes a bypass exceeding limitations as defined in Section 11.2 of this Part and shall be promptly abated and reported to the Department in accord with Section 5 of this Part. The permittee shall inspect all overflow facilities at least twice per year (once each spring and fall) during periods of dry weather flow to ensure they are functioning properly. Records of all inspections shall be maintained for inspection by the Department or its designated representative

c. The permittee shall identify all inflow to the tributary system and remove excessive infiltration/inflow to an extent which is economically feasible.

d. The permittee shall enact, maintain and enforce an up-to-date and effective Sewer Use Ordinance which has been approved by the Department.

e. New connections to a publicly owned sewer system or a privatized municipal sewer system are prohibited when the permittee is notified by the Department:

(1) that the discharge(s) regulated by this permit create(s) or is likely to create a public health or potential public health hazard, a contravention of water quality standards or the impairment of the best use of waters, as determined by the Commissioner; or

(2) that the discharge(s) regulated by this permit exceeded the permit limit for a specific parameter, including flow, in four of any six consecutive month periods or exceeded a permit limit by 1.4 (1.2 for toxics) times the permit limit in two of any six consecutive month periods; or

(3) that the permittee has failed or is likely to fail to carry out, meet or comply with any requirement of this permit, compliance schedule, order of the Department, judicial order, or consent decree.

f. The provisions provided for in e. above shall remain in effect until the Permittee can demonstrate to the Department's satisfaction and approval that adequate available capacity exists in the plant and that the facility is in full compliance with all of effluent limitations required by this permit.

12.2 NATIONAL PRETREATMENT STANDARDS: PROHIBITED DISCHARGES

a. General prohibitions:

Pollutants introduced into POTW's by a non-domestic source shall not pass through the POTW or interfere with the operation or performance of the works or disposal of sludge. These general prohibitions and the specific prohibitions in paragraph (b) of this section apply to all non-domestic sources introducing pollutants into a POTW whether or not the source is subject to other National Pretreatment Standards or any national, State, or local Pretreatment Requirements.

b. Specific prohibition:

In addition, the following pollutants shall not be introduced into a POTW:

(1) pollutants which create a fire or explosion hazard in the POTW;

(2) pollutants which will cause corrosive structural damage to the POTW, but in no case discharge with pH lower than 5.0 unless the works is specifically designed to accommodate such discharges;

(3) solid or viscous pollutants in amounts which will cause obstruction to the flow in the POTW resulting in interference;

(4) any pollutant, including oxygen demanding pollutants (BOD, etc.) released in a Discharge at a flow rate and/or pollutant concentration which will cause Interference with the POTW.

(5) heat in amounts which will inhibit biological activity in the POTW resulting in Interference, but in no case heat in such quantities that the temperature at the POTW Treatment Plant exceeds 40^{o} C (104^{o} F) unless the Approval Authority, upon request of the POTW, approves alternate temperature limits.

c. When Specific Limits Must be Developed by a POTW:

(1) POTW's developing POTW Pretreatment Programs pursuant to §403.8 shall develop and enforce specific limits to implement the prohibitions listed in §403.5(a) and (b).

(2) All other POTW's shall, in cases where pollutants contributed by User(s) result in Interference or Pass-Through, and such violation is likely to recur, develop and enforce specific effluent limits for Industrial User(s), and all other users, as appropriate, which, together with appropriate changes in the POTW Treatment Plant's Facilities or operation, are necessary to ensure renewed and continued compliance with the POTW's SPDES permit or sludge use or disposal practices.

(3) Specific effluent limits shall not be developed and enforced without individual notice to persons or groups who have requested such notice and an opportunity to respond.

d. Local Limits:

Where specific prohibitions or limits on pollutants or pollutant parameters are developed by a POTW in accordance with paragraph (c) above, such limits shall be deemed Pretreatment Standards for the purposes of §307(d) of the Act.

e. EPA and State Enforcement Actions:

If, within 30 days after notice of an Interference or Pass Through violation has been sent by EPA or DEC to the POTW, and to persons or groups who have requested such notice, the POTW fails to commence appropriate enforcement action to correct the violation, EPA and DEC may take appropriate enforcement action.

Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
James A. Fitzpatrick NPP
P.O. Box 110
Lycoming, NY 13093
Tel 315 349 6024 Fax 315 349 6480

June 7, 2002
JAFP-02-0121

T.A. Sullivan
Vice President, Operations-JAF

Mr. Paul J. Kolakowski, P.E.
Environmental Engineer II
New York State Department of Env. Conservation
625 Broadway
Albany, NY 12233

Subject: Notification of Intermittent Discharges to the Service Water System (Outfall 001H) at the James A. FitzPatrick Nuclear Power Plant
SPDES ID #NY0020109

Dear Mr. Kolakowski:

Per a recent phone conversation between yourself and members of the plant staff, this correspondence documents our intent to intermittently discharge 'nearly pure water' from three closed loop cooling systems to the service water system (SPDES Outfall 001H). The three systems are: reactor building closed loop cooling (RBCLC), turbine closed loop cooling (TBCLC) and stator water cooling. All three systems are filled and maintained as de-ionized water systems. Intermittent discharges of these systems are necessary to maintain water quality control and/or to drain the systems for maintenance. These intermittent discharges will be minimized to the extent possible.

The RBCLC system has a total volume of approximately 8,000 gallons. The water in this system is essentially 'pure water' with an iron content between 200-500 parts per billion (ppb). The intent is to 'feed and bleed' the system by discharging small batches of water on an as needed basis to the service water outfall. The system will be refilled with de-ionized make-up water.

The TBCLC system contains a total volume of approximately 14,000 gallon, while the stator water cooling system contains approximately 1,000 gallons. Similarly, these systems will be 'fed and bled' intermittently on an as needed basis and will be refilled with de-ionized make-up water.

Due to the extremely small volumes of water involved, these intermittent discharges will not impact our overall discharge to Lake Ontario in any material way. It is our intent to add these contributors to the site SPDES permit during the next renewal phase (2006).

If you have any further questions or comments, please contact Michael D. Rodgers, P.E. of my environmental staff at (315) 349-6571.

Very truly yours,

T.A. SULLIVAN

TAS/MDR/jbh

Xc: B. McCarthy (DEC-Region 7)
C. Boucher
J. Kelly (WPO)
B. Bock
D. Callen
RMS

New York State Department of Environmental Conservation
Division of Water
Bureau of Water Permits, 4th Floor
625 Broadway, Albany, New York 12233-3505
Phone: (518) 402-8111 • **FAX:** (518) 402-9029
Website: www.dec.state.ny.us

Erin M. Crotty
Commissioner

June 20, 2002

Mr. T. A. Sullivan
Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
James A. Fitzpatrick NPP
P.O. Box 110
Lycoming, NY 13093

Dear Mr. Sullivan:

Re: Discharge from closed-loop cooling systems to the Service Water System
SPDES No. NY 0020109

Your June 7, 2002 letter documenting the discussions concerning the proposed discharges has been reviewed and is acceptable as outlined. I would like to document further discussions concerning the closed-loop systems. The systems can only be discharged if they contain no other chemical additives (it was indicated that the make-up water for these systems is de-ionized water, and that the iron present is from the piping in the systems.

Should you have any questions, please contact me at (518) 402-8104.

Sincerely,

Paul J. Kolakowski, P.E.
Environmental Engineer II
Physical Systems Section

cc: Michael Rodgers - Entergy Nuclear Northeast
Bill McCarthy, Region 7

PK:da

File:W:PERMITS\0020109\fitz.wpd)

Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
James A. Fitzpatrick NPP
P.O. Box 110
Lycoming, NY 13093
Tel 315 349 6024 Fax 315 349 6480

April 8, 2002
JAFP-02-0079

T.A. Sullivan
Vice President, Operations-JAF

Mr. Paul J. Kolakowski, P.E.
Environmental Engineer II
New York State Department of Env. Conservation
625 Broadway
Albany, NY 12233

Subject: Chemical use request at the James A. FitzPatrick Nuclear Power Plant
SPDES ID #NY0020109

Dear Mr. Kolakowski:

Per a recent phone conversation between yourself and members of the plant staff, enclosed is the information necessary to support a Chemical Use Request for the addition of a deposit penetrant and corrosion inhibitor to the Emergency Service Water System.

The Emergency Service Water System (ESW) uses lake water to cool systems essential for the safe shutdown of the plant. Water from ESW discharges to the main discharge canal (Outfall 001M). Under normal plant operation, ESW is run on a quarterly basis with some additional runtimes for planned maintenance or testing of the system. The purpose of the addition of the penetrant and corrosion inhibitor is to prevent and control the tubercular build-up from MIC and oxygen cells which could affect the reliability of the system.

The two products that have been chosen are Nalco CL-103 (penetrant) and Nalco 2513 (corrosion inhibitor). Attached are the required WTC forms and MSDS's for these products. The proposed dosage frequencies, average and maximum outfall concentrations, chemical compositions and application methods are outlined in the WTC forms.

If you have any further questions or comments, please contact Michael D. Rodgers, P.E. of my environmental staff at (315)349-6571.

Very truly yours,

T.A. SULLIVAN

TAS/MDR/jbh
Attachments

Xc: C. Boucher
B. Bock
B. Burnham
J. Kelly (WPO)
B. Dunphy (WPO)
RMS

FAX 315-349-6480

Form WTCFX (9/99)

NYSDEC - Division of Water

WTC Usage Notification Requirements for SPDES Permittees

1.a. Date Signed by Permittee :	1.b. Date Signed by WTC Manufacturer :
2.b. SPDES No. : NY 0020109	2.c. Contact Name : B. Bock
3.a.. WTC Name : NALCO 2513	6.a. Avg./Max Daily Dosage: lbs/d

Generic WTC Usage Requirements

A. WTC usage shall not exceed the usage rate reported by the permittee or authorized below, whichever is less.

B. The discharge shall not cause or contribute to a violation of water quality or an exceedance of AWQC.

C. **The permittee must maintain a logbook** of all WTC use, noting for each WTC the date, time, exact location, and amount of each dosage, and, the name of the individual applying or measuring the chemical. The logbook must also document that adequate process controls are in place to ensure that excessive levels of WTCs are not used and subsequently discharged through outfalls. The permittee shall retain the logbook data for a period of at least 3 years. This period may be extended by request of the DEC.

D. **The permittee shall provide an annual report**, attached to the December DMR, containing the following information for each outfall: the current list of WTCs authorized for use and discharge by the DEC, for each WTC the amount in pounds used during the year, identification of authorized WTCs the permittee no longer uses, and any other pertinent information.

Items 15 - 16 must be completed by NYSDEC permit writer.

15. Review Decision (check the appropriate box).

[X] The proposed WTC usage may proceed as proposed without permit modification subject to the conditions noted above.

[ ] The proposed WTC usage may not proceed for one of the following three reasons:

- [ ] As noted below, the information provided is insufficient to complete our review.
- [ ] As noted below, the SPDES permit must first be modified to add new requirements.
- [ ] As noted below, the proposed use is prohibited.

16. Permit Writer Information:

PRINT NAME Paul J. Kolakowski, P.E. SIGNATURE Paul J. K

TITLE Environmental Engineer II DATE 5/29/02

ADDRESS 625 Broadway, Albany, NY 12233-3505

TELEPHONE 518-402-8104 FAX

Form WTCFX (9/99)

NYSDEC - Division of Water
WTC Usage Notification Requirements for SPDES Permittees

1.a. Date Signed by Permittee :	1.b. Date Signed by WTC Manufacturer :
2.b. SPDES No. : NY002 0109	2.c. Contact Name : B. Bock
3.a.. WTC Name : CL-103	6.a. Avg./Max Daily Dosage: lbs/d

Generic WTC Usage Requirements

A. WTC usage shall not exceed the usage rate reported by the permittee or authorized below, whichever is less.

B. The discharge shall not cause or contribute to a violation of water quality or an exceedance of AWQC.

C. **The permittee must maintain a logbook of all WTC use**, noting for each WTC the date, time, exact location, and amount of each dosage, and, the name of the individual applying or measuring the chemical. The logbook must also document that adequate process controls are in place to ensure that excessive levels of WTCs are not used and subsequently discharged through outfalls. The permittee shall retain the logbook data for a period of at least 3 years. This period may be extended by request of the DEC.

D. **The permittee shall provide an annual report**, attached to the December DMR, containing the following information for each outfall: the current list of WTCs authorized for use and discharge by the DEC, for each WTC the amount in pounds used during the year, identification of authorized WTCs the permittee no longer uses, and any other pertinent information.

Items 15 - 16 must be completed by NYSDEC permit writer.

15. Review Decision (check the appropriate box).

[X] The proposed WTC usage may proceed as proposed without permit modification subject to the conditions noted above.

[ ] The proposed WTC usage may not proceed for one of the following three reasons:

- [ ] As noted below, the information provided is insufficient to complete our review.
- [ ] As noted below, the SPDES permit must first be modified to add new requirements.
- [ ] As noted below, the proposed use is prohibited.

16. Permit Writer Information:

PRINT NAME Paul J. Kolakowski, P.E. SIGNATURE [signature]

TITLE Environmental Engineer II DATE 5/29/02

ADDRESS 625 Broadway, Albany, NY 12233-3505

TELEPHONE 518-402-8104 FAX

New York State Department of Environmental Conservation
50 Wolf Road, Albany, New York 12233-3505

Michael D. Zagata
Commissioner

March 1, 1996

Dr. Dennis J. Dunning, Administrator
Aquatic Programs and Permits
New York Power Authority
123 Main Street
White Plains, New York 10601

RE: BTA determination for FitzPatrick NGS

Dear Dr. Dunning:

The Department has evaluated the supplemental information provided in your letter of August 8, 1995 on the reconfiguration of the fish deterrent system and on alternative intake technologies/operational steps under consideration to mitigate impingement impacts at FitzPatrick NGS. The information you provided was helpful in ranking the competing approaches. The reconfigured fish deterrent system now under consideration, and as recommended by the Authority in a letter dated August 24, 1994, achieves an acceptable balance of cost and performance, and is therefore determined to be best technology available to mitigate fish impingement at the FitzPatrick NGS cooling water intake.

Additional Requirement 9.g. of the FitzPatrick NGS SPDES permit provides for mitigation of impingement impacts upon acceptance by the Department of the Authority's recommendation. Further, A.R. 9.g. provides that installation of the fish impingement mitigative technology, if accepted by the Department, shall become a condition of this permit and be implemented on a schedule to be agreed upon by the Authority and the Department of Environmental Conservation. Based upon A.R. 9.g. the Authority is directed to begin installation of the fish deterrent system, as specified in Attachment I to this letter.

The cost reduction to the reconfigured fish deterrent system is achieved through elimination of the 16 narrow-beam transducers that provide long range and, perhaps, redundant ensonification of the intake with acoustic energy. The reconfigured system will rely instead on wide-beam, short range transducers to keep fish an adequate distance from the cooling water intake flow to effectively reduce impingement. Department of Environmental Conservation staff are optimistic that elimination of the narrow beam transducers will continue to provide an effective system. It is prudent, however, to conduct a thorough evaluation of the reconfigured system after it is installed. Moreover, the fish deterrent system has not been evaluated as an entrainment mitigative device: we do not know at what stage entrainable larvae and juvenile alewife will/can effectively respond to high frequency ensonification of the area around the FitzPatrick intake and avoid entrapment.

One feature of the reconfigured fish deterrent evaluation program would be continued use of the Nine Mile Point NGS as a control. It is, therefore, necessary to coordinate the FitzPatrick NGS deterrent system studies with entrainment and impingement studies at Nine Mile Point NGS. For your information I have attached an October 24, 1995 letter from Mike Calaban of DEC to Mr. Carey Merritt of Niagara Mohawk approving a delay in the start of the studies there to allow for this coordination.

The Nine Mile Point NGS SPDES permit incorporates a reduction in the intensity of impingement monitoring to a one-year program each five year permit cycle. The renewed SPDES permit for FitzPatrick NGS will require a similar level of impingement monitoring as data gathering moves from the current intensive level to a period of long-term monitoring: deployment of a successful fish deterrent system will greatly decrease impingement mortality at this station, reducing the need for an annual program. This letter authorizes cessation of the 1996 impingement program, thereby maintaining consistency with the program now in effect at Nine Mile Point NGS.

The Department looks forward to working with the Authority as we continue maturation and deployment of this important intake mitigative technology.

Sincerely,

Paul J. Kolakowski

Paul J. Kolakowski, PE
Environmental Engineer II
Physical Systems Section
Wastewater Facilities Design

Attachments

cc/w: L. Wedge - Fisheries
E. Radle - BEP
K. Silliman -Legal
W. McCarthy - Water
M. Calaban - BEP

er01/FITZ6046

New York State Department of Environmental Conservation
DIVISION OF FISH AND WILDLIFE
Bureau of Environmental Protection
50 Wolf Road Room 530 Albany, NY 12233-4756

A century of commitment...
a foundation for the future

Michael D. Zagata
Commissioner

October 24, 1995

Mr. Carey M. Merritt
Environmental Protection Supervisor
Nine Mile Point Nuclear Station
P.O. Box 63
Lycoming, New York 13093

Dear Mr. Merritt:

In our telephone conversation on September 19, 1995 and your follow up letter soon thereafter, we discussed the possibility of delaying the commencement of biological monitoring at the NMP-1 facility until December 1996. This would allow the synchronization of sampling programs at both the NMP-1 and J.A. FitzPatrick stations for the purposes of a full one year evaluation of a reconfigured sonic fish deterrent system at the J.A. FitzPatrick intake. The NMP-1 intake will serve as a study control facility, as it did during Spring 1993 evaluation of the originally designed sonic system.

I will, therefore, begin procedures to modify additional Requirement III. 2. c. and III. 2. d. of your facility's SPDES permit (NY 000 1015), by changing the study startup date to EDM + 24 months, and the submittal of the six month data summary to EDM + 32 months. By this letter you may proceed to adjust any contract agreements with EA Engineering, Science and Technology.

Please call me at 518-457-9439 if you have any questions. Thank you.

Sincerely,

Michael Calaban
Conservation Biologist

cc: E. Radle
L. Wedge
P. Kolakowski

MC02/NMPE/1.MOD

FitzPatrick Nuclear Generating Station
Implementation of Additional Requirement 9.g.

Entrapment Mitigation - The permittee shall install, operate and maintain a fish deterrent system at the cooling water intake structure.

1. By April 30, 1996, the permittee shall submit for Department review and approval plans and timelines for the installation of a fish impingement mitigative system using high frequency/high amplitude sound to deter alewives from entering the cooling water intake structure. A system similar to that shown to be effective in reducing impingement of spring onshore migrants and previously tested at FitzPatrick Nuclear Generating Station (NGS) is required (ESEERCO Research Report EP 89-30: Reducing Impingement of Alewives with High Frequency Sound at a Power Plant Intake on Lake Ontario), excepting, however, the narrow beam transducers which may be eliminated as discussed more fully in the Authority letter of August 8, 1995.

   a. The permittee shall complete installation and commence operation of the fish deterrent system beginning April 1, 1997 and continuing each year thereafter, unless Department approval is provided for an alternate plan of operation.

   b. The permittee shall conduct a one-year biological monitoring program to establish the effectiveness of the deployed system. By May 31, 1996 the permittee shall submit for Department review and approval a scope of work for a system effectiveness evaluation. This scope of work should, at a minimum, meet the following criteria:

      i) Monitor and report on the effectiveness of the deterrent system to reduce impingement and entrainment of all life stages of alewife into the cooling water system of FitzPatrick NGS.

      ii) The time period of interest is April through November. Impingement monitoring should take place throughout this period. Entrainment should take place from May through November. Cessation of entrainment studies may be triggered when the density of entrained organisms falls below a permittee proposed minimum in samples taken during October.

2. By July 1, 1998, the permittee shall submit an assessment of

the reconfigured fish deterrent system to include a recommendation of the period of deployment, based upon the results of the studies outlined above. Failure to achieve mitigation of alewife impingement comparable to that of the prototype system tested in 1993 (see Authority letter of August 24, 1994) could lead to further efforts to mitigate these impingement impacts, including consideration of returning the narrow beam transducers to the system configuration.

New York State Department of Environmental Conservation
Albany, N. Y. 12201

Henry L. Diamond,
Commissioner

June 1, 1973

Mr. Asa George
General Manager
Power Authority of the
State of New York
10 Columbus Circle
New York, New York 10019

Dear Sir:

We have reviewed your request of March 9, 1973, pursuant to Section 401(a)(1) of the Federal Water Pollution Control Act Amendments of 1972 (P.L. 92-500) (the "Act") and referred, for details, to your permit to operate and discharge dated November 28, 1972, and letter of approval dated November 27, 1972.

Based upon the foregoing and that public notice was duly given, the Department of Environmental Conservation hereby certifies in accordance with Section 401(a)(1) of the Act, that as of the date hereof, there is no effluent limitation or other limitation formally established under Sections 301(b) and 302 of the Act and there is no standard formally established under Sections 306 and 307 of the Act applicable to the activity which the Power Authority of the State of New York proposes to conduct (namely, the operation of the James A. Fitzpatrick Nuclear Power Plant, located on the south shore of Lake Ontario, in the Town of Scriba, Oswego County, New York.)

Pursuant to Section 401(d) of the Act and in accordance with the requirements of the New York State Environmental Conservation Law and the Official Compilation Codes, Rules and Regulations of the State of New York, particularly Parts 700-704 Classifications and Standards governing the Quality and Purity of Waters of New York State (Water Quality Standards), this certification hereby sets forth the following requirements which shall become conditions on any Federal license or permit subject to the provisions of this section:

1. The applicants must sample and monitor the traveling screens, trash racks, and forebay at the Fitzpatrick Plant in a manner approved by the Department of Environmental Conservation. Fish abundance data must also be submitted to the Department of Environmental Conservation.

2. Prior to the full operation of the plant, the applicants shall submit a report for the approval of the Department of Environmental Conservation describing a contingency plan for operations to be implemented in the event a serious fish kill, or other serious aquatic life incident, occurs as a result of the operation of this facility.

- 2 -

3. The applicants must collect and sample organisms at the discharge. The applicants must submit to the Department of Environmental Conservation their assessment of the significance of entrainment mortality on the local area and on Lake Ontario.

4. A copy of all reports pertaining to the environment which the applicants prepare for any federal, state, or local agency, should also be submitted to the Department of Environmental Conservation.

5. Intake and effluent temperatures and flow must be measured and recorded continuously.

6. Plant electrical output must be monitored and daily maximum and minimum recorded and daily average determined and recorded.

7. All oil and chemical discharges must be treated before any dilution in facilities approved by the New York State Department of Environmental Conservation.

8. Triaxial isothermal mapping by actual temperature measurement must be conducted on a frequency in such a manner and pursuant to a program approved by the New York State Department of Environmental Conservation.

9. Reports of tests and measurements pertaining to temperatures, flows, electrical output, oil and chemical discharges, and triaxial isothermal mapping as prescribed by the New York State Department of Environmental Conservation must be submitted monthly.

The applicants shall also comply with all provisions of any other Department approvals and permits.

This certification is issued solely for the purpose of Section 401(a)(1) of the Act and should not be construed to indicate approval of the project for any other purposes.

Very truly yours,

Terence P. Curran

Terence P. Curran
Director of Environmental Analysis

INTERNAL CORRESPONDENCE

NIAGARA MOHAWK

DISTRICT Corporate

FROM R. W. Cummings, Jr.

DATE November 6, 1975 FILE CODE

TO Mr. R. W. Smith

SUBJECT JAF 401 Certification - Reporting Requirements

Please refer to the JAF 401 Certification dated June 1, 1973. As you recall, Conditions 5, 6, and 9 of the Certification require the monitoring, recording, and reporting of intake and effluent temperatures, circulating water flow, and station electrical output. The JAF document, however, does not specify exactly what is to be reported (hourly averages, daily averages, etc.) nor does it specify when the reporting of this data was to be initiated. The purpose of this memo is to provide guidance in the reporting of this information based on experience with other NMPC plants.

Data Collection and Reporting

The monitoring requirements contained in Conditions 5 and 6 should be implemented if such is not already being accomplished. The data should then be reduced and reported on a monthly basis as follows:

1. Station electrical output - daily minimum, maximum, and average for each day of the month;

2. Circulating water flow - daily minimum, maximum, and average (gal/hr or gal/min) for each day of the month;

3. Circulating water temperature - daily minimum inlet and outlet, daily maximum inlet and outlet, and daily average inlet and outlet (^{o}F) for each day of the month.

The data should be tabulated in a neat manner, and a brief cover letter should accompany the data transmittal. As an example of this, I have attached a copy of a typical submission for the Dunkirk Station. Note that the Station Superintendent should sign the cover letter.

These "401 Reports" should be submitted on a monthly basis by the 15th of each month.

Mr. R. W. Smith
Page 2
November 6, 1975

Initiation of Reporting

If possible, the first JAF "401 Report" should be prepared starting with the month of October 1975. This report should be submitted by November 15. Unless specifically requested by the NYSDEC, I see no need to submit reports for months prior to October.

Report Distribution

1. Original: Russell Mt. Pleasant, P. E.
Chief, Bureau of Monitoring and Surveillance
Division of Pure Water
NYS Department of Environmental Conservation
50 Wolf Road
Albany, New York 12201

2. Carbon Copies: Thomas E. Quinn, P. E.
Bureau of Industrial Wastes
NYS Department of Environmental Conservation
50 Wolf Road
Albany, New York 12233

Mr. Daniel Barolo
NYS Department of Environmental Conservation, Region 7
100 Elwood Davis Road
North Syracuse, New York 13212

3. Internal: Mr. J. M. Toennies, C-1

JAF File

PASNY

I presume that the foregoing clarifies the reporting requirements contained in Conditions 5, 6 and 9 of the JAF 401 Certification. If you have further questions, please contact me.

Raymond W Cummings Jr.

RWC/ed

cc Ms. C. A. Blum
Messrs. R. A. Burns
W. C. Hiestand
T. E. Lempges
E. A. Mulcahey
J. M. Toennies

Messrs. E. Abbott - PASNY
Z. Chilazi - PASNY
A. Martin - PASNY

NEW YORK POWER AUTHORITY
JAMES A. FITZPATRICK NUCLEAR POWER PLANT

CERTIFICATES, DOCUMENTS AND PERMITS

TITLE: 401 CERTIFICATION AND INITIAL REPORTING REQUIREMENTS

PROC. NO. CDP-02

PORC Review No./Date Meeting No. N/A Date 4/25/88

Approved By:
Resident Manager

Approved By:
Radiological and Environmental Services Superintendent

Page No.:	1	2	3	4
Rev. No.:	0	0	0	0

Rev. No. 1

Date 03/88

Attachment D

Coastal Management Program Consistency Determination

Federal Consistency Certification for Federal Permit and License Applicants[1]

This is Entergy Nuclear Generation Company's (Entergy) certification to the U. S. Nuclear Regulatory Commission (NRC) that the renewal of the James A. Fitzpatrick Nuclear Power Station (JAFNPP) operating license would be consistent with enforceable policies of the federally approved state coastal zone management program. The certification describes background requirements, the proposed action (i.e. license renewal), anticipated environmental impacts, New York State enforceable coastal resource protection policies, JAFNPP compliance status, and summary findings.

CONSISTENCY CERTIFICATION

Entergy certifies to the NRC that renewal of the JAFNPP operating license complies with the enforceable policies of New York's approved coastal zone management program and will be conducted in a manner consistent with such program. Entergy expects JAFNPP operations during the license renewal term to be a continuation of current operations as described below, with no physical or operational station alterations that would change effects on New York's coastal zone.

NECESSARY DATA AND INFORMATION

Statutory Background

The Federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on an applicant for a Federal license to conduct a review of any activity that could affect a state's coastal zone. The Act requires an applicant to certify to the licensing agency that the proposed action would be consistent with the state's federally approved coastal zone management program. The Act also requires the applicant to provide to the state a copy of the certification statement and requires the state, at the earliest practicable time, to notify the federal agency and the applicant whether the state concurs with, or objects to, the consistency certification. See 16 USC 1456(c)(3)(A).

The National Oceanic and Atmospheric Administration (NOAA) has promulgated implementing regulations that indicate the certification requirement is applicable to renewal of federal licenses for activities not previously reviewed by the state [15 CFR 930.51(b)(1)]. NOAA approved the New York coastal zone management program in 1982. In New York, the approved program is the New York State Coastal Management Program (CMP), 19 NYCRR Parts 600-601 and Executive Law, Article 42.

CMP regulations require review of federal activities that are listed or that could reasonably be expected to affect the coastal zone (15 CFR 930.11). NRC licensing is a listed activity and since JAFNPP is at a coastline that withdraws from and discharges to coastal waters, it could reasonably be expected to affect the coastal zone. The State regulation requires certification of compliance with the CMP policies as identified in the State of New York Coastal Management Program and Final Environmental Impact Statement, Section 6, August 1982. identifies the policies and the Entergy justification for certifying compliance.

---

1. This certification is patterned after the example certification included as Appendix E of Ref D-1.

Proposed Action

Entergy is applying to the NRC for renewal of the JAFNPP license to operate for an additional 20 years beyond the current expiration date of October 17, 2014. Entergy expects JAFNPP operations during the license renewal term to be a continuation of current operations as described in the following paragraphs, with no physical or operational changes that would affect the New York coastal zone. Entergy certifies that license renewal complies with the program policies of the New York approved coastal management program and will be conducted in a manner consistent with such policies.

Background Information

James A. FitzPatrick Nuclear Power Plant (JAFNPP) is located on a 702-acre site on the south shore of Lake Ontario, known as Nine Mile Point, in the Town of Scriba, Oswego County, New York. The site is in a rural area approximately five miles northeast of Oswego, 36 miles north-northwest of Syracuse, and 65 miles east of Rochester, New York. Syracuse is the largest city within 50 miles of JAFNPP. Constellation Nuclear's Nine Mile Point Nuclear Station is located immediately west of the site. The location of JAFNPP is shown in Figures 2-1 and 2-2.

JAFNPP is a single-unit plant with a boiling water reactor and turbine generator licensed for an output of 2,536 megawatts-thermal (MWt), and an electric rating of approximately 881 megawatts-electric (MWe).

JAFNPP is equipped with a once-through heat dissipation system that withdraws cooling water from and discharges to Lake Ontario. Three pumps in the intake structure provide a continuous supply (352,600 gallons per minute [gpm]) of condenser cooling water. After moving through the condensers, cooling water is discharged into a 1,400-foot long discharge tunnel, with the discharge nozzles being located 5 to 6 feet above the lake bottom. The design effluent flow rate to the discharge tunnel is 388,600 gpm. The maximum allowable increase in water temperature across the condensers is 32.4°F. Entergy holds a State Pollutant Discharge Elimination System (SPDES) Permit (NY 0020109) to regulate this activity and other plant/stormwater discharges. In accordance with permit requirements, Entergy monitors effluent parameters from discharges and reports the results to the New York State Department of Environmental Conservation (NYSDEC).

JAFNPP has an onsite wastewater treatment plant that is regulated under SPDES Permit NY 0020109. Sanitary wastewater which has been processed in the wastewater treatment facility and does not contain radioactive materials is discharged in accordance with JAFNPP's SPDES permit.

Entergy employs a permanent workforce of approximately 715 employees (including baseline permanent contractors) at JAFNPP. The majority of the JAFNPP workforce (approximately 95.5%) lives in Oswego and Onondaga Counties. JAFNPP is on a 24-month refueling cycle. During refueling outages, site employment increases above the approximately 715 person permanent workforce by as many as 700 to 900 workers for temporary duty (30 to 40 days).

Environmental Impacts

The NRC has prepared a Generic Environmental Impact Statement (Reference D-2) on impacts that nuclear power plant license renewal could have on the environment and has codified its findings (10 CFR 51, Subpart A, Appendix B, Table B-1). The codification identified 92 potential environmental issues, 69 of which the NRC identified as having small impacts and termed "Category 1 issues." The NRC defines "Small" as follows.

For the issue, 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 purpose 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 as the term is used in this table (10 CFR 51, Subpart A, Appendix B, Table B 1).

The NRC based its assessment of license renewal impacts on its evaluations of impacts from current plant operations. The NRC codification and the Generic Environmental Impact Statement discuss the following types of Category 1 environmental issues:

- Surface water quality, hydrology, and use
- Aquatic ecology
- Groundwater use and quality
- Terrestrial resources
- Air quality
- Land use
- Human health
- Postulated accidents
- Socioeconomics
- Uranium fuel cycle and waste management
- Decommissioning

In its decision making for plant-specific license renewal applications, absent new and significant information to the contrary, the NRC relies on its codified findings, as amplified by supporting information in the Generic Environmental Impact Statement, for assessment of environmental impacts from Category 1 issues [10 CFR 51.95(c)(4)]. For plants such as JAFNPP that are located in the coastal zone, many of these issues involve potential impacts to the coastal zone. Entergy has adopted by reference the NRC findings and Generic Environmental Impact Statement analyses for all 50 [2] Category 1 issues applicable to JAFNPP.

The NRC regulation identified 21 issues as "Category 2," for which license renewal applicants must submit additional site-specific information.[3] Of these, 11 apply to JAFNPP,[4] and like the Category 1 issues, could potentially involve impacts to the coastal zone. The applicable issues and Entergy's impact conclusions are listed below.

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2. The remaining 19 Category 1 issues do not apply to JAFNPP either because they are associated with design or operational features that JAFNPP does not have (e.g., cooling towers) or to a refurbishment activity that JAFNPP will not undertake.
3. 10 CFR 51, Subpart A, Appendix B, Table B-1 also identifies 2 issues as "NA" for which the NRC could not come to a conclusion regarding categorization. Entergy believes that these issues, chronic effects of electromagnetic fields and environmental justice, do not affect "coastal zone" as that phrase is defined by the Coastal Zone Management Act [16 USC 1453(1)].
4. The remaining 10 Category 2 issues do not apply to JAFNPP either because they are associated with design or operational features that JAFNPP does not have (e.g., cooling towers) or to a refurbishment activity that JAFNPP will not undertake.

- Aquatic ecology
  - <u>Entrainment of fish and shellfish in early life stages</u> – This issue addresses mortality of organisms small enough to pass through the plant's circulating cooling water system. In August 2001, JAFNPP was issued a SPDES permit which concluded that the high frequency/high amplitude fish deterrent system installed at the offshore intake structure from April to October of each year is the best technology available (BTA) for reducing both entrainment and impingement impacts. In addition to the BTA determination, JAFNPP also utilizes additional operational measures and technological design features to further minimize already small entrainment impacts. Entergy concludes that these impacts are small during current operations and there are no operational changes or plans which would affect this conclusion for the license renewal term.
  - <u>Impingement of fish and shellfish</u> – This issue addresses mortality of organisms large enough to be caught by intake screens before passing through the plant's circulating cooling water system. The permit and additional operational measures and technological design features discussed above also address impingement. Entergy concludes that these impacts are small during current operations and there are no operational changes or plans which would affect this conclusion for the license renewal term.
  - <u>Heat shock</u> – This issue addresses mortality of aquatic organisms by exposure to heated plant effluent. JAFNPP has a CWA Section 316(a) variance which concluded that the thermal effluent from JAFNPP would not result in long-term impacts to the fish and wildlife populations of Lake Ontario and that more stringent limits on the heated effluent are not necessary to protect the aquatic environment. Entergy concludes that these impacts are small during current operations and there are no operational changes or plans which would affect this conclusion for the license renewal term.
- Threatened or endangered species

  This issue addresses effects that JAFNPP operations potentially could have on species that are listed under federal law as threatened or endangered. In analyzing this issue, Entergy has also considered species that are listed under State of New York law (). Several other terrestrial species could potentially occur on the JAFNPP site, or along associated transmission corridors, although none have been observed. Entergy's and NYPA's (owner and operator of the transmission lines) environmental protection programs have identified no adverse impacts to such species and Entergy's consultation with cognizant Federal and State agencies has identified no impacts of concern. Entergy concludes that JAFNPP impacts to these species are small during current operations and there are no planned physical or operational changes to the plant that would affect this conclusion for the license renewal term.
- Human health

  <u>Electromagnetic fields, acute effects (electric shock)</u> – This issue addresses the potential for shock from induced currents, similar to static electricity effects, in the vicinity of transmission lines. Because this strictly human-health issue does not directly or indirectly

affect natural resources of concern within the Coastal Zone Management Act definition of "coastal zone" [16 USC 1453(1)], Entergy concludes that the issue is not subject to the certification requirement.

- Socioeconomics

  - Housing – This issue addresses impacts that JAFNPP could have on local housing availability, as it relates to the employees required to support license renewal. Presently in Oswego and Onondaga Counties, the vacancy rates have remained stable with the number of available units keeping pace with or exceeding the low population growth in the area. In addition, as Entergy does not intend to add additional permanent employees to the JAFNPP workforce, Entergy has concluded that impacts during the JAFNPP license renewal term would be small.

  - Public services; public utilities – This issue address impacts that JAFNPP could have on public water supply systems, as it relates to additional permanent workers added during the license renewal period. As Entergy does not intend to add additional permanent employees to the JAFNPP workforce, Entergy has concluded that impacts during the JAFNPP license renewal term would be small.

  - Offsite land use – This issue addresses impacts that local government spending of plant property tax dollars can have on land use patterns. JAFNPP property taxes comprise approximately 9 percent of the Town of Scriba's revenue and Entergy expects this to remain generally unchanged during the license renewal term. The NRC concluded, and Entergy concurs, that impacts to offsite land use would be small if tax payments are less than 10 percent of total revenue. Entergy concludes that impacts during the JAFNPP license renewal term would be small.

  - Public services; transportation – This issue addresses impacts that JAFNPP could have on local traffic patterns, as it relates to adding additional permanent workers during the license renewal period. As Entergy does not intend to add additional employees to the permanent workforce for the license renewal term, this would result in a small impact.

  - Historic and archaeological resources – This issue address impacts that license renewal activities could have on resources of historic or archaeological significance. Entergy is not aware of any adverse or detrimental impacts to any historical or archaeological resources from current operations and there are no plans to change the plant site physically or operationally during the license renewal period that would disturb these resources. Entergy correspondence with the New York State Historic Preservation Officer identified no issues of concern. Therefore, Entergy concludes that impacts during the JAFNPP license renewal term would be small.

  - Severe accidents – Results from the Entergy severe accident mitigation alternatives (SAMA) analysis have not identified additional cost beneficial alternatives to further mitigate risk to public health and the economy in the area of the plant, including the coastal zone, due to potential severe accidents at JAFNPP. The SAMAs, however, are unrelated to aging management issues that are the subject of the license renewal analysis and, therefore are not related to this consistency certification for license renewal.

State Program

The New York State Coastal Management Program is administered by the New York State, Department of State, Division of Coastal Resources. The Division maintains a website that describes the program in general terms (Reference D-3). The New York State Coastal Management Program (Reference D-4) contains details about the state's coastal policies. is the New York State Department of State, Coastal Management Program, Federal Consistency Assessment Program. Table D-1 lists these policies and discusses for each item, the applicability to JAFNPP and, where applicable, the status of JAFNPP compliance. Tables and identify licenses, permits, consultations and other approvals necessary for JAFNPP continued operation and license renewal, respectively.

Findings

1. The NRC has found that the environmental impacts of Category 1 issues are small. Entergy has adopted by reference NRC findings for Category 1 issues applicable to JAFNPP.

2. For Category 2 issues applicable to JAFNPP, Entergy has determined that the environmental impacts are small.

3. To the best of Entergy's knowledge, JAFNPP is in compliance with New York licensing and permitting requirements and is in compliance with its State-issued licenses and permits.

4. Entergy's license renewal and continued operation of JAFNPP would be consistent with the enforceable provisions of the New York Coastal Zone Management Program.

STATE NOTIFICATION

By this certification that JAFNPP license renewal is consistent with New York's coastal zone management program, the State of New York is notified that it has six months from receipt of this letter and accompanying information in which to concur with or object to Entergy's certification. However, pursuant to 15 CFR 930.62 if the State of New York has not issued a decision within three months following the commencement of state agency review, it shall notify the contacts listed below of the status of the matter and the basis for further delay. The State's concurrence, objection, or notification of review status shall be sent to the following.

Lesley Fields
U.S. Nuclear Regulatory Commission
One White Flint North
11555 Rockville Pike
Rockville, MD 02085-2738

Peter Dietrich
Site Vice-President
Entergy Nuclear James A. Fitzpatrick
P.O. Box 110
Lycoming, NY 13093

REFERENCES

D-1. U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulations, LIC-203, Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues, Revision 1, May 24, 2004.

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

D-3. NYS DOS Division of Coastal Resources, Coastal Resources Online, Consistency Review, available at http://www.nyswaterfronts.com/consistency.asp.

D-4. U.S. Fish & Wildlife Service, Threatened and Endangered Species System (TESS); Listings by State and Territory as of 12/08/2005: New York, 2005. Available at http://ecos.fws.gov/tess_public/TESSWebpageUsaLists?state=NY.

D-5. New York State Department of Environmental Conservation, List of Endangered, Threatened and Special Concern Fish & Wildlife Species of New York State. Available at http://www.dec.state.ny.us/website/drwmr/wildlife/endspec/etsclist.html, Accessed January 10, 2006.

D-6. U.S. Nuclear Regulatory Commission, Generic Environmental Impact Statement for License Renewal of Nuclear Plants, NUREG-1437, Supplement 24, Regarding Nine Mile Point Nuclear Station, Units 1 and 2, Draft Report for Comment, Office of Nuclear Reactor Regulation, Washington, DC, September 2005.

Table D-1
New York Coastal Management Program's
State Coastal Policies

The New York Coastal Management Program requires persons seeking approval for activities which may impact the Coastal Zone to demonstrate that the activity is consistent with all applicable policies (Located in the State of New York Coastal Management Program and Final Environmental Impact Statement, Section 6, August 1982, with changes made to incorporate routine program changes approved in 1983 and 2001). Entergy is seeking renewal of the operating license for JAFNPP. The following table details the New York Coastal Management policies and provides the Entergy demonstration that JAFNPP license renewal would be consistent with these policies.

POLICY	JUSTIFICATION/ CONSISTENCY
DEVELOPMENT POLICIES	
DEVELOPMENT POLICY 1: Restore, revitalize, and redevelop deteriorated and underutilized waterfront areas for commercial, industrial, cultural, recreational, and other compatible uses.	JAFNPP is a previously developed property. This policy does not apply to JAFNPP.
DEVELOPMENT POLICY 2: Facilitate the siting of water dependent uses and facilities on or adjacent to coastal waters	JAFNPP is a previously developed property. This policy does not apply to JAFNPP.
DEVELOPMENT POLICY 3: Further develop the state's major ports of Albany, Buffalo, New York, Ogdensburg, and Oswego as centers of commerce and industry, and encourage the siting, in these port areas, including those under the jurisdiction of state public authorities, of land use and development which is essential to, or in support of, the waterborne transportation of cargo and people	JAFNPP is not located in a port area. This policy does not apply to JAFNPP.
DEVELOPMENT POLICY 4: Strengthen the economic base of smaller harbor areas by encouraging the development and enhancement of those traditional uses and activities which have provided such areas with their unique maritime identity	JAFNPP is a previously developed property. This policy does not apply to JAFNPP.
DEVELOPMENT POLICY 5: Encourage the location of development in areas where public services and facilities essential to such development are adequate.	JAFNPP is a previously developed property. This policy does not apply to JAFNPP.
DEVELOPMENT POLICY 6: Expedite permit procedures in order to facilitate the siting of development activities at suitable locations.	JAFNPP is a previously developed property. This policy does not apply to JAFNPP.

POLICY	JUSTIFICATION/ CONSISTENCY
FISH AND WILDLIFE POLICIES	
FISH AND WILDLIFE POLICY 7: Significant coastal fish and wildlife habitats will be protected, preserved, and where practical, restored so as to maintain their viability as habitats.	JAFNPP expects operations during the license renewal term to be a continuation of current operational practices. There would be no additional effects on coastal fish and wildlife habitats as a result of JAFNPP license renewal.
FISH AND WILDLIFE POLICY 8: Protect fish and wildlife resources in the coastal area from the introduction of hazardous wastes and other pollutants which bio-accumulate in the food chain or which cause significant sublethal or lethal effects on those resources	Non-radiological effluent discharges from JAFNPP are regulated under its New York State SPDES Permit program. Radiological effluent discharges are regulated by the NRC. JAFNPP is in compliance with its environmental permits, both state and federal and does not discharge hazardous wastes within the coastal zone. All hazardous wastes are disposed of in accordance with all applicable state and federal regulations.
FISH AND WILDLIFE POLICY 9: Expand recreational use of fish and wildlife resources in coastal areas by increasing access to existing resources, supplementing existing stocks, and developing new resources.	Due to the heightened security environment, there is no public access to the immediate shorefront area in the JAFNPP vicinity.
FISH AND WILDLIFE POLICY 10: Further develop commercial finfish, shellfish, and crustacean resources in the coastal area by encouraging the construction of new, or improvement of existing on-shore commercial fishing facilities, increasing marketing of the states seafood products, maintaining adequate stocks, and expanding aquaculture facilities	This policy is not applicable to JAFNPP. JAFNPP is not a state agency or an aquaculture facility
FLOODING AND EROSION HAZARDS POLICIES	
FLOODING AND EROSION HAZARDS POLICY 11: Buildings and other structures will be sited in the coastal area so as to minimize damage to property and the endangering of human lives caused by flooding and erosion.	This policy is not applicable to JAFNPP. There are no plans to construct new buildings at the JAFNPP site.

POLICY	JUSTIFICATION/ CONSISTENCY
FLOODING AND EROSION HAZARDS POLICY 12: Activities or development in the coastal area will be undertaken so as to minimize damage to natural resources and property from flooding and erosion by protecting natural protective features including beaches, dunes, barrier islands, and bluffs.	This policy is not applicable to JAFNPP. There are no plans for construction or additional development at the JAFNPP site during the license renewal term.
FLOODING AND EROSION HAZARDS POLICY 13: The construction or reconstruction of erosion protection structures shall be undertaken only if they have a reasonable probability of controlling erosion for at least thirty years as demonstrated in design and construction standards and/or assured maintenance or replacement programs.	This policy is not applicable to JAFNPP. There are no plans for construction of erosion protection structures.
FLOODING AND EROSION HAZARDS POLICY 14: Activities and development, including the construction or reconstruction of erosion protection structures, shall be undertaken so that there will be no measurable increase in erosion or flooding at the site of such activities or development, or at other locations.	This policy is not applicable to JAFNPP. There are no plans for construction of erosion protection structures or other structures at the JAFNPP site.
FLOODING AND EROSION HAZARDS POLICY 15: Mining, excavation or dredging in coastal waters shall not significantly interfere with the natural coastal processes which supply beach materials to land adjacent to such waters and shall be undertaken in a manner which will not cause an increase in erosion of such land.	This policy is not applicable to JAFNPP. There are no plans for mining, excavation, or dredging in coastal waters by JAFNPP.
FLOODING AND EROSION HAZARDS POLICY 16: Public funds shall only be used for erosion protective structures where necessary to protect human life, and new development which requires a location within or adjacent to an erosion hazard area to be able to function, or existing development; and only where the public benefits outweigh the long term monetary and other costs including the potential for increasing erosion and adverse effects on natural protective features.	This policy does not apply to JAFNPP. JAFNPP is an existing facility and no new erosion structures are needed.
FLOODING AND EROSION HAZARDS POLICY 17: Non-structural measures to minimize damage to natural resources and property from flooding and erosion shall be used whenever possible.	JAFNPP is not at risk of being flooded. All appropriate erosion measures are taken when necessary. Natural erosion is not an issue of concern for JAFNPP.

POLICY	JUSTIFICATION/ CONSISTENCY
GENERAL POLICY	
GENERAL POLICY 18: To safeguard the vital economic, social, and environmental interests of the state and of its citizens, proposed major actions in the coastal area must give full consideration to those interests, and to the safeguards which the state has established to protect valuable coastal resource areas.	This policy is not applicable to JAFNPP. JAFNPP is an existing facility for which no major refurbishment is planned during the license renewal term.
PUBLIC ACCESS POLICIES	
PUBLIC ACCESS POLICY 19: Protect, maintain, and increase the level and types of access to water-related recreation resources and facilities.	This policy is not applicable to JAFNPP. JAFNPP is not a water recreation resource or facility.
PUBLIC ACCESS POLICY 20: Access to the publicly-owned foreshore and to lands immediately adjacent to the foreshore or the water's edge that are publicly owned shall be provided and it shall be provided in a manner compatible with adjoining uses.	This policy is not applicable to JAFNPP. Due to the heightened security environment, access is not allowed to the shorefront area immediately adjacent to JAFNPP.
RECREATION POLICIES	
RECREATION POLICY 21: Water-dependent and water-enhanced recreation will be encouraged and facilitated, and will be given priority over non-water-related uses along the coast.	This policy is not applicable to JAFNPP. JAFNPP is not associated with water dependent or enhanced recreation. Due to the heightened security environment, access is not allowed to the shorefront area immediately adjacent to JAFNPP.
RECREATION POLICY 22: Development, when located adjacent to the shore, will provide for water-related recreation, whenever such is compatible with reasonably anticipated demand for activities, and is compatible with the primary purpose of the development	This policy is not applicable to JAFNPP. Due to the heightened security environment, access is not allowed to the shorefront area immediately adjacent to JAFNPP.
HISTORIC AND SCENIC RESOURCES POLICIES	
HISTORIC AND SCENIC RESOURCES POLICY 23: Protect, enhance and restore structures, districts, areas or sites that are of significance in the history, architecture, archaeology or culture of the state, its communities, or the nation.	This policy is not applicable to JAFNPP. There are no sites of historic significance on the JAFNPP property.

POLICY	JUSTIFICATION/ CONSISTENCY
HISTORIC AND SCENIC RESOURCES POLICY 24: Prevent impairment of scenic resources of statewide significance	This policy is not applicable to JAFNPP. There are no identified scenic resources of statewide significance at JAFNPP
HISTORIC AND SCENIC RESOURCES POLICY 25: Protect, restore, or enhance natural and man-made resources which are not identified as being of statewide significance, but which contribute to the overall scenic quality of the coastal area.	This policy is not applicable to JAFNPP. There are no identified scenic resources of significance at JAFNPP
AGRICULTURAL LANDS POLICY	
AGRICULTURAL LANDS POLICY 26: Conserve and protect agricultural lands in the state's coastal area	This policy is not applicable to JAFNPP. There are no agricultural lands on JAFNPP property.
ENERGY AND ICE MANAGEMENT POLICIES	
ENERGY AND ICE MANAGEMENT POLICY 27: Encourage energy conservation and the use of alternative sources such as solar and wind power in order to assist in meeting the energy needs of the State.	This policy is not applicable to JAFNPP. JAFNPP is an existing operating nuclear power facility.
ENERGY AND ICE MANAGEMENT POLICY 28: Ice management practices shall not interfere with the production of hydroelectric power, damage significant fish and wildlife and their habitats, or increase shoreline erosion or flooding.	This policy is not applicable to JAFNPP. The only ice management at JAFNPP which is conducted is for frazzle ice mitigation at the intake structure.
ENERGY AND ICE MANAGEMENT POLICY 29: Encourage the development of energy resources on the outer continental shelf, in Lake Erie and in other water bodies, and ensure the environmental safety of such activities.	This policy is not applicable to JAFNPP. JAFNPP is an existing power production facility.
WATER AND AIR RESOURCES POLICIES	
WATER AND AIR RESOURCES POLICY 30: Municipal, industrial, and commercial discharge of pollutants, including but not limited to, toxic and hazardous substances, into coastal waters will conform to state and national water quality standards	All of JAFNPP's effluent discharges are regulated by the SPDES Permit program (Permit NY 0020109). JAFNPP is in compliance with SPDES Permit requirements.

POLICY	JUSTIFICATION/ CONSISTENCY
WATER AND AIR RESOURCES POLICY 31: State coastal area policies and management objectives of approved local waterfront revitalization programs will be considered while reviewing coastal water classifications and while modifying water quality standards; however those waters already overburdened with contaminants will be recognized as being a development constraint.	This policy is not applicable to JAFNPP. JAFNPP is not involved in a local waterfront revitalization program.
WATER AND AIR RESOURCES POLICY 32: Encourage the use of alternative or innovative sanitary waste systems in small communities where the costs of conventional facilities are unreasonably high, given the size of the existing tax base of these communities	This policy is not applicable to JAFNPP. JAFNPP is an existing industrial use facility, not a community in the development stage.
WATER AND AIR RESOURCES POLICY 33: Best management practices will be used to ensure the control of stormwater runoff and combined sewer overflows draining into coastal waters.	JAFNPP stormwater runoff is managed as a condition of it's SPDES Permit. JAFNPP is in compliance with the SPDES Permit.
WATER AND AIR RESOURCES POLICY 34: Discharge of waste materials into coastal waters from vessels subject to state jurisdictions will be limited so as to protect significant fish and wildlife habitats, recreational areas and water supply areas.	This policy is not applicable to JAFNPP. JAFNPP is not a vessel.
WATER AND AIR RESOURCES POLICY 35: Dredging and filling coastal waters and disposal of dredged material will be undertaken in a manner that meets existing state permit requirements, and protects significant fish and wildlife habitats, scenic resources, natural protective features, important agricultural lands and wetlands.	This policy is not applicable to JAFNPP. There are no plans for dredging or filling of coastal waters by JAFNPP.
WATER AND AIR RESOURCES POLICY 36: Activities related to the shipment and storage of petroleum and other hazardous materials will be conducted in a manner that will prevent or at least minimize spills into coastal waters; all practicable efforts will be undertaken to expedite the cleanup of such discharges; and restitution for damages will be required when these spills occur.	JAFNPP has internal procedures and polices to ensure that all activities related to hazardous materials are conducted in the safest manner. All policies and procedures are in compliance with state and federal regulations.
WATER AND AIR RESOURCES POLICY 37: Best management practices will be utilized to minimize the non-point discharge of excess nutrients, organics and eroded soils into coastal waters	This policy is not applicable to JAFNPP as JAFNPP does not make such discharges.

POLICY	JUSTIFICATION/ CONSISTENCY
WATER AND AIR RESOURCES POLICY 38: The quality and quantity of surface water and groundwater supplies will be conserved and protected particularly where such waters constitute the primary or sole source of water supply.	This policy is not applicable to JAFNPP as the facility does not use groundwater for either potable or service water.
WATER AND AIR RESOURCES POLICY 39: The transport, storage, treatment and disposal of solid wastes, particularly hazardous wastes, within coastal areas will be conducted in such a manner so as to protect groundwater and surface water supplies, significant fish and wildlife habitats, recreation areas, important agricultural land, and scenic resources.	JAFNPP has only temporary storage of hazardous waste onsite, which is regulated by applicable state and federal regulations, permits, and authorizations. All activities which involve hazardous wastes are conducted in a manner to minimize impacts on and protect the environment, including water supplies.
WATER AND AIR RESOURCES POLICY 40: Effluent discharged from major steam electric generating and industrial facilities into coastal waters will not be unduly injurious to fish and wildlife and shall conform to state water quality standards.	Discharge of effluent by JAFNPP is regulated under a SPDES permit (NY-0020109). JAFNPP is in compliance with requirements of the SPDES Permit.
WATER AND AIR RESOURCES POLICY 41: Land use or development in the coastal area will not cause national or state air quality standards to be violated.	JAFNPP is in compliance with its air emissions permit.
WATER AND AIR RESOURCES POLICY 42: Coastal management policies will be considered if the state reclassifies land areas pursuant to the prevention of significant deterioration regulations of the federal Clean Air Act;	This policy is not applicable to JAFNPP. The land where JAFNPP is situated has not been reclassified.
WATER AND AIR RESOURCES POLICY 43: Land use or development in the coastal areas must not cause the generation of significant amounts of acid rain precursors: nitrates and sulfates.	JAFNPP is a nuclear operating plant that is in compliance with its air emissions permit.
WETLANDS POLICY	
Wetlands Policy 44: Preserve and protect tidal and freshwater wetlands and preserve the benefits derived from these areas.	This policy is not applicable to JAFNPP. There are no tidal or freshwater wetlands at the JAFNPP site

Table D-2
Endangered and Threatened Species that occur in Oswego County, NY

Scientific Name	Common Name	Federal Status[a]	State Status[b, c]
Reptiles and Amphibians			
Crotalus horridus	timber rattlesnake	-	T
Ambystoma jeffersonianum	Jefferson salamander	-	SC
Ambystoma laterale	blue-spotted salamander	-	SC
Clemmys guttata	spotted turtle	-	SC
Clemmys insculpta	wood turtle	-	SC
Clemmys muhlenbergii	bog turtle	T	E
Sisturus catenatus catenatus	massasauga rattlesnake	C	E
Birds			
Accipiter cooperli	Cooper's hawk	-	SC
Accipiter striatus	sharp-shinned hawk	-	SC
Ammodramus henslowli	Henslow's sparrow	-	T
Ammodramus savannarum	grasshopper sparrow	-	SC
Aquila chrysaetos	golden eagle	-	E
Asio flammeus	short-eared owl	-	E
Bartramia longicauda	upland sandpiper	-	T
Buteo lineatus	red-shouldered hawk	-	SC
Charadrius melodius	piping plover	E	E
Chlidonias niger	black tern	-	E
Chordeiles minor	common nighthawk	-	SC
Circus cyaneus	northern harrier	-	T
Cistothorus platensis	sedge wren	-	T
Dendroica cerulea	cerulean warbler	-	SC
Eremophila alpestris	horned lark	-	SC
Falco peregrinus	peregrine falcon	-	E
Gavia immer	common loon	-	SC
Haliaeetus leucocephalus	bald eagle	E	

Scientific Name	Common Name	Federal Status[a]	State Status[b, c]
Ixobrychus exilis	least bittern	-	T
Lanius ludovicianus	loggerhead shrike	-	E
Melanerpes erythrocephalus	red-headed woodpecker	-	SC
Pandion haliaetus	osprey	-	SC
Podilymbus podiceps	pied-billed grebe	-	T
Pooecetes gramineus	vesper sparrow	-	SC
Sterna hirundo	common tern	-	T
Vermivora chrysoptera	golden-winged warbler	-	SC
Mammals			
Myotis leibii	small-footed bat	-	SC
Myotis sodalis	Indiana bat	E	E
Fish			
Acipenser fulvescens	lake sturgeon	-	T
Cottus ricei	spoonhead sculpin	-	E
Erimyzon sucetta	lake chubsucker	-	T
Hideon tergisus	mooneye	-	T
Lythrurus umbratilis	redfish shiner	-	SC
Myoxocephalus thompsoni	deepwater sculpin	-	E
Prosopium cylindraceum	round whitefish	-	E
Plants			
Asplenium scolopendrium var americanum	American Hart's-tongue fern	T	
Eleocharis quadrangulata	angled spikerush	-	E
Eleocharis obtuse var. ovata	blunt spikerush	-	E
Isotria medeoloides	small whorled begonia	T	
Lycopodium complanatum	northern running pine	-	E
Polygonum setaceum var interjectum	swamp smartweed	-	E
Polystichum archostichoides	Christmas fern	-	SC
Thelypteris noveboracensis	New York fern	-	SC

Scientific Name	Common Name	Federal Status[a]	State Status[b, c]
Trillium flexipes	nodding trillium	-	E
Trillium sessile	toad-shade	-	E
Trillium spp	trillium	-	SC
a. Reference D-4 b. Reference D-6 c. Reference D-5			

Table D-3
Environmental Authorizations for Current JAFNPP Operations

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
DOT	49 CFR 107, Subpart G	Hazardous Materials Certificate of Registration	060704551044 MN	June 30, 2006	Radioactive and hazardous materials shipments.
NRC	Atomic Energy Act, 10 CFR 50	License to operate	DPR-59	October 17, 2014	Operation of JAFNPP.
NYSDEC	6 NYCRR Part 201	Certificate to Operate an Air Contamination Source	7-3556-0020/ 00012	Not Applicable	Operation of air emission sources (diesel generators, diesel fire pumps, and boilers).
NYSDEC	6 NYCRR Part 372	Hazardous Waste Generator Identification	NYD00076507 3	Not Applicable	Hazardous waste generation
NYSDEC	6 NYCRR Part 675	Water Withdrawal Registration	NYGLWR-4004	November 20, 2006	Withdraw water from Lake Ontario.
NYSDEC	6 NYCRR Part 596	Hazardous Substance Bulk Storage Registration Certificate	7-000117	August 16, 2006	Onsite bulk storage of hazardous substances.
NYSDEC	6 NYCRR Part 750	State Pollutant Discharge Elimination System (SPDES) Permit	NY-0020109	August 1, 2006	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 613	Petroleum Bulk Storage Registration Certificate	7-140600	November 20, 2010	Onsite bulk storage of petroleum products.

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NYSDEC	6 NYCRR Part 750	Hazardous Waste Interim Status Authorization	NY000765073	Not Applicable	Accumulation and temporary storage onsite of mixed waste for >90 days.
NYSDEC	6 NYCRR Part 325	Pesticide Application Business Registration	79632	July 31, 2008	Pesticide application.
CVDEM	Title 44, Code of Virginia, Chapter 3.3, Section 44-146.30	Application for Registration to Transport Hazardous Radioactive Materials	EF-S0083107	August 31, 2007	Transportation of radioactive waste into the Commonwealth of Virginia
SCDHEC	Act No.429 of 1980, South Carolina Radioactive Waste Transportation and Disposal Act	South Carolina Radioactive Waste Transport Permit	0031-31-06	December 31, 2006	Transportation of radioactive waste into the State of South Carolina
TDEC	Tennessee Department of Environment and Conservation Regulations	Tennessee Radioactive Waste-License-for-Delivery	T-NY003-L06	December 31, 2006	Shipment of radioactive material into Tennessee to a disposal/processing facility

Table D-4
Environmental Authorizations for James A. Fitzpatrick Nuclear Power Station License Renewal

Agency	Authority	Activity Covered
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 (16 USC 1636)	Requires federal agency issuing a license to consult with USFWS.
New York Natural Heritage Program	Endangered Species Act Section 7 (16 USC 1636)	Requires federal agency issuing a license to consult with FWS.
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. Based on its review of the proposed activity, the state must concur with or object to the applicant's certification.
New York State Department of Environmental Conservation	Clean Water Act, Section 401 (33 USC 1341)	Requires New York certification that discharge would comply with CWA standards.

Attachment E

Severe Accident Mitigation Alternatives Analysis

Attachment E contains the following sections:

E.1 – Evaluation of PSA Model

E.2 – Evaluation of SAMA Candidates

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ATTACHMENT E.1

EVALUATION OF PSA MODEL

E.1 EVALUATION OF PROBABILISTIC SAFETY ANALYSIS MODEL

The severe accident risk was estimated using the Probabilistic Safety Analysis (PSA) model and a Level 3 model developed using the MACCS2 code. The CAFTA code was used to develop the James A. FitzPatrick Nuclear Power Plant (JAFNPP) PSA Level 1 and Level 2 models. This section provides the description of JAFNPP PSA levels 1, 2, 3 analyses, Core Damage Frequency (CDF) uncertainty, Individual Plant Examination of External Events (IPEEE) analyses, and PSA model peer review.

E.1.1 PSA Model – Level 1 Analysis

The PSA model (Level 1 and Level 2) used for the SAMA analysis was the most recent internal events risk model for JAFNPP (Revision 2, October 2004) [Reference E.1-1]. This model is an updated version of the model used in the 1991 IPE and reflects the JAFNPP configuration and design as of December 2003. It uses component failure and unavailability data as of December 2002 and resolves all findings and observations from the industry peer review of the model conducted in December 1997. The JAFNPP model adopts the small event tree/large fault tree approach and uses the CAFTA code for quantifying CDF.

The PSA model has been updated twice since the original IPE due to the following.

- Equipment performance – As data collection progresses, estimated failure rates and system unavailability data change.
- Plant configuration changes – Plant configuration changes are incorporated into the PSA model.
- Modeling changes – The PSA model is refined to incorporate the latest state of knowledge and recommendations from internal and industry peer reviews.

The PSA model contains the major initiators leading to core damage with baseline CDFs listed in Table E.1-1.

The JAFNPP Revision 2 PSA model was reviewed to identify those potential risk contributors that made a significant contribution to CDF. CDF-based Risk Reduction Worth (RRW) rankings were reviewed down to 1.005. Events below this point would influence the CDF by less than 0.5% and are judged to be highly unlikely contributors for the identification of cost-beneficial enhancements. These basic events, including component failures, operator actions, and initiating events, were reviewed to determine if additional SAMA actions may need to be considered.

Table E.1-2 provides a correlation between the Level 1 RRW risk significant events (component failures, operator actions, and initiating events) down to 1.005 identified from the JAFNPP PSA model and the SAMAs evaluated in Section E.2.

Table E.1-1
JAFNPP PSA Model CDF Results by Major Initiators

Accident Type	Point Estimate Core Damage Frequency (/ry) [1]	% Contribution to Point Estimate Core Damage Frequency
Station blackout	1.35×10^{-6}	43
Transients with loss of containment heat removal	1.03×10^{-6}	33
Transients with loss of all ECCS injection	2.92×10^{-7}	9
ATWS	1.42×10^{-7}	5
Loss of a 4.16kv AC safeguard bus	1.24×10^{-7}	4
Loss of both DC divisions	9.58×10^{-8}	3
LOCAs	2.83×10^{-8}	1
Loss of a division of DC power	2.61×10^{-8}	1
Relay room flooding	2.50×10^{-8}	1

1. The combined master cutsets, which derive the point-estimate CDF, have been subsumed from the contributions of these individual event categories, making the baseline CDF lower than the sum of the above sequence frequencies.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
IE-T1	3.50E-02	2.316	Loss of offsite power	This term represents the loss of offsite power initiating event. Industry efforts over the last twenty years have led to a significant reduction in plant scrams from all causes. Improvements to enhance offsite power availability and coping with SBO events including burying T2 offsite power cable, cross-tying diesel fuel oil supply lines, cross-tying AC buses, and adding additional diesel generators have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
NR-LOSP-7HR	7.40E-02	1.796	Non-recovery of offsite power in 7 hours	This term represents operator failure to recover offsite power within 7 hours. Phase I SAMAs to improve SBO procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
NVP-XHE-FO-LVENT	6.50E-03	1.213	Operator fails to initiate local containment vent	This term represents operator failure to recognize the need to vent the torus locally for pressure reduction during loss of containment heat removal accident sequences. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 057, to control containment venting within a narrow pressure band to prevent rapid containment depressurization during venting, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
EDG-ENG-FR-EDGAR	4.84E-02	1.127	EDG A fails to continue to run	This term represents random failure of EDG A. A Phase I SAMA to improve availability of the EDGs by cross-tying diesel fuel oil supply lines has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-ENG-FR-EDGBR	4.84E-02	1.117	EDG B fails to continue to run	This term represents random failure of EDG B. A Phase I SAMA to improve availability of the EDGs by cross-tying diesel fuel oil supply lines has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
RSW-MAI-MA-LOOPB	3.23E-02	1.113	RHRSW loop B out for maintenance	This term represents RHRSW loop B unavailable due to maintenance, leading to loss of cooling to RHR heat exchanger B and loss of injection from RHRSW loop B. Phase II SAMAs 058 and 059, to improve RHRSW system availability by providing a cross-tie between RHRSW pump discharge trains and by providing a means to cool RHR heat exchanger B with fire water, were evaluated.
EDG-ENG-FR-EDGCR	4.84E-02	1.112	EDG C fails to continue to run	This term represents random failure of EDG C. A Phase I SAMA to improve availability of the EDGs by cross-tying diesel fuel oil supply lines has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
IE-T2	1.85E-01	1.111	Loss of PCS transients	This term represents an initiating event caused by a transient with PCS unavailable. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. A Phase I SAMA to enhance reliability of SRVs and MSIVs by upgrading pneumatic components has been implemented. Phase II SAMA 039, to further improve MSIV design and mitigate the consequences of this event, was evaluated.
IE-T3A	2.61E+00	1.098	Transients with condenser initially available	This term represents an initiating event caused by a transient with PCS available. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. Phase II SAMAs 040 and 043, to further improve motor driven feedwater pump design and mitigate the consequences of this event, were evaluated.
SPC-XHE-FO-W1	1.40E-04	1.083	Operator fails to align suppression pool cooling mode of RHR	This term represents operator failure to align the suppression pool cooling mode of RHR for containment pressure reduction. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
EDG-ENG-FR-EDGDR	4.84E-02	1.079	EDG D fails to continue to run	This term represents random failure of EDG D. A Phase I SAMA to improve availability of the EDGs by cross-tying diesel fuel oil supply lines has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
ADS-XHE-FO-X1T2	3.60E-04	1.078	Operator fails to perform emergency depressurization (transient)	This term represents operator failure to manually open the SRVs for depressurization during transients. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
ESW-MAI-MA-LOOPB	2.20E-02	1.073	ESW loop B out for maintenance	This term represents ESW loop B unavailable due to maintenance, leading to loss of jacket cooling to EDGs B and D from ESW loop B. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.
ESW-RCK-NO-102A	2.50E-03	1.070	ESW 46MOV-102A control circuit failure	This term represents random failure of the ESW loop A valve to close, leading to loss of jacket cooling to EDGs A and C from ESW loop A. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.
RSW-RCK-NO-MV89A	2.50E-03	1.058	RHRSW 10MOV-89A control circuit failure	This term represents random failure of the RHRSW loop A discharge valve, leading to loss of cooling to RHR heat exchanger A. A Phase I SAMA to improve ability to cool RHR heat exchanger A by cross-tying fire water to RHRSW loop A has already been implemented. Phase II SAMA 059, to improve RHRSW system availability by providing a cross-tie between RHRSW discharge trains, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
C	5.80E-06	1.057	RPS failure	This term represents failure of the reactor protection system. Improvements to minimize the risks associated with ATWS scenarios including a SLC pump discharge line cross-tie, alternate rod insertion instrumentation, and alternate boron injection through the CRD system have already been implemented. No Phase II SAMAs were evaluated to further improve reliability of RPS. However, Phase II SAMA 053, to enhance reliability of the standby liquid control system to mitigate the consequences of an ATWS event, was evaluated.
ESW-CCF-OO-102AB	5.19E-05	1.056	ESW 46MOV-102A and B common cause failure	This term represents common cause failure of ESW loop A and B valves to close, leading to loss of jacket cooling to EDGs A, B, C, and D from the ESW system. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.
EDG-MAI-MA-EDGDM	3.50E-02	1.049	EDG D out for maintenance	This term represents EDG D out for maintenance. Phase I SAMAs to improve availability of the EDGs by maintaining proper fuel level in each day tank and providing backup source for diesel generator cooling have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
IE-TAC5	1.05E-03	1.046	Transient caused by loss of 4160VAC bus 10500	This term represents an initiating event caused by loss of 4.16kv bus 10500. Phase I SAMAs to proceduralize repair or replacement of failed 4.16kv breakers have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-CCF-FS-4EDGS	4.16E-05	1.044	Common cause failure of EDGs A, B, C, and D to start	This term represents common cause failure of four EDGs. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
HCI-MAI-MA-HPCIU	3.10E-02	1.043	HPCI unavailable due to maintenance	This term represents HPCI system unavailable due to maintenance. Phase I SAMAs to improve availability and reliability of the HPCI system that have already been implemented include raising backpressure trip set points and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 044, 045, 046, 047, 048, and 049.
ESW-RCK-NO-102B	2.50E-03	1.041	ESW 46MOV-102B control circuit failure	This term represents random failure of the ESW loop B valve to close, leading to loss of jacket cooling to EDGs B and D from ESW loop B. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
EDG-CCF-FR-ABC	2.36E-04	1.036	Common cause failure of EDGs A, B, and C to run	This term represents common cause failure of three EDGs. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
EDG-MAI-MA-EDGBM	1.82E-02	1.036	EDG B out for maintenance	This term represents EDG B out for maintenance. Phase I SAMAs to improve availability of the EDGs by maintaining proper fuel level in each day tank and providing backup source for diesel generator cooling have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
IE-TDC-CCF	9.55E-07	1.036	Common cause failure of 125VDC battery control boards 71BCB-2A and 71 BCB-2B	This term represents an initiating event caused by loss of 125VDC battery control boards 71BCB-2A and 71BCB-2B or random failure of batteries SB-1 and SB-2. Phase II SAMAs 026, 027, 028, 029, 030, 032, 033, 034, 035, and 036, for enhancing DC system availability and reliability, were evaluated.
NR-FPS-ESWA	1.30E-01	1.036	Operator fails to align fire protection system cross-tie to ESW loop A	This term represents operator failure to align the fire protection system cross-tie to ESW loop A. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
IE-T3C	4.70E-02	1.035	Transient caused by inadvertently opened relief valve	This term represents an initiating event caused by inadvertent opening of a relief valve. A Phase I SAMA to enhance reliability of SRVs and MSIVs by upgrading pneumatic components has been implemented. Improvement of SRV reseat reliability, to reduce the probability and consequences of this initiating event, was evaluated in Phase II SAMA 051.
RHR-MAI-MA-LOOPA	5.47E-03	1.031	RHR loop A unavailable due to maintenance	This term represents RHR loop A unavailable due to maintenance, leading to loop A RHR suppression pool cooling and drywell spray modes being unavailable for containment pressure reduction. Phase I SAMAs have already been implemented to use firewater for drywell spray and to use containment venting to reduce containment pressure. Phase II SAMAs 002, 010, 015, 058, and 059, to provide alternate means of suppression pool cooling and drywell spray and to enhance the availability and reliability of firewater for reactor vessel injection and drywell spray, were evaluated.
NVP-XHE-FO-RVENT	1.90E-03	1.027	Operator fails to initiate remote containment vent	This term represents operator failure to recognize the need to vent the torus remotely from relay panel for pressure reduction during loss of containment heat removal accident sequences. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 057, to control containment venting within a narrow pressure band to prevent rapid containment depressurization during venting, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
ESW-MAI-MA-LOOPA	7.38E-03	1.026	ESW loop A out for maintenance	This term represents ESW loop A unavailable due to maintenance, leading to loss of jacket cooling to EDGs A and C from ESW loop A. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.
EDG-CCF-FR-ABD	2.36E-04	1.023	Common cause failure of EDGs A, B, and D to run	This term represents common cause failure of three EDGs. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
EDG-CCF-FR-ACD	2.36E-04	1.023	Common cause failure of EDGs A, C, and D to run	This term represents common cause failure of three EDGs. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
IE-TAC6	1.05E-03	1.022	Transient caused by loss of 4160VAC bus 10300	This term represents an initiating event caused by loss of 4.16kv bus 10600. Phase I SAMAs to proceduralize repair or replacement of failed 4.16kv breakers have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
AC4-XHE-MC-UVRLA	8.00E-04	1.021	Miscalibration of 4.16kv bus 10500 under voltage relay	This term represents pre-accident human failure to properly calibrate the 4.16kv bus 10500 under voltage relay, leading to loss of 4.16kv bus 10500. Phase I SAMAs to improve AC bus cross-tie capability and proceduralize repair or replacement of failed 4.16kv breakers have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-CCF-FR-BCD	2.36E-04	1.020	Common cause failure of EDGs B, C, and D to run	This term represents common cause failure of three EDGs. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
NVP-AOV-CC-117	1.00E-03	1.020	27AOV-117 fails to open on demand	This term represents random failure of wetwell vent valve 27AOV-117 to open on demand, resulting in loss of containment venting capability to control containment pressure. Phase II SAMAs 002, 010, 015, 058, and 059, to provide alternate means of suppression pool cooling and drywell spray and to enhance the availability and reliability of firewater for reactor vessel injection and drywell spray, were evaluated.
NVP-AOV-CC-118	1.00E-03	1.020	27AOV-118 fails to open on demand	This term represents random failure of wetwell vent valve 27AOV-118 to open on demand, resulting in loss of containment venting capability to control containment pressure. Phase II SAMAs 002, 010, 015, 058, and 059, to provide alternate means of suppression pool cooling and drywell spray and to enhance the availability and reliability of firewater for reactor vessel injection and drywell spray, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
ADS-CCF-CC-10SRV	9.63E-05	1.019	Common cause failure of 10 SRVs to open on demand	This term represents common cause failure of ten SRVs to open on demand for over pressure protection during ATWS events. Phase I SAMAs to enhance reliability of SRVs by upgrading pneumatic components and by adding electrical signals to open them automatically have been implemented. No Phase II SAMAs were recommended for this subject.
SLC-XHE-FO-ISLCS	9.00E-03	1.019	Operator fails to initiate SLC system during ATWS	This term represents operator failure to initiate the standby liquid control system during ATWS. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
RSW-RCK-NO-MV89B	2.50E-03	1.018	RHRSW 10MOV-89B control circuit failure	This term represents random failure of the RHRSW loop B discharge valve, leading to loss of cooling to RHR heat exchanger B. Phase II SAMAs 058 and 059, to improve RHRSW system availability by providing a cross-tie between RHRSW pump discharge trains and by providing a means to cool RHR heat exchanger B with fire water, were evaluated.
ESW-SBR-DN-EP2A	3.00E-03	1.017	ESW pump 46P-2A circuit breaker 12510 fails to close	This term represents random failure of ESW pump 46P-2A circuit breaker 12510 to close, leading to loss of jacket cooling to EDGs A and C from ESW loop A. Phase I SAMAs to revise procedures to repair or replace failed circuit breakers and to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
NR-LOSP-4HR	1.45E-01	1.016	Non-recovery of offsite power in 4 hours	This term represents operator failure to recover offsite power within 4 hours. Phase I SAMAs to improve SBO procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
RCI-MAI-MA-RCITM	1.11E-02	1.016	RCIC unavailable due to maintenance	This term represents RCIC system unavailable due to maintenance. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include raising backpressure trip set points and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 044, 045, 046, 047, 048, and 049.
ADS-XHE-FO-X2	2.60E-03	1.015	Operator fails to perform emergency depressurization during ATWS	This term represents operator failure to manually open the SRVs for depressurization during ATWS. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
DC-SHED	2.20E-02	1.015	Operator fails to shed DC load during SBO event	This term represents operator failure to shed DC loads during an SBO event. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
IE-TDCA	3.453E-04	1.015	Transient caused by loss of battery control board 71BCB-2A	This term represents an initiating event caused by loss of 125VDC battery control board 71BCB-2A. Phase II SAMAs 026, 027, 028, 029, 030, 032, 033, 034, 035, and 036, for enhancing DC system availability and reliability, were evaluated.
IE-TRWL	9.30E-03	1.015	Transient caused by loss of instrument reference leg	This term represents an initiating event caused by loss of the reactor vessel level instrumentation system, leading to loss of feedwater and degraded HPCI and RCIC initiation on low reactor water level. A Phase I SAMA proceduralizing manual initiation of HPCI and RCIC given auto signal faults has been implemented. Phase II SAMA 063, to provide an additional reactor vessel monitoring system, was evaluated.
ESW-RCK-NO-P2A	2.50E-03	1.014	ESW pump 46P-2A control circuit failure	This term represents random failure of ESW pump 46P-2A control circuit, leading to loss of jacket cooling to EDGs A and C from ESW loop A. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.
IE-TAC3	2.63E-03	1.013	Transient caused by loss of 4160VAC bus 10300	This term represents an initiating event caused by loss of 4.16kv bus 10300. Phase I SAMAs to improve 4.16kv bus cross-tie capability and proceduralize repair or replacement of failed 4.16kv breakers have already been implemented. Phase II SAMAs Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

**Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**

Event Name	Probability	RRW	Event Description	Disposition
IE-IAS	4.42E-03	1.013	Transient caused by loss of instrument air system	This term represents an initiating event caused by loss of the instrument air system. A Phase I SAMA to replace station air compressors with a more reliable model has been implemented. Phase II SAMA 050, to provide diesel driven backup power to the air compressors, was evaluated.
RHR-MAI-MA-LOOPB	2.67E-03	1.013	RHR loop B unavailable due to maintenance	This term represents RHR loop B unavailable due to maintenance, leading to loop A RHR suppression pool cooling and drywell spray modes being unavailable for containment pressure reduction. Phase I SAMAs have already been implemented to use firewater for drywell spray and to use containment venting to reduce containment pressure. Phase II SAMAs 002, 010, 015, 058, and 059, to provide alternate means of suppression pool cooling and drywell spray and to enhance the availability and reliability of firewater for reactor vessel injection and drywell spray, were evaluated.
AC4-XHE-MC-UVRLB	8.00E-04	1.012	Miscalibration of 4.16kv bus 10600 under voltage relay	This term represents pre-accident human failure to properly calibrate the 4.16kv bus 10600 under voltage relay, leading to loss of 4.16kv bus 10600. Phase I SAMAs to improve AC bus cross-tie capability and proceduralize repair or replacement of failed 4.16kv breakers have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
NR-FPS-ESWB	3.20E-02	1.012	Operator fails to align fire protection system cross-tie to ESW loop B	This term represents operator failure to align the fire protection system cross-tie to ESW loop B. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
NR-FXT-RHRSW-ST	2.70E-02	1.012	Operator fails to align fire protection system cross-tie to RHRSW for RPV injection	This term represents operator failure to align the fire protection system cross-tie to RHRSW for RPV injection. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
AC4-SBR-DN-10640	3.00E-03	1.010	Circuit breaker 10640 fails to close	This term represents random failure of RHR pump 10P-3D circuit breaker 10640 to close. Phase I SAMAs to proceduralize repair or replacement of failed circuit breakers and align fire water for containment cooling have already been implemented. Phase II SAMAs 002, 010, 015, 058, and 059, to provide alternate means of suppression pool cooling and drywell spray and to enhance the availability and reliability of firewater for reactor vessel injection and drywell spray, were evaluated.
EDG-CCF-FR-4EDGS	7.02E-04	1.010	Common cause failure of EDGs A, B, C, and D to run	This term represents common cause failure of four EDGs. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
AC4-SBR-DN-10312	1.60E-03	1.009	Circuit breaker 10312 fails to close	This term represents random failure of circuit breaker 10312 (bus 10400 to bus 10300) to fast transfer to the reserve transformer 71T-3. A Phase I SAMA to revise procedures to repair or replace failed circuit breakers has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ESW-MOV-OO-102A	3.68E-04	1.009	ESW 46MOV-102A fails to close	This term represents random failure of the ESW loop A valve to close, leading to loss of jacket cooling to EDGs A and C from ESW loop A. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.
ESW-SBR-DN-EP2B	3.00E-03	1.009	ESW pump 46P-2B circuit breaker 12610 fails to close	This term represents random failure of ESW pump 46P-2B circuit breaker 12610 to close, leading to loss of jacket cooling to EDGs B and D from ESW loop B. Phase I SAMAs to proceduralize repair or replacement of failed circuit breakers and to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
IE-RRFLOOD	3.10E-05	1.009	Transient caused by internal flooding in relay room	This term represents an initiating event caused by a flooding event in the relay room. Procedure changes to facilitate restoration of plant control following a fire protection piping rupture inside the relay room have been implemented. A procedure change requiring that a visual check be made of the relay room within 5 minutes of a fire pump starting to ascertain whether a rupture has occurred within the relay room has also been implemented. No Phase II SAMAs were recommended for this subject.
IE-TDCB	3.453E-04	1.009	Transient caused by loss of 125VDC battery control board 71BCB-2B	This term represents an initiating event caused by loss of 125VDC battery control board 71BCB-2B. Phase II SAMAs 026, 027, 028, 029, 030, 032, 033, 034, 035, and 036, for enhancing DC system availability and reliability were evaluated.
NR-RRFLD	8.50E-03	1.009	Non-recovery of relay room flood	This term represents operator failure to restore plant control following a relay room flood. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
ESW-RCK-NO-P2B	2.50E-03	1.008	ESW pump 46P-2B control circuit failure	This term represents random failure of the ESW pump 46P-2B control circuit, leading to loss of jacket cooling to EDGs B and D from ESW loop B. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
FWS-XHE-FO-V1S2	4.00E-02	1.008	Operator fails to align condensate flow during small break LOCA	This term represents operator failure to align condensate flow during a small break LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
IE-T3B	1.15E-01	1.008	Transients caused by loss of feedwater with condenser available	This term represents an initiating event caused by loss of feedwater with the condenser available. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. Phase II SAMA 039, to improve MSIV design and mitigate the consequences of this event, was evaluated.
LCI-RCK-NO-RP-3D	2.50E-03	1.008	RHR pump 10-3D control circuit no output	This term represents random failure of RHR pump 10P-3D. A Phase I SAMA to align fire water for containment cooling has already been implemented. Phase II SAMAs 002, 010, 015, 058, and 059, to provide alternate means of suppression pool cooling and drywell spray and to enhance the availability and reliability of firewater for reactor vessel injection and drywell spray, were evaluated.
TBV-EHC-LOSS	2.00E-03	1.008	Turbine bypass valve and EHC system hardware and logic faults	This term represents random failures of the turbine bypass valve and EHC system hardware and logic. Industry efforts over the last twenty years have led to a significant reduction in failures of the EHC system. Phase II SAMA 060, to improve the availability of the turbine bypass valve, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
AC4-RCS-OO-94EA3	3.00E-04	1.007	Relay 94-1HOEA03 contacts fail to close	This term represents random failure of the control circuit for the tie breakers from EDGs A and C to bus 10500 as well as tripping 71-10514 (the bus tie from 10300 to 10500). A Phase I SAMA to revise procedures to repair or replace failed circuit breakers has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-CCF-FR-EDGAC	3.53E-04	1.007	Common cause failure of EDGs A, and C to run	This term represents common cause failure of two EDGs. A Phase I SAMAs to improve availability of the EDGs cross-tying diesel fuel oil supply lines has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
EDG-ENG-FS-EDGAS	3.65E-03	1.007	EDG A fails to start	This term represents random failure of EDG A. Phase I SAMAs to improve availability of the EDGs by maintaining proper fuel level in each day tank and providing backup source for diesel generator cooling have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
ESW-RCS-OO-A63A9	3.00E-04	1.007	Relay 63A-1ESWAO4 contacts 9-10 fail to close	This term represents random failure of the ESW pump 46P-2A control circuit, leading to loss of jacket cooling to EDGs A and C from ESW loop A. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.
FXT-ENG-FR-76P1	4.80E-02	1.007	Diesel driven fire water pump 76P-1 fails to continue to run	This term represents diesel fire pump 76P-1 failure to run. Phase II SAMA 049, to add a diverse injection system with an injection source other than fire water, was evaluated.
LCI-STR-PG-F-4B	1.08E-03	1.007	ECCS strainer F-4B plugged	This term represents failure of RHR suction strainer F-4B. A Phase I SAMA was implemented to install improved, passive suction strainers. Phase II SAMAs 046, 048, and 049, which recommend addition of independent injection systems to mitigate this failure event, were evaluated.
RCI-RCK-NO-MV131	2.50E-03	1.007	RCIC system steam admission valve 13MOV-131 control circuit failure	This term represents random failure of the RCIC system. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include raising backpressure trip set points and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 044, 045, 046, 047, 048, and 049.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
RCI-RCK-NO-MV132	2.50E-03	1.007	RCIC system lube oil cooler and barometric condenser cooling water supply valve 13MOV-132 control circuit failure	This term represents random failure of the RCIC system. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include raising backpressure trip set points and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 044, 045, 046, 047, 048, and 049.
RCI-RCK-NO-RMV21	2.50E-03	1.007	RCIC system pump discharge valve 13MOV-21 control circuit failure	This term represents random failure of the RCIC system. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include raising backpressure trip set points and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 044, 045, 046, 047, 048, and 049.
ADS-XHE-FO-X1S1	6.60E-03	1.007	Operator fails to perform emergency depressurization during medium LOCA	This term represents operator failure to manually open the SRVs for depressurization during a medium LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
EDG-ENG-FS-EDGBS	3.65E-03	1.006	EDG B fails to start	This term represents random failure of EDG B. Phase I SAMAs to improve availability of the EDGs maintaining proper fuel level in each day tank and providing backup source for diesel generator cooling have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-ENG-FS-EDGCS	3.65E-03	1.006	EDG C fails to start	This term represents random failure of EDG C. Phase I SAMAs to improve availability of the EDGs by maintaining proper fuel level in each day tank and providing backup source for diesel generator cooling have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-MAI-MA-EDGAM	4.52E-03	1.006	EDG A out for maintenance	This term represents EDG A out for maintenance. Phase I SAMAs to improve availability of the EDGs by maintaining proper fuel level in each day tank and providing backup source for diesel generator cooling have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
FPS- MAI-MA-P-4	6.47E-02	1.006	Fire water pump 76P-4 out for maintenance	This term represents fire water pump 76P-4 in maintenance. Phase II SAMA 049, to add a diverse injection system with an injection source other than fire water, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
IAS-MDC-MA-AC1C	2.38E-02	1.006	Instrument air compressor C out for maintenance	This term represents instrument air compressor C out for maintenance. A Phase I SAMA to replace station air compressors with a more reliable model has been implemented. Phase II SAMA 050, to provide diesel driven backup power to the air compressors, was evaluated.
IE-S1	4.00E-05	1.006	Medium LOCA	This term represents the medium LOCA initiating event. Phase I SAMAs have been implemented to provide more reliable or diverse high or low pressure injection systems to mitigate this event. Phase II SAMAs 040, 043, 044, 045, 046, 047, 048, and 049, to reduce the CDF contribution from medium LOCA, were evaluated.
NVP-SOV-FE-117	1.00E-03	1.006	Wetwell vent solenoid valve 27SOV-117 fails to energize	This term represents random failure of wetwell vent valve 27SOV-117 to energize and open on demand, resulting in loss of containment venting. Phase II SAMAs 002, 010, 015, 058, and 059, to provide alternate means of suppression pool cooling and drywell spray and to enhance the availability and reliability of firewater for reactor vessel injection and drywell spray, were evaluated.
NVP-SOV-FE-118	1.00E-03	1.006	Wetwell vent solenoid valve 27SOV-118 fails to energize	This term represents random failure of wetwell vent valve 27SOV-118 to energize and open on demand, resulting in loss of containment venting. Phase II SAMAs 002, 010, 015, 058, and 059, to provide alternate means of suppression pool cooling and drywell spray and to enhance the availability and reliability of firewater for reactor vessel injection and drywell spray, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
RCI-TDP-FR-RCIPM	2.35E-03	1.006	RCIC turbine driven pump fails to continue to run	This term represents random failure of the RCIC system. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include raising backpressure trip set points and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 044, 045, 046, 047, 048, and 049.
RCI-TDP-FS-RCIPM	2.23E-03	1.006	RCIC turbine driven pump fails to start	This term represents random failure of the RCIC system. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include raising backpressure trip set points and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 044, 045, 046, 047, 048, and 049.
RSW-MOV-CC-MV89A	3.31E-04	1.006	RHRSW 10MOV-89A fails to open	This term represents random failure of the RHRSW loop A discharge valve, leading to loss of cooling to RHR heat exchanger A. A Phase I SAMA to improve ability to cool RHR heat exchanger A by cross-tying fire water to RHRSW loop A has already been implemented. Phase II SAMA 059, to improve RHRSW system availability by providing a cross-tie between RHRSW discharge trains, was evaluated.
AC4-PRY-HW-5GEA1	1.15E-04	1.005	Relay 51GS-1HOEA01 failure	This term represents random failure of the control circuit for the tie breaker from bus 10300 to bus 10500. A Phase I SAMA to revise procedures to repair or replace failed circuit breakers has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
AC4-PRY-HW-5HA23	1.15E-04	1.005	Relay 51-1HOEA23 failure	This term represents random failure of the control circuit for the tie breaker from bus 10300 to bus 10500. A Phase I SAMA to revise procedures to repair or replace failed circuit breakers has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AC4-PRY-HW-5HEA1	1.15E-04	1.005	Relay 51-1HOEA01 failure	This term represents random failure of the control circuit for the tie breaker from bus 10300 to bus 10500. A Phase I SAMA to revise procedures to repair or replace failed circuit breakers has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AC4-PRY-HW-67A20	1.15E-04	1.005	Relay 67-1HOEA20 failure	This term represents random failure of the control circuit for the tie breaker from bus 10300 to bus 10500. A Phase I SAMA to revise procedures to repair or replace failed circuit breakers has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
AC4-SBR-DN-10502	3.00E-03	1.005	Circuit breaker 10502 does not operate properly	This term represents random failure of EDG A circuit breaker 10502 to close. A Phase I SAMA to revise procedures to repair or replace failed circuit breakers has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AC4-SBR-DN-10512	3.00E-03	1.005	Circuit breaker 10512 does not operate properly	This term represents random failure of EDG C circuit breaker 10512 to close. A Phase I SAMA to revise procedures to repair or replace failed circuit breakers has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AC4-SBR-DN-10602	3.00E-03	1.005	Circuit breaker 10602 does not operate properly	This term represents random failure of EDG B circuit breaker 10602 to close. A Phase I SAMA to revise procedures to repair or replace failed circuit breakers has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
DGV-MOD-CC-D143A	3.00E-03	1.005	EDG building damper 92MOD-143A fails to open on demand	This term represents random failure of EDG building damper 92MOD-143A to open on demand, leading to failure of EDG A. A Phase I SAMA, to install a high temperature alarm in EDG building A has already been implemented. Phase II SAMA 062, to proceduralize opening the door of EDG building A upon receipt of a high temperature alarm, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
DGV-MOD-CC-D143B	3.00E-03	1.005	EDG building damper 92MOD-143B fails to open on demand	This term represents random failure of EDG building damper 92MOD-143B to open on demand, leading to failure of EDG B. A Phase I SAMA to install a high temperature alarm in EDG building B has already been implemented. Phase II SAMA 062, to proceduralize opening the door of EDG building B upon receipt of a high temperature alarm, was evaluated.
DGV-MOD-CC-D143C	3.00E-03	1.005	EDG building damper 92MOD-143C fails to open on demand	This term represents random failure of EDG building damper 92MOD-143C to open on demand, leading to failure of EDG C. A Phase I SAMA to install a high temperature alarm in EDG building C has already been implemented. Phase II SAMA 062, to proceduralize opening the door of EDG building C upon receipt of a high temperature alarm, was evaluated.
DGV-MOD-CC-D149A	3.00E-03	1.005	EDG building damper 92MOD-149A fails to open on demand	This term represents random failure of EDG building damper 92MOD-149A to open on demand, leading to failure of EDG A. A Phase I SAMA to install a high temperature alarm in EDG building A has already been implemented. Phase II SAMA 062, to proceduralize opening the door of EDG building A upon receipt of a high temperature alarm, was evaluated.
DGV-MOD-CC-D149B	3.00E-03	1.005	EDG building damper 92MOD-149B fails to open on demand	This term represents random failure of EDG building damper 92MOD-149B to open on demand, leading to failure of EDG B. A Phase I SAMA to install a high temperature alarm in EDG building B has already been implemented. Phase II SAMA 062, to proceduralize opening the door of EDG building B upon receipt of a high temperature alarm, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
DGV-MOD-CC-D149C	3.00E-03	1.005	EDG building damper 92MOD-149C fails to open on demand	This term represents random failure of EDG building damper 92MOD-149C to open on demand, leading to failure of EDG C. A Phase I SAMA to install a high temperature alarm in EDG building C has already been implemented. Phase II SAMA 062, to proceduralize opening the door of EDG building C upon receipt of a high temperature alarm, was evaluated.
EDG-CCF-FR-EDGBD	3.53E-04	1.005	Common cause failure of EDGs B and D to run	This term represents common cause failure of two EDGs. A Phase I SAMA to improve availability of the EDGs by cross-tying diesel fuel oil supply lines has already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
EDG-ENG-FS-EDGDS	3.65E-03	1.005	EDG D fails to start	This term represents random failure of EDG D. Phase I SAMAs to improve availability of the EDGs by maintaining proper fuel level in each day tank and providing backup source for diesel generator cooling have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ESW-MOV-OO-102B	3.68E-04	1.005	ESW 46MOV-102B fails to close	This term represents random failure of the ESW loop B valve to close, leading to loss of jacket cooling to EDGs B and D from ESW loop B. Phase I SAMAs to use fire water for diesel cooling have already been implemented. Phase II SAMA 001, to improve ESW system availability by providing an additional service water pump, was evaluated.

Table E.1-2 (Continued)
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
IAS-MDC-MA-AC1A	3.91E-02	1.005	Instrument air compressor A out for maintenance	This term represents instrument air compressor A out for maintenance. A Phase I SAMA to replace station air compressors with a more reliable model has been implemented. Phase II SAMA 050, to provide diesel driven backup power to the air compressors, was evaluated.
LCI-XHE-RE-RM3DP	1.64E-03	1.005	Operator fails to restore RHR pump 10-P3D path components after testing and maintenance	This term represents pre-accident human failure to restore RHR pump 10P-3D after testing and maintenance. A Phase I SAMA to align fire water for containment cooling has already been implemented. Phase II SAMAs 002, 010, 015, 058, and 059, to provide alternate means of suppression pool cooling and drywell spray and to enhance the availability and reliability of firewater for reactor vessel injection and drywell spray, were evaluated.
RSW-CCF-FS-2MDPA	1.30E-04	1.005	Common cause failure of two RHRSW A pumps to start	This term represents common cause failure of the RHRSW loop A pumps to start, leading to loss of cooling to RHR heat exchanger A. A Phase I SAMA to improve ability to cool RHR heat exchanger A by cross-tying fire water to RHRSW loop A has already been implemented. Phase II SAMA 059, to improve RHRSW system availability by providing a cross-tie between RHRSW discharge trains, was evaluated.

CDF Uncertainty

The uncertainty associated with CDF was estimated using Monte Carlo techniques implemented in CAFTA for the base case mode. The results are shown in Table E.1-3.

Table E.1-3
Core Damage Frequency Uncertainty

Confidence	CDF (/ry)
Mean value	3.70E-6
5^{th} percentile	9.29E-7
50^{th} percentile	1.90E-6
95^{th} percentile	1.05E-5

The values in Table E.1-3 reflect the uncertainties associated with the data distributions used in the analysis. The ratio of the 95^{th} percentile to the mean is about 3.83. This uncertainty factor is included in the factor of 16 used to determine the **upper bound estimated benefit** described in Section 4.21.5.4.

E.1.2 PSA Model – Level 2 Analysis

E.1.2.1 Containment Performance Analysis

The JAFNPP Level 2 PSA model used for the SAMA analysis is the most recent internal events risk model, which is an updated version of the model used in the IPE. The Level 2 PSA model used for the SAMA analysis (JAFNPP Revision 2) reflects the JAFNPP operating configuration and design as of December 2003. Specifically, the Level 2 model has been updated to incorporate insights from the independent BWROG peer review.

The JAFNPP Level 2 model includes two types of considerations: (1) a deterministic analysis of the physical processes for a spectrum of severe accident progressions, and (2) a probabilistic analysis component in which the likelihood of the various outcomes are assessed. The deterministic analysis examines the response of the containment to the physical processes during a severe accident. This response is performed by

- utilization of the MAAP code [Reference E.1-2] to simulate severe accidents that have been identified as dominant contributors to core damage in the Level 1 analysis, and

- reference calculation of several hydrodynamic and heat transfer phenomena that occur during the progression of severe accidents. Examples include debris coolability, pressure spikes due to ex-vessel steam explosions, scoping calculation of direct containment heating, molten debris filling the pedestal sump and flowing over the drywell floor, containment bypass, deflagration and detonation of hydrogen, thrust forces at reactor vessel failure, liner melt-through, and thermal attack of containment penetrations.

The Level 2 analysis examined the dominant accident sequences and the resulting plant damage states (PDS) defined in Level 1. The Level 1 analysis involves the assessment of those scenarios that could lead to core damage. A list of the PDS groups and descriptions from the Level 2 analysis is presented in Table E.1-4.

A full Level 2 model was developed for the IPE and completed at the same time as the Level 1 model. The Level 2 model consists of a single containment event tree (CET) with functional nodes that represent phenomenological events and containment protection system status. The nodes were quantified using subordinate trees and logic rules. A list of the CET functional nodes and descriptions used for the Level 2 analysis is presented in Table E.1-5.

The Large Early Release Frequency (LERF) is an indicator of containment performance from the Level 2 results because the magnitude and timing of these releases provide the greatest potential for early health effects to the public. The frequency calculated is approximately 9.20E-8/ry. Figure E.1-1 and Figure E.1-2 summarize the Level 2 results.

LERF represents a small fraction (3.35%) of all release end states. Six types of accidents dominate the internal large early release: station blackout (SBO), interfacing system loss of coolant accidents (ISLOCA), anticipated transient without scram (ATWS), transients, vessel rupture events, and loss of coolant accidents (LOCA).

Table E.1-6 provides a correlation between the Level 2 RRW risk significant events (severe accident phenomenon, initiating events, component failures, and operator actions) down to 1.005 identified from the JAFNPP Revision 2 PSA LERF model and the SAMAs evaluated in Section E.2.

Table E.1-4
Summary of JAFNPP PSA Plant Damage State Groups

PDS Group	Simplified Description	Point Estimate Frequency /ry	% of Total Core Damage Frequency	Plant Damage States
Loss of Coolant Accident (LOCAs)	Large and small break LOCA with initial or long-term loss of core cooling. Core damage results at low or high reactor pressure. For most plant damage states, late injection and containment heat removal are available.	1.78×10^{-8}	0.65	3, 4, 7, 8, 9, 10, and 11

Table E.1-4
Summary of JAFNPP PSA Plant Damage State Groups

PDS Group	Simplified Description	Point Estimate Frequency /ry	% of Total Core Damage Frequency	Plant Damage States
Transient (TRANS)	Short and long-term transient events. Core damage results at either low or high reactor pressure. Late injection and containment heat removal are available.	3.54×10^{-7}	12.9	14, 15, 16, 17, 20, 21, 22, 23, 24, 25, 26, 27, and 28
Station Blackout (SBO)	SBO involving a loss of high-pressure injection. Core damage results at either low (stuck-open SRV) or high reactor pressure. All accident mitigating functions are recoverable when AC power is restored.	1.30×10^{-6}	47.3	29, 30, 31, and 32
Vessel Rupture (VSL_RUPT)	Vessel rupture event resulting in LOCA beyond ECCS capability. All plant damage states result in core damage at low reactor pressure with late injection available.	1.00×10^{-8}	0.364	33, 34, 35, and 36
Anticipated Transient Without Scram (ATWS)	Short-term ATWS that leads to early core damage at high reactor pressure following loss of reactivity control and rapid containment pressurization. Reactor coolant system leakage rates associated with boil-off of coolant through the cycling of SRVs with early core melt subsequent to containment overpressure failure. Late injection and containment heat removal are available.	1.52×10^{-7}	5.52	37, 38, 39, 41, 42, 45, and 46
Interfacing System LOCA (ISLOCA)	Large and small break interfacing system LOCA outside containment. Core damage results at low or high reactor pressure with a bypassed containment.	2.58×10^{-8}	0.940	47 and 48

Table E.1-4
Summary of JAFNPP PSA Plant Damage State Groups

PDS Group	Simplified Description	Point Estimate Frequency /ry	% of Total Core Damage Frequency	Plant Damage States
Loss of Containment Heat Removal (TW)	Containment decay heat removal systems are not available and coolant recirculation to the torus overpressurizes the containment to failure or venting. The torus is saturated.	8.90×10^{-7}	32.4	1, 2, 5, 6, 12, 13, 18, 19, 40, 43, and 44

Table E.1-5
Notation and Definitions for JAFNPP CET Functional Nodes Description

CET Node	CET Functional Node Description
Plant Damage State Event (PDS_EVNT)	This top event represents the initiators considered in the containment performance analysis.
RPV Pressure at Vessel Failure (RPV@VF)	This top event identifies the status of the reactor pressure vessel (RPV) pressure. RPV@VF is set to success when RPV pressure is low. RPV@VF is set to failure when RPV is high.
In-vessel Cooling Recovery (IN-REC)	This top event addresses the recovery of coolant injection into the vessel after core degradation, but prior to vessel breach. This top event considers the possibility of low-pressure injection systems working once the RPV is depressurized.
Vessel Failure (VF)	This top event addresses recovery from core degradation within the vessel and the prevention of vessel head thermal attack. Core melt recovery requires the recovery of core cooling prior to core blocking or relocation of molten debris to the lower plenum and thermal attack of the vessel head.
Early Containment Failure (CFE)	This top event node considers the potential loss of containment integrity at, or before, vessel failure. Several phenomena are considered credible mechanisms for early containment failure. They may occur alone or in combination. The phenomena are containment isolation failure; containment bypass; containment overpressure failure at vessel breach; hydrogen deflagration or detonation; fuel-coolant interactions (steam explosions); high pressure melt ejection and subsequent direct containment heating; and drywell steel shell melt-through.

Table E.1-5
Notation and Definitions for JAFNPP CET Functional Nodes Description

CET Node	CET Functional Node Description
Early Release to Torus (EPOOL)	This top event node considers the importance of early torus pool scrubbing in mitigating the magnitude of fission products released from the damaged core. Success implies that fission product transport path subsequent to early containment failure is through the torus water and the torus airspace. That is, the torus pool is not bypassed. Failure involves a release into the drywell.
Debris Cooled Ex-vessel (DCOOL)	This top event considers the delivery of water to the drywell, via drywell sprays, or via injection to the RPV and drainage out an RPV breach onto the drywell floor. Success implies the availability of water and the formation of a coolable debris bed such that concrete attack is precluded. Failure implies that the molten core attacks concrete in the reactor pedestal, that core debris remains hot, and sparing of the concrete decomposition products through the melt releases the less volatile fission products to the containment atmosphere.
Late Containment Failure (CFL)	This top event addresses the potential loss of containment integrity in the long-term. Late containment failure may result from long-term steam and non-condensable gas generation from the attack of molten core debris on concrete.
Late Release to Torus (LPOOL)	This top event node considers the importance of late torus pool scrubbing in mitigating the magnitude of fission products released from the damaged core. Success implies that fission product transport path subsequent to late containment failure is through the torus water and the torus airspace. That is, the torus pool is not bypassed. Failure involves a release into the drywell.
Fission Product Removal (FPR)	This top event addresses fission product releases from the fuel into the containment and airborne fission product removal mechanisms within the containment structure to characterize potential magnitude of fission product releases to the environment should the containment fail. Failure implies that most of the fission products from the fuel and containment are ultimately released to the environment without mitigation.
Reactor Building (RB)	This top event is used to assess the ability of the reactor building to retain fission products released from containment. Success of top event RB is defined to be a reduction of the containment release magnitude.

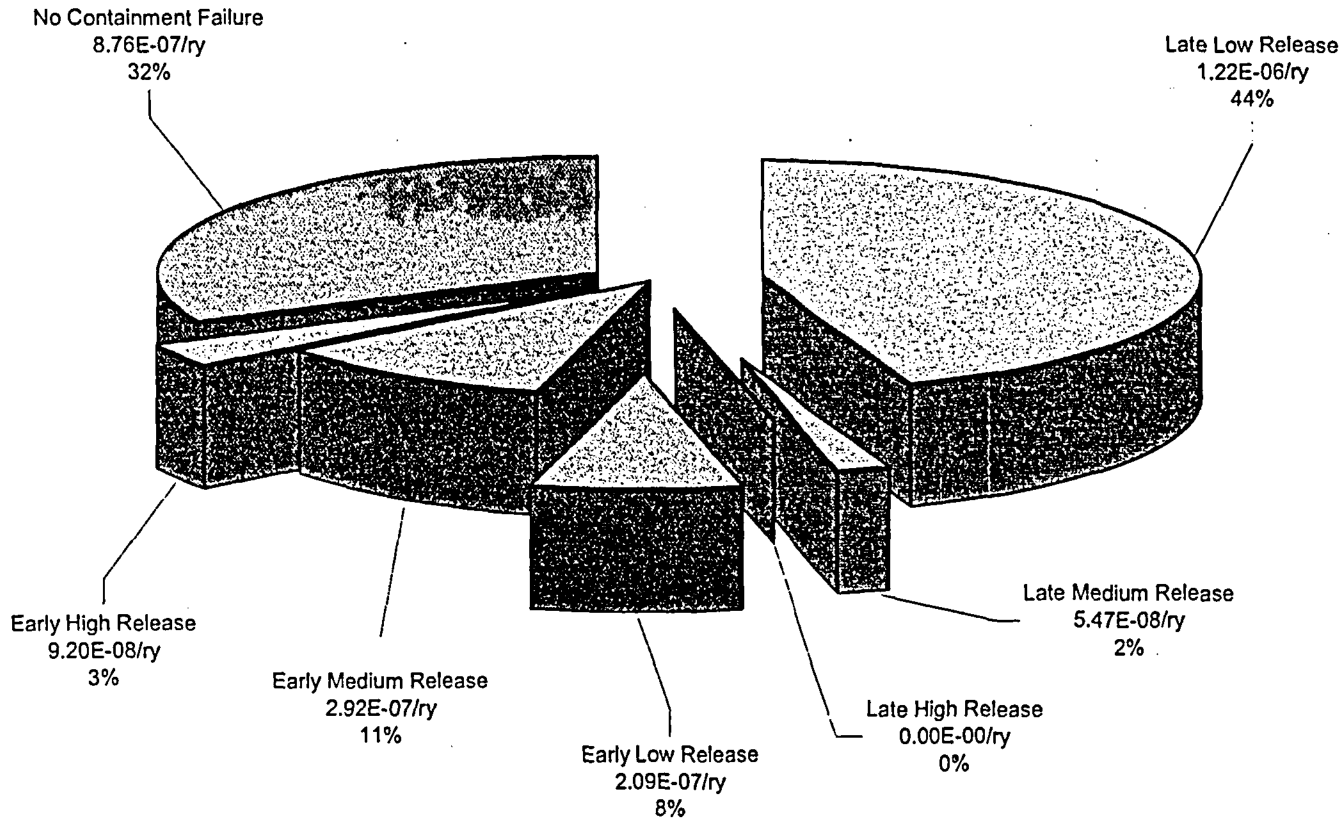

Figure E.1-1
JAFNPP Radionuclide Release Category Summary

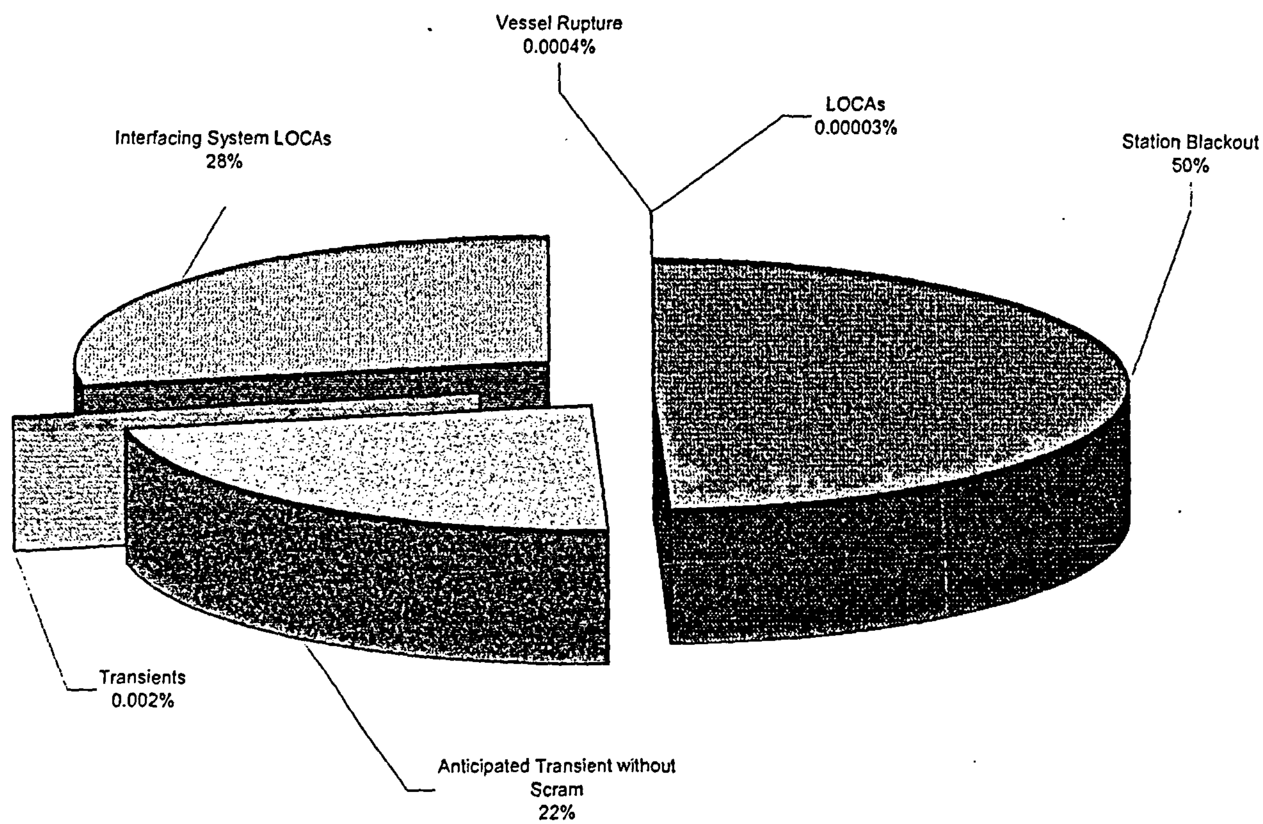

Figure E.1-2
JAFNPP Plant Damage State Contribution to LERF

Table E.1-6
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
CM>20	1.0	119.0	Core melt progression greater than 20%	This term represents the probability that core melt will be greater than 20%. Phase II SAMAs 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.
VF_3	1.0	115.0	Vessel failure occurs given core melt greater than 20% and no in-vessel cooling	This term represents the probability that core debris is not cooled in-vessel and fails the lower head. Phase II SAMA 013 was evaluated to consider the benefit of a reactor vessel exterior cooling system with the potential to cool a molten core before it causes vessel failure.
NAC_POWER_E2	4.90E-01	2.196	AC power not recovered prior to vessel breach in long-term SBO plant damage state	This term represents the probability that AC power will not be recovered between the onset of core damage and vessel breach in long-term SBO scenarios. Phase I SAMAs, including improvement of SBO procedures and training to enhance the likelihood of success of operator action in response to accident conditions, have already been implemented. No additional Phase II SAMAs were recommended for this subject.
PDS-29	1.28E-06	2.196	Long-term SBO plant damage at high RPV pressure	This term represents the plant damage state frequency of a long-term SBO scenario involving loss of injection at high RPV pressure from battery depletion. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
NO_SORV_LATE	5.00E-01	1.462	No SRV sticks open prior to vessel breach-late	This term represents the probability that an SRV remains closed while cycling prior to reactor vessel breach during a long-term accident scenario. Phase I SAMAs to enhance reliability of SRVs by upgrading pneumatic components and by adding electrical signals to open them automatically have been implemented. Therefore, no potentially cost-beneficial SAMAs were postulated to mitigate this event.
DW-PED_FAIL	1.75E-01	1.397	Drywell failure occurs given reactor pedestal failure	This term represents the probability that early drywell failure results from the movement of steam lines, feedwater lines or other fluid lines as a result of pedestal failure and vessel movement. Phase II SAMAs 005, 006, 009, 013, and 024 were evaluated for risk reduction.
NO-QUECH-1	9.99E-01	1.379	No debris quench, given dry pedestal, high RPV pressure, and no late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, given no water on the drywell floor, high RPV pressure at vessel breach, and no late water supply for debris cooling after vessel breach. Phase II SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
LOW_LIQUID_VB-2	9.00E-01	1.326	Small molten debris mass in lower RPV head at high RPV pressure	This term represents the probability of having a small amount of mobile core debris when vessel breach occurs at high pressure. Phase II SAMAs 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
NO_SORV_EARLY	9.00E-01	1.303	No SRV sticks open prior to vessel breach-early	This term represents the probability that an SRV remains closed while cycling prior to reactor vessel breach during a short-term accident scenario. Improvement of SRV reseat reliability, to reduce the probability and consequences of this initiating event, was evaluated in Phase II SAMA 051.
RPV-LOW29-1	7.36E-01	1.297	RPV pressure is low given the occurrence of a long-term SBO at initial high RPV pressure	This term represents the probability that RPV depressurization occurs subsequent to the occurrence of a long-term SBO scenario involving the loss of injection at high RPV pressure from battery depletion. Improvements related to enhancing offsite power availability or reliability and coping with SBO events were already implemented and evaluated during phase I SAMA screening. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events were evaluated.
VF_SIZE_PEN	9.00E-01	1.275	Vessel penetration failure occurs debris thermal attack	This term represents the probability of vessel failure due to a single lower head penetration failure. Phase II SAMA 013 was evaluated to consider the benefit of a reactor vessel exterior cooling system with the potential to cool a molten core before it causes vessel failure.
ADS-SRV-RBENV	6.41E-01	1.249	Adverse reactor building conditions cause SRVs failure	This term represents the probability of SRV/ADS failure after containment rupture due to the harsh environment created inside the reactor building. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
NO_RB-NATURAL_3	9.50E-01	1.246	Natural deposition does not occur given H_2 burn inside reactor building	This term represents the probability of reactor building failure to retain a significant fraction of the radionuclides released from the primary containment following a hydrogen burn in the reactor building. Phase II SAMAs 008 and 022, for mitigating fission product release into the reactor building, were evaluated..
RB-H2_BURN	8.33E-01	1.246	H_2 burn occurs inside reactor building given containment failure	This term represents the probability that hydrogen combustion in the reactor building results in high temperature and high gas flows inside the reactor building following containment failure. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.
NO-QUECH-3D	2.80E-01	1.237	No debris quench, given dry pedestal, high RPV pressure, and late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, given no initial water on the drywell floor, high RPV pressure at vessel breach, and the recovery of late water supply for debris cooling after vessel breach. Phase II SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
WWLAW	4.35E-01	1.236	Torus leakage above water line	This term represents the probability of torus failure above the water line. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.
PDS-47	1.89E-08	1.226	Unisolated LOCA outside containment with early core melt at high RPV pressure.	This term represents the plant damage state frequency of an ISLOCA outside containment with early core melt at high RPV pressure. Phase II SAMAs 037 and 038, to reduce the potential for ISLOCAs, were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
LOW_LIQUID_VB-3	9.00E-01	1.211	Small molten debris mass in lower RPV head at low RPV pressure	This term represents the probability of having a small amount of mobile core debris when vessel breach occurs at low pressure. Phase II SAMAs 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.
NO-QUECH-2	9.99E-01	1.194	No debris quench, given dry pedestal, low RPV pressure, and no late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, given no water on the drywell floor, low RPV pressure at vessel breach, and no late water supply for debris cooling after vessel breach. Phase II SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
NO_RB-NATURAL_1	9.99E-01	1.190	Natural deposition does not occur given large containment failure	This term represents the probability of reactor building failure to retain a significant fraction of the radionuclides released from the primary containment given a large primary containment failure. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated. In addition, SAMAs 008 and 022 for mitigating fission product release into the reactor building were evaluated.
EARLY_SPRAYS-4	1.00E+00	1.188	Drywell sprays operate before RPV failure (non-SBO plant damage states)	This term represents the probability that drywell sprays operate prior to reactor vessel failure for non-SBO plant damage states. Phase II SAMAs 006, 013, and 023 for enhancing coolability ex-vessel were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
PEDESTAL_FAIL-3	3.25E-01	1.172	Pedestal overpressure failure at high RPV and small breach	This term represents the probability that pedestal wall failure due to fuel coolant interactions, or over pressurization from blowdown, occurs given vessel breach at high RPV pressure. Phase II SAMAs 005, 006, 009, 013, and 024 were evaluated for risk reduction.
VF_GROSS	1.00E-01	1.169	Gross lower RPV head failure occurs given core debris thermal attack	This term represents the probability of vessel failure due to global thermally induced creep rupture of the lower head. Phase II SAMA 013 was evaluated to consider the benefit of a reactor vessel exterior cooling system with the potential to cool a molten core before it causes vessel failure.
PDS-45	7.01E-08	1.162	Short-term ATWS with containment failure and early core damage at high RPV pressure	This term represents the plant damage state frequency of a short-term ATWS with early containment failure and early core damage at high primary system pressure because of inadequate reactor water level following a loss of reactivity control. Phase II SAMAs 004, 052, and 053 for enhancing ATWS migration capabilities were evaluated.
LATE_H20-5	9.99E-01	1.157	Late water supply available for debris bed cooling (non-SBO plant damages states with core spray and LPCI failed)	This term represents the probability that late water is not provided to cool core debris ex-vessel for non-SBO plant damage states. Phase II SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
PDS-48	6.95E-09	1.146	Unisolated LOCA outside containment with early core melt at low RPV pressure	This term represents the plant damage state frequency of an ISLOCA outside containment with early core melt at low RPV pressure. Phase II SAMAs 037 and 038, to reduce the potential for ISLOCAs, were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
LATE_H20-3	6.08E-01	1.14	Late water supply available for debris bed cooling (long-term SBO plant damage states)	This term represents the probability that late water is not provided to cool core debris ex-vessel for long-term SBO plant damage states. Phase II SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
NO-QUECH-6D	8.40E-01	1.139	No debris quench given dry pedestal, low RPV pressure, late water supply and low debris superheat	This term represents the probability that debris is not quenched immediately after vessel failure, given no water on the drywell floor, low RPV pressure at vessel breach and late water supply for debris cooling after vessel breach. Phase II SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
DCOOL48-2	9.48E-01	1.136	Debris cooled given plant damage state 48	This term represents the probability that debris coolability does not occur given an ISLOCA outside containment with early core melt at low RPV pressure. Phase II SAMAs 037 and 038, to reduce the potential for ISLOCAs, were evaluated. Also, SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
PEDESTAL_FAIL-4	9.10E-01	1.096	Pedestal overpressure failure at low RPV pressure and large vessel breach	This term represents the probability that pedestal wall failure due to fuel coolant interactions, or over pressurization from blowdown, occurs given low vessel breach. Phase II SAMAs 005, 006, 009, 013, and 024 were evaluated for risk reduction.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
LATE_H20-4	1.00E+00	1.096	Late water supply available for debris bed cooling (Non-SBO ECCS available plant damage states)	This term represents the probability that late water is not provided to cool core debris ex-vessel for non-SBO plant damage states. Phase II SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
RB-SPRAYS	1.00E+00	1.092	Reactor building sprays (fire protection actuation) do not operate	This term represents the probability that reactor building sprays fail to mitigate fission product release into the reactor building. Phase II SAMAs 008 and 022 for mitigating fission product release into the reactor building were evaluated.
DCOOL47-4	7.18E-01	1.089	Debris cooled given PDS-47	This term represents the probability that debris coolability does not occur given an ISLOCA outside containment with early core melt at high RPV pressure. Phase II SAMAs 037 and 038, to reduce the potential for ISLOCAs, were evaluated. Also, SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
DCH_OCCURS	5.00E-01	1.082	DCH occurs given HPME phenomena	This term represents the probability that direct containment heating occurs, given that high pressure melt ejection has occurred previously. Phase II SAMAs 007 and 021, to provide a means for flooding the drywell head seal, and Phase II SAMA 019, to increase the temperature margin for drywell head seals such that if high drywell temperatures occur, the drywell head seal does not fail, were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
HPME_1	8.00E-01	1.082	High pressure melt ejection occurs with high pressure	This term represents the probability that high pressure melt ejection occurs at high reactor pressure vessel pressure. Phase II SAMAs 007 and 021, to provide a means for flooding the drywell head seal, and Phase II SAMA 019, to increase the temperature margin for drywell head seals such that if high drywell temperatures occur, the drywell head seal does not fail, were evaluated.
CFE@VF_5	7.90E-02	1.076	Drywell failure – given DW pressure less than 30 psig, wet pedestal cavity, and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given drywell pressure less than 30 psig, water on the drywell floor and direct containment heating. Phase II SAMAs 011, 014, 016, and 017 for enhancing containment integrity were evaluated. In addition, Phase II SAMA 013, addition of a reactor vessel exterior cooling system with the potential to cool a molten core before it causes vessel failure, was evaluated.
RPV-LOW47-1	3.84E-01	1.075	RPV pressure is low given PDS-47	This term represents the probability that RPV depressurization occurs subsequent to the occurrence of an ISLOCA outside containment with early core melt at high RPV pressure. Phase II SAMAs Phase II SAMAs 037 and 038, to reduce the potential for ISLOCAs, was evaluated.
LINER-MELT_2	6.00E-01	1.075	Liner melt-through given low RPV pressure with dry drywell	This term represents the probability that direct liner melt attack fails containment at vessel breach, given low reactor vessel pressure and a dry drywell floor. Phase II SAMAs 026, 027, 030, 034, 036 (SBO coping), 041, 042, 043, 044, 045, 046, 047, 048, and 049 (increased injection potential) were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
WWRBW	1.17E-01	1.072	Torus rupture below water line	This term represents the probability of torus rupture below the water line. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.
DWHL	1.91E-01	1.064	Drywell head leakage failure occurs	This term represents the probability of drywell head leakage failure. Phase II SAMAs 007, 019, and 021, providing means to reduce the likelihood of drywell head failure, were evaluated.
NO_RB-NATURAL_4	5.00E-01	1.054	Natural deposition does not occur given containment failure at high elevation	This term represents the probability of reactor building failure to retain a significant fraction of the radionuclides released from the primary containment given containment failure at high elevation. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated. In addition, SAMAs 008 and 022, for mitigating fission product release into the reactor building, were evaluated.
PEDESTAL_FAIL-2	1.00E+00	1.053	Pedestal overpressure failure at high RPV pressure and large vessel breach	This term represents the probability that pedestal wall failure due to fuel coolant interactions, or over pressurization from blowdown, occurs given high vessel breach and gross vessel breach. Phase II SAMAs 005, 006, 009, 013, and 024 were evaluated for risk reduction.
ALPHA	1.00E-01	1.051	Given in-vessel FCI, 'ALPHA' mode failure, fails reactor and containment	This term represents the probability of vessel and containment failure given an in-vessel fuel-coolant interaction. Phase II SAMAs 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 to increase injection potential were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
SLUMP_2	1.00E-01	1.05	Core slump probability given CM >20% and no injection	This term represents the probability of core slump to the lower head as a large mass, given no in-vessel injection. Phase II SAMAs 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 for enhancing reactor vessel injection during transients, small LOCA, and SBO were evaluated.
FCI_IV_2	8.60E-01	1.048	In-vessel fuel coolant interactions at low RPV pressure	This term represents the probability of a fuel-coolant interaction occurring inside the reactor vessel at low reactor vessel pressure. Phase II SAMAs 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 to increase injection potential were evaluated.
CWWR	7.31E-02	1.044	Torus bellows catastrophic rupture event	This term represents the probability of torus catastrophic rupture below the water line. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.
PCF_OK-1	8.76E-01	1.041	Containment flooding initiated (NON-SBO RHRSW&FWXT OK plant damage states)	This term represents the probability that plant operators fail to align primary containment flooding in accordance with severe accident operating guidelines during non-SBO plant damages states. Phase I SAMAs, including training to enhance the likelihood of success of operator action in response to accident conditions, have already been implemented. No additional phase II SAMAs were recommended for this subject.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
HIGH_LIQUID_VB-3	1.00E-01	1.04	Large molten debris mass in lower RPV head at low RPV pressure	This term represents the probability of having a large amount of mobile core debris when vessel breach occurs at low pressure. Phase II SAMAs 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 for enhancing reactor vessel injection during transients, small LOCA, and SBO were evaluated.
LINER-MELT_3	6.00E-01	1.039	Liner melt-through given high RPV pressure, dry drywell, and no late water supply	This term represents the probability that direct liner melt attack fails containment at vessel breach, given high reactor vessel pressure and no late water supply onto the drywell floor. Phase II SAMAs 026, 027, 030, 034, 036 (SBO coping), 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 (increased injection potential) were evaluated.
RPV-VENTING_2	5.00E-02	1.038	RPV venting occurs given containment flooding and vessel failure	This term represents the probability that reactor vessel venting occurs following containment flooding and vessel failure. Phase II SAMA 013 was evaluated to consider the benefit of a reactor vessel exterior cooling system with the potential to cool a molten core before it causes vessel failure.
WWRAW	6.93E-02	1.034	Torus rupture above water line	This term represents the probability of torus rupture above the water line. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
NO-QUECH-5D	8.40E-01	1.033	No debris quench, given dry pedestal, low RPV pressure and late water supply ex-vessel, and high superheat	This term represents the probability that debris is not quenched immediately after vessel failure, given no water on the drywell floor, low RPV pressure at vessel breach and late water supply for debris cooling after vessel breach and high superheat. Phase II SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
OP-NO-VENT_LATE	1.00E-01	1.032	Plant operators do not vent containment late	This term represents the probability that plant operators fail to align primary containment venting via the torus vent path when torus cooling and drywell sprays failed to reduce drywell/torus pressure. Phase I SAMAs, including improvement of procedures and installation of instrumentation to enhance the likelihood of success of operator action in response to accident conditions, have already been implemented. Phase II SAMA 057 to control containment venting within a narrow pressure band to prevent rapid containment depressurization during venting was evaluated.
NO_DP_SRV	1.00E-01	1.032	RPV not depressurized by opening SRVs	This term represents the probability that plant operators fail to perform RPV depressurized prior to vessel breach by opening the SRVs. Phase I SAMAs, including improvement of procedures and installation of instrumentation to enhance the likelihood of success of operator action in response to accident conditions, have already been implemented. Phase I SAMAs to enhance SRV reliability for RPV depressurization have also been implemented. No Phase II SAMAs were recommended for this subject.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
HIGH_LIQUID_VB-2	1.00E-01	1.028	Large molten debris mass in lower RPV head at high RPV pressure	This term represents the probability of having a large amount of mobile core debris when vessel breach occurs at high pressure. Phase II SAMAs 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 for enhancing reactor vessel injection during transients, small LOCA, and SBO were evaluated.
PCI-RWCU-SBO1	1.00E+00	1.026	RWCU inboard suction valve 12MOV15-remains open post-SBO	This term represents the probability of the inboard RWCU suction valve, 12MOV-15, remaining open during an SBO event. At JAFNPP, primary containment isolation inboard valves are AC-powered while outboard valves are DC-powered. Hence, during an SBO event, RWCU suction line valve 12MOV-15 remains open. However, because primary containment isolation valves are pairs of valves mounted in series and DC-power is available to close the outboard valve, in this case 12MOV-18, the probability of primary containment isolation failure under this scenario is low. Therefore, no potentially cost-beneficial SAMAs were postulated to mitigate this event
RWC-MOV-OO-MOV18	3.05E-03	1.026	RWCU 12MOV-18 fails to close	This term represents the probability of the outboard RWCU suction valve, 12MOV-18, failing to close during an SBO event.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
NO_RB-NATURAL_2	1.00E-01	1.025	Natural deposition does not occur given small containment failure	This term represents the probability of reactor building failure to retain a significant fraction of the radionuclides released from the primary containment given a small primary containment failure. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated. In addition, SAMAs 008 and 022, for mitigating fission product release into the reactor building, were evaluated.
RPV-LOW45-1	3.84E-01	1.024	RPV pressure is low given PDS-45	This term represents the probability that RPV depressurization occurs subsequent to a short-term ATWS with early containment failure and early core damage at high primary system pressure because of inadequate reactor water level following a loss of reactivity control. Phase II SAMAs 004, 052, and 053 for enhancing ATWS migration capabilities were evaluated.
DWR	3.70E-02	1.021	Drywell line rupture event	This term represents the probability of drywell rupture. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.
WWLBW	3.64E-02	1.018	Torus leakage below water line	This term represents the probability of torus failure below the water line. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
OP_SPRAY_LATE_1	5.20E-02	1.017	Operator does not align drywell sprays per SAOGs	This event represents operator failure to align drywell sprays. Phase I SAMAs, including training to enhance the likelihood of success of operator action in response to accident conditions, have already been implemented. Phase II SAMA 010, installing a passive containment spray system, was evaluated.
SGT-RCK-NO-M100A	2.50E-03	1.016	SGTS train 'A' decay heat cooling inlet valve 01-125MOV-100A control circuit failure	This term represents failure of the 'A' train standby gas treatment system to provide a means of effective fission product mitigation inside the reactor building during severe accident scenarios. Phase II SAMA 008, enhancing fission product scrubbing, was evaluated.
SGT-RCK-NO-M100B	2.50E-03	1.016	SGTS train 'B' decay heat cooling inlet valve 01-125MOV-100B control circuit failure	This term represents failure of the 'B' train standby gas treatment system to provide a means of effective fission product mitigation inside the reactor building during severe accident scenarios. Phase II SAMA 008, enhancing fission product scrubbing, was evaluated.
SGT-RCK-NO-MOV11	2.50E-03	1.016	SGTS Rx Bldg suction above 369EL isolation valve 01-125MOV-11 control circuit failure	This term represents failure of the standby gas treatment system to provide a means of effective fission product mitigation inside the reactor building during severe accident scenarios. Phase II SAMA 008, enhancing fission product scrubbing, was evaluated.
SGT-RCK-NO-MOV12	2.50E-03	1.016	SGTS Rx Bldg suction below 369EL isolation valve 01-125MOV-12 control circuit failure	This term represents failure of the standby gas treatment system to provide a means of effective fission product mitigation inside the reactor building during severe accident scenarios. Phase II SAMA 008, enhancing fission product scrubbing, was evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
DCOOL47-2	2.23E-01	1.015	Debris cooled given PDS-47	This term represents the probability that debris coolability does not occur given an ISLOCA outside containment with early core melt at high RPV pressure. Phase II SAMAs 037 and 038, to reduce the potential for ISLOCAs, were evaluated. Also, SAMA 023, providing a means of flooding the debris bed to enhance debris coolability ex-vessel, was evaluated.
DWL	2.88E-02	1.014	Small drywell line failure event	This term represents the probability of a small drywell failure. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.
INJ-REC29-1	5.10E-01	1.008	In-vessel cooling available given PDS-29	This term represents the probability that in-vessel cooling is not restored prior to vessel breach for long-term SBO scenarios involving the loss of injection at high RPV pressure from battery depletion. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events were evaluated.
FWS-CKV-CO-FW28A	1.00E-03	1.008	Feedwater system 'A' supply inboard check 34FWS-28A fails to close on demand	This term represents failure of the feedwater/condensate system to provide reactor vessel injection or containment isolation in the event that 12MOV-69 fails to close. Phase II SAMAs 031, 040, 041, and 043 to enhance feedwater/condensate system flow were evaluated.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
PCI-RDW-SBO1	1.00E+00	1.008	Drywell floor drain isolation valve 20MOV-82 remains open post SBO	This term represents the probability that the inboard drywell floor drain isolation valve, 20MOV-82, remains open during an SBO event. Similar to event PCI-RWCU-SBO1, DC-powered outboard drywell floor drain valve 20AOV-83 is available to perform the containment isolation function. Hence, the probability of containment isolation failure occurring in the drywell floor drain line is low. Therefore, no potentially cost-beneficial SAMAs were postulated to mitigate this event.
PCI-RWCU-SBO2	1.00E+00	1.008	RWCU inboard return valve 12MOV-69 remains open post SBO	This term represents the probability of the inboard RWCU return valve, 12MOV-69, remaining open during an SBO event. During an SBO event, AC power to close 12MOV-69 is not available, and it remains open. However, similar to events PCI-RWCU-SBO1 and PCI-RDW-SBO1, a second valve failure must occur to result in a containment isolation failure. For this event, primary containment isolation capability is provided by feedwater system check valve 34FWS-28A, making the probability of primary containment isolation failure under this scenario low. Therefore, no potentially cost-beneficial SAMAs were postulated to mitigate this event.
RDW-AOV-OO-AOV83	1.00E-03	1.008	Drywell floor drain valve 20AOV-83 fails to close	This term represents the probability of the outboard drywell floor suction valve, 20AOV-83 failing to close during an SBO event.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
DWOT_FAIL	2.47E-01	1.007	Drywell failure results at low pressure from high drywell temperatures	This term represents the probability of a drywell failure due to high temperatures. Phase II SAMAs 007, 019, and 021, reducing the likelihood of drywell head failure due to high temperatures, were evaluated.
EPOOL29-4	5.69E-01	1.007	No early torus bypass given PDS-29	This term represents the probability that no early torus bypass event occurs during a long-term SBO scenario involving the loss of injection at high RPV pressure from battery depletion. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 061, and 062, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events were evaluated.
DWHR	1.04E-02	1.006	Drywell head rupture event	This term represents the probability of drywell rupture. Phase II SAMAs 007, 011, 014, 016, 017, 019, and 021 for enhancing containment integrity were evaluated.
LATE_INJ-VF-1	8.88E-01	1.005	Late injection at vessel breach (given TW LPCI+CS FAIL PDS)	This term represents the probability that late injection is not available for both in-vessel and ex-vessel cooling given a loss of containment decay heat removal scenario. Phase II SAMAs 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 (increased injection potential) were evaluated. Also, Phase II SAMAs 002, 010, 015, 057, and 058 were evaluated for containment pressure control.

Table E.1-6 (Continued)
Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on Large Early Release Frequency)

Event Name	Probability	RRW	Event Description	Disposition
LINER-MELT_4	1.00E-01	1.005	Liner melt-through given high RPV pressure, dry drywell, and late water supply availability	This term represents the probability that direct liner melt attack fails containment at vessel breach, given high reactor vessel pressure and no late water supply onto the drywell floor. Phase II SAMAs 026, 027, 030, 034, 036 (SBO coping), 040, 041, 042, 043, 044, 045, 046, 047, 048, and 049 (increased injection potential) were evaluated.
CFE@VF_4	6.00E-03	1.005	Drywell failure given drywell pressure <30 psig, dry pedestal cavity and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given drywell pressure less than 30 psig, no water on the drywell floor and direct containment heating. Phase II SAMAs 011, 014, 016, and 017 for enhancing containment integrity were evaluated. In addition, Phase II SAMA 013, addition of a reactor vessel exterior cooling system with the potential to cool a molten core before it causes vessel failure, was evaluated.

E.1.2.2 Radionuclide Analysis

E.1.2.2.1 Introduction

A major feature of a Level 2 analysis is the estimation of the source term for every possible outcome of the containment event tree (CET). The CET end points represent the outcomes of possible in-containment accident progression sequences. These end points represent complete severe accident sequences from initiating event to release of radionuclides to the environment. The Level 1 and plant system information is passed through to the CET evaluation in discrete PDS. An atmospheric source term may be associated with each of these CET sequences. Because of the large number of postulated accident scenarios considered, mechanistic calculations (i.e., MAAP calculations) are not performed for every end-state in the CET. Rather, accident sequences produced by the CET are grouped or "binned" into a limited number of release categories each of which represents all postulated accident scenarios that would produce a similar fission product source term.

The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides. The predicted source term associated with each release category, including both the timing and magnitude of the release, is determined using the results of MAAP calculations. [Reference E.1-2]

E.1.2.2.2 Timing of Release

Timing completely governs the extent of radioactive decay of short-lived radioisotopes prior to an off-site release and therefore has a first-order influence on immediate health effects. JAFNPP characterizes the release timing relative to the time at which the release begins, measured from the time of accident initiation. Two timing categories are used: early (0-24 hours) and late (> 24 hours).

Based on MAAP calculations for a spectrum of severe accident sequences, JAFNPP expects that an Emergency Action Level (as defined by the JAFNPP Emergency Plan) will be reached within the first half hour after accident initiation. Reaching an Emergency Action Level initiates a formal decision-making process that is designed to provide public protective actions. Within 24 hours of accident initiation, the Level 2 analysis assumed that off-site protective measures would be effective. Therefore, the definitions of the release timing categories are as follows.

- Early releases are CET end-states involving containment failure prior to or at vessel failure or after vessel failure and occurring within 0 to 24 hours measured from the time of accident initiation and for which minimal offsite protective measures would be accomplished.

- Late releases are CET end-states involving containment failure greater than 24 hours from the time of accident initiation, for which offsite measures are fully effective.

E.1.2.2.3 Magnitude of Release

Source term results from previous risk studies suggest that categorization of release magnitude based on cesium iodide (CsI) release fractions alone are appropriate [Reference E.1-3]. The CsI release fraction indicates the fraction of in-vessel radionuclides escaping to the environment (Noble gas release levels are non-informative since release of the total core inventory of noble gases is essentially complete given containment failure).

The source terms were grouped into four distinct radionuclide release categories or bins according to release magnitude as follows.

High

A radionuclide release of sufficient magnitude to have the potential to cause early fatalities. This implies a total integrated release of > 10% of the initial core inventory of CsI [Reference E.1-3].[1]

Medium

A radionuclide release of sufficient magnitude to cause near-term health effects. This implies a total integrated release of between 1% and 10% of the initial core inventory of CsI [Reference E.1-3].[2]

Low

A radionuclide release with the potential for latent health effects. This implies a total integrated release of between 0.001% and 1% of the initial core inventory of CsI.

Negligible (No Containment Failure (NCF))

A radionuclide release that is less than or equal to the containment design base leakage. This implies total integrated release of < 0.001% of the initial core inventory of CsI.

The "total integrated release" as used in the above categories is defined as the integrated release within 36 hours after RPV failure. If no RPV failure occurs, then the "total integrated release" is defined as the integrated release within 36 hours after accident initiation.

1. Once the CsI source term exceeds 10 percent, the source term is large enough that doses above the early fatality threshold can sometimes occur within a population center a few miles from the site.
2. The reference document indicates that for CsI release fractions of 1 to 10 percent, the number of latent fatalities is found to be at least 10% of the latent fatalities for the highest release.

E.1.2.2.4 Release Category Bin Assignments

Table E.1-7 summarizes the scheme used to bin sequences with respect to magnitude of release, based on the predicted CsI release fraction and release timing. The combination of release magnitude and timing produce seven distinct release categories for source terms. These are the representative release categories presented in Table E.1-8.

Table E.1-7
Release Severity and Timing Classification Scheme Summary

Release Severity		Release Timing	
Classification Category	**CsI % Release**	**Classification Category**	**Time of Initial Release from Accident Initiation**
High	Greater than 10	Early (E)	Less than 24 hours
Medium	1 to 10		
Low	0.001 to 1	Late (L)	Greater than 24 hours
Negligible	Less than 0.001		

Table E.1-8
JAFNPP Release Categories

Timing of Release	Magnitude of Release			
	Low	Medium	High	NCF
Early	Early/Low	Early/Medium	Early/High	
Late	Late/Low	Late/Medium	Late/High	

E.1.2.2.5 Mapping of Level 1 Results into the Various Release Categories

Plant Damage States (PDS) provide the interface between the Level 1 and Level 2 analyses (i.e. between core damage accident sequences and fission product release categories). In the PDS analysis, Level 1 results were grouped ("binned") according to plant characteristics that define the status of the reactor, containment, and core cooling systems at the time of core damage. This ensures that systems important to core damage in the Level 1 event trees and the dependencies between containment and other systems are handled consistently in the Level 2 analysis. A PDS therefore represents a grouping of Level 1 sequences that defines a unique set of initial conditions that are likely to yield a similar accident progression through the Level 2 CETs and the attendant challenges to containment integrity.

From the perspective of the Level 2 assessment, PDS binning entails the transfer of specific information from the Level 1 to the Level 2 analyses.

Equipment Failures in Level 1

Equipment failures in support systems, accident prevention systems, and mitigation systems that have been noted in the Level 1 analysis are carried into the Level 2 analysis. In this latter analysis, the repair or recovery of failed equipment is not allowed unless an explicit evaluation, including a consideration of adverse environments where appropriate, has been performed as part of the Level II analysis.

RPV Status

The RPV pressure condition is explicitly transferred from the Level 1 analysis to the CET.

Containment Status

The containment status is explicitly transferred from the Level 1 analysis to the CET. This includes recognition of whether the containment is bypassed or is intact at the onset of core damage.

Accident Sequence Timing

Differences in accident sequence timing are transferred with the Level 1 sequences. Timing affects such sequences as SBO, internal flooding, and containment bypass (ISLOCA).

This transfer of information allows timing to be properly assessed in the Level 2 analysis.

Based on the above criteria, the Level 1 results were binned into 48 PDS. These PDS define important combinations of system states that can result in distinctly different accident progression pathways and therefore different containment failure and source term characteristics. Table E.1-9 provides a description of the JAFNPP PDS that are used to summarize the Level 1 results.

Table E.1-9
Summary of JAFNPP Core Damage Accident Sequences Plant Damage States

PDS	Description	Point Estimate (/ry)	% of CDF
PDS-1	Long-term LOCA with loss of high-pressure core makeup from HPCI and RCIC, loss of containment heat removal, and failure to depressurize the primary system for low-pressure core makeup. Core damage results at high primary system pressure. Late injection from low-pressure systems (core spray, LPCI, and firewater) is available, provided primary system depressurization occurs. The containment is vented and intact.	0.00E+00	0.00
PDS-2	Long-term LOCA with loss of both high-pressure core makeup (HPCI and RCIC) and containment heat removal. Core damage results at high primary system pressure. Because containment venting fails, containment failure occurs long-term. Late injection is available from low-pressure systems (core spray, LPCI, and fire water) provided they survive containment failure.	1.44E-09	0.05
PDS-3	Short-term LOCA with loss of high-pressure core makeup and failure to depressurize the primary system for low-pressure core makeup. Core damage occurs at high primary system pressure. Late injection from core spray, LPCI, and firewater is available, provided primary system depressurization occurs. Containment heat removal is available.	1.60E-08	0.58
PDS-4	Short-term LOCA with loss of high-pressure core makeup, loss of containment heat removal, and failure to depressurize the primary system for low-pressure core makeup. Core damage occurs at high primary system pressure. Late injection from core spray, LPCI, and firewater is available, provided primary system depressurization occurs. Unlike PDS-3, containment heat removal is unavailable.	0.00E+00	0.00
PDS-5	Long-term LOCA with loss of high-pressure core makeup and containment heat removal. Core damage occurs at low primary system. Late injection is available from low-pressure systems (core spray, LPCI, and fire water). The containment is vented and intact.	3.02E-11	0.00
PDS-6	Long-term large LOCA. High-pressure core makeup from HPCI and RCIC are unavailable due to the large LOCA. Because containment venting fails, containment failure occurs long-term. Late injection is available from low-pressure systems (core spray, LPCI, and fire water) provided they survive containment failure. Core damage occurs at low primary system pressure.	6.73E-11	0.00

Table E.1-9 (Continued)
Summary of JAFNPP Core Damage Accident Sequences Plant Damage States

PDS	Description	Point Estimate (/ry)	% of CDF
PDS-7	Short-term large LOCA with loss of core cooling. Core damage results at low primary system pressure. Late injection from firewater cross tie and containment heat removal are available.	1.47E-09	0.05
PDS-8	Short-term large LOCA with loss of core cooling. Core damage results at low primary system pressure. Late injection from firewater cross tie is available. However, unlike PDS-7, containment heat removal is unavailable.	0.00E+00	0.00
PDS-9	Short-term LOCA with loss of high and low-pressure core cooling. Because the primary system is depressurized, core damage results at low primary system pressure. Late injection from RHRSW system, containment venting, and containment heat removal are available.	3.18E-10	0.01
PDS-10	Short-term LOCA with loss of high and low-pressure core cooling. Because the primary system is depressurized, core damage results at low primary system pressure. Late injection from RHRSW system and containment heat removal are available. However, unlike PDS-9, containment venting is not available.	0.00E+00	0.00
PDS-11	Short-term LOCA with loss of high and low-pressure core cooling. Core damage results at low primary system pressure. Late injection from RHRSW system is available. However, unlike PDS-9, containment venting and containment heat removal are unavailable.	0.00E+00	0.00
PDS-12	Transient with a loss of long-term decay heat removal. Core damage results at high primary system pressure. Late in-vessel and ex-vessel injection is available. The containment is vented and remains intact at the time of core damage.	2.63E-08	0.96
PDS-13	Transient with a loss of long-term decay heat removal. Core damage results at high primary system pressure. Late in-vessel and ex-vessel injection is available. Unlike PDS-12, containment venting fails.	6.93E-07	25.24
PDS-14	Short-term transient with failure to depressurize the primary system. Core damage results at high primary system pressure. Late in-vessel and ex-vessel injection is available. Containment heat removal from RHR is available.	2.32E-07	8.44

Table E.1-9 (Continued)
Summary of JAFNPP Core Damage Accident Sequences Plant Damage States

PDS	Description	Point Estimate (/ry)	% of CDF
PDS-15	Short-term transient with failure to depressurize the primary system. Core damage results at high primary system pressure. Late in-vessel and ex-vessel injection is available. Containment heat removal from RHR is available. However, containment venting is not available.	0.00E+00	0.00
PDS-16	Short-term transient with failure to depressurize the primary system. Core damage results at high primary system pressure. Late in-vessel and ex-vessel injection is available. Containment heat removal from RHR is not available, but containment venting is available.	1.07E-07	3.91
PDS-17	Short-term transient with failure to depressurize the primary system. Core damage results at high primary system pressure. Late in-vessel and ex-vessel injection is available. Neither containment heat removal from RHR nor containment venting is available.	0.00E+00	0.00
PDS-18	Transient with a loss of long-term decay heat removal. Core damage results at low primary system pressure. Late in-vessel and ex-vessel injection is available. The containment is vented and remains intact at the time of core damage.	8.66E-08	3.16
PDS-19	Transient with a loss of long-term decay heat removal. Core damage results at low primary system pressure. Late in-vessel and ex-vessel injection is available. Unlike PDS-18, containment venting fails.	8.19E-08	2.98
PDS-20	Long-term transients with loss of core cooling. Core damage results at low primary system pressure. No late injection, but containment heat removal is available.	2.06E-09	0.08
PDS-21	Short-term transients with loss of core cooling. Core damage results at low primary system pressure. Late injection, containment venting, and containment heat removal are available.	9.71E-09	0.35
PDS-22	Short-term transients with loss of core cooling. Core damage results at low primary system pressure. Late injection and containment heat removal are available. However, containment venting is not available.	0.00E+00	0.00

**Table E.1-9 (Continued)
Summary of JAFNPP Core Damage Accident Sequences Plant Damage States**

PDS	Description	Point Estimate (/ry)	% of CDF
PDS-23	Short-term transients with loss of core cooling. Core damage results at low primary system pressure. Late injection and containment venting are available, but containment heat removal is not available.	2.87E-10	0.01
PDS-24	Similar to PDS-23, except that containment venting is not available.	0.00E+00	0.00
PDS-25	Short-term transients with loss of core cooling. Core damage results at low primary system pressure. No late injection, but containment heat removal and containment venting are available.	9.45E-10	0.03
PDS-26	Similar to PDS-25, except that containment venting is not available.	0.00E+00	0.00
PDS-27	Short-term transients with loss of core cooling. Core damage results at low primary system pressure. Late injection and containment heat removal are not available. However, containment venting is available.	1.52E-09	0.06
PDS-28	Short-term transients with loss of core cooling. Core damage results at low primary system pressure. Late injection, containment heat removal, and containment venting are not available.	0.00E+00	0.00
PDS-29	Long-term SBO involving loss of injection at high primary system pressure from battery depletion. All accident-mitigating functions are recoverable when AC power is restored.	1.28E-06	46.69
PDS-30	Short-term SBO sequence involving a loss of high-pressure injection at high primary system pressure from loss of all AC power and DC power or failure of SRVs. All accident-mitigating functions are recoverable when offsite power is restored.	1.03E-08	0.37
PDS-31	Long-term SBO sequence involving a loss of high-pressure injection because of one/two stuck-open safety relief valve or long-term failure of HPCI/RCIC and subsequent failure to depressurize the primary system. Core damage results at low primary system pressure. All accident-mitigating functions are recoverable when offsite power is restored.	5.20E-09	0.19

Table E.1-9 (Continued)
Summary of JAFNPP Core Damage Accident Sequences Plant Damage States

PDS	Description	Point Estimate (/ry)	% of CDF
PDS-32	Short-term SBO sequence involving a loss of high-pressure injection due to two stuck-open safety relief valves or failure of HPCI/RCIC and one stuck-open safety relief valve. Core damage results at low primary system pressure. All accident-mitigating functions are recoverable when offsite power is restored.	2.88E-11	0.00
PDS-33	Short-term large reactor vessel rupture. The resulting loss of coolant is beyond the makeup capability of ECCS. Core damage occurs in the short term at low primary system pressure. Vessel injection and all forms of containment heat removal (RHR and containment venting) are available. The containment is not bypassed and AC power is available.	1.00E-08	0.36
PDS-34	Similar to PDS-33, except that containment heat removal from RHR fails.	0.00E+00	0.00
PDS-35	Short-term large reactor vessel rupture. The resulting loss of coolant is beyond the makeup capability of ECCS. Core damage occurs in the short term at low primary system pressure. Vessel injection is unavailable. However, all forms of containment heat removal (RHR and containment venting) are available. The containment is not bypassed and AC power is available.	0.00E+00	0.00
PDS-36	Similar to PDS-35, except that containment heat removal from RHR fails.	0.00E+00	0.00
PDS-37	Short-term ATWS with failure of SRVs to open to reduce primary system pressure. The ensuing primary system over pressurization leads to a LOCA beyond core cooling capabilities. Late injection and containment heat removal are available.	5.49E-08	2.00
PDS-38	Short-term ATWS that leads to early core damage at low primary system pressure following successful reactivity control. Late injection is not available. However, containment heat removal is available.	6.91E-11	0.00
PDS-39	Similar to PDS-38, except that containment heat removal from the RHR system is not available.	4.06E-10	0.01

Table E.1-9 (Continued)
Summary of JAFNPP Core Damage Accident Sequences Plant Damage States

PDS	Description	Point Estimate (/ry)	% of CDF
PDS-40	Long-term ATWS that leads to late core damage at low primary system pressure following successful reactivity control. Late injection is available; containment heat removal from the RHR is not available. The containment is vented.	0.00E+00	0.00
PDS-41	Short-term ATWS that leads to early core damage at high primary system pressure following successful reactivity control. Late injection and containment heat removal are available.	2.60E-08	0.95
PDS-42	Similar to PDS-41, except that containment heat removal from the RHR system is not available.	0.00E+00	0.00
PDS-43	Long-term ATWS that leads to late core damage at high primary system pressure following successful reactivity control. Late injection is available; containment heat removal from the RHR is not available. The containment is vented.	2.54E-11	0.00
PDS-44	Long-term ATWS that leads to late core damage at high primary system pressure following successful reactivity control. Late injection is available. However, containment heat removal from the RHR system and containment venting are not available.	0.00E+00	0.00
PDS-45	Short-term ATWS that leads to containment failure and early core damage at high primary system pressure because of inadequate reactor water level control following a loss of reactivity control. Late injection and containment venting are available.	7.01E-08	2.55
PDS-46	Short-term ATWS that leads to containment failure and early core damage at high primary system pressure because of inadequate reactor water level control following successful reactivity control. No late injection; however, containment venting is available.	0.00E+00	0.00
PDS-47	Unisolated LOCA outside containment with early core melt at high RPV pressure.	1.89E-08	0.69
PDS-48	Unisolated LOCA outside containment with early core melt at low RPV pressure.	6.95E-09	0.25

The PDS designators listed in Table E.1-9 represent the core damage end state categories from the Level 1 analysis which are grouped together as entry conditions for the Level 2 analysis. The Level 2 accident progression for each of the PDS is then evaluated using a single CET to determine the appropriate release category for each Level 2 sequence. Each end state associated with a Level 2 sequence is assigned to one of the release categories depicted in Table E.1-8. Note, however, that since not all the Level 2 sequences associated with each Level 1 plant damage state may be assigned to the same release category, there is no direct link between a specific Level 1 core damage PDS and Level 2 release category. Rather, the sum of the Level 2 end state frequencies assigned to each release category determines the overall frequency of that release category. The CET described in the Level 2 model determines the release category frequency attributed to each Level 1 core damage PDS.

Based on the above binning methodology, the salient Level 2 results are summarized in Table E.1-10. Table E.1-10 summarizes the results of the CET quantification. This table identifies the total annual release frequency for each Level 2 release category.

The following is a summary of dominant risk scenarios for each release bin.

No Containment Failure (NCF)

The most likely NCF release scenarios involve the occurrence of an SBO with recovery of AC power after core damage. Restoration of AC power allows balance-of-plant systems, emergency core cooling systems, and containment heat removal systems to become operable. Hence, vessel failure is precluded and containment integrity is not challenged. Other dominant scenarios for this release bin involve the occurrence of plant transients with subsequent loss of high pressure injection (HPCI and RCIC) that proceeds to core damage at high RPV pressure. Subsequently, RPV pressure is lower (via SRVs vessel depressurization), thereby allowing low-pressure systems to become available (LPCI, core spray, and RHRSW). The low pressure systems are used to preclude vessel breach, to flood containment to prevent liner melt-through, or to quench core debris ex-vessel to prevent core-concrete interactions.

Early High Release (LERF)

Early high releases are dominated by SBO, ATWS, and ISLOCA plant damage states.

The most probable SBO scenario involves loss of normal 115-kV power to the reserve station transformers, which trips the turbine generator. The reactor is successfully scrammed. Subsequently, onsite power from the EDG to the 4.160kV buses fails. SRVs open and reclose to relieve pressure transients resulting from the scram. The resulting SBO renders all systems inoperable, except HPCI, RCIC, and the diesel-driven firewater pump. At a reactor water level of 126.5 inches above top-of-active-fuel, HPCI and RCIC automatically initiate. HPCI injects water to control core water level. To provide time to recover a source of onsite or offsite AC power, plant operators successfully shed DC loads. This prolongs the life of the batteries to 4 hours. However, attempts to recover offsite power are unsuccessful. Therefore, after 7 hours (assuming a 3-hour boil-off time), HPCI, RCIC, and SRVs fail because of battery depletion. In addition, because the SRVs cannot maintain RPV pressure below the shutoff head of the diesel driven firewater pump, all means of RPV injection fail. However, during the course of the accident progression, one SRV sticks open. The ensuing core damage results at low RPV pressure.

The containment event tree assessment predicts that AC power is not restored following core damage. Therefore, core melt and vessel breach at low RPV pressure result. With a 'dry' drywell floor and no late water supply available for primary containment flooding, containment failure due to liner melt-through with low RPV pressure occurs. The subsequent early release is considered large because containment failure bypasses the torus; thereby an effective means of scrubbing fission products in the torus pool is precluded. In addition, without AC power, drywell spray, another means of fission product scrubbing, is precluded.

The most probable ATWS scenario involves a plant transient with MSIVs open that requires the reactor to scram. The electrical portion of the RPS functions successfully. However, the mechanical portion of the RPS fails. The recirculation pumps trip; however, extremely high power excursions occur either from a failure to override ADS or plant operator's inability to control water level at top-of-active fuel (Failure to override ADS results in depressurization of the reactor to below the shutoff head of low-pressure injection systems such as LPCI and core spray. Consequently, injection of LPCI or core spray results in power spikes associated with the rapid insertion of cold water from these high volume sources.). Although the SRVs open to reduce reactor pressure, the inability to prevent high reactor water level results in a large steaming rate into the torus pool and eventual containment failure. This sequence of events results in core damage with a bypassed containment.

The containment event tree assessment predicts early containment failure in the drywell, thereby bypassing the torus fission product scrubbing capabilities. In addition, upon containment failure, all RPV injection and late water supply fail due to pipe ruptures inside the drywell or harsh reactor building environment. The containment failure also results in reactor building bypass. With no RPV injection and no late water supply, vessel breach occurs at low RPV pressure and is followed by core-concrete interaction. Therefore, the combination of the above events results in large early release.

The most probable ISLOCA scenario involves an ISLOCA in the reactor building. The breach is equivalent to a small LOCA. Plant operators recognize that reactor building parameters have exceeded threshold values and primary coolant is accumulating in the reactor building. However, because of the ISLOCA break size and location, isolation is not possible. As a result, water lost from the primary coolant system and torus precludes long-term core cooling. With inadequate RPV injection and failure to isolate the breached low-pressure piping pathway, core damage and a bypassed containment result.

The containment event tree assessment indicates that core makeup systems are available (no random mechanical faults have occurred to disable system operation) and vessel breach occurs at medium RCS pressure due to the small ISLOCA break. The release is large because the containment is bypassed at core damage. As a result, the direct flow pathway from the RCS to outside the containment boundary eliminates the ability of natural processes and engineered safety systems (e.g., containment spray) to mitigate or attenuate the release of fission products from the core.

Early Medium Release

Early medium releases are dominated by SBO and ATWS plant damage states. For both SBO and ATWS plant damage states, early medium release scenarios are similar to early high releases scenarios except that these sequences involve fission product removal via natural processes, drywell sprays, or reactor building mitigation. In addition, unlike the early high release bins, torus bypass does not occur as frequently. The containment failure location is below the water line in the torus.

Early Low Release

Early low release scenarios are similar to early medium release scenarios except that the most probable scenarios involve the availability of late water supply for ex-vessel cooling of core debris.

Late Medium Release

Late medium releases are dominated by SBO and loss of containment decay heat removal (TW) plant damage states.

The most probable SBO scenario involves a long-term SBO, in which containment failure occurs late, due to steam or noble gas overpressurization, basemat melt-through, or torus venting failures.

The most probable TW scenario is initiated by a transient resulting in loss of the power conversion system. The reactor scrams, and AC offsite power is available. The SRVs open and reclose to relieve pressure and HPCI is successful. However, torus cooling and RHR containment sprays fail resulting in loss of containment heat removal. Long term venting of the containment fails, resulting in containment failure. All high pressure systems fail after containment failure, resulting in core damage.

The top cut set for this sequence entails maintenance on RHRSW loop B along with failure of RHRSW loop A valve 10MOV-89A resulting in loss of containment heat removal. Operators fail to vent containment resulting in overpressurization and containment failure. As a consequence, high-pressure system piping fails resulting in core damage. Other key contributors to this sequence include combinations of common cause failures of RHRSW pumps.

These releases are affected by natural fission product removal mechanisms (gravitational settling and plate-out onto cooler RPV and containment surfaces) that act on the radioactive airborne materials within the drywell and torus.

Late Low Release

Late low releases are dominated by TW and SBO plant damage states. Late low release scenarios are similar to late medium release scenarios except that the most probable scenarios involve the availability of late water supply for ex-vessel cooling of core debris or late containment venting.

Table E.1-10
Summary of Containment Event Tree Quantification
JAFNPP IPE Model Revision 2

Release Category (Timing/Magnitude)	Release Frequency (Per ry)
Late Low	1.22E-06
Late Medium	5.46E-08
Late High	0.00E+00
Early Low	2.08E-07
Early Medium	2.92E-07
Early High	9.20E-08
No Containment Failure (NCF)	8.75E-07
Total	**2.74E-06**

Nomenclature

Timing

L (late) - greater than 24 hours
E (early) - less than 24 hours

Magnitude

NCF (little to no release) - less than 0.001% CsI
Low - 0.001% to 1% CsI
Medium - 1% to 10% CsI
High - greater than 10% CsI

E.1.2.2.6 Consequence Analysis Source Terms

Input to the Level 3 JAFNPP model from the Level 2 model is a combination of radionuclide release fractions, timing of radionuclide releases, and frequencies at which the releases occur. This combination of information is used in conjunction with JAFNPP site characteristics in the Level 3 model to evaluate the off-site consequences of a core damage event.

Source terms were developed for the seven release categories identified in Table E.1-8. Table E.1-11 provides a summary of the Level 2 results that were used as Level 3 input for the JAFNPP SAMA analysis.

Generating of specific source terms for the internal initiators resulted in hundreds of source terms for internal initiators. As a result, it was not computationally feasible to perform a calculation with the MACCS2 [Reference E.1-4] consequence model for each of the source terms. Therefore, the source terms presented in Table E.1.11 were grouped into three distinct source term bins: no containment failure, early release, and late release.

The frequency and release magnitude for the three consequence analysis source terms are as follows.

No Containment Failure Release Bin

Both the release bin frequency and release bin source term magnitude are the same as presented in Table E.1-11.

Early Release Bin

The early release bin frequency is the sum of early high, early medium, and early low bin frequencies. The release magnitude for the early release bin is conservatively assigned the value of the early high release bin presented in Table E.1-11.

Late Release Bin

The late release bin frequency is the sum of late medium and late low bin frequencies (the late high release category was excluded, as it was a negligible contributor). The release magnitude for the late release bin is conservatively assigned the value of the late medium release bin presented in Table E.1-11.

Consequences corresponding to each of the release categories are developed in the JAFNPP Level 3 model, which is discussed in Section E.1.5.

E.1.2.2.7 Release Magnitude Calculations

The MAAP computer code is used to assign both the radionuclide release magnitude and timing based on the accident progression characterization. Specifically, MAAP provides the following information:

- containment pressure and temperature (time of containment failure is determined by comparing these values with the nominal containment capability);
- radionuclide release timing and magnitude for a large number of radioisotopes; and
- release fractions for twelve radionuclide species.

Table E.1-11
JAFNPP Release Category Source Terms

	Release Characterization	Frequency (/ry)	Warning Time (sec)	Elevation (m)	Release Start (hours)	Release Duration (hours)	Release Energy (W)
1	NCF	8.75E-07	3.96E+03	3.00E+01	0.00E+00	3.60E+01	1.30E+07
2	Early High	9.20E-08	4.54E+03	3.00E+01	4.10E+00	4.50E+01	1.27E+07
3	Early Medium	2.92E-07	8.28E+03	3.00E+01	7.54E+00	4.18E+01	1.08E+07
4	Early Low	2.08E-07	4.34E+03	3.00E+01	3.93E+00	4.50E+01	1.28E+07
5	Late High	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
6	Late Medium	5.46E-08	2.88E+04	3.00E+01	3.63E+01	4.37E+01	2.50E+05
7	Late Low	1.22E-06	2.80E+04	3.00E+01	3.59E+01	4.03E+01	6.72E+05

Table E.1-11
JAFNPP Release Category Source Terms
(continued)

	Release Fractions								
	NG	I	Cs	Te	Sr	Ru	La	Ce	Ba
1	1.68E-04	1.12E-05	1.12E-05	5.27E-06	1.09E-07	1.93E-06	7.69E-09	7.32E-08	4.36E-07
2	8.30E-01	2.45E-01	2.45E-01	1.83E-01	1.37E-04	1.37E-04	1.61E-04	1.43E-03	1.72E-04
3	9.53E-01	2.41E-02	2.41E-02	1.96E-02	1.03E-04	5.20E-05	1.11E-04	9.83E-04	8.41E-05
4	9.67E-01	2.72E-03	2.72E-03	6.03E-03	8.57E-05	8.58E-05	8.59E-05	1.07E-04	8.52E-05
5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
6	1.00E+00	6.04E-02	6.04E-02	4.71E-02	6.34E-03	7.89E-03	6.10E-03	6.31E-03	6.45E-03
7	8.04E-01	2.39E-03	2.39E-03	1.60E-03	4.26E-05	2.71E-04	2.77E-05	3.21E-05	7.66E-05

E.1.3 IPEEE Analysis

E.1.3.1 Seismic Analysis

The seismic portion of the IPEEE was completed in conjunction with the SQUG program [References E.1-5 and E.1-6]. JAFNPP performed a seismic margin assessment (SMA) 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 [Reference E.1-7], and EPRI NP-6041-SL, Revision 1, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin," August 1991 [Reference E.1-8]. The SMA approach is a deterministic and conservative evaluation that does not calculate risk on a probabilistic basis. Therefore, its results should not be compared directly with the best-estimate internal events results. Conservative assumptions in the seismic margin analysis include the following.

- Each of the sequences in the seismic margin assessment 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 are presently credited in the analysis.

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

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

The conclusions of the JAFNPP IPEEE seismic margin analysis are as follows:

- The overall plant HCLPF (High Confidence Low Probability of Failure) capacity at JAFNPP is 0.22g PGA. This value reflects the plant modification to strengthen block walls EGB-272-6, 7, 9, and 10.

- No unique decay heat removal vulnerabilities to seismic events were found. Because the overall plant HCLPF capacity with respect to decay heat removal is estimated to be 0.30g PGA, it can be concluded that the decay heat removal pathways are seismically robust with a considerable margin above the 0.15g safe shutdown design basis earthquake.

- Seismic-induced flooding and fires do not pose major risks.

- No unique seismic-induced containment failure mechanisms were identified.

A number of plant improvements were identified and, as described in NUREG-1742 [Reference E.1-9], these improvements were implemented.

E.1.3.2 Fire Analysis

The JAFNPP internal fire risk model was performed in 1996 as part of the IPEEE submittal report. The JAFNPP fire analysis was performed using EPRI's Fire PRA Implementation Guide [Reference E.1-10]. The EPRI Fire Induced Vulnerability Evaluation method was used for the initial screening, for treatment of transient combustibles, and as the source of fire frequency data [Reference E.1-11].

Table E.1-12 presents the results of current JAFNPP IPEEE fire analysis. The values presented in Table E.1-12 are the same as those listed in NUREG-1742 [Reference E.1-9]. These values reflect the re-evaluation of the IPEEE fire CDF results to include response to NRC questions/ issues regarding fire-modeling progression.

A number of plant improvements were identified and, are described in NUREG-1742. These improvements have been implemented. In addition, a number of administrative procedures were revised to improve combustible and flammable material control.

E.1.3.3 Other External Hazards

The JAFNPP IPEEE submittal, in addition to the internal fires and seismic events, examined a number of other external hazards:

- high winds and tornadoes;
- external flooding; and
- ice, hazardous chemical, transportation, and nearby facility incidents.

In consequence of the above external hazards evaluation, no plant modifications were required for JAFNPP.

No risks to the plant occasioned by high winds and tornadoes, external floods, ice, and hazardous chemical, transportation, and nearby facility incidents were identified that might lead to core damage with a predicted frequency in excess of 10^{-6}/year. Therefore, these other external event hazards are not included in this attachment and are not expected to impact the conclusions of this SAMA evaluation.

Table E.1-12
JAFNPP Updated IPEEE Fire Events—Core Damage Frequency Results

Building/ Area	Fire Zone	Description	Total Compartment CDF (/yr)	Percent Contribution
Battery room	BR-1	Train A battery charger room 1 (Elev. 272)	2.40E-07	0.938
	BR-2	Train A battery room 2 (Elev. 272)	4.62E-07	1.805
	BR-3	Train B battery room 3 (Elev. 272)	3.30E-07	1.289
	BR-4	Train B battery charger room 4 (Elev. 272)	1.04E-07	0.406
	BR-5	Battery rooms corridor (Elev. 272)	8.50E-08	0.332
	BR-4 /BR-1	Train B battery charger room 4 (Elev. 272)/ Train A battery charger room 1 (Elev. 272)	2.24E-07	0.875
Cable spreading room	CS-1	Cable spreading room (Elev. 272)	6.57E-06	25.666
	AD-3 /CS-1	Administration building, machine shop, locker rooms, stores and lunch room (Elev. 272)/ cable spreading room (Elev. 272)	1.37E-07	0.535
Control room	CR-1	Main control room (Elev. 300)	3.00E-06	11.719
Cable tunnels	CT-1	West cable tunnel (Elev. 260)	7.21E-07	2.817
	CT-2	East cable tunnel (Elev. 260)	2.24E-07	0.875
	CT-3	South cable tunnel/relay room (Elev. 286)	5.52E-07	2.156
	CT-4	North cable tunnel/relay room (Elev. 286)	4.62E-07	1.805

Table E.1-12 (Continued)
JAFNPP Updated IPEEE Fire Events—Core Damage Frequency Results

Building/ Area	Fire Zone	Description	Total Compartment CDF (/yr)	Percent Contribution
Diesel generator building	EG-5	EDG A and C switchgear room south (Elev. 272)	1.32E-06	5.157
	EG-6	EDG B and D switchgear room north (Elev. 272)	6.05E-07	2.363
Electric bays	SW-1	West electric bay (Elev. 272)	6.61E-10	0.003
	SW-2	East electric bay (Elev. 272)	2.37E-10	0.001
Reactor building	RB-1A	Reactor building eastside (Elev. 272), southeast quadrant (Elev. 300), entire floor at Elev. 326, 344, and 369	2.25E-08	0.088
	RB-1B	Reactor building westside (Elev. 272)	1.35E-06	5.274
	RB-1B	Reactor building southwest quadrant (Elev. 300)	1.52E-07	0.594
	RB-1C	Reactor building northeast and northwest quadrants (Elev. 300)	2.19E-07	0.856
	RB-1E	Reactor building east crescent (Elev. 227 and 242)	1.02E-06	3.985
	RB-1W	Reactor building west crescent (Elev. 227 and 242)	9.52E-08	0.372
	RB-1E RB-1A	Reactor building east crescent (Elev. 227 and 242)/ reactor building eastside (Elev. 272), southeast quadrant (Elev. 300), entire floor at Elev. 326, 344, and 369	1.11E-07	0.434
	MG-1 /RB-1C	Motor generator set room (Elev. 300) and fan room (Elev. 326.9)/reactor building northeast and northwest quadrants (Elev. 300)	2.06E-07	0.805

Table E.1-12 (Continued)
JAFNPP Updated IPEEE Fire Events—Core Damage Frequency Results

Building/ Area	Fire Zone	Description	Total Compartment CDF (/yr)	Percent Contribution
	AD-3 /RB-1A	Administration building machine shop, locker rooms, stores and lunch room (Elev. 272)/ reactor building eastside (Elev. 272), southeast quadrant (Elev. 300), entire floor at Elev. 326, 344, and 369	2.54E-07	0.992
Relay room	RR-1	Relay room (Elev. 286)	5.40E-06	21.095
	RR-1 AD-4	Relay room (Elev. 286)/admin. bldg. office area, records area, computer rooms and technical support center (Elev. 286)/	3.80E-07	1.484
	RR-1 /RB-1A	Relay room (Elev. 286)/ reactor building eastside (Elev. 272), southeast quadrant (Elev. 300), entire floor at Elev. 326, 344, and 369	1.33E-08	0.052
	RR-1 /TB-1	Relay room (Elev. 286)/ turbine building (Elev. 252, 272, 292, 300)	1.33E-08	0.052
Turbine Building	TB-1	Turbine room or hall or building (Elev. 252, 272, 292, 300)	3.73E-07	1.457
	TB-1 /CT-2	Turbine building (Elev. 252, 272, 292, 300)/ east cable tunnel (Elev. 260)	2.89E-07	1.129
	TB-1 /RR-1	Turbine building (Elev. 252, 272, 292, 300)/ relay room (Elev. 286)	6.26E-07	2.445
Standby Gas Treatment Building	SG-1 /RB-1A	Standby gas filter room (Elev. 272)/ reactor building eastside (Elev. 272), southeast quadrant (Elev. 300), entire floor at Elev. 326, 344, and 369	3.72E-08	0.145
			2.56E-05	100.0

E.1.4 PSA Model Peer Review and Difference between JAFNPP Revision 2 PSA Model and Original IPE Model

E.1.4.1 PSA Model Peer Review

The draft of the Revision 1 PSA model was peer reviewed in December 1997 using the BWROG PSA Peer Review Certification Implementation Guidelines. Facts and Observation sheets documented the certification teams' insights and potential level of significance. The certification team concluded that the PSA model was sufficient to support meaningful rankings for the assessment of systems, structures, and components, when combined with deterministic insights, and would be fully capable of supporting absolute risk determination applications when footnoted items are addressed. All issues and observations from the BWROG Peer Review (i.e., Level A, B, C, and D observations, including footnoted items) have been addressed and incorporated into the PSA model used for the SAMA analysis (JAFNPP Revision 2, October 2004). Therefore, the 2004 PSA model is appropriate for use in the SAMA analysis.

For the PSA model update, individual work packages (event tree, fault tree, human reliability analysis (HRA), data, etc.), and internal flooding analysis were circulated to each PSA member for independent peer review. The accident sequence packages, system work packages, HRA, and internal flooding analyses were also assigned to the appropriate JAFNPP plant personnel for review. For example, event trees, system analyses, and fault tree models were forwarded to the applicable plant systems engineers and the HRA was assigned to individuals from the plant Operations Training department for review. Similarly, the accident sequence packages, system work packages, HRA report, containment performance analysis, fault tree, and event tree models, and Level 2 models were peer reviewed by an outside consultant.

The Entergy license renewal project team and plant staff reviewed consequence and risk estimates for the SAMA analyses.

The peer review process emphasized the role of plant staff, external consultants, and BWROG PSA certification in this recent model update. The peer reviews served to ensure the accuracy of both the assumptions made in the models and the results. The results of the peer review and resolutions are presented in Section 5 of "James A FitzPatrick Nuclear Power Plant Individual Plant Examination for Internal Events," Revision 2, October 2004 [Reference E.1-1].

E.1.4.2 Major Differences between the JAFNPP Revision 2 PSA Model and Original IPE Model

E.1.4.2.1 Core Damage—Comparison to the Original IPE Model

Significant changes have been made to the PSA models since completion of the original IPE. These changes were made to reflect new data, new calculations, and modifications to the plant design and procedures, and to incorporate results of the BWROG peer review.

E.1.4.2.1.1 Changes to Calculations and Databases

This updated PSA made use of the following:

- an updated initiating event database that includes all scrams and a blackout event that occurred between 7/28/1975 and 12/31/2003;
- an updated component failure database that includes failure and unavailability data from the 8 years of plant operation between 1/1/1995 and 12/31/2002 (The updated database includes more common-cause failure equipment groups and reflects current on-line maintenance practices.); and
- revised calculation of station battery depletion time from 8 hours to 4 hours, decreasing the available time for recovery of loss of offsite power during an SBO event from 13 to 7 hours.

E.1.4.2.1.2 Changes to PSA Model and Data to Reflect Design and Procedure Modifications

Changes were made to the PSA model to reflect design and procedure modifications subsequent to the original IPE. These modifications include the following.

- A modification to the fire protection system allows it to supply EDG jacket cooling water directly through the ESW system cross-tie. This modification reduces the contribution to plant risk by the dominant SBO event. A step to direct the operator to use this cross-tie has been incorporated in procedures.
- Bonnet vents were installed on the LPCI and core spray injection valves to preclude common-cause pressure locking of the valves.
- A new keylock bypass switch allows LPCI and core spray injection valves to be manually opened from the control room. The switch can be used to help recover from reactor pressure permissive logic failures that cause low-pressure system injection valves to remain closed. Use of this switch reduces the probability of core damage during LOCAs and transients with stuck open SRVs in which all low-pressure ECCSs are unavailable.
- A new keylock bypass switch allows HPCI auto-transfer on high suppression pool level to be bypassed from the control room, rather than the relay room. This action is important in ATWS events with MSIVs closed and in handling other transients and LOCAs. Steps directing operators to use this switch in accident sequences identified in the original IPE have been incorporated in procedures.
- RHR minimum flow bypass valves were changed from normally closed to normally open. This modification reduces the probability of pump damage as a result of loss of one emergency bus.

- Switches were installed to permit transfer to the alternative power supply for LPCI injection valves to occur from the control room.
- RCIC enclosure fan power supply changed from an AC feed to an AC inverter feed from a DC power source. This modification enhances the availability of RCIC enclosure ventilation during SBO events.
- SRV alternate actuation system and ATWS recirculation pump level trip were modified.
- Service, instrument, and breathing air compressors were replaced.
- RCIC turbine exhaust trip set points were increased.
- Operators are directed to enhance CRD flow in certain accident sequences.
- A new procedure directs operators to align the fire protection system to the tube side of the RHR heat exchanger in loss of containment heat removal accident sequences.
- Revised SBO procedures explicitly address bus recovery.
- Revised procedure directs operators to locally open valves 27AOV-117 and 27AOV-118 should it not be possible to open these valves from the relay room during loss of containment heat removal sequences (provisions were made to permanently stage tools to allow for local manual operation of the vent valves).
- Improved technical specifications (ITS) and change of the ATTS (Analog Transmitter Trip System) instrumentation surveillance frequency from monthly to quarterly altered unavailability data.

E.1.4.2.1.3 Changes to PSA Model to Incorporate Peer Review Recommendations

- The core damage definition was changed from the original definition given in NUREG/ CR-4550, "Analysis of Core Damage Frequency – Internal Events Methodology," which defines core damage as reactor water level less than two feet above the bottom of the active fuel, to the definition given in EPRI Report TR-105396, "PSA Applications Guide," which defines core damage as peak clad temperatures greater than or equal to 2200°F. The greatest impact of the change in core damage definition was a decrease in time available for operators to perform post-accident actions and thus an increase in the human error probabilities (HEPs) for certain actions.
- Additional initiating events and associated event trees were added for loss of non-safeguard 4.16kv AC buses 10300 and 10400, loss of condensate system, loss of instrument air system, loss of ultimate heat sink, loss of reactor water vessel level instrumentation reference leg, and manual shutdown. These additional event trees contributed to an increased CDF contribution from containment heat removal.

- The event tree modeling structure was revised to move the containment pressure control function before the core cooling injection function. In addition, continued operation of both HPCI and RCIC during an accident that involves a loss of containment heat removal is precluded because primary system depressurization would be required on HCTL (High Capacity Temperature Limit). These changes contributed to an increased CDF contribution from the loss of containment heat removal.

- Fault trees were modified to include additional common-cause equipment failure groups such as fans, check valves, dampers, and electrical and I&C components (circuit breakers, relays, and transmitters). In addition, the common cause failure analysis was revised to incorporate NRC-recommended alpha factor methodology.

- The loss of DC battery control board models were revised to assume loss of all AC power in the same division in which there is a loss of DC power.

- A catastrophic common cause failure of both 125V DC battery control boards 71BCB-2A and 71BCB-2B was included as an initiator, which results in an SBO with loss of HPCI and RCIC and subsequent core damage.

- A catastrophic, non-recoverable failure of the reactor pressure vessel was included as an initiator. This resulted in a higher LOCA contribution to the overall CDF.

- Core damage sequences which entail immediate loss of high pressure systems, such as HPCI or RCIC, were revised to directly result in core damage upon a subsequent failure to manually depressurize the reactor vessel. Operators are directed to inhibit ADS for transients and ATWS events. Therefore, a failure to manually depressurize the reactor will fail ADS.

- The standby liquid control (SLC) system model was changed to result in core damage following failure to initiate SLC. This change, along with updated human reliability probabilities increased the ATWS contribution to CDF.

- The offsite power recovery model was revised to reflect loss of offsite power events in NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996," in conjunction with the EPRI TR-1009889, "Losses of Off-site Power at U.S. Nuclear Power Plants-Through 2003."

- The human reliability analysis was updated to incorporate emergency operating procedure changes, DC power load shedding to extend battery life in the event of an SBO, use of the firewater crosstie to RHR/LPCI injection path through RHRSW loop A, and alignment of CST flow to the core spray system for core cooling during a loss of the ultimate heat sink.

- The 125VDC power system fault tree model logic pertaining to battery and charger failure was changed from an "AND" gate to an "OR" gate (NRC SDP notebook benchmarking comment).

- Rupture of fire protection system piping and fire suppression effects analysis were considered in the internal flooding analysis.

- The accident sequence quantification truncation limit was lowered from 10^{-9} to 10^{-11}. This resulted in the inclusion of more accident sequence minimal cut sets, raising the overall CDF.

E.1.4.2.2 Containment Performance—Comparison to the Original IPE Model

Noteworthy changes have been made to the Large Early Release PSA model since completion of the original IPE. These changes were made to reflect updated Level 2 methodology and to incorporate recommendations from the BWROG peer review.

E.1.4.2.2.1 Changes Due to Updated Containment Performance Methodology

- The original IPE Level 2 model was transferred into the same software used for the Level 1 model (changed from Event Progress Analysis Code-EVNTRE to CAFTA).

- The Level 1 and Level 2 models are now one integrated fault tree model; propagation of Level 1 cutsets to the Level 2 CET was developed. This ensures that mitigating systems degraded in Level 1 sequences are not considered in the containment event fault tree models.

- A detailed LERF model was developed to ensure that LERF calculations are consistent with the PSA Applications Guide and NRC requirements for Reg. Guide 1.174 [Reference E.1-12].

- Because transients initiated by a loss-of-containment heat removal (TW) result in containment failure more than six hours after the initiation of the event, these events are now considered late releases instead of early releases. The removal of TW sequences decreases the LERF contribution.

- The probabilities of drywell liner melt-through from core debris melt were changed to reflect current industry understanding of the impact of water on the drywell floor. Analysis by Theofanous [Reference E.1-13] indicates a liner melt-through probability of 10^{-4} or less for low-pressure sequences with a flooded drywell and a probability of 0.6 for dry drywell and low RPV pressure. This change contributes to a decreased LERF contribution from drywell liner melt-through failure.

- JAFNPP Severe Accident Operating Guidelines (SAOGs) mitigating strategies for primary containment flooding, drywell sprays, and reactor vessel depressurization were modeled.

- Containment event fault tree models were revised to allow credit for AC power recovery following core damage. This ensures that the models do not allow SBO core damage sequences to benefit from AC supported equipment in Level 2 without explicit consideration of AC power recovery. This change increases the LERF, since potential mitigating actions from plant systems that rely on AC power must consider AC power restoration.

E.1.4.2.2.2 Changes to Containment Performance PSA Model to Incorporate Peer Review Recommendations

- Included the ISLOCA and vessel rupture plant damage states in the containment performance analysis to ensure that the LERF contribution is captured.

- Revised model to include the impact of high containment pressure and high RPV pressure on early containment failure. The combination of high containment pressure concurrent with RPV failure at high pressure increases the likelihood of early containment failure and therefore, contributes to an increase in LERF.

- Included primary containment flooding and RPV venting as directed by the SAOGs.

- Incorporated containment failure due hydrogen phenomena given deinerted containment.

- The primary containment isolation fault tree model was updated to reflect the failure of a greater number of containment isolation valves. In addition, the primary containment isolation fault tree takes into consideration the potential for either a large or small pre-existing containment leak.

- Incorporated a number of operator actions for severe accident mitigation.

- Incorporated a containment failure mode related to flooding and loss of vapor suppression, accounted for RPV venting, and considered the drywell spray initiation limit curve in the assessment of drywell spray viability.

E.1.5 The MACCS2 Model—Level 3 Analysis

E.1.5.1 Introduction

SAMA evaluation relies on Level 3 PRA results to measure the effects of potential plant modifications. A Level 3 PRA model using the MELCOR Accident Consequences Code System Version 2 (MACCS2) [Reference E.1-4] was created for JAFNPP. This model, which requires detailed site-specific meteorological, population, and economic data, estimates the consequences in terms of population dose and offsite economic cost. Risks in terms of population dose risk (PDR) and offsite economic cost risk (OECR) were also estimated in this analysis. Risk is defined as the product of consequence and frequency of an accidental release.

This analysis considers a base case and two sensitivity cases to account for variations in data and assumptions for postulated internal events. The base case uses estimated time and speed for evacuation. Sensitivity case 1 is the base case with delayed evacuation. Sensitivity case 2 is the base case with lower evacuation speed.

PDR was estimated by summing over all releases the product of population dose and frequency for each accidental release. Similarly, OECR was estimated by summing over all releases the product of offsite economic cost and frequency for each accidental release. Offsite economic cost includes costs that could be incurred during the emergency response phase and costs that could be incurred through long-term protective actions.

E.1.5.2 Input

The following sections describe the site-specific input parameters used to obtain the off-site dose and economic impacts for cost-benefit analyses.

E.1.5.2.1 Projected Total Population by Spatial Element

The total population within a 50-mile radius of JAFNPP was estimated for the year 2034, the end of the proposed license renewal period, for each spatial element by combining total resident population projections with transient populations. The 2034 permanent population was estimated by extrapolating the county-level resident projections (2000 to 2030) obtained from the New York Statistical Information System to the target year (2034) using least squares regression. The 2034 transient population was assumed to be the 2003 transient to population ratio multiplied by the extrapolated permanent population. The 2003 transient data were obtained from the Northern New York Travel and Tourism Research Center. Table E.1-13 shows the estimated population distribution.

Table E.1-13
Estimated Population Distribution within a 50-Mile Radius

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	50-Mile Total
N	2	0	478	1,575	10,083	12,138
NNE	2	175	4,478	7,760	15,097	27,512
NE	4	2,956	8,730	10,887	14,197	36,774
ENE	49	6,652	11,603	6,731	3,458	28,493
E	1,273	7,189	11,900	8,657	8,292	37,311
ESE	2,528	7,576	12,341	25,316	31,724	79,485
SE	2,349	6,556	14,600	26,380	23,200	73,085
SSE	2,245	6,907	42,086	69,218	88,045	208,501
S	2,496	7,098	46,518	62,901	53,488	172,501
SSW	2,445	7,427	10,201	15,406	15,227	50,706
SW	2,484	6,304	13,959	23,198	27,139	73,084
WSW	414	242	464	5,874	18,417	25,411
W	26	0	0	0	0	26
WNW	7	0	0	0	875	882
NW	3	0	0	989	9,520	10,512
NNW	2	0	10	42	2,619	2673
Total	16,329	59,082	177,368	264,934	321,381	839,094

E.1.5.2.2 Land Fraction

The land fraction for each spatial element was estimated within the 50-mile radius area. The National Hydrography Dataset was used to estimate the extent of land and surface water coverage.

E.1.5.2.3 Watershed Class

There are two watershed types in the 50-mile zone surrounding JAFNPP: large lake and land drained by rivers. For JAFNPP, spatial elements comprised of 10% or more Lake Ontario were treated as large lake. All other areas were treated as land drained by rivers.

E.1.5.2.4 Regional Economic Data

County level economic data were obtained from the US Department of Agriculture for 2002.

Region Index

Each spatial element was assigned to an economic region, defined in this report as a county. Where a spatial element covers portions of more than one county, it was assigned to that county having the most area within the element.

VALWF—Value of Farm Wealth

MACCS2 requires an average value of farm wealth (dollars/hectare) for the 50-mile radius area around JAFNPP. The county-level farmland property value was used as a basis for deriving this value. VALWF is $4,645/hectare.

VALWNF—Value of Non-Farm Wealth

MACCS2 also requires an average value of non-farm wealth. The county-level non-farm property value was used as a basis for deriving this value. VALWNF is $99,351/ person.

Other economic parameters and their values are shown below. The values were obtained by adjusting the economic data from a past census given as default values in Reference E.1-4 with the consumer price index of 179.9, which is the average value for the year 2002, as appropriate.

Variable	Description	Value
EVACST	Daily cost for a person who has been evacuated ($/person-day)	43.0
POPCST	Population relocation cost ($/person)	7960
RELCST	Daily cost for a person who is relocated ($/person-day)	43.0
CDFRM0	Cost of farm decontamination for the various levels of decontamination ($/hectare)	895.5 1990
CDNFRM	Cost of non-farm decontamination for the various levels of decontamination ($/person)	4776 12736
DLBCST	Average cost of decontamination labor ($/person-year)	55721
DPRATE	Property depreciation rate (per year)	0.2
DSRATE	Investment rate of return (per year)	0.12

E.1.5.2.5 Agriculture Data

The source of regional crop information is the 2002 Census of Agriculture. The crops listed for each county within the 50-mile area were summed and mapped into the seven MACCS2 crop categories.

E.1.5.2.6 Meteorological Data

The MACCS2 model requires meteorological data for wind speed, wind direction, atmospheric stability, accumulated precipitation, and atmospheric mixing heights. The required data was obtained from the Nine Mile Point / JAFNPP meteorological monitoring system and regional National Weather Service stations.

JAFNPP meteorological monitoring system, which is operated jointly with Nine Mile Point nuclear, includes both primary and backup systems. The primary meteorological system was the data source for the MACCS2 input file. Based on a review of annual meteorological data collected at the site between 1985 and 2001, data from calendar year 1994 were selected for the MACCS2 input file. The year 1994 was considered to be a representative year because data of interest contained no significant extremes and reflected average meteorological conditions at the site. Over 98% of the hourly observations in 1994 were recorded successfully. Missing data for parameters of interest were estimated using data substitution methods. These methods include interpolation between valid data and substitution of valid data collected from upper elevations on the met tower.

Mixing height is defined as the height of the atmosphere above ground level within which a released contaminant will become mixed (from turbulence) within approximately one hour. JAFNPP mixing height data were estimated using the ground-level and upper-air data from the National Weather Service.

E.1.5.2.7 Emergency Response Assumptions

A detailed analysis of evacuation scenarios in EPZ were addressed in the JAFNPP evacuation travel time estimate study. The study was conducted in 2003 and provides an analysis of the range and variation of public reaction to the evacuation notification process.

The elapsed time between the issuance of an evacuation notification and the beginning of the public evacuation is 2.25 hours. A sensitivity case that assumes 4.5 hours for evacuees to begin evacuation was considered in this study to evaluate consequence sensitivities due to uncertainties in delay time.

Evacuation travel speed ranges from 5.7 miles/hour (2.5 meters/second) to 3.1 miles/hour (1.4 meters/sec). The average evacuation speed was conservatively estimated to be approximately 4.4 miles/hour (2.0 meters/second). A sensitivity case that assumes a lower evacuation speed of 1.0 meter/second was considered in this study to evaluate consequence sensitivities due to uncertainties in evacuation speed.

The entire population (or 100% of the population) within the 10-mile emergency planning zone was assumed to evacuate.

E.1.5.2.8 Core Inventory

The estimated JAFNPP core inventory (Table E.1-14) used in the MACCS2 input is based on a power level of 2536 MWt.

Table E.1-14
JAFNPP Core Inventory (Becquerels)[1]

Nuclide	Inventory	Nuclide	Inventory	Nuclide	Inventory
Co-58	1.44E+16	Ru-103	3.46E+18	Cs-136	1.06E+17
Co-60	1.72E+16	Ru-105	2.31E+18	Cs-137	2.38E+17
Kr-85	2.35E+16	Ru-106	9.41E+17	Ba-139	4.69E+18
Kr-85m	8.55E+17	Rh-105	1.72E+18	Ba-140	4.62E+18
Kr-87	1.55E+18	Sb-127	2.18E+17	La-140	4.72E+18
Kr-88	2.10E+18	Sb-129	7.57E+17	La-141	4.36E+18
Rb-86	1.32E+15	Te-127	2.11E+17	La-142	4.19E+18
Sr-89	2.60E+18	Te-127m	2.84E+16	Ce-141	4.20E+18
Sr-90	1.84E+17	Te-129	7.10E+17	Ce-143	4.09E+18
Sr-91	3.38E+18	Te-129m	1.87E+17	Ce-144	2.72E+18
Sr-92	3.53E+18	Te-131m	3.59E+17	Pr-143	4.00E+18
Y-90	1.97E+17	Te-132	3.51E+18	Nd-147	1.79E+18
Y-91	3.18E+18	I-131	2.42E+18	Np-239	5.33E+19
Y-92	3.55E+18	I-132	3.56E+18	Pu-238	3.71E+15
Y-93	4.03E+18	I-133	5.08E+18	Pu-239	9.39E+14
Zr-95	4.18E+18	I-134	5.57E+18	Pu-240	1.18E+15
Zr-97	4.31E+18	I-135	4.79E+18	Pu-241	2.02E+17
Nb-95	3.96E+18	Xe-133	5.09E+18	Am-241	2.06E+14
Mo-99	4.56E+18	Xe-135	1.21E+18	Cm-242	5.44E+16
Tc-99m	3.94E+18	Cs-134	3.97E+17	Cm-244	2.93E+15

1. Derived from Reference E.1-14 for a power level of 2536 MWth with an increase of 25% for long half-life nuclides Sr-90, Cs-134, and Cs-137 to reflect the average core exposure at JAFNPP

E.1.5.2.9 Source Terms

Three release categories, corresponding to internal event sequences, were part of the MACCS2 input. Section E.1.2.2.6 provides details of the source terms for postulated internal events. A linear release rate was assumed between the time the release started and the time the release ended.

E.1.5.3 Results

Risk estimates for one base case and two sensitivity cases were analyzed with MACCS2. The base case assumes 2.25 hours delay and 2.0 meter/sec speed of evacuation. Sensitivity Case 1 is the base case with delayed evacuation of 4.5 hours. Sensitivity Case 2 is the base case with an evacuation speed of 1.0 meter/sec.

Table E.1-15 shows estimated base case mean risk values for each release mode. The estimated mean values of PDR and offsite OECR for JAFNPP are 1.63 person-rem/yr and $3,340/yr, respectively.

Table E.1-15
Base Case Mean PDR and OECR Values

Release Mode	Frequency (/yr)	Population Dose (person-sv)[1]	Offsite Economic Cost ($)	Population Dose Risk (PDR) (person-rem/yr)	Offsite Economic Cost Risk (OECR) ($/yr)
NCF	8.75E-07	9.15E+00	6.06E+05	8.01E-04[2]	5.30E-01
EARLY	5.92E-07	1.28E+04	2.75E+09	7.58E-01	1.63E+03
LATE	1.28E-06	6.81E+03	1.34E+09	8.69E-01	1.71E+03
			Totals	**1.63E+00**	**3.34E+03**

1. 1 sv = 100 rem
2. 8.01E-04 (person-rem/yr) = 8.75E-07 (/yr) x 9.15E+00 (person-sv) x 100 (rem/sv)

Results of sensitivity analyses indicate that a delayed evacuation or a lower evacuation speed would not have any significant effects on the offsite consequences or risks determined in this study. Table E.1-16 summarizes offsite consequences in terms of population dose (person-sv) and offsite economic cost ($) for the base case and the sensitivity cases. Comparison of the consequences indicates that the maximal deviation is less than 1% between the base case population dose and the Sensitivity Case 1 population dose for release mode EARLY.

Table E.1-16
Summary of Offsite Consequence Sensitivity Results

	Population Dose (person-sv)			Offsite Economic Cost ($)		
Release Mode	**Base Case**	**4.5-hr Delayed Evacuation**	**Lower Speed of Evacuation**	**Base Case**	**4.5-hr Delayed Evacuation**	**Lower Speed of Evacuation**
NCF	9.146E+00	9.149E+00	9.149E+00	6.06E+05	6.06E+05	6.06E+05
Early	1.275E+04	1.279E+04	1.277E+04	2.75E+09	2.75E+09	2.75E+09
Late	6.810E+03	6.810E+03	6.810E+03	1.34E+09	1.34E+09	1.34E+09

E.1.6 References

E.1-1 ENN Engineering Report JAF-RPT-MULTI-02107, "James A FitzPatrick Nuclear Power Plant Individual Plant Examination for Internal Events," Revision 2, October 2004.

E.1-2 Modular Accident Analysis Program Boiling Water Reactor (MAAP BWR) Code, Version 4.0.4 and Fauske & Associates, Inc., "MAAP 4.0 Users manual," prepared for The Electric Power Research Institute, May 1994.

E.1-3 Kaiser, "The Implications of Reduced Source Terms for Ex-Plant Consequence Modeling," Executive Conference on the Ramifications of the Source Term (Charleston, SC), March 12, 1985.

E.1-4 Chanin, D. I., and Young, M. L., Code Manual for MACCS2: Volume 1, User's Guide, SAND97-0594, Sandia National Laboratories, Albuquerque, NM, 1997.

E.1-5 New York Power Authority, "James A. FitzPatrick Nuclear Power Plant Individual Plant Examination for External Events," (JAF-RPT-MISC-02211), June 1996, Revision 0.

E.1-6 SQUG, "Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment", Revision 2, Corrected, February 14, 1992.

E.1-7 NUREG-1407, *Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities*, U.S. Nuclear Regulatory Commission, June 1991.

E.1-8 EPRI NP-6041-SL, *A Methodology for Assessment of Nuclear Power Plant Seismic Margin*, Electric Power Research Institute, Revision 1, August 1991.

E.1-9 NUREG-1742, *Perspectives Gained From the Individual Plant Examination of External Events (IPEEE) Program*, Volume 1 & 2, Final Report, U.S. Nuclear Regulatory Commission, April 2002.

E.1-10 EPRI TR-105928, *EPRI Fire PRA Implementation Guide*, Electric Power Research Institute, December 1995.

E.1-11 EPRI TR-100370, *Fire-Induced Vulnerability Evaluation*, Electric Power Research Institute, April 1992.

E.1-12 EPRI TR-105396, *PSA Applications Guide*, Electric Power Research Institute, August 1995.

E.1-13 NUREG/CR-5423, *The Probability of Liner Failure In a Mark-I Containment*, T.G. Theofanous, et al. for U.S. Nuclear Regulatory Commission, August 1991.

E.1-14 NUREG/CR-4551, *Evaluation of Severe Accident Risks: Quantification of Major Input Parameters*, Vol. 2, Rev. 1, Part 7, MACCS Input, December 1990.

ATTACHMENT E.2

SAMA CANDIDATES SCREENING AND EVALUATION

E.2 EVALUATION OF SAMA CANDIDATES

This section describes the generation of the initial list of potential SAMA candidates, screening methods, and the analysis of the remaining SAMA candidates.

E.2.1 SAMA List Compilation

A list of SAMA candidates was developed by reviewing industry documents and considering plant-specific enhancements not identified in published industry documents. Since JAFNPP is a conventional GE nuclear power reactor, considerable attention was paid to the SAMA candidates from SAMA analyses for other GE plants. Industry documents reviewed include the following.

- Hatch SAMA Analysis (Reference E.2-1)
- Calvert Cliffs Nuclear Power Plant SAMA Analysis (Reference E.2-2)
- GE ABWR SAMDA Analysis (Reference E.2-3)
- Peach Bottom SAMA Analysis (Reference E.2-4)
- Quad Cities SAMA Analysis (Reference E.2-5)
- Dresden SAMA Analysis (Reference E.2-6)
- Arkansas Nuclear One Unit 2 SAMA Evaluation (Reference E.2-7)

The above documents represent a compilation of most SAMA candidates developed from the industry documents. These sources of other industry documents include the following.

- Limerick SAMDA cost estimate report (Reference E.2-8)
- NUREG-1437 description of Limerick SAMDA (Reference E.2-9)
- NUREG-1437 description of Comanche Peak SAMDA (Reference E.2-10)
- Watts Bar SAMDA submittal (Reference E.2-11)
- TVA response to NRC's RAI on the Watts Bar SAMDA submittal (Reference E.2-12)
- Westinghouse AP600 SAMDA (Reference E.2-13)
- NUREG-0498, Watts Bar Final Environmental Statement, Supplement 1, Section 7 (Reference E.2-14)
- NUREG-1560, Volume 2, NRC Perspectives on the IPE Program (Reference E.2-15)
- NUREG/CR-5474, Assessment of Candidate Accident Management Strategies (Reference E.2-16)

In addition to SAMA candidates from review of industry documents, SAMA candidates were obtained from plant-specific sources, such as the JAFNPP IPE and updates (Reference E.2-17) and IPEEE (Reference E.2-18). In the original IPE, PSA model updates, and IPEEE several enhancements related to severe accident insights were recommended and implemented. The JAFNPP Revision 2 PSA levels 1 and 2 models were also used to identify plant-specific modifications for inclusion in the comprehensive list of SAMA candidates. The risk significant terms from the JAFNPP Revision 2 PSA model were reviewed for similar failure modes and effects that could be addressed through a potential enhancement to the plant. The correlation between SAMAs and the risk significant terms are listed in Table E.1-2 and Table E.1-6.

The comprehensive list contained a total of 293 phase I SAMA candidates and is available in onsite documentation.

E.2.2 Qualitative Screening of SAMA Candidates (Phase I)

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at JAFNPP. Potential SAMA candidates were screened out if they modified features not applicable to JAFNPP, if they had already been implemented at JAFNPP, 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. During this process, 64 of the phase I SAMA candidates were screened out because they were not applicable to JAFNPP, 7 of the phase I SAMA candidates were screened out because they were similar in nature and could be combined with another SAMA candidate, and 159 of the phase I SAMA candidates were screened out because they had already been implemented at JAFNPP, leaving 63 SAMA candidates for further analysis. The final screening process involved identifying and eliminating those items whose implementation cost would exceed their benefit as described below. Table E.2-1 provides a description of each of the 63 phase II SAMA candidates.

E.2.3 Final Screening and Cost Benefit Evaluation of SAMA Candidates (Phase II)

A cost/benefit analysis was performed on each of the remaining SAMA candidates. If the implementation cost of a SAMA candidate was determined to be greater than the potential benefit (i.e. there was a negative net value) the SAMA candidate was considered not to be cost beneficial and was not retained as a potential enhancement.

The expected cost of implementation of each SAMA was established from existing estimates of similar modifications. Most of the cost estimates were developed from similar modifications considered in previously performed SAMA and SAMDA analyses. In particular, these cost-estimates were derived from the following major sources.

- GE ABWR SAMDA Analysis (Reference E.2-3)
- Peach Bottom SAMA Analysis (Reference E.2-4)
- Quad Cities SAMA Analysis (Reference E.2-5)
- ANO-2 SAMA Analysis (Reference E.2-7)

The cost estimates 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 (or estimation), and were not adjusted to present-day dollars. In addition, several implementation costs were originally developed for SAMDA analyses (i.e., during the design phase of the plant), and therefore, do not capture the additional costs associated with performing design modifications to existing plants (i.e., reduced efficiency, minimizing dose, disposal of contaminated material, etc.). Therefore, the cost estimates were conservative.

The benefit of implementing a SAMA candidate was estimated in terms of averted consequences. The benefit was estimated by calculating the arithmetic difference between the total estimated costs associated with the four impact areas for the baseline plant design and the total estimated impact area costs for the enhanced plant design (following implementation of the SAMA candidate).

Values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NUREG/BR-0184 (Reference E.2-19) 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.

As this analysis focuses on establishing the economic viability of potential plant enhancement when compared to attainable benefit, detailed cost estimates often were not required to make informed decisions regarding the economic viability of a particular modification. 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 on the cost associated with procedural changes, engineering analysis, testing, training, and hardware modification was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. Based on a review of previous submittals' SAMA evaluations and an evaluation of expected implementation costs at JAFNPP, the following estimated costs for each potential element of the proposed SAMA implementation were used.

Type of Change	Estimated Cost Range
Procedural only	$25K-$50K
Procedural change with engineering required	$50K-$200K
Procedural change with engineering and testing/training required	$200K-$300K
Hardware modification	$100K to >$1000K

In most cases, more detailed cost estimates were not required, particularly if the SAMA called for the implementation of a hardware modification. Nonetheless, the cost of each unscreened SAMA 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 63 phase II SAMA candidates is presented in Table E.2-1.

Bounding evaluations (or analysis cases) were performed to address specific SAMA candidates or groups of similar SAMA candidates. These analysis cases overestimated the benefit and thus were 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 040 of Table E.2-1). This calculation obviously overestimated the benefit, but if the inflated benefit indicated that the SAMA candidate was not cost-beneficial, then the purpose of the analysis was satisfied.

A description of the analysis cases used in the evaluation follows.

Additional Emergency Service Water Pump

This analysis case was used to evaluate the change in plant risk from installing an additional emergency service water pump. An additional emergency service water pump reduces the impact of common cause failures on the emergency service water system. A bounding analysis was performed by setting the CDF contribution due to the common cause failures of two emergency service water pumps to start and to continue to run to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $18,416. This analysis case was used to model the benefit of phase II SAMA 1.

Decay Heat Removal Capability – Torus Cooling

This analysis case was used to evaluate the change in plant risk from installing an additional decay heat removal system. Enhancements of decay heat removal capability decrease the probability of loss of containment heat removal. A bounding analysis was performed by setting the events for loss of the torus cooling mode of the RHR system to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $161,552. This analysis case was used to model the benefit of phase II SAMAs 2 and 15.

Decay Heat Removal Capability – Drywell Spray

This analysis case was used to evaluate the change in plant risk from installing an additional decay heat removal system. Enhancements of decay heat removal capability decrease the probability of loss of containment heat removal. A bounding analysis was performed by setting the events for loss of the drywell spray mode of the RHR system to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $158,368. This analysis case was used to model the benefit of phase II SAMA 10.

Filtered Vent

This analysis case was used to evaluate the change in plant risk from installing a filtered containment vent to provide fission product scrubbing. A bounding analysis was performed by reducing the successful torus venting accident progression source terms by a factor of 2 to reflect the additional filtered capability, which resulted in an upper bound benefit of approximately $65,440. This analysis case was used to model the benefit of phase II SAMAs 3 and 20.

Containment Vent for ATWS Decay Heat Removal

This analysis case was used to evaluate the change in plant risk from installing a containment vent to provide alternate decay heat removal capability during an ATWS event. A bounding analysis was performed by setting the ATWS sequences associated with containment bypass to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $112,080. This analysis case was used to model the benefit of phase II SAMAs 4 and 52.

Molten Core Debris Removal

This analysis case was used to estimate the change in plant risk from providing a molten core debris cooling mechanism. A bounding analysis was performed by setting containment failure due to core-concrete interaction (not including liner failure) to zero in the level 2 PSA model, which resulted in an upper bound benefit of approximately $55,104. This analysis case was used to model the benefit of phase II SAMAs 5, 6, 9, and 24.

Drywell Head Flooding

This analysis case was used to evaluate the change in plant risk from providing a modification to flood the drywell head such that if high drywell temperature occurred, the drywell head seal would not fail. A bounding analysis was performed by setting the probability of drywell head failure due to high temperature to zero in the level 2 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of phase II SAMAs 7, 19, and 21.

Reactor Building Effectiveness

This analysis case was used to evaluate the change in plant risk by ensuring the reactor building is available to provide effective fission product removal. Reactor building effectiveness was conservatively modeled by assuming reactor building availability for all accident sequences. This resulted in no benefit. This analysis case was used to model the benefit of phase II SAMAs 8, 14, and 22.

Strengthen Containment

This analysis case was used to evaluate the change in plant risk from strengthening containment to reduce the probability of containment over-pressurization failure. A bounding analysis was performed by setting all energetic containment failure modes (direct containment heating (DCH), steam explosions, late over-pressurization) to zero in the level 2 PSA model, which resulted in an upper bound benefit of approximately $120,544. This analysis case was used to model the benefit of phase II SAMAs 11, 16, 17, and 25.

Base Mat Melt-Through

This analysis case was used to evaluate the change in plant risk from increasing the depth of the concrete base mat to ensure base mat melt-through does not occur. A bounding analysis was performed by setting containment failure due to base mat melt-through to zero in the level 2 PSA model, which resulted in an upper bound benefit of approximately $1,712. This analysis case was used to model the benefit of phase II SAMA 12.

Reactor Vessel Exterior Cooling

This analysis case was used to evaluate the change in plant risk from providing a method to perform ex-vessel cooling of the lower reactor vessel head. A bounding analysis was performed by modifying the probability of vessel failure by a factor of two to account for ex-vessel cooling in the level 2 PSA model, which resulted in an upper bound benefit of approximately $27,552. This analysis case was used to model the benefit of phase II SAMA 13.

Vacuum Breakers

This analysis case was used to evaluate the change in plant risk from improving the reliability of vacuum breakers to reseat following a successful opening and eliminate suppression pool scrubbing failures from the containment analysis. A bounding analysis was performed by setting the vacuum breaker failure probability to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $89,552. This analysis case was used to model the benefit of phase II SAMA 18.

Flooding the Rubble Bed

This analysis case was used to evaluate the change in plant risk from providing a source of water to the drywell floor to flood core debris. A bounding analysis was performed by substituting the probabilities of wet core concrete interactions for dry core concrete interactions in the level 2 PSA model, which resulted in an upper bound benefit of approximately $13,776. This analysis case was used to model the benefit of phase II SAMA 23.

DC Power

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of Class 1E DC power (e.g., increasing battery capacity, using fuel cells, or extending SBO injection provisions). It was assumed that battery life could be significantly extended from the existing battery capacity. This enhancement would extend HPCI and RCIC operability and allow more credit for AC power recovery. A bounding analysis was performed by changing the time available to recover offsite power before HPCI and RCIC are lost from 7 hours to 24 hours during SBO scenarios in the level 1 PSA model. This resulted in an upper bound benefit of approximately $837,840. This analysis case was used to model the benefit of phase II SAMAs 26, 27, 30, 34, and 36.

Improve DC System

This analysis case was used to evaluate the change in plant risk from improving injection capability by auto-transfer of AC bus control power to a standby DC power source upon loss of the normal DC source or from enhancing procedure to make use of DC bus cross-tie to improve DC power availability and reliability. A bounding analysis was performed by setting the loss of DC battery control boards BCB-2A initiator to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $18,160. This analysis case was used to model the benefit of phase II SAMAs 29 and 35.

Alternate Pump Power Source

This analysis case was used to evaluate the change in plant risk from adding a small, dedicated power source such as a dedicated diesel or gas turbine for the feedwater or condensate pumps so that they do not rely on offsite power. A bounding analysis was performed by setting failure of the normal power supply to condensate pumps to zero in level 1 PSA model, which resulted in an upper bound benefit of approximately $13,248. This analysis case was used to model the benefit of phase II SAMA 31.

Incorporate Alternate Battery Charging Capability

This analysis case was used to evaluate the change in plant risk from incorporate alternate battery charging capability to improve DC power reliability by cross-tying AC buses or installing a portable diesel driven battery charger. A bounding analysis was performed by setting failure of both DC battery chargers 71BC-1A and 71BC-1B to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $33,808. This analysis case was used to model the benefit of phase II SAMA 28 and 61.

Dedicated DC Power and Additional Batteries and Divisions

This analysis case was used to evaluate the change in plant risk from plant modifications that would provide motive power to components (e.g., providing a dedicated DC power supply, additional batteries, or additional divisions). A bounding analysis was performed by setting the loss of DC battery control board BCB-2A initiator to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $18,160. This analysis case was used to model the benefit of phase II SAMAs 32 and 33.

Locate RHR Inside Containment

This analysis case was used to evaluate the change in plant risk from moving the RHR system inside containment to prevent an RHR system ISLOCA event outside containment. A bounding analysis was performed by setting the RHR ISLOCA sequences to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $13,248. This analysis case was used to model the benefit of phase II SAMA 37.

ISLOCA

This analysis case was used to evaluate the change in plant risk from reducing the probability of an ISLOCA by increasing the frequency of valve leak testing. A bounding analysis was performed by setting the ISLOCA initiator to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $28,752. This analysis case was used to model the benefit of phase II SAMA 38.

MSIV Design

This analysis case was used to evaluate the change in plant risk from improving MSIV design to decrease the likelihood of containment bypass scenarios. A bounding analysis was performed by setting the containment bypass failure due to MSIV leakage to zero in the level 2 PSA model, which resulted in an upper bound benefit of approximately $89,552. This analysis case was used to model the benefit of phase II SAMA 39.

Digital Feedwater Upgrade

This analysis case was used to evaluate the change in plant risk from installing a digital feedwater upgrade to reduce the probability of a loss of main feedwater following a plant trip. A bounding analysis was performed by setting the loss of main feedwater initiator to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $13,248. This analysis case was used to model the benefit of phase II SAMA 40.

Ability for Emergency Connections of Alternate Water Sources to Feedwater/ Condensate

This analysis case was used to evaluate the change in plant risk from providing the ability for emergency connections of alternate water sources to feedwater/condensate system for RPV injection during LOCAs and transients. A bounding analysis was performed by setting the CDF contribution due to the failure of alternate injection from feedwater/condensate system to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $13,248. This analysis case was used to model the benefit of phase II SAMA 41.

Diesel to Condensate Storage Tank (CST) Makeup Pumps

This analysis case was used to evaluate the change in plant risk from installing an independent diesel for the CST makeup pumps to allow continued operation of the high pressure injection system during an SBO event. As currently modeled, if CST water level is low, swapping HPCI/RCIC suction from the CST to the torus allows continued HPCI/RCIC injection. Therefore, a bounding analysis was performed by setting the failure to switchover from CST to torus to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $9,552. This analysis case was used to model the benefit of phase II SAMA 42.

Install Motor-Driven Feedwater Pump

This analysis case was used to evaluate the change in plant risk from installing a motor-driven feedwater pump to enhance the availability of feed water injection subsequent to MSIV closure. A bounding analysis was performed by setting the CDF contribution due to the failure of steam-driven feedwater pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of phase II SAMA 43.

High Pressure Injection System

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of high pressure injection (e.g., installing an independent AC powered high pressure injection system, passive high pressure injection system, or an additional high pressure injection system). A bounding analysis was performed by setting the CDF contribution due to unavailability of the HPCI system to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $33,808. This analysis case was used to model the benefit of phase II SAMAs 44, 45, 46, 48, and 49.

Improve the Reliability of High Pressure Injection System

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the reliability of the high pressure injection system. A bounding analysis was performed by reducing the HPCI system failure probability by a factor of three in the level 1 PSA model, which resulted in an upper bound benefit of approximately $24,256. This analysis case was used to model the benefit of phase II SAMA 47.

Ability to Align Diesel Power to Air Compressors

This analysis case was used to evaluate the change in plant risk from providing the ability for aligning emergency diesel power to all normal and backup air compressors to increase the reliability of instrument air after a loss offsite power event. A bounding analysis was performed by setting the failure probability of normal electrical power supply to all air compressors by a factor of ten in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of phase II SAMA 50.

SRV Reseat

This analysis case was used to evaluate the change in plant risk from improving the reliability of SRVs reseating. A bounding analysis was performed by setting the stuck open SRVs initiator and SRVs failing to re-close to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $73,152. This analysis case was used to model the benefit of phase II SAMA 51.

Diversity of Explosive Valves

This analysis case was used to evaluate the change in plant risk from providing an alternate means of opening a pathway to the RPV for SLC system injection, thereby improving success probability for reactor shutdown. A bounding analysis was performed by setting common cause failure of SLC explosive valves to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of phase II SAMA 53.

Passive Overpressure Relief

This analysis case was used to evaluate the change in plant risk from installing passive overpressure relief in the containment vent path to prevent catastrophic failure of containment during the loss of containment heat removal sequences. A bounding analysis was performed by reducing the CDF contribution of successful containment venting accident sequences by a factor of two in the level 1 PSA model, which resulted in an upper bound benefit of approximately $41,744. This analysis case was used to model the benefit of phase II SAMA 54.

CRD Flow Control Valve Failure Position

This analysis case was used to evaluate the change in plant risk from changing the CRD flow control valve position from failing closed to failing open upon loss of instrument air to improve the availability of the CRD system. A bounding analysis was performed by setting the CDF contribution from loss of the CRD system to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of phase II SAMA 55.

Large Break LOCA

This analysis case was used to evaluate the change in plant risk from installing a digital large break LOCA protection system. A bounding analysis was performed by setting the large break LOCA initiator to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of phase II SAMA 56.

Controlled Containment Venting

This analysis case was used to evaluate the change in plant risk from changing the containment venting procedure to establish a narrow pressure control band. This would prevent rapid containment depressurization when venting, thus avoiding adverse impact on the ability of the low pressure ECCS injection systems to take suction from the torus. A bounding analysis was performed by reducing the probability of the operator failing to recognize the need to vent the torus by a factor of three in the level 1 PSA model, which resulted in an upper bound benefit of approximately $295,152. This analysis case was used to model the benefit of phase II SAMA 57.

Cross-Tie of Fire Protection to RHR Loop B via RHRSW Loop B

This analysis case was used to evaluate the change in plant risk from installing a cross-tie from the fire protection system to RHR loop B heat exchanger via RHRSW loop B, for alternate decay heat removal during loss of containment heat removal sequences. A bounding analysis was performed by setting the CDF contribution from failure of the cross-tie from the fire protection system to RHR loop A heat exchanger via RHRSW loop A to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $8,352. This analysis case was used to model the benefit of phase II SAMA 58.

Cross-Tie between RHRSW Loops A and B

This analysis case was used to evaluate the change in plant risk from installing a cross-tie between RHRSW loops A and B downstream of the RHRSW pumps discharge valve. This design modification would to enhance the availability of RHRSW system injection and heat removal capabilities during LOCAs and transients. A bounding analysis was performed by setting the CDF contribution due to failure of RHRSW loop B to zero in the level 1 PSA model. This resulted in an upper bound benefit of approximately $225,168. This analysis case was used to model the benefit of phase II SAMA 59.

Improvements on Turbine Bypass Valve Capability

This analysis case was used to evaluate the change in plant risk from improving the availability of the turbine bypass valve to reduce the CDF during a transient. A bounding analysis was performed by setting the loss of power conversion system initiator to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $166,880. This analysis case was used to model the benefit of phase II SAMA 60.

Proceduralize Opening the EDG Building Doors

This analysis case was used to evaluate the change in plant risk from providing a procedure to open the EDG building doors upon receipt of a high temperature alarm to improve the reliability of the EDGs during LOCAs and transients. A bounding analysis was performed by reducing the failure probability of both EDGs to continue to run by a factor of three in the level 1 PSA model, which resulted in an upper bound benefit of approximately $463,600. This analysis case was used to model the benefit of phase II SAMA 62.

Additional Reactor Vessel Monitoring and Actuation System

This analysis case was used to evaluate the change in plant risk from providing additional reactor vessel level instrumentation. A bounding analysis was performed by setting the loss of instrument reference leg initiator to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $28,224. This analysis case was used to model the benefit of phase II SAMA 63.

E.2.4 Sensitivity Analyses

Two sensitivity analyses were conducted to gauge the impact of assumptions upon the analysis. The benefits estimated for each of these sensitivities are presented in Table E.2-2.

A description of each sensitivity case 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 28-year period for remaining plant life (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 was calculated using 28 years remaining until end of facility life to investigate the impact on each analysis case. Results of this sensitivity case for one SAMA (034) were slightly higher than the estimated cost. However, due to conservatisms in the benefit estimates and the sensitivity case results, and the fact that most of the costs were estimated only to the point of obtaining reasonable assurance that they were higher than the base case benefit estimate, SAMA 034 is not considered cost-effective.

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 7.0% used in the base case analyses is conservative relative to corporate practices. Nonetheless, a lower discount rate of 3.0% was assumed in this case to investigate the impact on each analysis case. Results of this sensitivity case for one SAMA (034) were slightly higher than the estimated cost. However, due to conservatisms in the benefit estimates and the sensitivity case results, and the fact that most of the costs were estimated only to the point of obtaining reasonable assurance that they were higher than the base case benefit estimate, SAMA 034 is not considered cost-effective.

E.2.5 References

E.2-1 Appendix D–Attachment F, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Edwin I. Hatch Nuclear Power Plant Units 1 and 2, March 2000.

E.2-2 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Calvert Cliffs Nuclear Power Plant*, Supplement 1, U.S. Nuclear Regulatory Commission, February 1999.

E.2-3 General Electric Nuclear Energy, Technical Support Document for the ABWR, 25A5680, Revision 1, January 18, 1995.

E.2-4 Appendix E— Environmental Report, Appendix G, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Peach Bottom Nuclear Power Plant Units 2 and 3, July 2001.

E.2-5 Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal for the Quad Cities Nuclear Power Plant Units 1 and 2, January 2003.

E.2-6 Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal for the Dresden Nuclear Power Plant Units 2 and 3, January 2003.

E.2-7 Appendix E—Attachment E, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Arkansas Nuclear One - Unit 2, October 2003.

E.2-8 Cost Estimate for Severe Accident Mitigation Design Alternatives, Limerick Generating Station for Philadelphia Electric Company, Bechtel Power Corporation, June 22, 1989.

E.2-9 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*, Volume 1, 5.35, Listing of SAMDAs considered for the Limerick Generating Station, U.S. Nuclear Regulatory Commission, May 1996.

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E.2-11 Museler, W.J. (Tennessee Valley Authority) to NRC Document Control Desk, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDAs)," letter dated October 7, 1994.

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E.2-14 NUREG-0498, *Final Environmental Statement Related to the Operation of Watts Bar Nuclear Plant, Units 1 and 2*, Supplement No. 1, U.S. Nuclear Regulatory Commission, April 1995.

E.2-15 NUREG-1560, *Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance*, Volume 2, U.S. Nuclear Regulatory Commission, December 1997.

E.2-16 NUREG/CR-5474, *Assessment of Candidate Accident Management Strategies*, U.S. Nuclear Regulatory Commission, March 1990.

E.2-17 New York Power Authority, "James A FitzPatrick Nuclear Power Plant Individual Plant Examination for Internal Events," Revision 0, September 1991.

E.2-18 New York Power Authority, "James A FitzPatrick Nuclear Power Plant Individual Plant Examination of External Events," (JAF-RPT-MISC-02211) June 1996.

E.2-19 NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook*, U.S. Nuclear Regulatory Commission, January 1997.

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
Improvements Related to RCP Seal LOCAs (Loss of CCW or SW)								
001	8.a. Add a service water pump.	SAMA would reduce the impact of common cause failures on the SW system.	0.91%	1.07%	$1,151	$18,416	$5,900,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to common cause failure of ESW pumps to start and to continue to run was eliminated to conservatively assess the potential benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be $5.9 million. Therefore, this SAMA is not cost effective for JAFNPP.							
Improvements Related to Accident Mitigation Containment Phenomena								
002	Install an independent method of suppression pool cooling.	SAMA would decrease the probability of loss of containment heat removal.	7.77%	8.81%	$10,097	$161,552	$5,800,000	Not cost effective
	Basis for Conclusion: The CDF contribution from loss of the torus cooling mode of RHR was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be $5.8 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

<table>
<tr><th>Phase II SAMA ID</th><th>SAMA Title</th><th>Result of Potential Enhancement</th><th>CDF Reduction</th><th>Off-Site Dose Reduction</th><th>Estimated Benefit</th><th>Upper Bound Estimated Benefit</th><th>Estimated Cost</th><th>Conclusion</th></tr>
<tr><td rowspan="2">003</td><td>Install a filtered containment vent to provide fission product scrubbing.
Option 1: Gravel Bed Filter
Option 2: Multiple Venturi Scrubber</td><td>SAMA would provide an alternate decay heat removal method for non-ATWS events, with fission product scrubbing.</td><td>0.00%</td><td>3.73%</td><td>$4,090</td><td>$65,440</td><td>$1,500,000</td><td>Not cost effective</td></tr>
<tr><td colspan="8">Basis for Conclusion: Successful torus venting accident progression source terms were reduced by a factor of 2 to reflect the additional filtered capability. The cost of implementing this SAMA at Peach Bottom was estimated to be $3 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is $1.5 million. Therefore, this SAMA is not cost effective for JAFNPP.</td></tr>
</table>

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
004	Install a containment vent large enough to remove ATWS decay heat.	Assuming that injection is available, this SAMA would provide alternate decay heat removal in an ATWS event.	2.55%	8.14%	$7,005	$112,080	>$1,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution from ATWS sequences associated with containment bypass were eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
005	Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris.	SAMA would ensure that molten core debris escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through of the base mat.	0.00%	5.03%	$3,444	$55,104	>$100 million	Not cost effective
	Basis for Conclusion: Containment failure due to core-concrete interactions (not including liner failures) was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at ANO-2 was estimated to be $100 million. Therefore, this SAMA is not cost effective for JAFNPP.							
006	Create a water-cooled rubble bed on the pedestal.	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.	0.00%	5.03%	$3,444	$55,104	$19 million	Not cost effective
	Basis for Conclusion: Containment failure due to core-concrete interactions (not including liner failures) was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at ANO-2 was estimated to be $19 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
007	Provide modification for flooding the drywell head.	SAMA would provide intentional flooding of the upper drywell head such that if high drywell temperatures occurred, the drywell head seal would not fail.	0.00%	0.00%	$0	$0	>$1,000,000	Not cost effective
	Basis for Conclusion: Drywell head failures due to high temperature were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $1 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
008	Enhance fire protection system and standby gas treatment system hardware and procedures.	SAMA would improve fission product scrubbing in severe accidents.	0.00%	0.00%	$0	$0	>$2,500,000	Not cost effective
	Basis for Conclusion: Failure of the reactor building to contain releases was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $2.5 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
009	Create a core melt source reduction system.	SAMA would provide cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur.	0.00%	5.03%	$3,444	$55,104	>$5,000,000	Not cost effective
	Basis for Conclusion: Containment failure due to core-concrete interactions (not including liner failures) was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $5 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
010	Install a passive containment spray system.	SAMA would decrease the probability of loss of containment heat removal.	7.67%	8.71%	$9,898	$158,368	$5,800,000	Not cost effective
	Basis for Conclusion: The CDF contribution from loss of the drywell spray mode of RHR was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be $5.8 million. Therefore, this SAMA is not cost effective for JAFNPP.							
011	Strengthen primary and secondary containment.	SAMA would reduce the probability of containment over-pressurization failure.	7.36%	10.15%	$7,534	$120,544	$12,000,000	Not cost effective
	Basis for Conclusion: Energetic containment failure modes (DCH, steam explosion, late over-pressurization) were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities and ABWR was estimated to be $12 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
012	Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.	SAMA would prevent base mat melt-through.	0.00%	0.28%	$107	$1,712	>$5,000,000	Not cost effective
	Basis for Conclusion: Containment failure due to base mat melt-through was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $5 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
013	Provide a reactor vessel exterior cooling system.	SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head could be submerged in water.	0.00%	2.62%	$1,722	$27,552	$2,500,000	Not cost effective
	Basis for Conclusion: The probability of vessel failure was modified by a factor of 2 to account for potential ex-vessel cooling to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be $2.5 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
014	Construct a building connected to primary containment that is maintained at a vacuum.	SAMA would provide a method to depressurize containment and reduce fission product release.	0.00%	0.00%	$0	$0	>$1,000,000	Not cost effective
	Basis for Conclusion: Failure of the reactor building to contain releases was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $2 million at Peach Bottom. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							
015	2.g. Add dedicated suppression pool cooling.	SAMA would decrease the probability of loss of containment heat removal.	7.77%	8.81%	$10,097	$161,552	$5,800,000	Not cost effective
	Basis for Conclusion: The CDF contribution from loss of the torus cooling mode of RHR was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be $5.8 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
016	3.a. Create a larger volume in containment.	SAMA increases time before containment failure and increases time for recovery.	7.36%	10.15%	$7,534	$120,544	$8,000,000	Not cost effective
	Basis for Conclusion: Energetic containment failure modes (DCH, steam explosion, late over-pressurization) were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be $8 million. Therefore, this SAMA is not cost effective for JAFNPP.							
017	3.b. Increase containment pressure capability (sufficient pressure to withstand severe accidents).	SAMA minimizes likelihood of large releases.	7.36%	10.15%	$7,534	$120,544	$12,000,000	Not cost effective
	Basis for Conclusion: Energetic containment failure modes (DCH, steam explosion, late over-pressurization) were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities and ABWR was estimated to be $12 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
018	3.c. Install improved vacuum breakers (redundant valves in each line).	This SAMA addresses the reliability of a vacuum breaker to reseat following a successful opening.	0.02%	7.44%	$5,597	$89,552	>$500,000	Not cost effective
	Basis for Conclusion: Vacuum breaker failures were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $1 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $500,000. Therefore, this SAMA is not cost effective for JAFNPP.							
019	3.d. Increase the temperature margin for seals.	This SAMA would reduce the potential for containment failure under adverse conditions.	0.00%	0.00%	$0	$0	$12,000,000	Not cost effective
	Basis for Conclusion: Drywell head failure due to high temperature drywell seal failure was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities and ABWR was estimated to be $12 million. Therefore, this SAMA was not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
020	5.b/c. Install a filtered vent.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with fission product scrubbing.	0.00%	3.73%	$4,090	$65,440	$1,500,000	Not cost effective
		Basis for Conclusion: Successful torus venting accident progression source terms were reduced by a factor of 2 to reflect the additional filtered capability. The cost of implementing this SAMA at Peach Bottom was estimated to be $3 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is $1.5 million. Therefore, this SAMA is not cost effective for JAFNPP.						
021	7. a. Provide a method of drywell head flooding.	SAMA would provide intentional flooding of the upper drywell head such that if high drywell temperatures occurred, the drywell head seal would not fail.	0.00%	0.00%	$0	$0	>$1,000,000	Not cost effective
		Basis for Conclusion: Drywell head failures due to high temperature drywell seal failure were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $1 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.						

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
022	13. a. Use alternate method of reactor building spray.	This SAMA provides the capability to use firewater sprays in the reactor building to mitigate release of fission products into the reactor building following an accident.	0.00%	0.00%	$0	$0	>$2,500,000	Not cost effective
	Basis for Conclusion: Failure of the reactor building to contain releases was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $2.5 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
023	14.a. Provide a means of flooding the rubble bed.	SAMA would allow the debris to be cooled.	0.00%	1.22%	$861	$13,776	$2,500,000	Not cost effective
	Basis for Conclusion: The probabilities of wet core concrete interactions were substituted for dry core concrete interactions to assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be $2.5 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
024	14.b. Install a reactor cavity flooding system.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.	0.00%	5.03%	$3,444	$55,104	$8,750,000	Not cost effective
	Basis for Conclusion: Containment failure due to core-concrete interactions (not including liner failures) was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at ANO-2 was estimated to be $8.75 million. Therefore, this SAMA is not cost effective for JAFNPP.							
025	Add ribbing to the containment shell.	This SAMA would reduce the chance of buckling of containment under reverse pressure loading.	0.00%	10.15%	$7,534	$120,544	$12,000,000	Not cost effective
	Basis for Conclusion: Energetic containment failure modes (DCH, steam explosion, late over-pressurization) were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities and ABWR was estimated to be $12 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
Improvements Related to Enhanced AC/DC Power Reliability/Availability								
026	Provide additional DC battery capacity.	SAMA would ensure longer battery capability during an SBO, which would extend HPCI/RCIC operability and allow more time for AC power recovery.	39.0%	43.74%	$52,365	$837,840	$500,000	Retain
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 7 hours to 24 hours during SBO scenarios to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $500,000 by engineering judgment.							
027	Use fuel cells instead of lead-acid batteries.	SAMA would extend DC power availability in an SBO, which would extend HPCI/ RCIC operability and allow more time for AC power recovery.	39.0%	43.74%	$52,365	$837,840	>$1,000,000	Not cost effective
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 7 hours to 24 hours during SBO scenarios to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
028	Incorporate an alternate battery charging capability.	SAMA would improve DC power reliability by either cross-tying the AC buses or installing a portable diesel-driven battery charger.	3.49%	0.39%	$2,113	$33,808	$90,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of DC battery chargers 71BC-1A and 71BC-1B was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $90,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
029	Install a modification improving DC bus reliability.	SAMA would increase reliability of AC power and injection capability.	1.46%	1.20%	$1,135	$18,160	$500,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of DC battery control board BCB-2A initiator was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $500,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
030	2.i. Provide 16 hour SBO injection.	SAMA includes improved capability to cope with longer SBO scenarios.	39.0%	43.74%	$52,365	$837,840	$500,000	Retain
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 7 hours to 24 hours during SBO scenarios to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $500,000 by engineering judgment.							
031	9.b. Provide an alternate pump power source.	This SAMA would provide a small, dedicated power source such as a dedicated diesel or gas turbine for the feedwater or condensate pumps so that they do not rely on offsite power.	0.78%	0.67%	$828	$13,248	>$1,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to failure of the normal power supply to condensate pumps was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
032	10.a. Add a dedicated DC power supply.	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).	1.46%	1.20%	$1,135	$18,160	$3,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of DC battery control board BCB-2A initiator was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be $3 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
033	10.b. Install additional batteries or divisions.	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).	1.46%	1.20%	$1,135	$18,160	$3,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of DC battery control board BCB-2A initiator was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be $3 million. Therefore, this SAMA is not cost effective for JAFNPP.							
034	10.c. Install fuel cells.	SAMA would extend DC power availability in an SBO, which would extend HPCI/ RCIC operability and allow more time for AC power recovery.	39.0%	43.74%	$52,365	$837,840	>$1,000,000	Not cost effective
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 7 hours to 24 hours during SBO scenarios to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
035	10.d. Install DC bus cross-ties.	This SAMA would improve DC power reliability.	1.46%	1.20%	$1,135	$18,160	$300,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of DC battery control board BCB-2A initiator was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $300,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
036	10.e. Extended SBO provisions.	SAMA would extend DC power availability in an SBO, which would extend HPCI/ RCIC operability and allow more time for AC power recovery.	39.0%	43.74%	$52,365	$837,840	$500,000	Retain
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 7 hours to 24 hours during SBO scenarios to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $500,000 by engineering judgment.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
Improvements in Identifying and Mitigating Containment Bypass								
037	Locate residual heat removal (RHR) inside containment.	SAMA would prevent intersystem LOCA (ISLOCA) outside containment.	0.78%	0.67%	$828	$13,248	>$500,000	Not cost effective
	Basis for Conclusion: RHR ISLOCA accident sequences were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Quad Cities was estimated to be greater than $500,000. Therefore, this SAMA is not cost effective for JAFNPP.							
038	Increase frequency of valve leak testing.	SAMA could reduce ISLOCA frequency.	0.93%	2.09%	$1,797	$28,752	$100,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to ISLOCA was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $100,00 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
039	8.e. Improve MSIV design.	This SAMA would decrease the likelihood of containment bypass scenarios.	0.20%	7.44%	$5,597	$89,552	>$1,000,000	Not cost effective
	Basis for Conclusion: Containment bypass failure due to MSIV leakage was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							
Improvements Related to Feedwater/Feed and Bleed Reliability/Availability								
040	Install a digital feed water upgrade.	This SAMA would reduce the chance of a loss of main feed water following a plant trip.	0.78%	0.67%	$828	$13,248	$1,500,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to the loss of feedwater initiator was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $1.5 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
041	Create ability for emergency connections of existing or alternate water sources to feedwater/ condensate.	This SAMA would provide a backup water supply for the feedwater/ condensate systems.	0.78%	0.67%	$828	$13,248	$170,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to the failure of alternate injection from feedwater /condensate was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $170,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
042	Install an independent diesel for the CST makeup pumps.	SAMA would allow continued inventory in CST during a SBO.	1.78%	0.24%	$597	$9,552	$135,000	Not cost effective
	Basis for Conclusion: As currently modeled, if CST water level is low, swapping HPCI/RCIC suction from the CST to the torus allows continued HPCI/RCIC injection. Therefore, the failure to switchover from CST to torus was eliminated to conservatively assess the benefit of this SAMA on CDF. The cost of implementing this SAMA was estimated to be $135,000 by engineering judgment. Therefore, this SAMA was not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
043	Install motor-driven feed water pump.	SAMA would increase the availability of injection subsequent to MSIV closure.	0.18%	0.00%	$0	$0	$1,650,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to the failure of feedwater turbine driven pumps was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $1.65 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
Improvements Related to Core Cooling System								
044	Provide an additional high pressure injection pump with independent diesel.	SAMA would reduce frequency of core melt from small LOCA and SBO sequences.	3.44%	0.54%	$2,113	$33.808	>$1,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to failure of the HPCI system was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
045	Install independent AC high pressure injection system.	SAMA would allow makeup capabilities during transients, small LOCA and SBO.	3.44%	0.54%	$2,113	$33,808	>$1,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to failure of the HPCI system was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
046	2. a. Install a passive high pressure system.	SAMA would improve prevention of core melt sequences by providing additional high pressure capability to remove decay heat through an isolation condenser type system.	3.44%	0.54%	$2,113	$33,808	>$1,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to failure of the HPCI system was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $2 million at Peach Bottom. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
047	2. d. Improved high pressure systems.	SAMA will improve prevention of core melt sequences by improving reliability of high pressure capability to remove decay heat.	2.43%	0.41%	$1,516	$24,256	>$1,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution from reducing the HPCI system failure probability by a factor of 3 was estimated to bound the potential impact of this SAMA. The cost of implementing this SAMA was estimated to be greater than $2 million at Peach Bottom. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							
048	2. e. Install an additional active high pressure system.	SAMA will improve reliability of high-pressure decay heat removal by adding an additional system.	3.44%	0.54%	$2,113	$33,808	>$1,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to failure of the HPCI system was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
049	8.c. Add a diverse injection system.	SAMA will improve prevention of core melt sequences by providing additional injection capabilities.	3.44%	0.54%	$2,113	$33,808	>$1,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to failure of the HPCI system was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							
Improvements Related to Instrument Air and Nitrogen Supply								
050	Modify EOPs for ability to align diesel power to more air compressors.	For plants, which do not have diesel power to all normal and backup air compressors, this change allows increased reliability of instrument air after a LOSP.	0.12%	0.00%	$0	$0	$1,200,000	Not cost effective
	Basis for Conclusion: The probability of failure of the normal electrical power supply to air compressors was reduced by a factor of ten to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $1.20 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered In Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
Improvements Related to ATWS Mitigation								
051	Increase safety relief valve (SRV) reseat reliability.	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.	3.67%	3.92%	$4,572	$73,152	$2,200,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to stuck open relief valves was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $2.2 million at JAFNPP. Therefore, this SAMA is not cost effective for JAFNPP.							
052	11. a. Install an ATWS sized vent.	This SAMA would provide the ability to remove reactor heat from ATWS events.	2.55%	8.14%	$7,005	$112,080	>$1,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution from ATWS sequences associated with containment bypass were eliminated to conservatively assess the benefit of this SAMA. The cost of implementing of this SAMA at Peach Bottom was estimated to be greater than $2 million. Since Peach Bottom is a two-unit site, the cost of implementing this SAMA for one unit is greater than $1 million. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
053	Diversify explosive valve operation.	An alternate means of opening a pathway to the RPV for SLC system injection would improve the success probability for reactor shutdown.	0.03%	0.00%	$0	$0	>$200,000	Not cost effective
	Basis for Conclusion: Common cause failure of SLC explosive valves was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $200,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
Other Improvements								
054	4. d. Implement passive overpressure relief.	This SAMA will prevent catastrophic failure of the containment by controlled relief through a selected vent path, which has a greater potential for reducing the release of radioactive material than through a random break.	2.05%	2.43%	$2,609	$41,744	>$500,000	Not cost effective
	Basis for Conclusion: The CDF contribution from accident sequences in which containment venting is successful was reduced by a factor of 2 to reflect the additional pressure relief capability. The cost of implementing this SAMA was estimated to be greater than $500,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
055	Change CRD flow control valve failure position.	SAMA would change control valve failure position to the "fail-safest" position for crediting CRD injection during loss of instrument air event.	0.09%	0.00%	$0	$0	>$140,000	Not cost effective
	Basis for Conclusion: The CDF contribution from loss of CRD reactor vessel injection was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $140,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
056	Provide digital large break LOCA protection.	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/ precursors of a large break LOCA (a leak before break).	0.06%	0.00%	$0	$0	>$100,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to large break LOCA was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $100,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
Improvements Related to Internal Event Model (IPE, IPE Update, EPU) Insights								
057	Control containment venting within a narrow band of pressure.	This SAMA would establish a narrow pressure control band to prevent rapid containment depressurization when venting is implemented thus avoiding adverse impact on the low pressure ECCS injection systems taking suction from the torus.	13.84%	15.94%	$18,447	$295,152	$400,000	Not cost effective
	Basis for Conclusion: The probability of the operator failing to recognize the need to vent the torus was reduced by a factor of 3 to conservatively assess the benefit of this SAMA on CDF. The cost of implementing this SAMA was estimated to be $400,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
058	Provide a tap from the fire protection system to RHR heat exchanger "B" via RHRSW header B.	This SAMA would provide firewater to RHR heat exchanger "B" for heat removal during a loss of containment heat removal sequence.	0.39%	0.51%	$522	$8,352	$150,000	Not cost effective
	Basis for Conclusion: The CDF contribution from failure of the cross-tie from the fire protection system to RHR heat exchanger "A" via RHRSW loop A was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $150,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
059	Provide a cross-tie between RHRSW trains downstream of the RHRSW pump discharge valves.	This SAMA would improve injection and containment heat removal capabilities.	10.52%	12.13%	$14,073	$225,168	$400,000	Not cost effective
	Basis for Conclusion: The CDF contribution from failure of RHRSW loop B was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $400,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
060	Improve turbine bypass valve capability.	This SAMA would improve the availability of the turbine bypass valve to reduce the transient core damage frequency.	9.97%	7.23%	$10,430	$166,880	$745,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of PCS initiator was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $745,000 by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							
061	Develop a procedure to use a portable power supply for battery chargers.	This SAMA would improve the availability of the DC power system.	3.49%	0.39%	$2,113	$33,808	$10,000	Retain
	Basis for Conclusion: The CDF contribution due to loss of DC battery chargers 71BC-1A and 71BC-1B was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $10,000 by engineering judgment.							

Table E.2-1 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
062	Develop a procedure to open the doors of the EDG buildings upon receipt of a high temperature alarm.	This SAMA would improve the reliability of the EDGs following high temperatures in the EDG buildings.	21.15%	24.28%	$28,975	$463,600	$10,000	Retain
	Basis for Conclusion: The probability of EDG run failures was reduced by a factor of three to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $10,000 by engineering judgment.							
063	Provide additional reactor vessel monitoring and actuation system.	This SAMA would improve the availability of the reactor vessel instrumentation system during the loss of the instrument reference leg.	1.51%	1.53%	$1,764	$28,224	$1,200,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of reactor water level referenced leg was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $1.2 million by engineering judgment. Therefore, this SAMA is not cost effective for JAFNPP.							

Table E.2-2
Sensitivity Analysis Results

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
1	Add a service water pump.	$1,151	$18,416	$5,900,000	$1,400	$22,400	$1,501	$24,016
2	Install an independent method of suppression pool cooling.	$10,097	$161,552	$5,800,000	$12,427	$198,832	$12,974	$207,584
3	Install a filtered containment vent to provide fission product scrubbing. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber	$4,090	$65,440	$1,500,000	$4,664	$74,624	$5,716	$91,456
4	Install a containment vent large enough to remove ATWS decay heat.	$7,005	$112,080	>$1,000,000	$8,250	$132,000	$9,465	$151,440

**Table E.2-2 (Continued)
Sensitivity Analysis Results**

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
5	Create a large concrete crucible with heat removal potential under the basemat to contain molten core debris.	$3,444	$55,104	>$100 million	$3,928	$62,848	$4,813	$77,008
6	Create a water-cooled rubble bed on the pedestal.	$3,444	$55,104	$19,000,000	$3,928	$62,848	$4,813	$77,008
7	Provide modification for flooding the drywell head	$0	$0	>$1,000,000	$0	$0	$0	$0
8	Enhance fire protection system and/or standby gas treatment system hardware and procedures.	$0	$0	>$2,500,000	$0	$0	$0	$0
9	Create a core melt source reduction system.	$3,444	$55,104	>$5,000,000	$3,928	$62,848	$4,813	$77,008

Table E.2-2 (Continued)
Sensitivity Analysis Results

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
10	Install a passive containment spray system.	$9,898	$158,368	$5,800,000	$12,157	$194,512	$12,750	$204,000
11	Strengthen primary/ secondary containment.	$7,534	$120,544	$12,000,000	$8,592	$137,472	$10,528	$168,448
12	Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur	$107	$1,712	>$5,000,000	$123	$1,968	$151	$2,416
13	Provide a reactor vessel exterior cooling system (see #7)	$1,722	$27,552	$2,500,000	$1,964	$31,424	$2,407	$38,512
14	Construct a building to be connected to primary/secondary containment that is maintained at a vacuum	$0	$0	>$2,000,000	$0	$0	$0	$0

**Table E.2-2 (Continued)
Sensitivity Analysis Results**

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
15	2.g. Dedicated Suppression Pool Cooling	$10,097	$161,552	$5,800,000	$12,427	$198,832	$12,974	$207,584
16	3.a. Create a larger volume in containment.	$7,534	$120,544	$8,000,000	$8,592	$137,472	$10,528	$168,448
17	3.b. Increase containment pressure capability (sufficient pressure to withstand severe accidents).	$7,534	$120,544	$12,000,000	$8,592	$137,472	$10,528	$168,448
18	3.c. Install improved vacuum breakers (redundant valves in each line).	$5,597	$89,552	>$500,000	$6,382	$102,112	$7,821	$125,136
19	3.d. Increase the temperature margin for seals.	$0	$0	$12,000,000	$0	$0	$0	$0
20	5.b/c. Install a filtered vent	$4,090	$65,440	$1,500,000	$4,664	$74,624	$5,716	$91,456

Table E.2-2 (Continued)
Sensitivity Analysis Results

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
21	7.a. Provide a method of drywell head flooding.	$0	$0	>$1,000,000	$0	$0	$0	$0
22	13.a. Use alternate method of reactor building spray.	$0	$0	>$2,500,000	$0	$0	$0	$0
23	14.a. Provide a means of flooding the rubble bed.	$861	$13,776	$2,500,000	$982	$15,712	$1,204	$19,264
24	14.b. Install a reactor cavity flooding system.	$3,444	$55,104	$8,750,000	$3,928	$62,848	$4,813	$77,008
25	Add ribbing to the containment shell.	$7,534	$120,544	$12,000,000	$8,592	$137,472	$10,528	$168,448
26	Provide additional DC battery capacity.	$52,365	$837,840	$500,000	$64,321	$1,029,136	$67,436	$1,078,976
27	Use fuel cells instead of lead-acid batteries.	$52,365	$837,840	>$1,000,000	$64,321	$1,029,136	$67,436	$1,078,976
28	Incorporate an alternate battery charging capability	$2,113	$33,808	$90,000	$2,801	$44,816	$2,467	$39,472

Table E.2-2 (Continued)
Sensitivity Analysis Results

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
29	Modification for Improving DC Bus Reliability	$1,135	$18,160	$500,000	$1,425	$22,800	$1,424	$22,784
30	2.i. Provide 16 hour SBO injection.	$52,365	$837,840	$500,000	$64,321	$1,029,136	$67,436	$1,078,976
31	9.b. Provide an alternate pump power source.	$828	$13,248	>$1,000,000	$1,032	$16,512	$1,050	$16,800
32	10.a. Add a dedicated DC power supply.	$1,135	$18,160	$3,000,000	$1,425	$22,800	$1,424	$22,784
33	10.b. Install additional batteries or divisions.	$1,135	$18,160	$3,000,000	$1,425	$22,800	$1,424	$22,784
34	10.c. Install fuel cells.	$52,365	$837,840	>$1,000,000	$64,321	$1,029,136	$67,436	$1,078,976
35	10.d. DC Cross-Ties	$1,135	$18,160	$300,000	$1,425	$22,800	$1,424	$22,784
36	10.e. Extended SBO provisions.	$52,365	$837,840	$500,000	$64,321	$1,029,136	$67,436	$1,078,976
37	Locate residual heat removal (RHR) inside containment.	$828	$13,248	>$500,000	$1,032	$16,512	$1,050	$16,800

Table E.2-2 (Continued)
Sensitivity Analysis Results

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
38	Increase frequency of valve leak testing.	$1,797	$28,752	$100,000	$2,136	$34,176	$2,403	$38,448
39	8.e. Improve MSIV design.	$5,597	$89,552	>$1,000,000	$6,382	$102,112	$7,821	$125,136
40	Install a digital feed water upgrade	$828	$13,248	$1,500,000	$1,032	$16,512	$1,050	$16,800
41	Create ability for emergency connections of existing or alternate water sources to feedwater.	$828	$13,248	$170,000	$1,032	$16,512	$1,050	$16,800
42	Install an independent diesel for the CST makeup pumps.	$597	$9,552	$135,000	$811	$12,976	$672	$10,752
43	Install motor-driven feed water pump.	$0	$0	$1,650,000	$0	$0	$0	$0
44	Provide an additional high pressure injection pump with independent diesel.	$2,113	$33,808	>$1,000,000	$2,801	$44,816	$2,467	$39,472

Table E.2-2 (Continued)
Sensitivity Analysis Results

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
45	Install independent AC high pressure injection system.	$2,113	$33,808	>$1,000,000	$2,801	$44,816	$2,467	$39,472
46	2.a. Install a passive high pressure system.	$2,113	$33,808	>$1,000,000	$2,801	$44,816	$2,467	$39,472
47	2.d. Improved high pressure systems	$1,516	$24,256	>$1,000,000	$1,990	$31,840	$1,795	$28,720
48	2.e. Install an additional active high pressure system.	$2,113	$33,808	>$1,000,000	$2,801	$44,816	$2,467	$39,472
49	8.c. Add a diverse injection system.	$2,113	$33,808	>$1,000,000	$2,801	$44,816	$2,467	$39,472
50	Modify EOPs for ability to align diesel power to more air compressors.	$0	$0	$1,200,000	$0	$0	$0	$0
51	Increase safety relief valve (SRV) reseat reliability.	$4,572	$73,152	$2,200,000	$5,649	$90,384	$5,849	$93,584

Table E.2-2 (Continued)
Sensitivity Analysis Results

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
52	11.a. Install an ATWS sized vent.	$7,005	$112,080	>$1,000,000	$8,250	$132,000	$9,465	$151,440
53	Diversify explosive valve operation.	$0	$0	>$200,000	$0	$0	$0	$0
54	4.d. Passive Overpressure Relief	$2,609	$41,744	>$500,000	$3,193	$51,088	$9,347	$149,552
55	Change CRD flow control valve failure position.	$0	$0	>$140,000	$0	$0	$0	$0
56	Provide digital large break LOCA protection.	$0	$0	>$100,000	$0	$0	$0	$0
57	Control containment venting within a narrow band of pressure	$18,447	$295,152	$400,000	$22,644	$362,304	$23,775	$380,400
58	Provide a tap from the fire protection system to RHR heat exchanger "B" via RHRSW header B	$522	$8,352	$150,000	$639	$10,224	$676	$10,816

Table E.2-2 (Continued)
Sensitivity Analysis Results

Phase II SAMA ID	SAMA Title	Base Line		Estimated Cost	Sensitivity Case 1		Sensitivity Case 2	
		Estimated Benefit	Upper Bound Estimate Benefit		Estimated Benefit	Upper Bound Estimate Benefit	Estimated Benefit	Upper Bound Estimate Benefit
59	Provide a cross-tie between RHRSW trains downstream of the RHRSW pump discharge valves.	$14,073	$225,168	$400,000	$17,265	$276,240	$18,150	$290,400
60	Improve turbine bypass valve capability.	$10,430	$166,880	$745,000	$13,067	$209,072	$13,114	$209,824
61	Develop a procedure to use a portable supply power for battery chargers.	$2,113	$33,808	$10,000	$2,801	$44,816	$2,467	$39,472
62	Develop a procedure to open the door EDG buildings upon the high temperature alarm.	$28,975	$463,600	$10,000	$35,562	$568,992	$37,349	$597,584
63	Provide additional reactor vessel monitoring and actuation system.	$1,764	$28,224	$1,200,000	$2,186	$34,976	$2,250	$36,000