Appendix E

Applicant's Environmental Report

Operating License Renewal Stage

Pilgrim Nuclear Power Station

Introduction

Entergy Nuclear Generation Company, Inc. (hereafter referred to as "Entergy"), submits this Environmental Report (ER) in conjunction with the application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Pilgrim Nuclear Power Station (PNPS) 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 PNPS operating license. This ER is designed to assist the NRC staff with the preparation of the PNPS specific Supplemental Environmental Impact Statement required for license renewal.

The PNPS 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, 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 is commensurate with the environmental significance of the topic or issue.

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

The application to renew the operating license of PNPS 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 PNPS 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
AC	alternating current
ADS	automatic depressurization system
AEC	Atomic Energy Commission
ALARA	as low as reasonably achievable
AOG	augmented off-gas
AQCR	Air Quality Control Region
ASOS	automated surface observatory system
ATWS	anticipated transient without scram
Btu	British thermal unit
BWR	boiling water reactor
BWROG	Boiling Water Reactor Owners Group
CaO	calcium oxide (lime)
CAPB	collapsed accident progression bins
$CaSO_4$ $2H_2O$	calcium sulfate dihydrate
CDF	core damage frequency
CEQ	Council on Environmental Quality
CET	containment event tree
CFR	Code of Federal Regulations
CMR	Code of Massachusetts Regulations
CO	carbon monoxide

CPUE	catch per unit effort

Acronyms and Abbreviations (continued)

CsI	cesium iodide
CST	condensate storage tank
CWA	Clean Water Act
DC	direct current
DCH	direct containment heating
DECON	decontamination and dismantlement
DOE	United States Department of Energy
DOT	U. S. Department of Transportation
DSM	demand side management
DTV	direct torus vent
ECCS	emergency core cooling system
EDG	emergency diesel generator
EIA	Energy Information Administration
ENSR	ENSR Corporation
EPA	U.S. Environmental Protection Agency
EPG	emergency plant guidelines
EPRI	Electric Power Research Institute
ER	environmental report
EREN	Energy Efficiency and Renewable Energy Network

Acronyms and Abbreviations (continued)

FES	Final Environmental Statement
FHA	Federal Highway Administration
FIVE	fire induced vulnerability evaluation
ft^3	cubic feet
FWS	U.S. Fish and Wildlife Service
gal	gallon
GE	General Electric
GEIS	Generic Environmental Impact Statement
GIS	geographic information system
gpm	gallons per minute
HEP	human error probability
HIC	high integrity container
HPCI	high pressure coolant injection
HRA	human reliability analysis
IDCOR	Industrial Degraded Core Rulemaking
INEL	Idaho National Engineering Laboratory
IPA	integrated plant assessment
IPE	individual plant examination
IPEEE	individual plant examination of external events
ISLOCA	interface system loss of coolant accident
ISO	International Standards Organization

Acronyms and Abbreviations (continued)

IORV	inadvertent stuck open relief valve
KM	kilometer
kV	kilovolts
kWh	kilowatt-hour
lb	pound
LERF	large early release frequency
LLRWSF	low-level radwaste storage facility
LOCA	loss of coolant accident
LOOP	loss of offsite power
LPCI	low pressure core injection
MACCS2	Melcor Accident Consequences Code System 2
MAPC	Metropolitan Area Planning Council
MCC	motor control center
MCZM	Massachusetts Coastal Zone Management
MDEP	Massachusetts Department of Environmental Protection
MDFW	Massachusetts Division of Fisheries and Wildlife
MDTE	Massachusetts Department of Telecommunications and Energy
MG	million gallons
MGD	million gallons per day
MGL	Massachusetts General Laws
MISER	Massachusetts Institute for Social and Economic Research
MM	million

Acronyms and Abbreviations (continued)

MOV	motor-operated valve
mrad	millirad
mrem	millirem
MSIV	main steam isolation valve
MW	megawatt
MWe	megawatts, electric
MWt	megawatts, thermal
NA	not applicable
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NESC	National Electric Safety Code
NHESP	Natural Heritage and Endangered Species Program
NMFS	National Marine Fisheries Service
NO_x	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
ODCM	Offsite Dose Calculation Manual
OECR	offsite economic cost risk
PCS	primary containment system

Acronyms and Abbreviations (continued)

PDR	population dose risk
PDS	plant damage states
PM_{10}	particulate matter with diameter less than 10 microns
PNPS	Pilgrim Nuclear Power Station
ppm	parts per million
PRA	probabilistic risk assessment
PSA	probabilistic safety analysis
RAI	Request for Additional Information
RBCCW	reactor building closed cooling water
RCIC	reactor core isolation cooling
RHR	residual heat removal
RPS	reactor protection system
RPV	reactor pressure vessel
RRW	risk reduction worth
RWCU	reactor water cleanup
SAFSTOR	safe storage
SAMA	severe accident mitigation alternatives
SAMDA	severe accident mitigation design alternatives
SBO	station blackout
SCR	selective catalytic reduction
SGTS	standby gas treatment system
SHPO	State Historic Preservation Officer

Acronyms and Abbreviations (continued)

SLC	standby liquid control
SO_x	oxides of sulfur
SQUG	Seismic Qualification Utility Group
SRV	safety relief valve
SSCs	systems, structures, and components
SSW	salt service water
TCA	Tennessee Code Annotated
TCF	trash compaction facility
T-H	thermal-hydraulic
THERP	technique for human error rate probability
TSP	total suspended particulates
TtNUS	Tetratech NUS
TVA	Tennessee Valley Authority
UFSAR	Updated Final Safety Analysis Report
URC	ultrasonic resin cleaner
USC	United States Code
USCB	U. S. Census Bureau
WMS	waste management system
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 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*: "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. As stated in 10 CFR 54.17(c), "[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 PNPS for a period of 20 years beyond the current operating license expiration date. For PNPS (Facility Operating License DPR-35), the requested renewal would extend the existing license expiration date from midnight June 8, 2012, until midnight June 8, 2032.

2.0 SITE AND ENVIRONMENTAL INTERFACES

2.1 Location and Features

PNPS is located on the western shore of Cape Cod Bay in the Town of Plymouth, Plymouth County, Massachusetts. It is 38 miles southwest of Boston, Massachusetts, and 44 miles east of Providence, Rhode Island. Approximately 60% of the area within a 50-mile radius is open water. Figure 2-1 and Figure 2-2 are PNPS 50-mile and 6-mile vicinity maps, respectively.

Access to the site is available by road or from Cape Cod Bay. Land access is provided by a private two-lane paved road, which connects PNPS with Route 3A, which leads to Plymouth, White Horse Beach, and nearby Route 3. Alternate access to Plymouth and Route 3, via Route 3A, is provided by Rocky Hill Road. Immediately south of the intake is a boat landing providing sea access to the site. The landing is used for off-loading large equipment or large structural assemblies from barges.

The industrial facility encompasses approximately 140 acres (Figure 2-3). In addition, approximately 1,500 acres owned by Entergy is in a forest management trust. The nearest residences lie outside the site boundary to the northwest. The nearest residence is 2395 feet (0.45 mile) from the reactor. A single tract of land within Entergy's property is still owned by a private party. Entergy has made no arrangements with the current owner regarding future use or occupancy of the property. The tract is outside the NRC-mandated 1,800-foot buffer between the reactor and the nearest residence. The site boundary (Figure 2-3) is posted and a perimeter security fence surrounds the protected area of the station.

The principal structures at PNPS consist of the reactor and turbine buildings (each with auxiliary bays), the offgas retention building, the radwaste building, the diesel generator building, the administration building, the intake structure, and the main stack [Reference 2-37, Section 12.1]. The reactor and nuclear steam supply system for PNPS, along with the mechanical and electrical systems required for the safe operation of PNPS, are primarily located in the reactor building. Figure 3-1 shows the general features of PNPS and the station layout. Figure 2-3 shows the site boundaries. No residences are permitted within this exclusion zone.

State and Federal lands within a 50-mile radius are shown in Figure 2-12.

The nearest population centers are Boston, Massachusetts, and Providence, Rhode Island. The region within 6 miles of the site (Figure 2-2) is completely within Plymouth County and includes part of the Town of Plymouth, the nearest urbanized area. Topography consists of rolling forested hills interspersed with urban areas and a small number of agricultural areas, the majority of which are cranberry bogs. The area within 2 miles of PNPS is developed with permanent and seasonal residences in Plymouth, Priscilla Beach, and White Horse Beach.

Section 3.2 describes key features of PNPS, including reactor and containment systems, cooling and auxiliary water systems, radwaste system, and transmission facilities.

2.2 Aquatic and Riparian Ecological Communities

PNPS lies on the western shore of Cape Cod Bay near Plymouth, Massachusetts (Figure 2-1). Cape Cod Bay has a surface area of approximately 430 square nautical miles, or about 365,000 acres [Reference 2-1, Section 2.D]. Water in Cape Cod Bay tends to circulate counterclockwise; as a result, there is a consistent net flow of water to the south along the coast in the general vicinity of PNPS. However, this circulation pattern is less evident in the shallow waters (< 30 feet deep) immediately offshore of PNPS, where submarine ledges disrupt the typical north-to-south movement of water. Water of the bay is exchanged by at least three processes: (1) tidal exchange, (2) the general counter-clockwise circulation, and (3) wind-induced motion. Approximately 10% of the total volume of water in the bay is exchanged daily by these processes [Reference 2-1, Section 2.D].

Water temperatures in the vicinity of the station show typical annual cycles. Highest surface temperatures typically occur in August, when temperatures average around 65°F and are as high as approximately 73°F [Reference 2-1, Section 2.D]. Summer water temperatures tend to fluctuate dramatically, however, and may dip into the low 40s. Lowest surface water temperatures occur between December and March, when mean temperatures range between 30°F and 40°F [Reference 2-1, Section 2.D]. In summer and early fall, surface water temperature may be up to 10° warmer than bottom temperatures [Reference 2-1, Section 2.D]. A weak thermocline may be present at these times of year.

The Final Environmental Statement (FES) [Reference 2-1] briefly describes the biological communities of the PNPS area, focusing on two species of commercial importance, the American lobster (*Homarus americanus*) and the marine alga Irish moss (*Chrondrus crispus*). At the time the FES was written, as many as 10,000 lobster pots were fished between the two submarine ledges, Rocky Point and White Horse, that bracket the site, and the 50-foot contour, an area of roughly one square mile [Reference 2-1, Section 2.E]. In 1970, roughly half of the lobsters brought ashore at Plymouth were captured in this general area. Irish moss is a periphytic marine alga that contains carrageenan, which is used as a stabilizing agent in paints, medicines, and foods. It was harvested in the area of PNPS until the 1990s.

At the time the FES was written, mollusks were not found in large numbers in the vicinity of the station. This was attributed to the absence of suitable substrate. Groundfish (e.g., cod, haddock, winter flounder, and hake) were not sought by commercial fishermen in the vicinity of PNPS in the early 1970s as regulations restricted commercial fishing in Cape Cod Bay to areas at least 3 miles from shore between April 1 and November 1. Inshore trawling for winter flounder was permitted from November to March, with an annual catch of approximately 115,000 pounds [Reference 2-1, Section 2.E]. Sport fishing for inshore species such as tautog, bluefish, and flounder was relatively unimportant in the vicinity of the station and sport fishing for pelagic species such as tunas, striped bass, and mackerel was difficult because of the many lobster pots and their floats.

The March 2000 *316 Demonstration Report - Pilgrim Nuclear Power Station* [Reference 2-12] is an up-to-date source of information on the aquatic communities of western Cape Cod Bay, including those in the vicinity of PNPS. This report summarizes research and monitoring studies

conducted since the late 1960s by Boston Edison Company and its contractors, Entergy and its contractors, university researchers, and state and federal resource agencies. Although focused on the potential impacts of PNPS operations, it contains a wealth of baseline information on the marine life of Plymouth Bay, Cape Cod Bay, and the Gulf of Maine.

2.2.1 Phytoplankton

The phytoplankton community of western Cape Cod Bay, including the vicinity of PNPS, appeared to be more similar to the Gulf of Maine (the area north of Cape Cod) than to the community to the south of Cape Cod [Reference 2-12, Section 4.2.1]. In the vicinity of PNPS, phytoplankton density showed two annual peaks, one in early spring and another in mid-summer. Lowest densities were observed in mid-winter. Diatoms dominated collections in the 1970s. Monitoring studies of Massachusetts Bay and Cape Cod Bay in the 1990s to assess impacts of an offshore sewage outfall in Boston Harbor showed the nuisance phytoflagellate *Phaetocystis pouchetii* dominating collections in early spring and microflagellates and diatoms dominating collections in the fall [Reference 2-12, Section 4.2.1]. The increased abundance of nuisance phytoplankton species in Cape Cod Bay may be related to water quality degradation. Spring blooms of *Phaetocystis pouchetii* are a regular occurrence in coastal portions of the Gulf of Maine, and are associated with eutrophication in coastal waters [Reference 2-16].

2.2.2 Zooplankton

Zooplankton abundance showed seasonal cycles, with highest densities in late summer and lowest densities in late winter [Reference 2-12, Section 4.2.2]. Copepods, especially *Acartia clausi* and *A. tonsi*, dominated samples, with two distinct species aggregations, inshore and offshore [Reference 2-12, Section 4.2.2]. Differences in species composition were attributed to higher nutrient levels in inshore areas.

2.2.3 Macroinvertebrates/Shellfish

Macroinvertebrates are found in four kinds of habitats near PNPS: rocky intertidal, rocky subtidal, sandy intertidal, and sandy subtidal. The common barnacle, *Balanus balanus*, is ubiquitous in rocky intertidal areas near PNPS and is the dominant macrofaunal organism in the upper rocky intertidal zone [Reference 2-12, Section 4.2.4.1]. The marine gastropods *Littorira littorea* and *Littorira obtusata* are also common in this zone. In the middle and lower intertidal zones, *Balanus* is often replaced by the blue mussel (*Mytilus edulis*) and macroalgae. Sessile species in the rocky intertidal zone are subject to predation by *Asterias* spp. and the carnivorous gastropod *Nucella lapillus* [Reference 2-12, Section 4.2.4.1]. The benthic fauna of the rocky subtidal zone were dominated by amphipods (34 species collected), polychaetes (30 species collected), and molluscs (30 species collected). Species representing other groups such as nemertea, echinoderms, and anemones were collected less frequently. Measures of species richness (total number of species collected) varied considerably from year to year, and appeared to be independent of PNPS operations (capacity factors) [Reference 2-12, Figure 4.2-13]. Total faunal densities also varied widely, due in part to annual fluctuations in numbers of the blue mussel [Reference 2-12, Section 4.2.4.2]. The two most common species in sandy subtidal areas were the marine amphipods *Acanthohaustorius millsi* and *Protohaustorius deichmannae*

[Reference 2-12, Section 4.2.4.3]. Other species found in the sandy subtidal areas included the common sand shrimp (*Crangon septemspinosus*), the moon snail (*Lunatia heros*), and the sand dollar (*Echinarachnius parma*). No differences were seen between the station near the PNPS discharge canal and the White Horse Beach (control) station, approximately 1.3 miles from PNPS, in terms of species richness (number of species observed), except where there were obvious differences in substrate type [Reference 2-12, Section 4.2.4.3].

2.2.3.1 American Lobster

The American lobster is common in western Cape Cod Bay and supports a valuable commercial fishery in the PNPS area, primarily between March and November. Because of the commercial importance of this species, a number of special studies have been conducted in the vicinity of PNPS. Studies suggest that a significant percentage of larval lobsters in Cape Cod Bay in June may have come through the Cape Cod Canal, having been spawned in the eastern end of the canal or even points south (Buzzard's Bay, south of Cape Cod). A study of sublegal, sexually immature lobsters captured and released in the vicinity of PNPS indicated that movement of sub-adults was limited: 71% were recaptured on the rocky ledges where they had been captured previously [Reference 2-12, Section 4.2.4.3]. An evaluation of lobster harvest in the PNPS area, reference areas, and the Gulf of Maine showed that catch rates in the PNPS area (and reference areas) tracked those in the Gulf of Maine and appeared to be unaffected by PNPS operations [Reference 2-12, Section 4.2.4.3].

2.2.4 Fish Community

The species composition of finfish in western Cape Cod Bay reflects a transition between the Gulf of Maine and the Mid-Atlantic Bight [Reference 2-12, Section 4.2.5]. Cape Cod serves as the southern-most boundary for several northern Atlantic fish species and the northern-most boundary for several fish species that inhabit the warmer waters south of Cape Cod, an overlap that results in high species richness and diversity. Fish move freely through the Cape Cod Canal, a 17.5-mile long man-made waterway that connects Cape Cod Bay (on the north) and Buzzards Bay (on the south).

Marine finfish were monitored in the vicinity of PNPS from 1970 to 1994 to assess possible effects of station operations on local populations. Bottom trawling gear was used to collect bottom-dwelling fish species inhabiting inshore bottom waters. Gill nets were used to collect pelagic species inhabiting open waters (higher in the water column). Haul seines were used to collect inshore species in relatively shallow waters.

2.2.4.1 Bottom Trawl Sampling

Bottom trawling was carried out at stations at the entrance to Plymouth Bay (west of PNPS) and within a 2-mile radius of the station. A total of 50 species were collected over a 13-year (1970-1982) period [Reference 2-12, Table 4.2-7]. Six species accounted for 92% of all fish collected. In order of abundance, these species were winter flounder (*Pseudopleuronectes americanus*; 44.2% of total catch), yellowtail flounder (*Pleuronectes ferrugineus*; 13.2%), skates (*Raja* spp.; 10.3%), ocean pout (*Macrozoarces americanus*; 9.1%), longhorn sculpin (*Myoxocephalus*

octodecemspinosus; 8.9%), and windowpane flounder (*Scopthalmus aquosus*; 6.4%). Winter flounder ranked first in abundance in each of the 13 years, with the other species' rankings changing over time. Relative abundance of ocean pout decreased over the course of the study, while relative abundance of skates increased [Reference 2-12, Section 4.2.5.2].

Trawling continued through 1993, but the analysis focused on 3 common species: winter flounder, little skate (*Raja erinacea*), and windowpane flounder. These 3 species comprised between 75 and 91% of the total bottom trawl catch between 1989 and 1993 [Reference 2-12, Section 4.2.5.2]. Winter flounder numbers decreased steadily from 1983 to 1991, then rebounded in 1992 and 1993 [Reference 2-12, Figure 4.2-25]. Little skate and windowpane flounder showed declines over the same period, but the declines occurred later (1987-1988) and were more precipitous [Reference 2-12, Figures 4.2-27 and 4.2-28]. Like the winter flounder, windowpane and little skate showed an increase from 1991 to 1992 and 1993.

2.2.4.2 Gill Net Sampling

Pelagic fish were collected from 1971-1992 at a site just north of the station, partially within the thermal plume. Abundance of these pelagic species (indicated by pooled catch-per-unit-effort, or CPUE) was highest in 1977, declined from 1977 to 1985, increased from 1985 to 1988, then declined from 1988 to 1992 (1992 had the lowest CPUE of the study) [Reference 2-12, Figure 4.2-31].

Pollock (*Pollachius virens*) dominated gill-net collections over the 22-year study period, and comprised 40% of the total gill net catch in 1992 [Reference 2-12, Section 4.2.5.2]. Pollock abundance declined from 1977-1981 (CPUE of 85 to 145 fish per gill net set) to 1990-1992 (CPUE of 15 to 45 fish per gill net set) [Reference 2-12, Figure 4.2-32]. Striped bass (*Morone saxatilis*), unlike other pelagic species, increased in abundance from the late 1970s to the early 1990s, apparently responding to restrictions on commercial and recreational fishing and other initiatives intended to restore this species along the Atlantic Coast. Atlantic herring (*Clupea harengus*) abundance increased from the late 1970s until the mid-1980s, fluctuated through the late 1980s, increased greatly in 1990, then plunged to low levels in 1991 and 1992. Population trends of pelagic fishes in the vicinity of PNPS appeared tied to population trends in the Gulf of Maine and the western North Atlantic and are unaffected by station operations.

2.2.4.3 Haul-Seine Sampling

Haul seines were used to collect fish from shallow inshore habitats in the area of PNPS from 1981 to 1991. Three stations were west of PNPS in Plymouth Harbor (Gray's Beach, Long Point, and Warren's Cove), two stations were east of PNPS (White Horse Beach and Manomet Beach), and one station was near the PNPS intake. These haul-seine samples yielded 185,000 fish representing 46 species, with the Atlantic silverside (*Menidia menidia*) dominating collections (67% of the 11-year total) [Reference 2-12, Section 4.2.5.2]. The greatest number of species was observed at the intake station, followed by Long Point, Warren's Cove, and Manomet Beach. Numbers of fish collected tended to fluctuate dramatically from year to year, probably due to the schooling nature of several common species. Although statistical variances were large, some trends were apparent. For example, catch rates of the most abundant shallow-water species, the

Atlantic silverside, showed no statistically significant downward trend in the intake area over the 1981-1991 period. There was no discernible trend in winter flounder catch rates in the vicinity of PNPS during the 11-year study period.

2.2.4.4 Recreational Creel Surveys

Recreational creel surveys were conducted (1973 to 1975, 1983, and 1985) to determine the extent of the shore-based recreational fishery in the area of PNPS. Cunner (*Tautogolabrus adspersus*; 45.7%), bluefish (*Pomatomus saltatrix*; 29.7%), pollock (9.3%), striped bass (6.0%), and winter flounder (4.8%) were the species caught most often by surf fishermen [Reference 2-12, Section 4.2.5.2]. Between 1990 and 1998 bluefish and striped bass were the species most often caught by shore anglers in the area of PNPS. Creel data are an indirect measure of abundance and depend on angler effort, the state of the local economy, and even changing trends in "desirable" species. Nevertheless, these creel data provide additional evidence of a recovering striped bass fishery in the Cape Cod area.

2.2.4.5 Atlantic Menhaden

In the early years of PNPS operation, substantial numbers of Atlantic menhaden (*Brevoortia tyrannus*) died in the vicinity of the PNPS discharge canal from gas bubble disease. Gas bubble disease occurs when the dissolved gases in a fish's tissues and blood come out of solution and form bubbles, interfering with normal blood flow and respiration. This is normally caused by a change in temperature or pressure, or by supersaturated conditions that sometimes occur in the heated discharge areas of power plants. In 1973, a total of 43,000 Atlanta menhaden succumbed to gas bubble disease in the area of the PNPS discharge canal. Another 5,000 menhaden were lost in 1976 [Reference 2-12, Section 4.2.6.1, and Reference 2-32, page 4-22].

Following the 1976 fish kill, a barrier net was placed across the mouth of the discharge canal from April 1 to November 1 to prevent fish from moving into the canal. Because no outbreaks of gas bubble disease and no significant fish kills were observed in the discharge canal from 1976 through the early 1990s, Boston Edison sought approval from EPA to discontinue deployment of the barrier net. Boston Edison received approval from EPA in November 1994 to discontinue regular use of the barrier net in the discharge canal, provided the net is kept nearby in serviceable condition should a recurrence require its use in the future.

2.2.4.6 Winter Flounder

The local population of winter flounder is of special concern because it provides an important commercial and recreational fishery and because the area around PNPS serves as spawning, nursery, and feeding grounds for the species. As noted previously, this species dominated bottom trawl collections from 1970-1982 in the vicinity of PNPS. Since 1993, trawl surveys and mark-and-recapture studies have been carried out to determine distribution, abundance, and movement patterns of the local winter flounder population [Reference 2-12, Section 4.2.5.2]. These trawl surveys indicated that annual mean CPUE increased until 1996, peaked in 1997, and declined in 1998 and 1999 [Reference 2-12, Table 4.2-9]. Measures of adult abundance also peaked in 1996 and 1997 and declined in 1998 and 1999.

Spring 2000 surveys yielded higher CPUEs and markedly higher measures of abundance [Reference 2-13, Section 3.1]. Unadjusted estimates of winter flounder abundance in the study area were 232,087 adults and 422,572 total winter flounder; adjusted numbers (assuming a trawl efficiency of 50%) were 464,172 and 826,548 respectively [Reference 2-13, Section 3.1]. Winter flounder absolute abundance estimates for adults and total flounder (adults and sub-adults) were 1.8 and 1.5 times their respective 1995-1999 means, suggesting that abundance was substantially higher in 2000 than in the previous 5 years. This increase in abundance of sub-adults and adults was consistent with the apparent high abundance of larval winter flounder in 1997 and 1998 [Reference 2-13, Section 3.1].

2.2.5 Summary

The aquatic communities of western Cape Cod Bay have been monitored by Boston Edison and Entergy since 1969 to assess potential impacts of PNPS operations. These monitoring studies suggest that PNPS operations have not had a significant effect on local and regional populations of fish and shellfish. Trends in abundance of groundfish, pelagic fish, and shellfish (lobsters in particular) in western Cape Cod Bay mirror population trends in the larger Gulf of Maine and the western North Atlantic and do not appear to be influenced by PNPS operations.

2.3 Groundwater Resources

PNPS is located on the shore of Cape Cod Bay within the Northeast Uplands Physiographic Province of the Appalachian Mountains. The rocks and sediment in the region range in age from Precambrian to Recent. Pleistocene Glacial till and outwash of variable thickness generally mantles bedrock in the area. Bedrock at the site is approximately 65 feet below ground surface. Groundwater in the area generally occurs in the glacial soils [Reference 2-37]. Most of the residences in the area receive their water from the Town of Plymouth, as does PNPS. The source of Plymouth's water is 11 groundwater wells [Reference 2-41]. Groundwater use is limited to a few locations because the Town of Plymouth supplies most of the residences in the area. There is no current or proposed major groundwater use in the vicinity of the site. The groundwater at the site generally follows the site surface topography. As a result, moderately steep groundwater gradients are present with flow toward Cape Cod Bay [Reference 2-37, Section 1.6].

2.4 Critical and Important Terrestrial Habitats

The 140-acre PNPS site that contains the major generating facilities, office buildings, warehouses, parking lots, and switchyard, is industrial in character, and provides some limited wildlife habitat (lawns, shrubs, and flowerbeds around buildings) for species that tolerate high levels of human activity. Wooded areas immediately north, south, and west of the developed portion of the site offer higher-quality wildlife habitat, but the value of these areas is diminished by proximity to PNPS and to Rocky Hill Road. Cape Cod Bay lies to the east of the site.

In addition, Entergy owns approximately 1,500 acres south and west of Rocky Hill Road. These Entergy-owned lands are managed in a forest trust and are not considered part of the PNPS site proper. This acreage has been designated "Forest Land" under Chapter 61/Chapter 61A of the

General Laws of the Commonwealth, meaning that the State Forester has certified that the land is being managed under an approved Forest Management Plan to "...improve the quality and quantity of a continuous forest crop" (from Certificate for Chapter 61/Chapter 61A Forest Lands, dated September 16, 2002, and signed by the State Forester).

The Forest Management Plan [Reference 2-14] prepared for the Massachusetts Department of Environmental Management provides a history of forest management on the property, descriptions of each timber stand (dominant species, age/size of trees, soils, topography), and future plans for each stand (i.e., planting, fertilizing, weeding, thinning, or harvesting). This forestland, which is dominated by second-growth mixed hardwoods (mostly oaks) and pines (mostly white pine and pitch pine), also contains some small wetland areas and abandoned fields in varying stages of succession. These natural areas provide habitat for a variety of wildlife including amphibians (e.g., spotted salamander, redback salamander), reptiles (e.g., Eastern box turtle, Eastern painted turtle), small mammals (e.g., white-footed mouse, gray squirrel, Eastern cottontail rabbit), white-tailed deer, upland game birds (e.g., ruffed grouse, turkey), songbirds (e.g., warblers, sparrows, flycatchers), and birds of prey (e.g., red-tailed hawk, great horned owl) [Reference 2-1; Reference 2-7; Reference 2-11; Reference 2-35].

To determine if sensitive or ecologically-significant habitats were present in the vicinity of the PNPS site, Entergy reviewed Massachusetts Geographic Information System (GIS) data layers for "priority habitat" (known habitats of state-protected plants and animals), "estimated habitat" (known habitats of state-protected wildlife occurring in wetland areas), and certified vernal pools (vernal pools are afforded protection under the Massachusetts Wetlands Protection Act when they satisfy specific criteria with regard to hydrology and indicator species). These data layers are derived from databases maintained by the Massachusetts Division of Fisheries and Wildlife's (MDFW) Natural Heritage & Endangered Species Program (NHESP). Entergy also reviewed lists of threatened and endangered species known to occur in Massachusetts to determine if critical habitat had been identified in the PNPS vicinity for any of these species.

Based on this investigation and correspondence with the MDFW, there is one site of both priority and estimated habitat for the spotted turtle (*Clemmys guttata*), which is a state species of special concern, on the 140-acre PNPS site. Two NHESP priority sites of rare species habitats lie within several hundred yards of the PNPS-to-Snake Hill Road transmission corridor. NHESP prefers not to reveal the sensitive species found or potentially found in these areas. The PNPS-to-Snake Hill Road corridor does not actually cross these significant areas, nor does it encroach or impinge upon them in any way. The closest certified vernal pool is approximately one mile away from the transmission corridor.

A 0.5-mile-long segment of the PNPS-to-Snake Hill Road transmission corridor passes through an area designated critical habitat (at 50 CFR 17.95) for the northern red-bellied cooter (*Pseudemys rubriventris*). Critical habitat is defined and used in the Endangered Species Act to describe specific geographic areas essential to the conservation of a threatened or endangered species that may require special management and protection. Federal agencies are required to consult with the U.S. Fish and Wildlife Service (FWS) on activities they carry out, fund, or authorize to ensure that these activities will not destroy or adversely modify critical habitats. As

noted elsewhere in this document, Entergy does not own, operate, or maintain the PNPS-to-Snake Hill Road transmission corridor.

Section 3.2.7 describes the transmission lines that Boston Edison built to connect PNPS to the transmission system. Two 345-kilovolt (kV) transmission lines leave the PNPS switchyard, but these transmission lines merge and share a single, 300-foot-wide corridor from the PNPS site to the Snake Hill Road substation. These transmission lines are owned and maintained by NSTAR, which transmits and delivers electricity to homes and businesses in eastern Massachusetts. NSTAR normally controls woody vegetation in transmission corridors in accessible upland areas by mowing. NSTAR's corridor vegetation maintenance program is an integrated one that uses a combination of mechanical, chemical, and biological control methods. This methodology creates stable communities of native plants that are not capable of growing into electric conductors, provides excellent habitat for wildlife, and supports biodiversity. NSTAR's vegetation program complies with all state and federal regulations. Prior to carrying out vegetation management in rights-of-way, NSTAR environmental personnel review work plans with maintenance crews and consult with local town conservation committees when necessary to ensure that wetland areas and sensitive plant communities are protected. NSTAR also schedules vegetation management practices in consideration of species life cycles in the areas to be maintained.

No additional areas designated by FWS as critical habitat for listed species occur at PNPS or occur within or adjacent to associated transmission lines. In addition, the transmission corridors do not cross any state or federal parks, wildlife refuges, or wildlife management areas.

2.5 Threatened or Endangered Species

More than 80 state- and federally-listed species could occur in Plymouth County, a relatively large county that encompasses a variety of habitats ranging from upland forests to farmlands to bogs to marshlands [Reference 2-27; Reference 2-28] (Table 2-1). Another 10 marine species listed by the FWS and National Marine Fisheries Service (NMFS) could occur in Cape Cod Bay [Reference 2-15; Reference 2-28]: 5 species of whale (sei, right, blue, finback, and humpback) and 5 species of sea turtle (loggerhead, leatherback, hawksbill, green, and Kemp's ridley).

No state- or federally-listed endangered or threatened species is known or believed to occur on the PNPS site. The PNPS-to-Snake Hill Road transmission corridor crosses habitat designated critical for the endangered northern red-bellied cooter (see Section 2.4 for a discussion of this critical habitat), but the part of the critical habitat crossed by the transmission corridor appears to be a buffer area for the population rather than high-quality turtle habitat. Northern red-bellied cooters have never been observed by Boston Edison, Entergy, or NSTAR biologists in this transmission corridor. No other state- or federally-listed endangered or threatened species is known or believed to occur in this transmission corridor. A state-listed species of special concern, the spotted turtle, does have a priority habitat area on the PNPS site property. Spotted turtles have not been observed by Entergy personnel or contractors on the PNPS site.

Several listed species are known to occur in the general vicinity of the PNPS site, however, and cannot be ruled out as occasional visitors to the PNPS site and environs. These include the bald eagle, piping plover, and roseate tern. Bald eagles are present year-round in Massachusetts and

congregate in significant numbers in wintering areas along the coast of Cape Cod and Buzzards Bay [Reference 2-28]. PNPS environmental personnel have never observed bald eagles foraging in the vicinity of the PNPS site. In March 2005, juvenile and adult bald eagles were observed at Plimoth Plantation in Plymouth, Massachusetts, which is approximately four miles from PNPS. Piping plovers nest in summer on sandy coastal beaches along the Massachusetts coast, preferring the dry, light-colored sand found along the outer shores [Reference 2-28]. Although piping plover nesting has not been documented on the PNPS site, individual birds almost certainly move through the PNPS area when migrating to breeding areas farther north of Plymouth Bay and returning to wintering areas along the south Atlantic and Gulf coasts. Like the piping plover, the roseate tern nests in colonies along the Massachusetts coast in summer [Reference 2-28]. The roseate tern nests in areas with thick vegetative cover, always in association with the common tern. Although suitable nesting habitat has not been identified at PNPS, migrating terns may move through the site in late spring (en route to nesting areas in Maine and Nova Scotia) and late summer (en route to wintering areas in the West Indies and Latin America).

Six great whale species migrate along the coast of Massachusetts, with concentrations occurring in spring in the plankton-rich and fish-filled waters of Stellwagen Bank, an 800-square-mile area of shallow water just off the tip of Cape Cod. The whale species seen most frequently off the coast of Massachusetts are minke, finback, and humpback whales. The minke whale is the most abundant of the baleen whales and is not a listed or candidate species at present. The finback and humpback are listed as federally endangered. The northern right whale, rarest of the great whales, is occasionally observed in Cape Cod Bay in spring and summer months. The western North Atlantic population is believed to number between 290 and 350 individuals [Reference 2-8; Reference 2-30]. Critical habitat has been designated for the endangered northern right whale in Cape Cod Bay (50 CFR 226). No whales have been observed in the shallow waters off PNPS (or in the intake and discharge canal areas) by Boston Edison or Entergy biologists since biological monitoring began in the late 1960s.

Five species of sea turtle occur along the Massachusetts coast, but sightings are uncommon and limited for the most part to sub-adult "wanderers" [Reference 2-39]. Young sea turtles often "migrate" north (float with Gulf stream currents) and feed in Cape Cod Bay during the warm summer months. When water temperatures drop suddenly in late fall/early winter, turtles still in Cape Cod waters are sometime cold-stunned and washed ashore on area beaches. In most years, fewer than 20 sea turtles are stranded, but in the winter of 1999-2000, a total of 277 sea turtles were found on Cape Cod beaches. Slightly more than half (144) of the turtles were transported alive to Boston's New England Aquarium for treatment and subsequently relocated to Florida. In 2003, 89 sea turtles were found stranded on Cape Cod beaches [Reference 2-24]. Forty-four of these turtles survived [Reference 2-24]. In the twenty-five years that records have been kept documenting the numbers of cold-stunned sea turtle strandings in Massachusetts, only one sea turtle has stranded in Plymouth. In November 2003, a small (approximately 50 pounds) loggerhead sea turtle stranded on Priscilla Beach, which is approximately 0.63 miles from PNPS [Reference 2-40]. However, no sea turtles have ever been observed in the intake or discharge canals or along the PNPS waterfront.

Table 2-1
Endangered and Threatened Species that Occur in the Vicinity of PNPS or in Plymouth County, MA

Scientific Name	Common Name	Federal Status[1]	State Status[1]
Mammals			
Balaenoptera borealis	Sei whale	E	E
Balaena glacialis	Right whale	E	E
Balaenoptera musculus	Blue whale	E	E
Balaenoptera physalus	Finback whale	E	E
Megaptera novaeangliae	Humpback whale	E	E
Birds			
Ammodramus savannarum	Grasshopper sparrow	-	T
Bartramia longicauda	Upland sandpiper	-	E
Botaurus lentiginosus	American bittern	-	E
Charadrius melodus[2]	Piping plover	T	T
Circus cyaneus	Northern harrier	-	T
Haliaeetus leucocephalus	Bald eagle	T	E
Ixobrychus exilis[2]	Least bittern	-	E
Parula americana	Northern parula	-	T
Podilymbus podiceps	Pied-billed grebe	-	E
Rallus elegans	King rail	-	T
Sterna dougallii dougallii[2]	Roseate tern	E	E
Reptiles			
Caretta caretta	Loggerhead sea turtle	T	T
Chelonia mydas	Green sea turtle	T	T
Dermochelys coriacea	Leatherback sea turtle	E	E
Emydoidea blandingii	Blanding's turtle	-	T
Eretmochelys imbricata	Hawksbill sea turtle	E	E
Lepidochelys kempii	Kemp's Ridley sea turtle	E	E
Malaclemys terrapin	Diamondback terrapin	-	T
Pseudemys rubriventris bangsi[2]	Northern red-bellied cooter	E	E

Table 2-1
Endangered and Threatened Species that Occur in the Vicinity of PNPS or in Plymouth County, MA
(Continued)

Scientific Name	Common Name	Federal Status[1]	State Status[1]
Amphibians			
Ambystoma opacum	Marbled salamander	-	T
Scaphiopus holbrookii	Eastern spadefoot toad	-	T
Invertebrates			
Acronicta albarufa	Barrens daggermoth	-	T
Alasmidonta heterodon	Dwarf wedgemussel	E	E
Cicinnus melsheimeri	Melsheimer's sack bearer	-	T
Cycnia inopinatus	Unexpected cycnia	-	T
Enallagma recurvatum[2]	Pine barrens bluet	-	T
Erynnis persius persius[2]	Persius duskywing	-	E
Hypomecis buchholzaria	Buchholz's gray	-	E
Lampsilis cariosa	Yellow lampmussel	-	E
Metarranthis apiciaria	Barrens metarranthis moth	-	E
Nicrophorus americanus	American burying beetle	E	-
Papaipema appassionata	Pitcher plant borer moth	-	T
Papaipema stenocelis	Chain fern borer moth	-	T
Papaipema sulphurata[2]	Water-willow stem borer	-	T
Somatochlora kennedyi	Kennedy's emerald	-	E
Zanclognatha martha	Pine barrens zanclognatha	-	T
Vascular Plants			
Agalinis acuta	Sandplain gerardia	E	-
Aristida purpurascens	Purple needlegrass	-	T
Asclepias verticillata	Linear-leaved milkweed	-	T
Bidens hyperborea var. *hyperborea*	Estuary beggarticks	-	E
Calamagrostis pickeringii	Reed bentgrass	-	E
Cardamine longii	Long's bittercress	-	E
Carex polymorpha	Variable sedge	-	E

Table 2-1
Endangered and Threatened Species that Occur in the Vicinity of PNPS or in Plymouth County, MA
(Continued)

Scientific Name	Common Name	Federal Status[1]	State Status[1]
Carex striata var. *brevis*	Walter's sedge	-	E
Crassula aquatica	Pygmyweed	-	T
Cyperus houghtonii	Houghton's flatsedge	-	E
Dichanthelium mattamuskeetense	Mattamuskeet panic-grass	-	E
Elatine americana	American waterwort	-	E
Eriocaulon parkeri	Estuary pipewort	-	E
Eupatorium aromaticum	Lesser snakeroot	-	E
Eupatorium leucolepis var. *novae-angliae*[2]	New England boneset	-	E
Isoetes acadiensis	Acadian quillwort	-	E
Isotria medeoloides	Small whorled pogonia	T	-
Linum medium var. *texanum*	Rigid flax	-	T
Lipocarpha micrantha	Dwarf bulrush	-	T
Ludwigia sphaerocarpa	Round-fruited false-loosestrife	-	E
Lycopus rubellus	Gypsywort	-	E
Mertensia maritima	Oysterleaf	-	E
Ophioglossum pusillum	Northern adder's-tongue	-	T
Panicum rigidulum var. *Pubescens*	Long-leaved panic-grass	-	T
Platanthera flava var. *herbiola*	Pale green orchid	-	T
Polygonum setaceum var. *interjectum*	Strigose knotweed	-	T
Prenanthes serpentaria	Lion's foot	-	E
Ranunculus micranthus	Tiny-flowered buttercup	-	E
Ranunculus pensylvanicus	Bristly buttercup	-	T
Rhynchospora inundata[2]	Inundated horned-sedge	-	T
Rhynchospora nitens[2]	Short-beaked bald-sedge	-	T
Rhynchospora torreyana[2]	Torrey's beak-sedge	-	E
Rumex pallidus	Seabeach dock	-	T

Table 2-1
Endangered and Threatened Species that Occur in the Vicinity of PNPS or in Plymouth County, MA
(Continued)

Scientific Name	Common Name	Federal Status[1]	State Status[1]
Sabatia campanulata	Slender marsh pink	-	E
Sagittaria subulata var. *subulata*	River arrowhead	-	E
Sanicula canadensis	Canadian sanicle	-	T
Scirpus longii	Long's bulrush	-	T
Senna hebecarpa	Wild senna	-	E
Spartina cynosuroides	Salt reedgrass	-	T
Sphenopholis pensylvanica	Swamp oats	-	T
Symphyotrichum concolor	Eastern silvery aster	-	E
Triosteum perfoliatum	Broad tinker's weed	-	E
Viola brittoniana	Britton's violet	-	T

1. E = Endangered; T = Threatened; - = Not listed.
2. Species reported by the Massachusetts NHESP as occurring within six miles of PNPS.

Source: References 2-15, 2-27, 2-28 and 2-51.

2.6 Regional Demography

2.6.1 Regional Population

The *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* presents a population characterization method that is based on two factors: "sparseness" and "proximity" [Reference 2-32, 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 2-32		

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

Demographic Categories Based on Proximity		
		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 2-32		

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 2-32

Entergy used 2000 census data from the U.S. Census Bureau (USCB) website [Reference 2-43] and GIS software (ArcView®) to determine demographic characteristics in the PNPS vicinity.

As derived from USCB information, approximately 285,547 people live within 20 miles of PNPS. Massachusetts has a population density of 422 persons per square mile within 20 miles of PNPS and, applying the GEIS sparseness index, falls into the least sparse category, Category 4 (having greater than or equal to 120 persons per square mile within 20 miles). This calculation and the one for the population within 50 miles corrects for the area within the radius that is water.

As estimated from USCB information, approximately 4,629,116 people live within 50 miles of PNPS. This equates to a population density of 1,167 persons per square mile within 50 miles. Applying the GEIS proximity index, PNPS is classified as Category 4 proximity (having greater than or equal to 190 persons per square mile within 50 miles). According to the GEIS sparseness and proximity matrix, the PNPS ranks of sparseness Category 4 and proximity Category 4 result in the conclusion that PNPS is located in a "high" population area.

All or parts of 15 counties (Figure 2-1) and the cities of Boston, Massachusetts, and Providence, Rhode Island, are located within 50 miles of PNPS.

Plymouth and Barnstable Counties are largely residential and have a combined total population of approximately 700,000 [References 2-46 and 2-47]. Plymouth County extends to metropolitan Boston and is primarily made of small towns, such as the coastal towns along Cape Cod Bay. Barnstable County is made up of 15 small towns and is bordered by Cape Cod Bay, the Atlantic Ocean, Nantucket Sound, and Plymouth County. From 1970 to 2000, Plymouth County had an average annual growth rate of 1.4% and Barnstable County had an average annual growth rate of 4.3%. Both Plymouth and Barnstable Counties have been growing at a rate faster than that of Massachusetts as a whole. From 1970 to 2000, Massachusetts's average annual population growth rate was 0.39% [adapted from Reference 2-43].

Table 2-2 shows estimated populations and annual growth rates through 2040 for the two counties with the greatest potential to be socioeconomically affected by license renewal activities. The license renewal term is through 2032.

Table 2-2
Estimated Populations and Annual Growth Rates in Plymouth and Barnstable Counties 1980-2040

	Plymouth County		Barnstable County	
Year	Population	Percent Annual Growth	Population	Percent Annual Growth
1980	405,437[1]		147,925[1]	
1990	435,276[1]	0.7	186,605[1]	2.6
2000	472,822[2]	0.9	222,230[2]	1.9
2010	496,053[3]	0.5	257,844[3]	1.6
2020	517,644[3]	0.4	299,035[4]	1.6
2030	551,005[4]	0.6	334,766[4]	1.2
2040	579,529[4]	0.5	368,720[4]	1.0

1. Reference 2-42
2. References 2-46 and 2-47
3. Reference 2-29
4. Reference 2-38

2.6.2 Minority and Low-Income Populations

2.6.2.1 Background

The NRC 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. Entergy has adopted this approach for identifying the minority and low-income populations that could be affected by PNPS operations.

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 characteristics on a block-group level and low-income characteristics on a census tract. Entergy included all census tracts/block groups if any of their area lay within 50 miles of PNPS. The 50-mile radius includes 3,845 block groups and 1,034 census tracts. Entergy defines the geographic area for PNPS as a two-state area, with the largest portion of that area located in Massachusetts and a smaller portion in Rhode Island.

2.6.2.2 Minority Populations

The NRC procedural guidance for performing environmental assessments and considering environmental issues defines a "minority" population as American Indian or Alaskan Native; Asian; Native Hawaiian or Pacific Islander; Black races; other; multi-racial; the aggregate of all minority races; or Hispanic ethnicity [Reference 2-33]. 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 [References 2-43 and 2-44] to determine the percentage of the total populations in the two states that belong to each minority group, and to identify minority populations within 50 miles of PNPS.

For each minority, 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 the minority. For each of the 3,845 block groups within 50 miles of PNPS, Entergy calculated the percent of the population in each minority category and compared the result to the corresponding geographic area's minority threshold percentages to determine whether minority populations exist.

Massachusetts had approximately 83% of the block groups with the remaining 17% in Rhode Island. USCB data [Reference 2-43] for Massachusetts characterize 0.2% of the state's population as American Indian or Alaskan Native; 3.8% Asian; 0.0% Native Hawaiian or other Pacific Islander; 5.4% Black races; 3.7% all other single minorities; 2.3% multi-racial; 15.5% aggregate of minority races; and 6.8% Hispanic ethnicity. USCB data [Reference 2-44] for Rhode Island characterizes 0.5% of the state's population as American Indian or Alaskan Native; 2.3% Asian; 0.1% Native Hawaiian or other Pacific Islander; 4.5% Black races; 5.0% all other single minorities; 2.7% multi-racial; 15% aggregate of minority races; and 8.7% Hispanic ethnicity.

Based on either the "more than 20 percent" or the "exceeds 50 percent" criteria, no multi-racial block groups exist in the geographic area.

Based on the "more than 20 percent" criterion, an American Indian or Alaskan Native minority population exists in one block group, in Dukes County, Massachusetts (Table 2-3, Figure 2-4).

Based on the "more than 20 percent" criterion, Asian minority populations exist in 57 block groups; 54 in Massachusetts and 3 in Rhode Island (Table 2-3, Figure 2-5).

Based on the "more than 20 percent" criterion, a Native Hawaiian or other Pacific Islander minority population exists in one block group in Suffolk County, Massachusetts (Table 2-3, Figure 2-6).

Based on the "more than 20 percent" criterion, Black Races minority populations exist in 261 block groups (Table 2-3, Figure 2-7) with 233 of the block groups in Massachusetts and the remaining 28 in Rhode Island.

Based on the "more than 20 percent" criterion, All Other Single Minority Races populations exist in 135 block groups (Table 2-3, Figure 2-8). Seventy-seven of the block groups are in Massachusetts and 58 are in Providence County, Rhode Island.

Based on the "more than 20 percent" criterion, Aggregate of Minority Races populations exist in 597 block groups (Table 2-3, Figure 2-9) with 477 of the block groups in Massachusetts and 120 in Rhode Island.

Based on the "more than 20 percent" criterion, Hispanic Ethnicity minority populations exist in 240 block groups (Table 2-3, Figure 2-10) with 145 of them in Massachusetts and the other 95 in Providence County, Rhode Island.

As a general matter, there are relatively few block groups in the geographic areas that constitute minority populations, and these are generally in towns or urban areas more than 20 miles from the site.

2.6.2.3 Low-Income Populations

NRC guidance defines "low-income" by using USCB statistical poverty thresholds [Reference 2-33, Appendix D]. The USCB characterizes 9.9% of Massachusetts and 12.4% of Rhode Island households as low-income [Reference 2-45].

For each census tract within the 50-mile radius of PNPS (see Section 2.6.2.1 for a discussion of how census tracts were selected and population percentages were calculated), the number of low-income households was divided by the number of total households in that tract to obtain the percent of low-income households for that tract. A low-income population is considered to be present if

(1) the low-income population of the census tract or environmental impact site exceeds 50%, or

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

Based on the "more than 20 percent" criterion, low-income populations exist in 69 census tracts (Table 2-3, Figure 2-11), 48 in Massachusetts and 21 in Providence County, Rhode Island.

As a general matter, there are relatively few low income populations in the geographic areas, and these are generally in towns or urban areas more than 20 miles from the site.

Table 2-3
Minority and Low-Income Population Information

County	State	2000 Block Groups	American Indian or Alaskan Native	Asian	Native Hawaiian or Other Pacific Islander	Black Races	All Other Single Minorities	Multi-Racial Minorities	Aggregate of Minority Races	Hispanic Ethnicity	2000 Census Tracts	Census 2000 Tracts Low Income
Barnstable	MA	199	0	0	0	0	0	0	0	0	51	0
Bristol	MA	417	0	1	0	0	11	0	22	6	117	9
Dukes	MA	20	1	0	0	0	0	0	1	0	4	0
Essex	MA	311	0	0	0	1	5	0	33	25	81	2
Middlesex	MA	753	0	11	0	14	2	0	53	8	194	0
Nantucket	MA	5	0	0	0	0	0	0	0	0	3	0
Norfolk	MA	473	0	14	0	5	0	0	21	0	121	0
Plymouth	MA	366	0	0	0	17	8	0	43	0	92	1
Suffolk	MA	631	0	28	1	196	51	0	304	106	177	36
Worchester	MA	14	0	0	0	0	0	0	0	0	6	0
Bristol	RI	41	0	0	0	0	0	0	0	0	11	0
Kent	RI	83	0	0	0	0	0	0	0	0	23	0
Newport	RI	60	0	0	0	1	0	0	2	0	22	0
Providence	RI	468	0	3	0	27	58	0	118	95	130	21
Washington	RI	4	0	0	0	0	0	0	0	0	2	0

Table 2-3
Minority and Low-Income Population Information (Continued)

Totals	3845	1	57	1	261	135	0	597	240	1034	69
State		**American Indian or Alaskan Native**	**Asian**	**Native Hawaiian or Other Pacific Islander**	**Black Races**	**All Other Single Minorities**	**Multi-Racial Minorities**	**Aggregate of Minority Races**	**Hispanic Ethnicity**	**Low Income**	
State Averages											
Massachusetts		0.2%	3.8%	0.0%	5.4%	3.7%	2.3%	15.5%	6.8%	9.9%	
Rhode Island		0.5%	2.3%	0.1%	4.5%	5.0%	2.7%	15%	8.7%	12.4%	
Percentage that Identifies a Minority Block on Low-Income Tract											
Massachusetts		20.2%	23.8%	20%	25.4%	27.3%	22.3%	35.5%	26.8%	29.9%	
Rhode Island		20.5%	22.3%	20.1%	24.5%	25%	22.7%	35%	28.7%	32.4%	

2.7 Taxes

PNPS pays annual property taxes to the Town of Plymouth. Taxes fund the Town of Plymouth's operations, the school system, public works, the Town General Fund, and the police and fire departments [Reference 2-19].

In 1998, the Commonwealth of Massachusetts deregulated its utility industry. As a result, the Massachusetts legislature changed property tax assessment methodologies for utilities from net book value to fair market value. In 1999, Boston Edison Company sold PNPS to Entergy Corporation for roughly an order of magnitude less than the value being carried on the books at that time. Therefore, the property taxes being paid to the Town of Plymouth for PNPS have been reduced from pre-1999 payments. Entergy paid $1.6 million in property taxes for the Town's 1999-2000 fiscal year. For the fiscal year 2004, Entergy's property tax bill was $1.6 million. The Town of Plymouth and Entergy have negotiated payment in lieu of taxes of $1 million annually with the potential for payments to increase should Entergy make capital improvements or substantial additions to the plant. The agreement is through 2012, and would be renegotiated in the event of license renewal. Boston Edison's parent, NSTAR, retained ownership of all transmission functions and facilities and will continue to pay property taxes to the Town of Plymouth for those facilities. Because the transmission facilities are part of the utility industry and also subject to the new property tax assessment methodologies, NSTAR will pay reduced property taxes to the Town of Plymouth. In order to ease deregulation impacts to the Town of Plymouth, the Massachusetts legislature has required NSTAR to make payments to the Town of Plymouth until the end of PNPS' current license in 2012. Those payments are gradually being reduced until they reach $1 million in 2007. From 2007 to 2012, NSTAR will pay the Town of Plymouth $1 million annually. This is a significant reduction from the $15 million in tax revenues previously received by the Town from Boston Edison Company. Table 2-4 lists the tax payments for the years 1997 through 2012.

Until 1999, PNPS' property taxes provided approximately 24% of the Town of Plymouth's total property tax revenues. Currently, PNPS pays approximately 2 to 3% of the total property taxes received by the Town of Plymouth.

Table 2-4
Property Taxes

Year	Town of Plymouth Property Tax Revenues	Property Tax Paid by PNPS	Boston Edison or PNPS % of Total Property Taxes	Property Tax Paid by Boston Edison or NSTAR
1997[2]	$63,082,579[1]	NA	24	$15,000,000
1998[2]	$64,415,102[1]	NA	24	$15,187,000
1999	$67,179,636[1]	$800,000	prorated	$15,187,000
2000	$71,834,404[1]	$1,600,000	2	$15,187,000
2001	$75,157,498[3]	$2,500,000	3	$15,187,000
2002	$76,393,522[3]	$2,011,445	3	$13,000,000
2003	$78,703,111[3]	$1,617,779	2	$13,000,000
2004	$86,587,205[3]	$1,600,000	2	$13,000,000
2005	--	$1,400,000	--	$13,000,000
2006	--	$1,000,000	--	$11,000,000
2007	--	$1,000,000	--	$1,000,000
2008	--	$1,000,000	--	$1,000,000
2009	--	$1,000,000	--	$1,000,000
2010	--	$1,000,000	--	$1,000,000
2011	--	$1,000,000	--	$1,000,000
2012	--	$1,000,000	--	$1,000,000

1. Reference 2-17
2. Boston Edison owned PNPS until 1999 and paid taxes to the Town of Plymouth on the plant and transmission facilities.
3. Reference 2-20

NA = Not applicable.

2.8 Land Use Planning

Localities in southeastern Massachusetts have united to develop a regional growth management project called the *Southeastern Massachusetts Vision 2020 Project*, which has been designed to address the rapid growth and change occurring in the area of Massachusetts between Boston, Cape Cod, and Rhode Island. The project includes 51 cities and towns, including all communities in Plymouth and Bristol Counties and four communities in Norfolk County. Three regional planning agencies in southeastern Massachusetts are overseeing the project: the Old Colony Planning Council, the Southeastern Regional Planning and Economic Development District, and the Metropolitan Area Planning Council [Reference 2-34, Chapter 1].

This section focuses on Plymouth and Barnstable Counties because most of the permanent PNPS workforce live in these counties (see Section 3.5) and Entergy pays property taxes in the Town of Plymouth. The planning commissions for the areas of Plymouth County where most Pilgrim employees reside are the Old Colony Planning Council, the Metropolitan Area Planning Council, and the Southeastern Regional Planning and Economic Development District. Barnstable County has its own regional planning organization, the Cape Cod Commission [Reference 2-4, Section 1].

Both counties have experienced growth over the last several decades (Table 2-2) and their regional policy plans reflect planning efforts and public involvement in the planning process. Land use planning tools, such as zoning, historic districts, and incentives for redevelopment guide, but do not restrict, future growth and development. All plans share the goals of managing growth and development, protecting public drinking water supplies, reducing traffic congestion, and controlling sprawl. As demonstrated below, the land use plans for the two counties guide development, but do not contain strict growth control measures that limit overall housing development [Reference 2-9].

2.8.1 Plymouth County

Plymouth County occupies roughly 661 square miles of land area [Reference 2-46]. Over 59,000 acres of farmland are in Plymouth County and it is ranked third of 14 counties in Massachusetts in agricultural sales [Reference 2-48].

2.8.1.1 Existing Land Use Trends

As of 1991, 22 to 47% of the land within the Old Colony Planning Council portion of Plymouth County was potentially "developable" (i.e., agricultural, forest, and open space) [Reference 2-34, Figure 4.7]. The developed land is primarily residential [Reference 2-34, Chapter 4]; however, Plymouth County is also home to industry, wholesale and retail businesses, and service-based businesses [Reference 2-36]. The South Shore subregion (Rockland, Norwell, Scituate, Marshfield, Hanover, and Duxbury) is classified as suburban/rural. Because of the limited public sewerage and public transit in the South Shore subregion, the Metropolitan Area Planning Council designates this area as appropriate for very limited new growth [Reference 2-18, page 12].

The land within the Town of Plymouth, where PNPS is located, and where roughly 30% of the employees reside, was classified in 1999 as follows: 15.8% residential, 0.9% commercial, 3.0% industrial, 4.2% agriculture, 3.44% urban open land, 6.4% water, 3.1% open land, and 63.3% natural land/ undisturbed vegetation [Reference 2-21]. The Town of Plymouth has zoning districts for a range of residential, commercial, and industrial development, and regulations that guide that development [Reference 2-34, Appendix].

2.8.1.2 Future Land Use Trends

The Old Colony Planning Council guides much of the land development in Plymouth County. The Council is charged with designating priority development areas that have combinations of land, infrastructure, services, accessibility, and amenities suited to accommodate a significant portion of the region's anticipated growth. Growth will be encouraged within the boundaries of the priority development areas. The region's desired pattern for new growth is the compact, mixed-use community center. Communities will allocate land for future residential development with guidance from the Council. This future residential development will occur in areas which are designated for growth, are compatible with adjoining uses, and where there will be no significant adverse or unmitigated impacts to environmental resources. Build-out and site-suitability analyses will be conducted throughout the region to assist in identifying areas for future development [Reference 2-34, Chapter 3].

The Town of Plymouth conducted a build-out study considering local zoning requirements, geographic limitations, transportation, and water supply constraints in 1999. The study identified 29,000 acres that would be appropriate for residential development and approximately 375 acres for commercial and industrial development.

2.8.2 Barnstable County

Barnstable County encompasses approximately 396 square miles [Reference 2-47]. According to the Barnstable Regional Policy Plan, Barnstable County is treasured for the distinctive historic and small town character of its communities and its open landscapes [Reference 2-6, Section II.6.

2.8.2.1 Existing Land Use Trends

Every Barnstable County community is struggling to manage growth, preserve historic resources, and maintain town character, often without adequate growth controls and zoning standards. In 1990, land use classifications in Barnstable County were as follows: 30% residential, 0.8% crop land and pasture, 47% forest, 8.3% open land, 1.9% commercial, 0.50% industrial, and 4.6% water [adapted from Reference 2-5]. Recent land development in Barnstable County has been primarily residential. In 1996, developed land represented more than 33% of Barnstable County's total land area [Reference 2-6, Section II.1].

2.8.2.2 Future Land Use Trends

Barnstable County, through its regional planning organization, the Cape Cod Commission, has developed land use and growth policies. The Cape Cod Commission's goal for future land use

and growth has been "to encourage growth and development consistent with the carrying capacity of Cape Cod's natural environment in order to maintain the Cape's economic health and quality of life, and to encourage the preservation and creation of village centers and downtown areas that provide a pleasant environment for living, working, and shopping for residents and visitors" [Reference 2-4]. To achieve this goal, Barnstable has the following requirements [Reference 2-4]:

- Compact forms of development such as cluster development, redevelopment within certified growth/activity centers, and, where appropriate, mixed-use residential/ commercial development shall be encouraged in order to minimize further land consumption and protect open space.
- All residential subdivisions of five or more lots shall submit a cluster development preliminary plan for consideration by towns or the Commission as appropriate during the development review process.
- Extension or creation of new roadside "strip" commercial development outside of certified growth/activity centers shall be prohibited.
- Development and redevelopment shall be directed away from Significant Natural Resource Areas as illustrated on the Cape Cod Significant Natural Resource Area Map dated September 5, 1996, as amended.

2.9 Social Services and Public Facilities

2.9.1 Public Water Supply

Because PNPS is located in Plymouth County and most of the PNPS employees reside in Plymouth or Barnstable Counties, the discussion of public water supply systems will focus on towns within these counties (Table 2-5 and Table 2-6). County-level data is not available.

2.9.1.1 Plymouth County

Groundwater is the primary source of potable water for the communities in Plymouth County. However, the Scituate and Abington-Rockland drinking water systems are supplied from both groundwater and surface water. The Brockton water system is supplied by surface water only. The various water systems buy from or sell to other nearby water systems, depending on demand. System water demand for the communities in Plymouth County which make up a large percentage of the PNPS employment population in 2003 ranged from a low of 0.26 million gallons per day (MGD) to a high of 4.61 MGD. Average daily consumption among these towns is approximately 1.73 MGD (calculated from data provided by Reference 2-25). There are several towns where a number of PNPS employees reside which do not have municipal water, but rather individual private wells.

Table 2-5 compares average daily use and authorized withdrawal volumes (capacities) for selected Plymouth County water systems.

Table 2-5
Selected Plymouth County Public Water Suppliers and Capacities for the Year 2003

	Average Consumption (MGD)[1]	Authorized Withdrawal Volume (Capacity MGD)[2]
Duxbury Water Department	1.35	1.85
Halifax Water Department	0.49	0.68
Kingston Water Department	1.39	1.56
Marshfield Water Department	2.90	3.3
Middleborough Water Department	1.53	3.03
Pembroke Water Division	1.33	1.26
Plymouth Water Division	4.61	6.36
Plymouth Water Co.	0.26	0.22

1. Reference 2-25
2. Reference 2-26

Because no county-level data were available, Entergy evaluated the water systems in the Plymouth and Barnstable Counties towns where approximately 70% of the Pilgrim workforce reside. The remaining 30% of the workforce was scattered among numerous towns and few employees lived in any single town.

Shading indicates communities where consumption exceeds capacity and shortfalls are made up by purchase.

2.9.1.2 Barnstable County

A network of 145 groundwater wells supported by the Cape Cod Aquifer supplies Barnstable County's potable water. A 1994 U.S. Geological Survey study indicated that approximately 5.6% of Barnstable County's land area would be suitable for new well sites [Reference 2-4, Section 2.1]. The average daily water demand for 2003 for the water systems serving the areas of Barnstable County where the majority of PNPS employees reside is 1.15 MGD. The water demand ranged from a low of 0.10 MGD to a high of 2.74 MGD (calculated from data provided by Reference 2-25].

Table 2-6 compares average daily use and authorized withdrawal volumes (capacities) for the Barnstable County water systems.

Table 2-6
Barnstable County Public Water Suppliers and Capacities for the Year 2003

	Average Consumption (MGD)[3]	Authorized Withdrawal Volume (Capacity MGD)[4]
Barnstable Fire District[1]	0.54	0.66
Barnstable Water Company[1]	2.57	3.42
Bourne Water District[2]	1.17	1.40
Buzzards Bay Water District[2]	0.46	0.53
COMM Water Department[1]	2.74	3.57
Cotuit Water Department[1]	0.49	0.48
Mashpee Water Department	1.26	1.30
North Sagamore Water District[2]	0.51	0.48
Sandwich Water District	1.67	2.64
South Sagamore Water District[2]	0.10	0.09

1. The Town of Barnstable is composed of 7 villages and is serviced by 4 water suppliers.
2. The Town of Bourne is composed of 7 villages and is serviced by 4 water suppliers.
3. Reference 2-25
4. Reference 2-26

Because no county-level data were available, Entergy evaluated the water systems in the Plymouth and Barnstable County towns where approximately 70% of the Pilgrim workforce reside. The remaining 30% of the workforce was scattered among numerous towns and few employees lived in any single town.

Shading indicates communities where consumption exceeds capacity and shortfalls are made up by purchase.

2.9.1.3 Assessment

As presented in Table 2-5 and Table 2-6, average daily consumption rates exceed the authorized withdrawal limits (capacities) in several communities. Those communities purchase water from communities with excess capacity to meet the residual demand. Overall, the region has excess capacity and has been able to meet total demand. The Town of Plymouth is reviewing options for meeting future demand [Reference 2-10].

2.9.2 Transportation

Road access to PNPS is via Rocky Hill Road or Power House Road (formerly known as Edison Access Road). Both are two-lane paved roads, the second of which is privately owned by Entergy (see Figure 2-2 and Figure 2-3). Rocky Hill Road intersects with State Route 3A approximately 1.5 miles west of the station, and Power House Road intersects with State Route 3A, approximately 1.5 miles south of the station and 2.5 miles east of the Rocky Hill/3A intersection.

State Route 3A runs north-south through the Town of Plymouth, providing access to Rocky Hill Road and Power House Roads from Plymouth. State Route 3A provides access to the major north-south highway in the vicinity of the Town of Plymouth, State Route 3. State Route 3 is used by employees traveling south from the towns of Marshfield, Duxbury, Kingston, and Pembroke.

Employees traveling north would use either State Route 3A or 3 to Beaver Dam Road, which intersects State Route 3A south of Power House Road. Employees traveling east to PNPS would use State Route 44 to State Route 3A or 3. The level of service determination for the State Route 3A intersection with Beaver Dam Road (southeast of PNPS) and White Horse Road (the eastern extension of Beaver Dam Road) is C [Reference 2-50]. Table 2-7 provides daily traffic counts for roads in the vicinity of PNPS. The Massachusetts Highway Department does not have level-of-service data for those roads.

Table 2-7
Traffic Counts for Roads in the Vicinity of PNPS

Route No.	Route Location	Estimated Average Daily Traffic Volume	Year
3	North of Clark Road[1]	30,500	1992
3A	North of Beaver Dam Road	14,400	2003
3A	South of Rocky Hill Road	13,000	1995
3A	South of Route 44	12,700	1998
44	East of Route 3	17,677	1990
Source: Reference 2-22			

1. Beaver Dam Road is known as Clark Road south of the intersection with Sandwich Road (see Figure 2-2)

2.10 Meteorological and Air Quality

PNPS is located along the rocky western shoreline of Cape Cod Bay in the Town of Plymouth, Plymouth County, Massachusetts. The station proper is on the Bay side of the northeast end of Pine Hills, a ridge of low hills about four miles long and tending in a north-south direction [Reference 2-1, Section II.D]. These hills reach a maximum height of 395 feet and form the major drainage divide in the area [Reference 2-1, Section II.D]. Since the site is located along the coast, approximately 60% of the area within a 50-mile radius is open water [Reference 2-1, Section II.B].

The temperature regime of the region is influenced by the proximity of the adjacent waters and as such does not exhibit the wider diurnal and seasonal variations of nearby inland locations. The average annual temperature at Plymouth is 50°F with a high monthly average of 71°F in July and low monthly average of 29°F in February [Reference 2-37, Section 2.3.5]. Monthly averages for precipitation at Plymouth vary from about 3 inches to 4.5 inches. Although snowfall amounts typically average 42 inches per year, the Plymouth area is subjected to a wide range of snowfall since it is located in the northeastern part of the United States. The storm cycle consists generally of northeasters in the winter and spring, and thunderstorms in late spring and summer. Hurricanes sometimes occur in the late summer and fall, with tornado activity in eastern Massachusetts being uncommon.

Plymouth County is part of the Metropolitan Providence Interstate Air Quality Control Region (AQCR). This AQCR is composed of part of Massachusetts and all of Rhode Island. Based on 40 CFR 81 and the EPA's 2003 Annual Report on Air Quality in New England, PNPS is located in a non-attainment area for ozone that is classified as serious for the 1-hour standard and moderate for the 8-hour standard. For particulate matter (PM_{10}), sulfur dioxide, carbon monoxide, nitrogen dioxide, and lead, the area is either in attainment or designated as unclassifiable.

The closest non-attainment area for particulate matter is New Haven, Connecticut, approximately 135 miles from PNPS. The closest non-attainment area for sulfur dioxide is Mansfield, New Jersey, approximately 250 miles from PNPS. There are no designated Class I Federal areas listed in 40CFR81.41 within a 50-mile radius of PNPS.

PNPS has house heating boilers and diesel generators located on-site. Emissions from these sources are regulated by an emissions cap approved by the MDEP in July 2005. This cap limits facility emissions to less than 50% of the major source category emissions. This permit limits the fuel usage and hours of operation of these emission sources.

2.11 Historic and Archaeological Resources

2.11.1 Pre- and Post-Construction Historic/Archaeological Analyses

The FES for construction of PNPS, published in 1972, states that the Atomic Energy Commission (AEC) consulted with the Department of the Interior's Advisory Council on Historic Preservation regarding the potential impacts of PNPS on local historic landmarks [Reference 2-1]. The

Council concluded that the probable effect on these properties cannot be judged to be sufficiently adverse to warrant Council comment [Reference 2-1]. The FES also stated that there is no evidence that the site has any specific historical significance [Reference 2-1].

The FES for construction of the proposed PNPS Unit 2[1], published in 1974, indicated that an extensive archaeological survey was conducted in October 1972 on the original 517-acre station site plus the transmission corridor extending southwest to Jordan Road [Reference 2-2]. Archaeologists and students from the Archaeological Research Department of Plimoth Plantation and the Brown University Department of Anthropology conducted the survey. Twenty-four historic sites were discovered and determined to be insignificant [Reference 2-2]. One pre-historic site (located in the southwest corner of the original PNPS property) was considered to be significant [Reference 2-2]. A second more extensive examination, conducted with the assistance of the Massachusetts Archaeological Society, resulted in the conclusion that there was "no evidence of Indian occupation" in the area of the station [Reference 2-2]. The Massachusetts Archaeological Society report also concluded that the onsite pre-historic site was not significant [Reference 2-3]. Therefore, Boston Edison concluded that there were no historical, cultural, archaeological, or architectural resources that would be affected by the construction or operation of Unit 2 [Reference 2-2]. This conclusion was supported by the Massachusetts Historical Commission in a letter dated April 24, 1974 [Reference 2-2].

On November 27, 1990, the NRC issued an Environmental Assessment for the extension of the PNPS operating license from August 26, 2008, to June 9, 2012. In the environmental assessment, the NRC reported that the continued operation of PNPS would meet 36 CFR 800 "Protection of Historic Properties" requirements [Reference 2-31]. After researching the National Historic Register files through the Massachusetts Historical Commission and consulting with a number of local and national historical organizations, NRC concluded that there had been no evidence of local historic site deterioration due to plant operations [Reference 2-31]. Therefore, the NRC concluded that "the operation of Pilgrim Nuclear Power Station...will cause no adverse effect or induce any detrimental impact on the historic sites located in Plymouth" [Reference 2-31].

2.11.2 Additional Information Regarding the Plimoth Plantation/Brown University Archaeological Survey

The October 1972 survey reported that, because pre-historic archaeological sites in the general locale were of a very low profile, they would be difficult to discover in the rugged terrain of the survey area. None of the areas surveyed was heavily populated during the historic period (Colonial or European settlements). Nearby Plymouth was sparsely settled in 1620. Most of the Rocky Hill area was considered too rugged for settlers' habitation or agricultural production. Seventeenth and eighteenth century sites may have existed in the well-drained land and oceanfront areas. Local informants recall an early cellar that may have been destroyed in the construction of Power House Road. An indication of this particular habitation appears on a late nineteenth century map of the area. However, the same map reinforces the observation that few sites of early habitation would be found in the Rocky Hill area [Reference 2-3, Amendment 6].

1. Unit 2 was never built.

2.11.3 Current Historic/Archaeological Analysis

An examination of the archaeological site files and maps maintained by the Office of the State Archaeologist at the Massachusetts Historical Commission revealed approximately 130 archaeological (pre-historic and historic) sites within a 6-mile radius of the station. Five sites (84, 813, 815, 816, and 19-68) appear to fall within or near the Jordan Road transmission corridor. Beyond the Jordan Road tap, site 361 appears to fall near the corridor. Protective measures for such sites can include signage warning against ground disturbance without proper authorization and supportive procedures for protecting the resource in place or, in the extreme, relocating the resource. However, Entergy does not own or manage these rights of way and has no authority to implement protective measures.

Currently, 109 "above-ground" locations are listed in the National Register of Historic Places for Plymouth County [Reference 2-49]. Twenty of these locations are within the Town of Plymouth. The State Register of Historic Places 2003, a report published by the Massachusetts Historical Commission, states that the Town of Plymouth is home to 21 sites or areas of historic significance [Reference 2-23]. Table 2-8 lists the 21 sites, recognized by either one or both of the two agencies, which are located within the Town of Plymouth.

Table 2-8
Town of Plymouth, Massachusetts, Sites Listed in the National Register of Historic Places and/or the State Register of Historic Places

Site Name	Location
Bartlett-Russell-Hedge House	32 Court Street
Bradford-Union Street Historic District	Bradford, Union, Emerald, Water Cure, and Freedom Streets
Clifford-Warren House	East of Plymouth at 3 Clifford Road
Cole's Hill	Carver Street
Harlow Old Fort House	119 Sandwich Street
Sgt. William Harlow Family Homestead	8 Winter Street
Hillside	230 Summer Street
Jabez Howland House	33 Sandwich Street
Light Houses of Massachusetts (Thematic Group Nomination)	42 properties in 23 towns
National Monument to the Forefathers	Allerton Street
Old County Courthouse	Leyden and Market Streets
Parting Ways Archaeological District	Address Restricted

Table 2-8
Town of Plymouth, Massachusetts, Sites Listed in the National Register of Historic Places and/or the State Register of Historic Places
(Continued)

Site Name	Location
Pilgrim Hall	75 Court Street
Plymouth Antiquarian House	126 Water Street
Plymouth Historic District[1]	Roughly bounded by Town Square, Town Brook, Court, Main, and Water Streets from Samoset to Sandwich Streets
Plymouth Light Station	Gurnet Point
Plymouth Post Office Building	5 Main Street
Plymouth Rock	Water Street
Plymouth Village Historic District	Roughly bounded by Water, Main, and Brewster Streets
Richard Sparrow House	42 Summer Street
Town Brook Historic and Archaeological District	Address Restricted

Source: Reference 2-49

1. Not listed in the National Register of Historic Places, but listed in the State Register of Historic Places 2003 [Reference 2-23].

2.12 Known and Forseeable Federal and Non-Federal Actions

Entergy did not identify any known or reasonably foreseeable federal or non-federal projects or other activities that may contribute to the cumulative environmental impacts of license renewal.

2.13 References

Note to reader: Some web pages cited in this document are no longer available, or are no longer available through the original URL addresses. Hard copies of all cited web pages are available in Entergy files. Some sites (e.g., the census data) cannot be accessed through their URLs. The only way to access these pages is to follow queries on previous web pages. The complete URLs used by Entergy have been cited for these pages, even though they may not be directly accessible.

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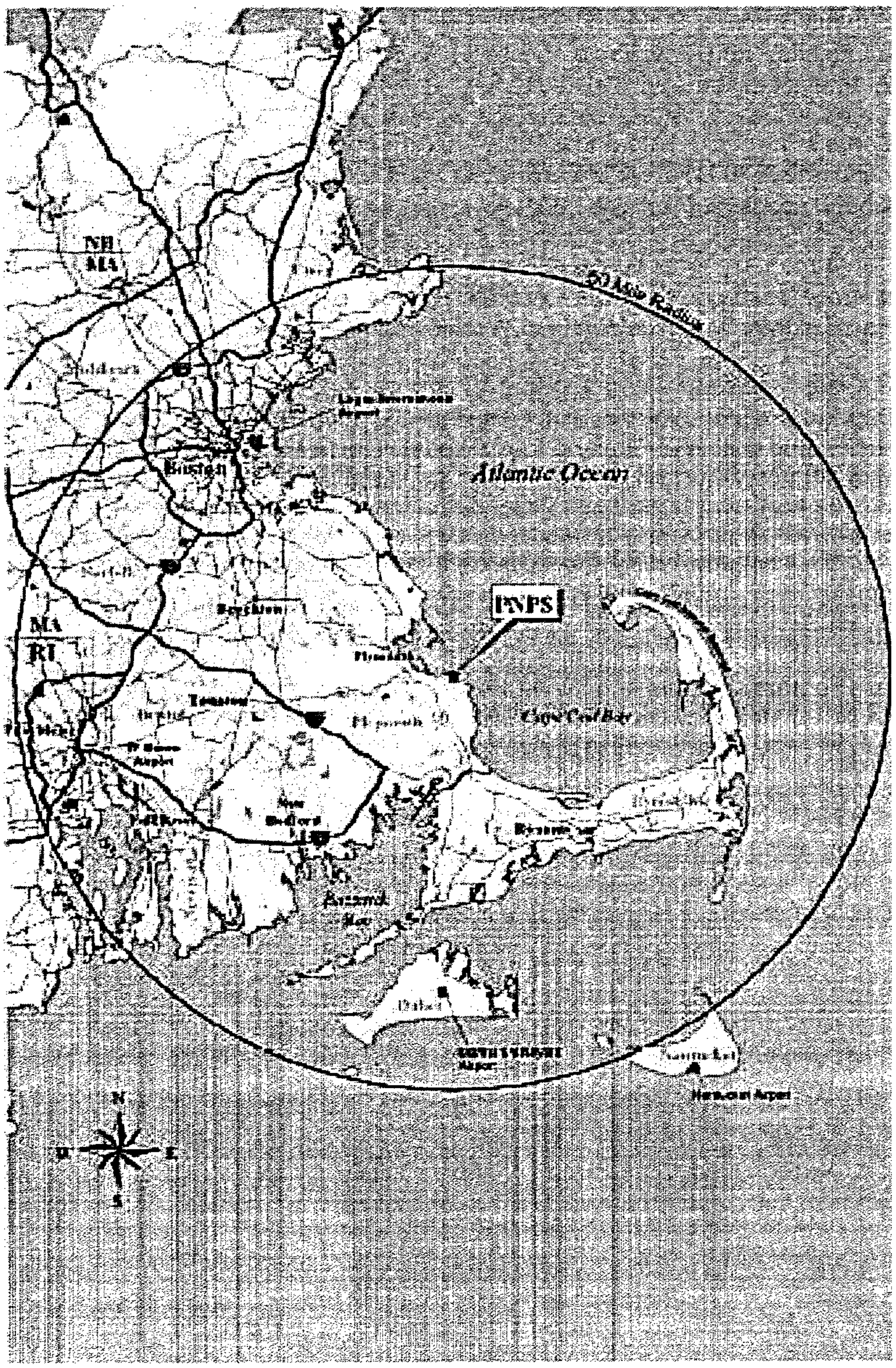

Figure 2-1
50-Mile Vicinity Map

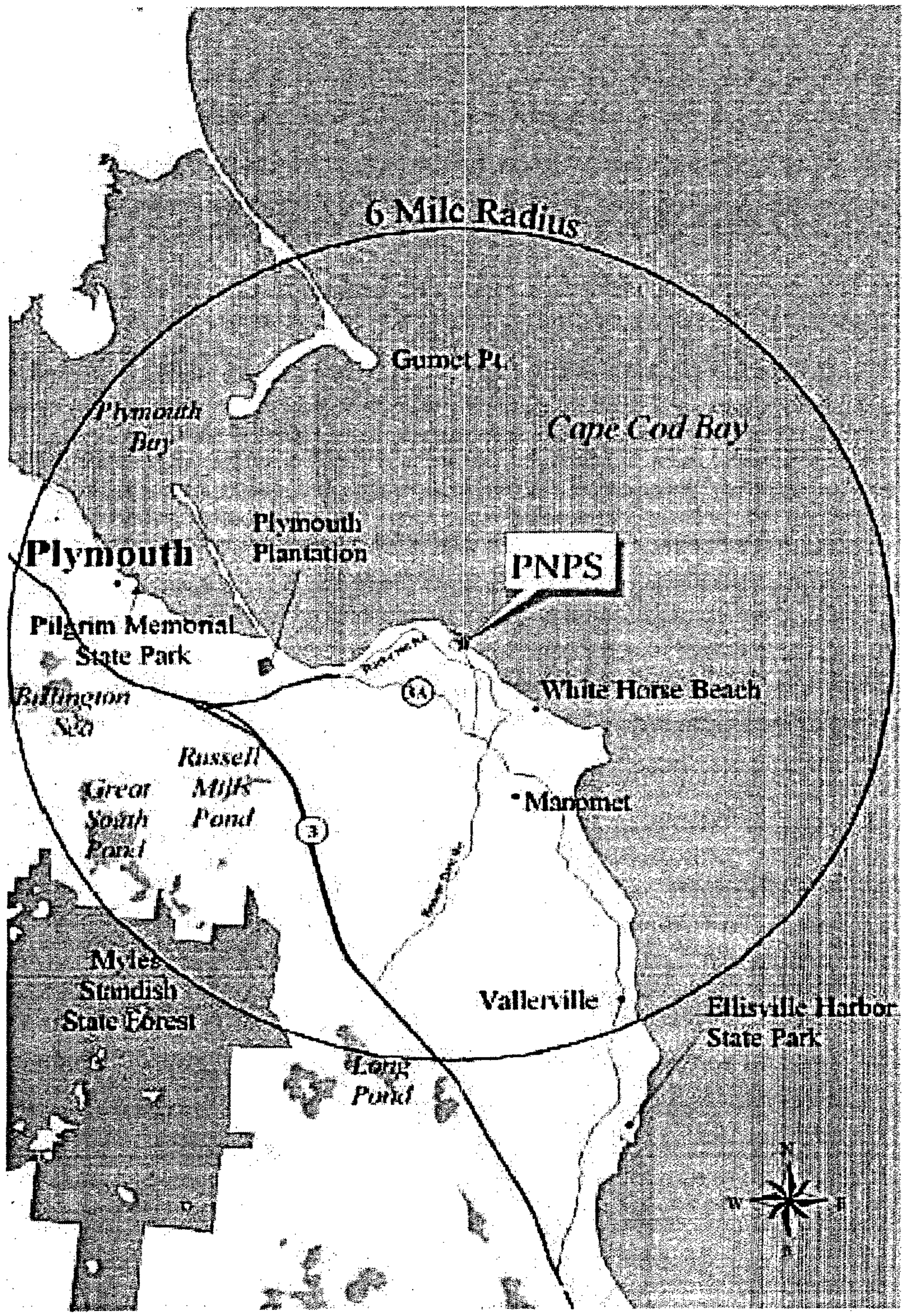

Figure 2-2
General Area Near PNPS

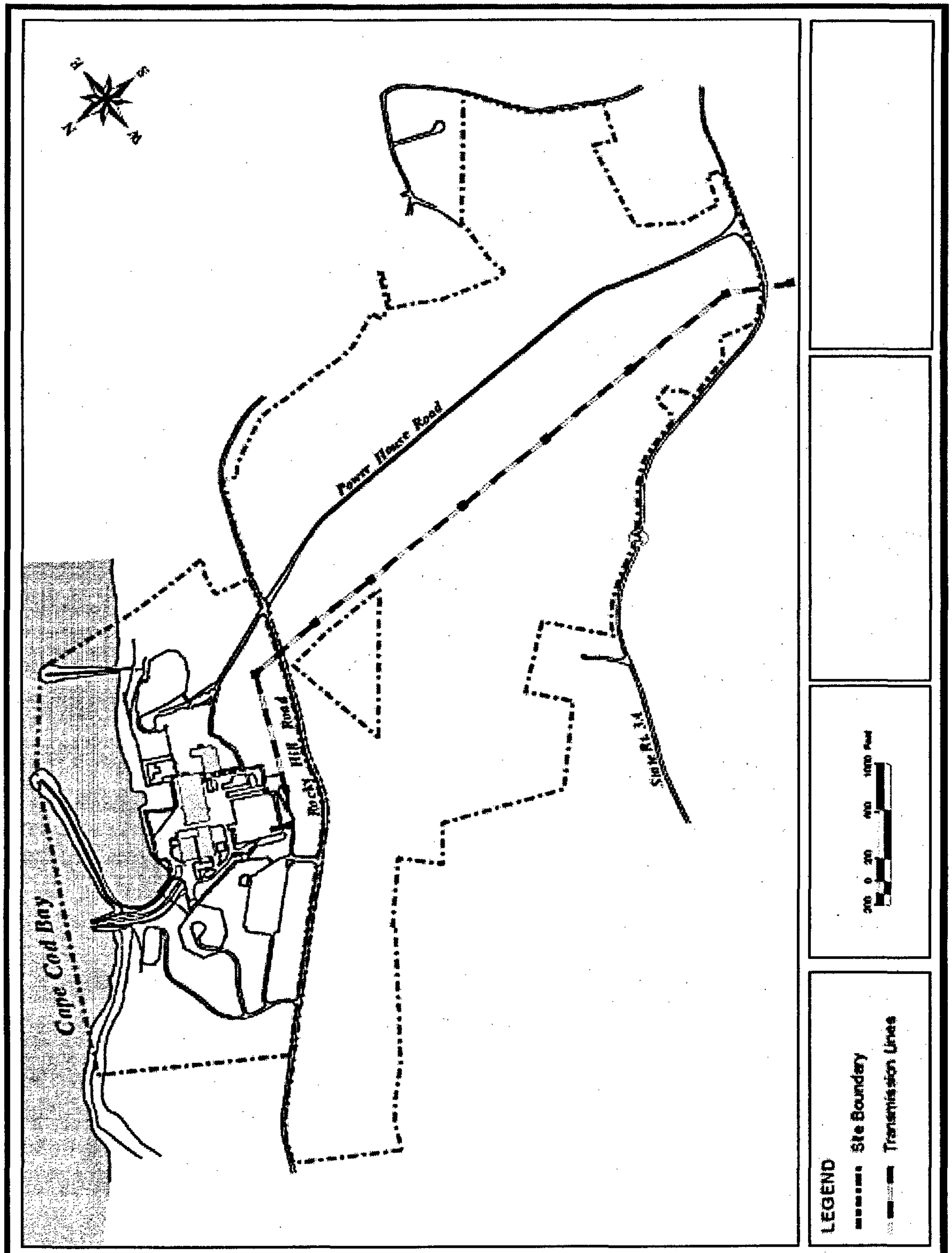

Figure 2-3
Site Boundary

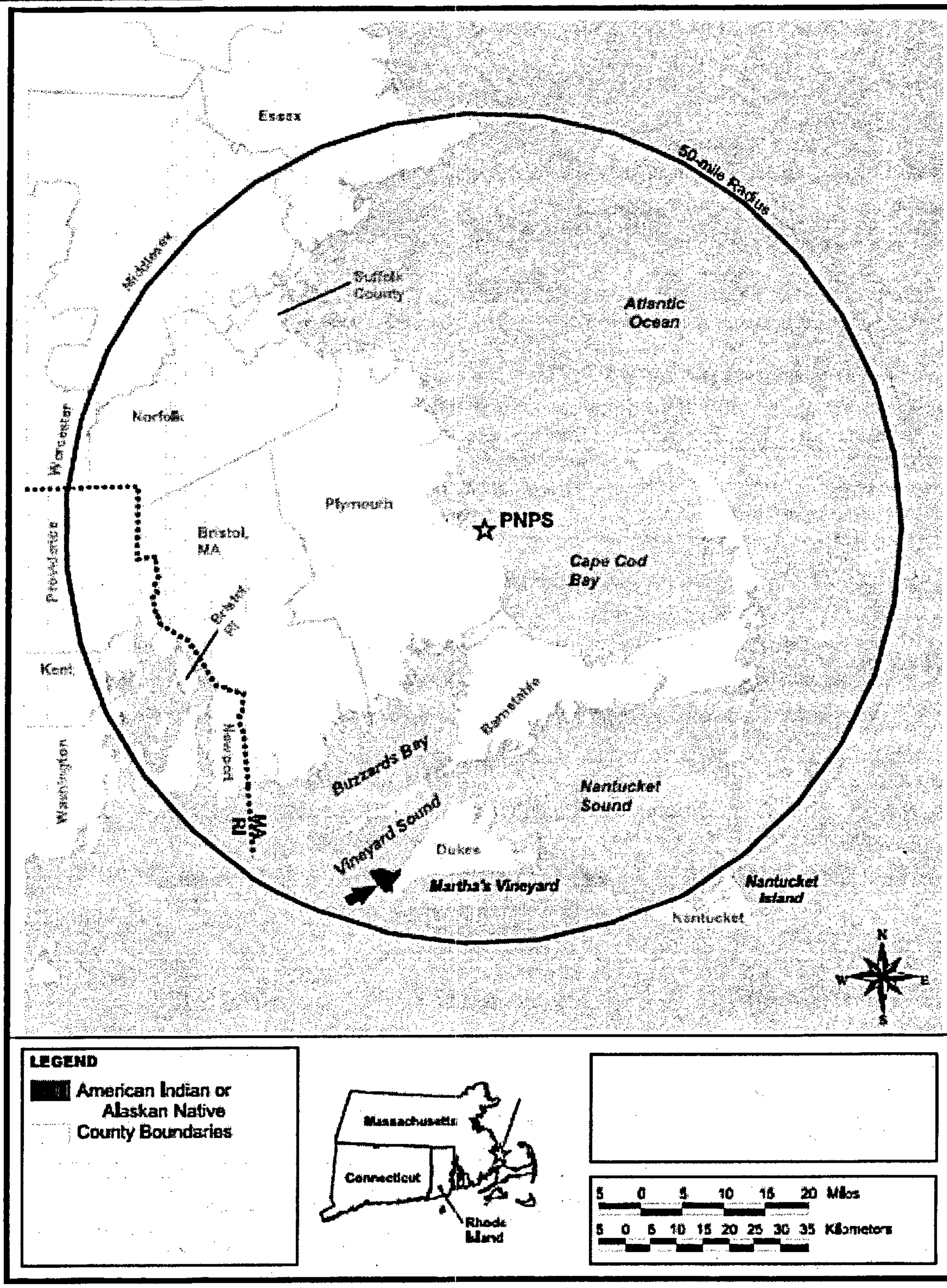

Figure 2-4
American Indian or Alaskan Native Minority Population Map

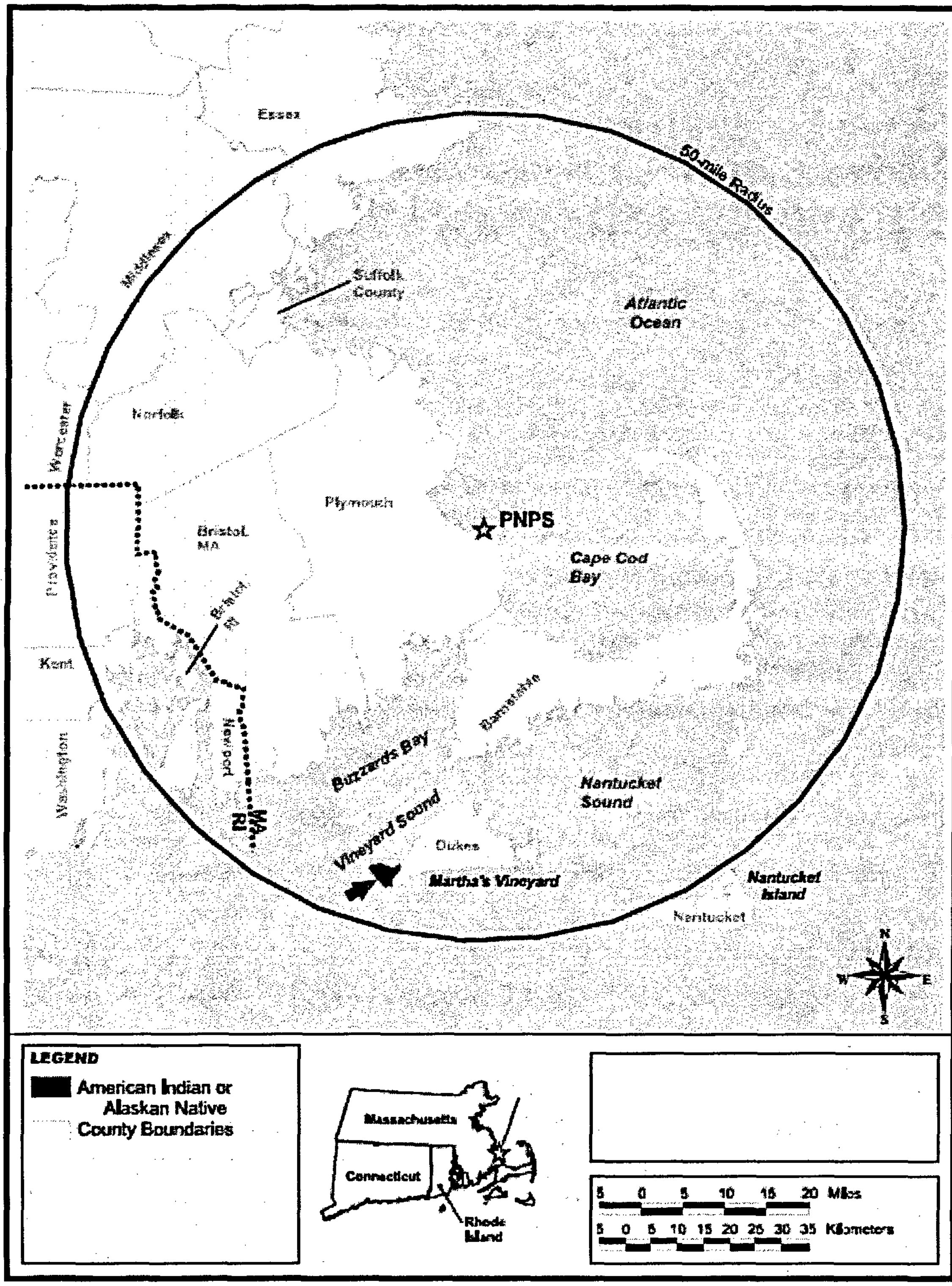

Figure 2-5
Asian or Pacific Islander Minority Population Map

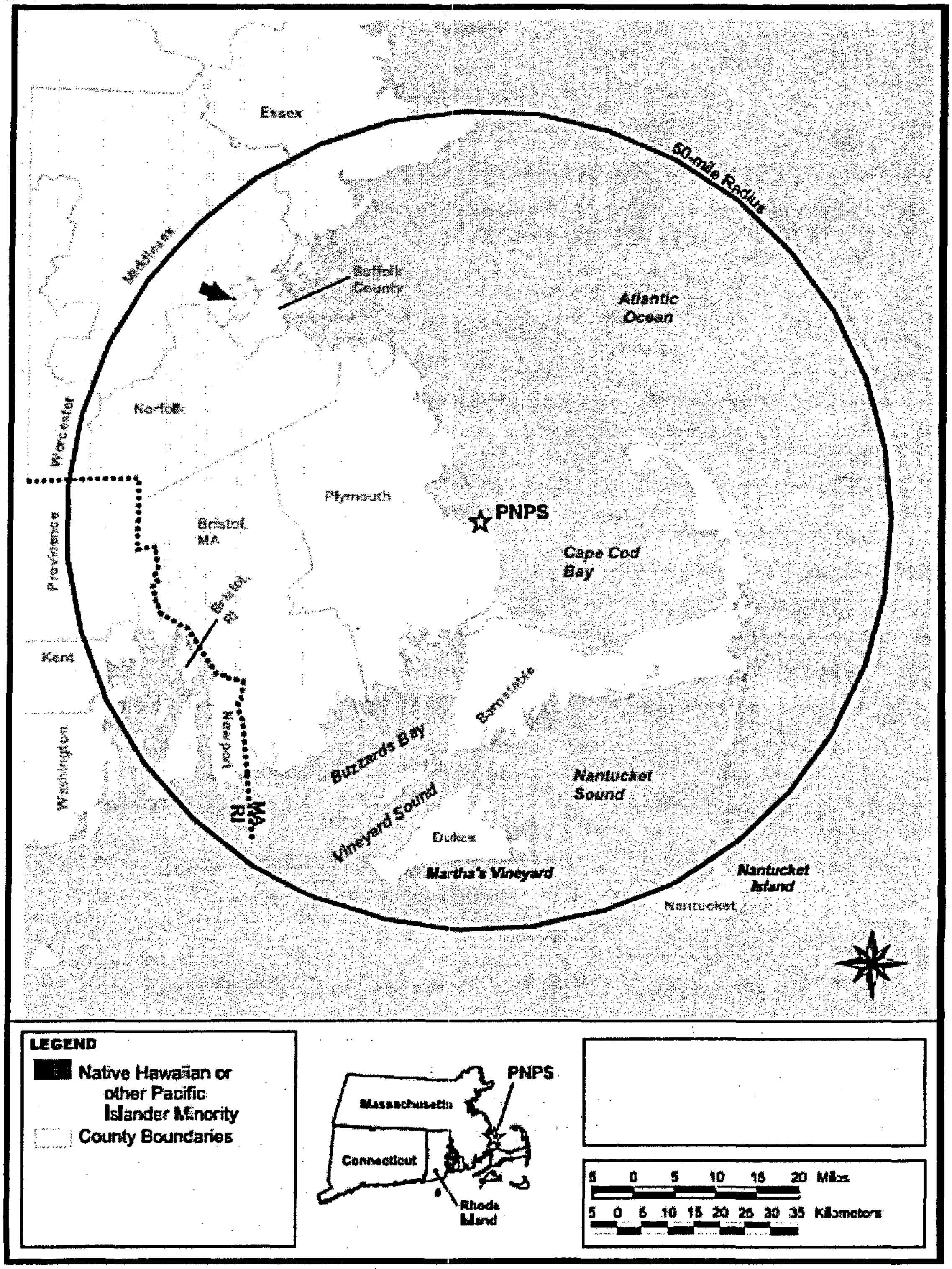

Figure 2-6
Native Hawaiian or Other Pacific Islander Minority Population Map

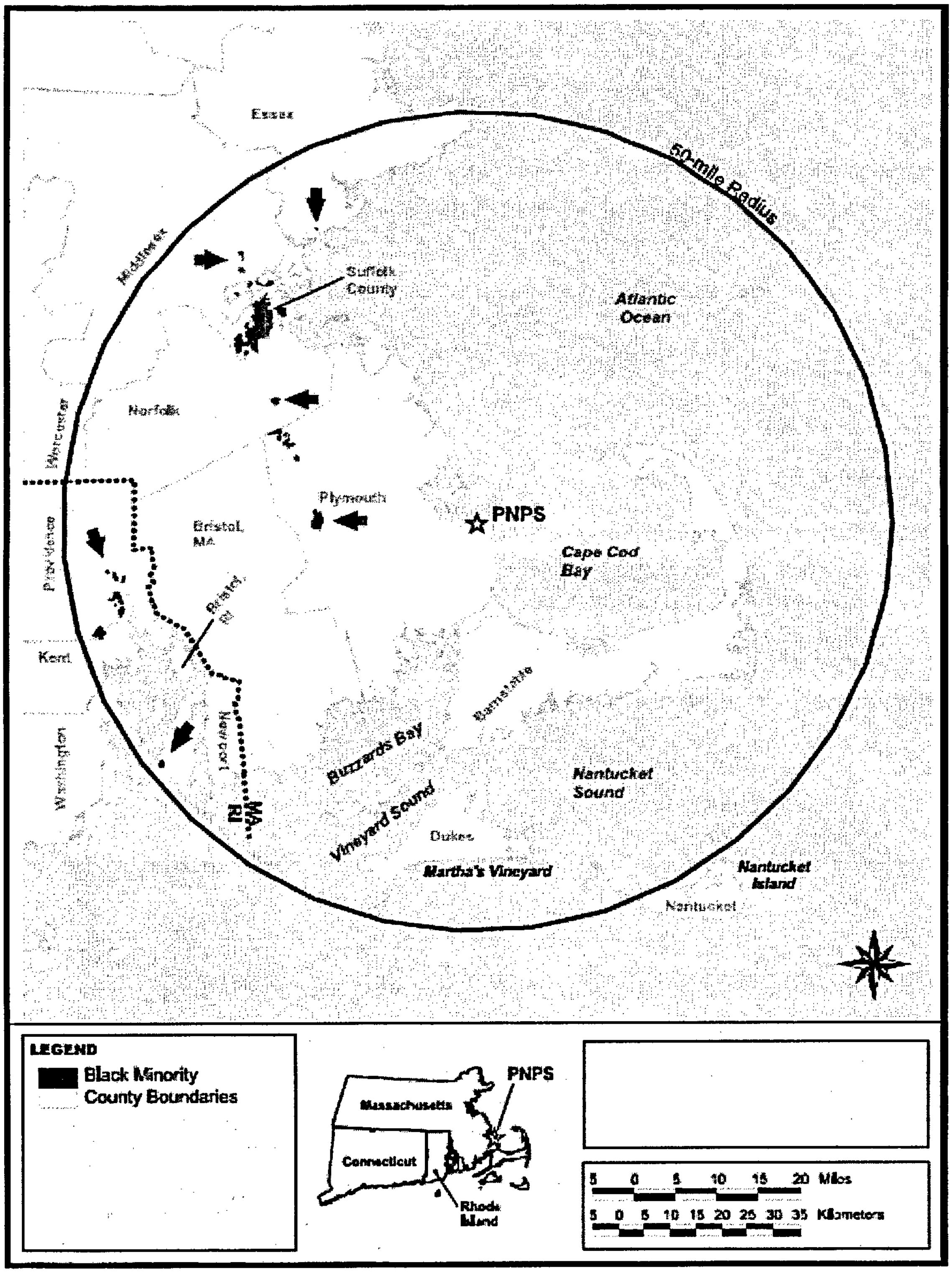

Figure 2-7
Black Races Minority Population Map

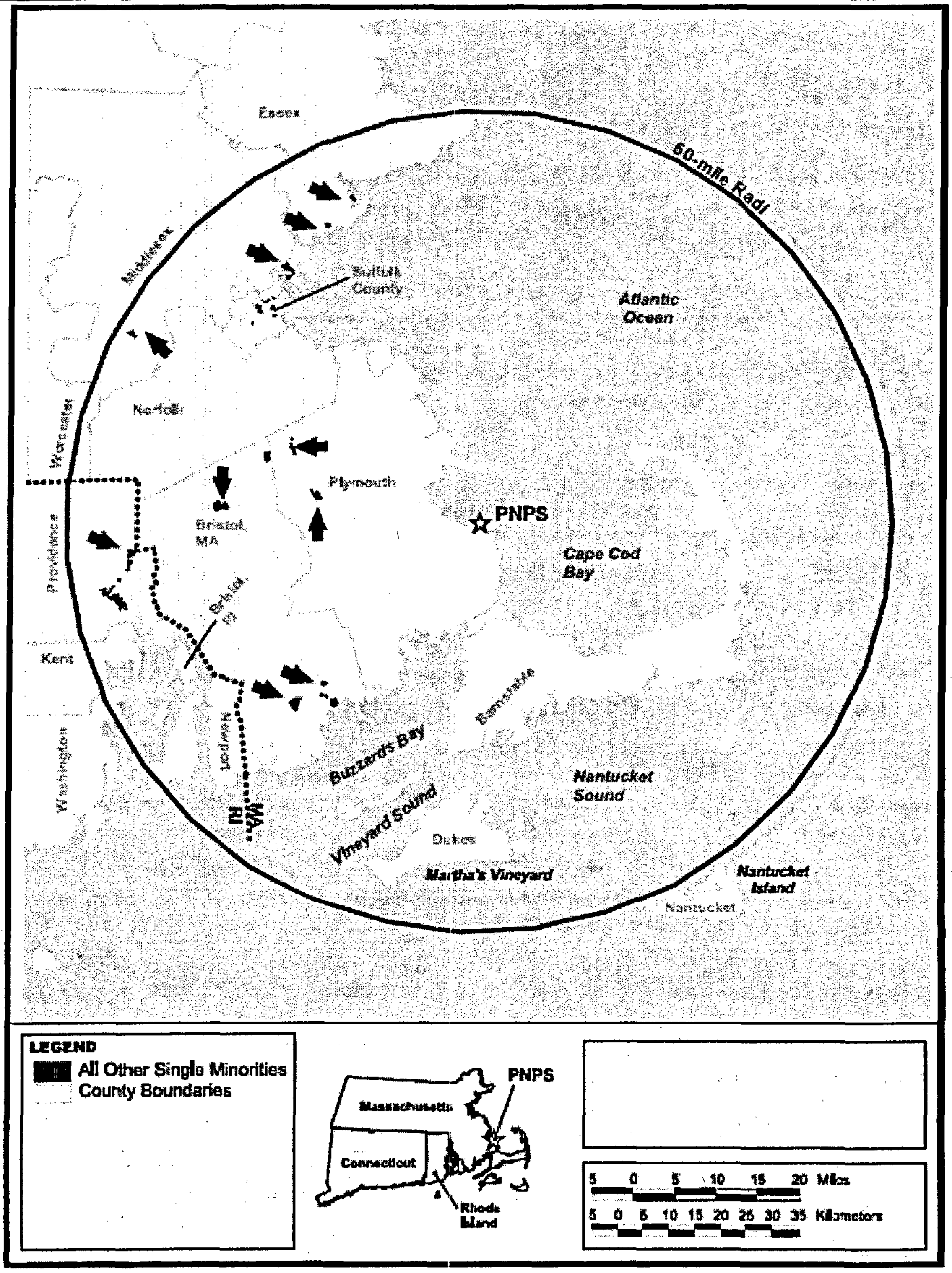

Figure 2-8
All Other Single Minorities Map

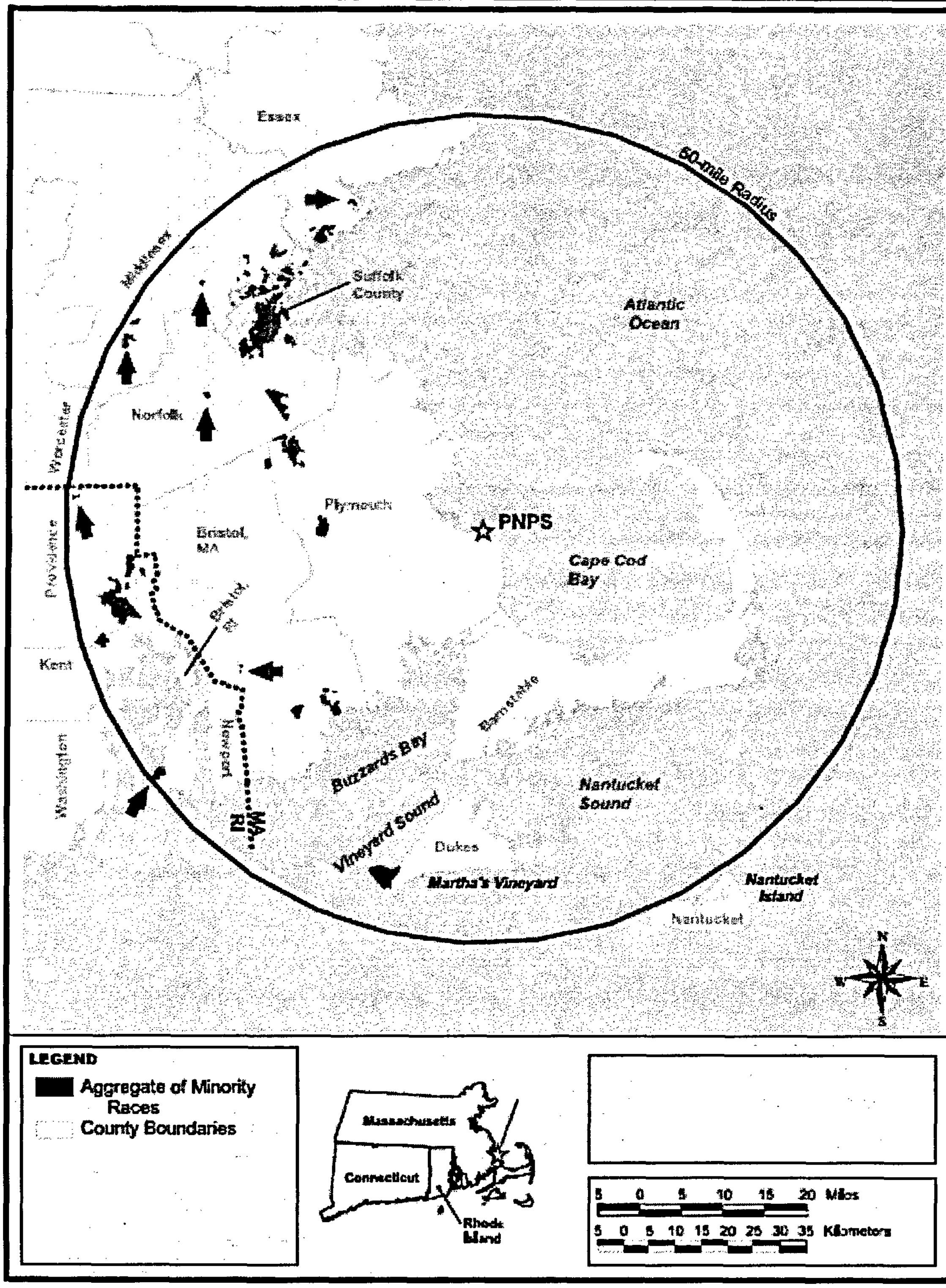

Figure 2-9
Aggregate of Minority Races Population Map

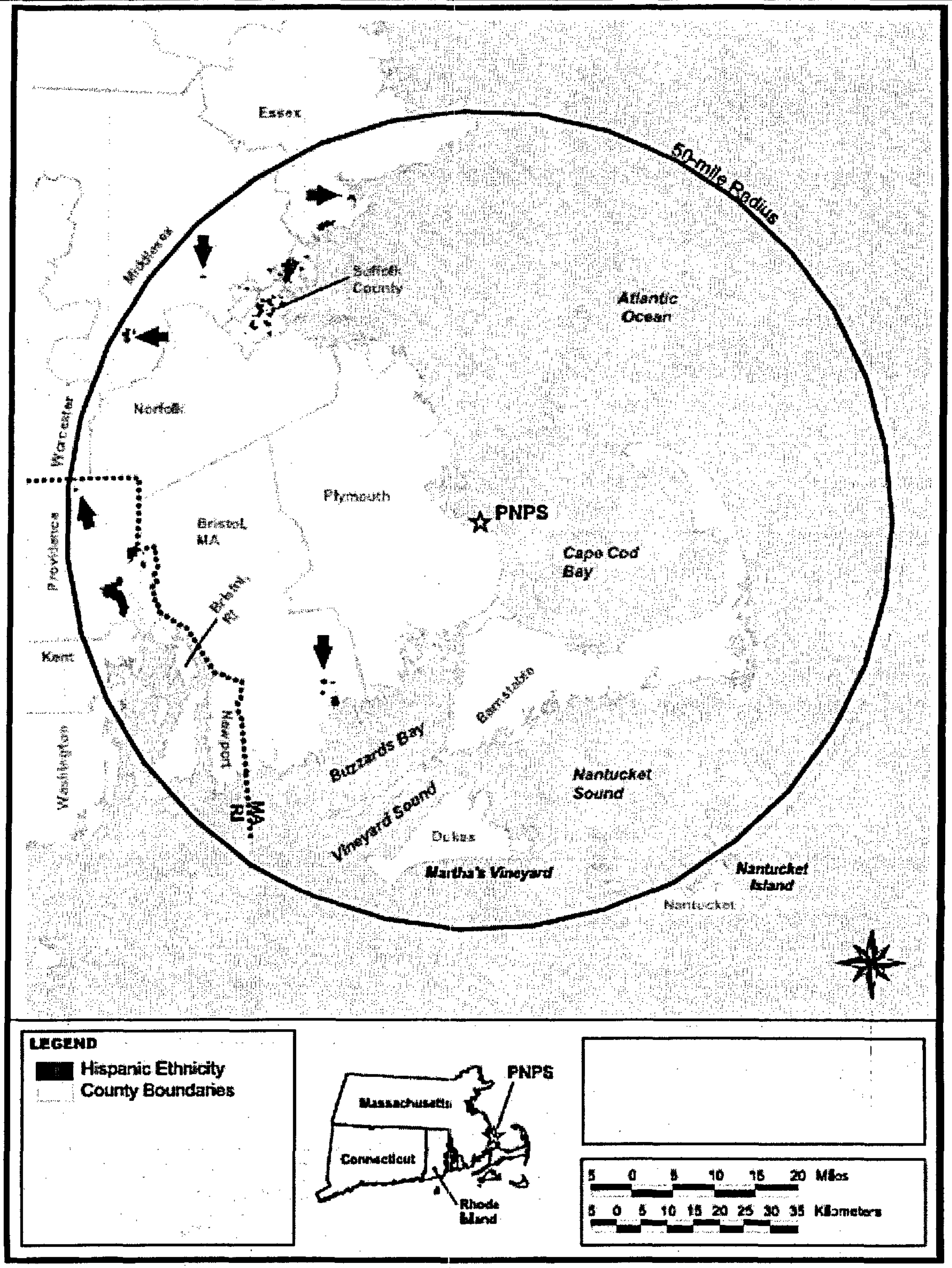

Figure 2-10
Hispanic Minority Population Map

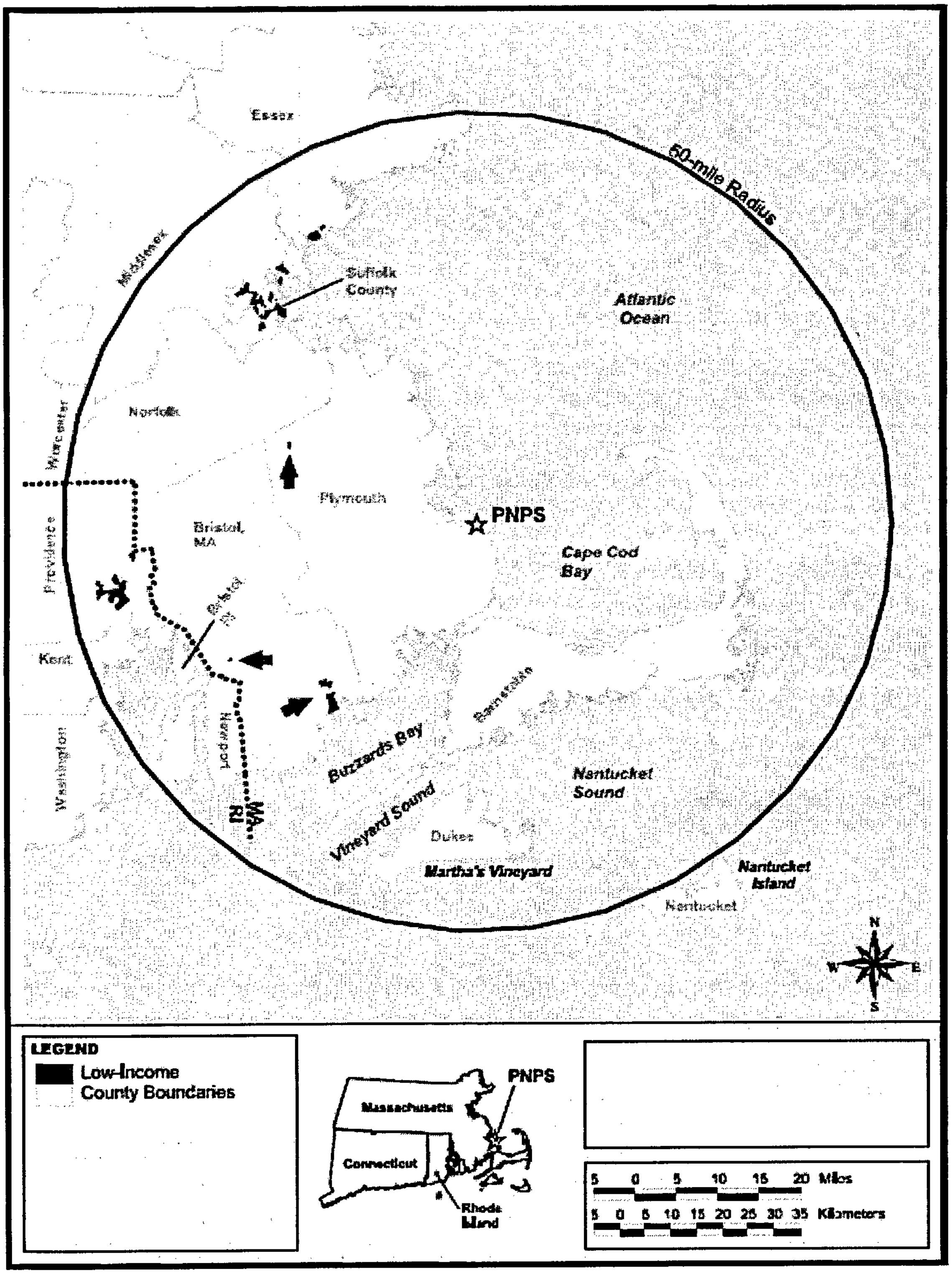

Figure 2-11
Low-Income Population Map

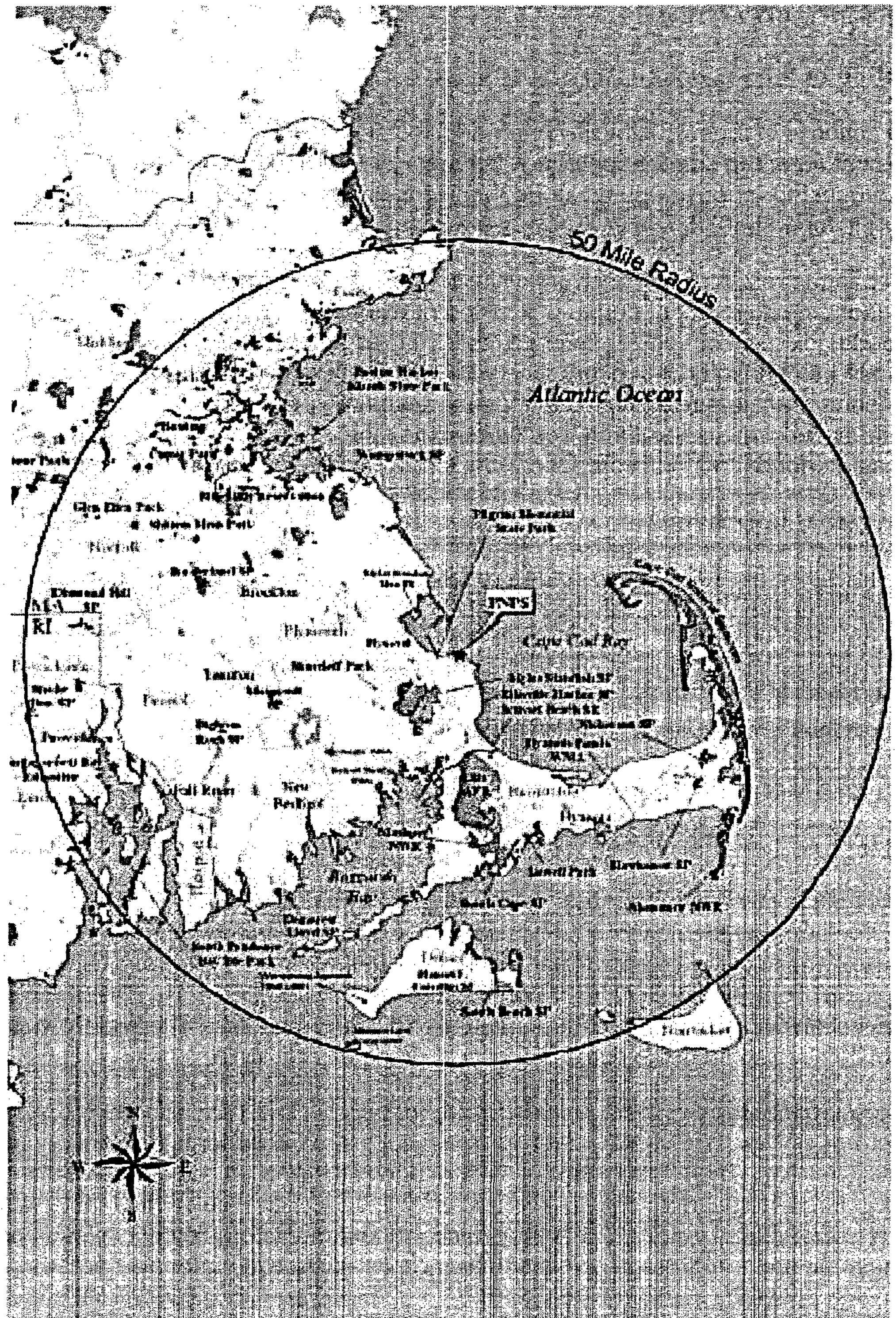

Figure 2-12
State and Federal Lands—50 Mile Radius

3.0 THE PROPOSED ACTION

3.1 Description of the Proposed Action

The proposed action is to renew the facility operating license for PNPS for an additional 20 years beyond the expiration of the current operating license. For PNPS (Facility Operating License DPR-35), the requested renewal would extend the license expiration date from midnight June 8, 2012, to midnight June 8, 2032.

There are no changes related to license renewal with respect to operation of PNPS that would significantly affect the environment during the period of extended operation. The application to renew the operating license of PNPS 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 PNPS 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 structures at PNPS consist of the reactor and turbine buildings (each with auxiliary bays), the offgas retention building, the radwaste building, the diesel generator building, the administration building, the intake structure, and the main stack [Reference 3-6, Section 12.1]. The reactor and nuclear steam supply system for PNPS, along with the mechanical and electrical systems required for the safe operation of PNPS, are primarily located in the reactor building. Figure 3-1 shows the general features of PNPS and the station layout. Figure 2-3 shows the site boundaries. No residences are permitted within the site boundaries, with the nearest residence being outside of the NRC-mandated 1800-foot exclusion zone.

3.2.1 Reactor and Containment Systems

PNPS is a single-unit plant with a boiling water reactor design and a turbine generator manufactured by General Electric Company. The architect/engineer and constructor was Bechtel. The unit was initially licensed for an output of 1,998 megawatts-thermal (MWt), and an electric rating of 687 megawatts-electric (MWe) [Reference 3-6, Section 1.1]. PNPS achieved commercial operation in December 1972. In 2003, PNPS implemented a Thermal Power Optimization of 1.5% to achieve the current electrical rating of 715 MWe.

The reactor's primary containment is a pressure suppression system consisting of a drywell, pressure suppression chamber, vent system, isolation valves, containment cooling system, and other service equipment. The containment is designed to withstand an internal pressure of 62 pounds per square inch above atmospheric pressure and act as a radioactive materials barrier [Reference 3-6, Section 5.2.3.2]. A secondary containment completely encloses both primary containment and fuel storage areas and acts as a radioactive materials barrier.

Together with their engineered safety features, each containment is designed to provide adequate radiation protection for both normal operation and postulated design-basis events or accidents, such as earthquakes or loss of coolant.

PNPS fuel is low-enriched uranium dioxide with maximum enrichments of 4.6% by weight uranium-235 and fuel burnup levels of 48,000 megawatt-days per metric ton uranium.

3.2.2 Cooling and Auxiliary Water Systems

3.2.2.1 Surface Water

PNPS is equipped with a once-through heat dissipation system that withdraws cooling water from and discharges it to Cape Cod Bay (Figure 3-1). The principal components of the circulating water system are the intake canal, intake structure or "screen house" with the intake pumps, condenser and service water systems, and discharge canal (Figure 3-1).

Two pumps in the intake structure provide a continuous supply (311,000 gallons per minute [gpm]) of condenser cooling water. Also housed in the intake structure are five service water pumps (four running and one on standby) that can supply 13,500 gpm of cooling water to the service water system. Seawater for cooling and service water is withdrawn from Cape Cod Bay via an embayment formed by two breakwaters. The intake structure consists of wing walls, a skimmer wall which functions as a submerged baffle, vertical bar racks that capture large debris, and vertical traveling screens. The four traveling screens (two per condenser cooling water pump) prevent small debris and small aquatic organisms from being entrained into the cooling water or service water systems. Each screen is made up of 53 basket segments with ¼ inch by ½ inch stainless steel mesh. The screens are washed when they are operating. The wash normally is discharged via a sluice to the intake embayment approximately 300 feet from the intake structure. During storms, the wash is discharged to the discharge canal [Reference 3-6].

During spring, summer, and fall, the circulating water system is chlorinated for up to two hours per day, one hour each pump, to control nuisance biological growth. Total residual chlorine cannot exceed 0.10 parts per million (ppm) in the cooling water discharge [Reference 3-3]. Continuous chlorination of the service water system can be used to control nuisance biological organisms with a maximum daily concentration of 1.0 ppm and an average monthly concentration of 0.5 ppm [Reference 3-3] in the service water discharge. During chlorination, the screens are operated, and sodium thiosulfate is added to the wash water to remove chlorine and protect organisms returned to the intake canal. Molluscicides are not permitted without the prior approval of the EPA and the Commonwealth [Reference 3-3].

After moving through the condensers, cooling water is discharged into a 900-foot-long discharge channel immediately adjacent to the intake embayment. The discharge channel is created by two breakwaters, one of which is shared with the intake embayment. At low tide, the water in the discharge channel is several feet higher than sea level and the discharge is rapid and turbulent. At high tide, the velocity is much lower. The increase in water temperature across the condensers ranges from 27 to 30°F [Reference 3-2]; the plant is permitted for as much as a 32°F temperature change [Reference 3-3].

3.2.2.2 Groundwater

The Town of Plymouth gets its water from groundwater (see Section 2.9.1) and supplies potable and reactor makeup water to PNPS via the town's municipal water system. PNPS's estimated

annual water consumption for a non-outage year (based on May 2003 through April 2004 actual consumption) is approximately 39.1 million gallons.

PNPS has an onsite sewage treatment and disposal facility. Wastewater is processed in the wastewater treatment facility and ultimately discharged to a leach field (Reference 3-4). Because the groundwater flow at the site is toward Cape Cod Bay, any treated discharge that may reach the groundwater does not enter a drinking water source.

The site has one groundwater well, which has been used in the past for irrigation purposes only. The well is capable of producing at a rate of 20 gpm. This well was installed in 2000; however, it is no longer in use for irrigation purposes, and it is not anticipated that the well will be returned to service at anytime in the future.

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

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

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

Radioactive wastes resulting from station operation are classified as liquid, gaseous, and solid. The following definitions apply to radioactive wastes [Reference 3-6, Section 9.1].

(1) Liquid Radioactive Wastes - Liquids directly from the reactor process and auxiliary systems or liquids which can become contaminated due to contact with these liquids from reactor process systems

(2) Gaseous Radioactive Wastes - Gases or airborne particulates vented directly from reactor and turbine equipment containing radioactive material or indirectly from the main stack

(3) Solid Radioactive Wastes - Solids from the reactor primary or auxiliary systems, solids in contact with reactor primary system liquids or gases, and solids (such as cleaning materials), used in reactor primary, turbine systems, and auxiliary systems operations.

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, if needed, at an onsite interim spent fuel storage installation provided necessary regulatory approvals are obtained. PNPS 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, as amended, and storage of hazardous wastes is regulated by the EPA under the Resource Conservation and Recovery Act of 1976.

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

3.2.3.1 Liquid Waste Processing Systems and Effluent Controls

The Liquid Radwaste System collects, processes, stores, and disposes of all radioactive liquid wastes. Equipment is selected, arranged, and shielded to permit operation, inspection, and maintenance within personnel radiation exposure limits. Sumps, pumps, valves, and instruments are located in controlled access areas. Tanks and processing equipment which may contain quantities of liquid radwastes are shielded. In addition, equipment is selected for a minimum of maintenance. [Reference 3-6, Section 9.2.4]

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 liquid radwastes are classified, collected, and treated in subsystems as either clean, chemical, or miscellaneous radwastes. [Reference 3-6, Section 9.2.4]

Very lows levels of radioactivity may be released in plant effluents if they meet the limits specified in the NRC's regulations. These releases are closely monitored and evaluated for compliance with NRC restrictions in accordance with the PNPS Offsite Dose Calculation Manual.

3.2.3.1.1 Clean Radwaste

Clean radwastes are liquids having a varying amount of radioactivity and are expected to have low conductivity. Clean radwaste is collected in the following sumps. [Reference 3-6, Section 9.2.4.1]

- drywell equipment drain sump
- reactor building equipment drain sump
- turbine building equipment drain sump
- radwaste building equipment drain sump
- retention building equipment drain sump

From these sumps, the wastes are transferred to the clean waste receiver tanks for processing. The drywell and turbine equipment drain sump discharge may be directed to the main condenser in order to provide operating flexibility and reduce water inventory delivered to radwaste for processing. Resin transfer water, ultrasonic resin cleaner (URC) flushwater, and drains are routed to the clean waste receiver tank. [Reference 3-6, Section 9.2.4.1]

The clean radwaste system also receives liquid from the URC. The URC is designed to remove suspended solids from condensate demineralizer resins without requiring chemical regeneration. The major components of the URC are the cleaning column, flow adjustment panel, and control panel. Resin enters the cleaning column and falls through an ultrasonic field where the solids are removed. A countercurrent flow of water removes the solids and resin fines and transfers them to a holding tank. The wastewater containing the solids is then pumped to the clean radwaste system and/or chemical waste system. The cleaned resin is then transferred back to the condensate demineralizer system for reuse. [Reference 3-6, Section 9.2.4.1]

Wastes from the receiver tanks are processed through flat bed filters and/or a mixed bed demineralizer, thermex, and/or radwaste filter demineralizer, or other water processing equipment before collection in the treated water holdup tanks. After the liquid wastes in the treated water holdup tanks have been sampled and analyzed, they are normally returned to the condensate storage tanks (CST) for reuse within the plant or sent to the main condenser hotwell. If the analysis of the sample reveals water of high contaminants or high radioactivity concentration, it may be reprocessed. Abnormally high conductivity water may either be reprocessed in the chemical waste system or be discharged at a controlled rate through the liquid radwaste discharge header to the circulating water discharge canal. [Reference 3-6, Section 9.2.4.1]

3.2.3.1.2 Chemical Radwaste

Chemical radwastes are liquid wastes which generally have low concentrations of radioactive impurities and rather high conductivities. [Reference 3-6, Section 9.2.4.2.1]

Chemical radwastes are collected in the following sumps [Reference 3-6, Section 9.2.4.2.1].

- drywell floor drain sump
- reactor building floor drain sump
- turbine building floor drain sump
- radwaste building floor drain sump
- retention building floor drain sump

The sump wastes are primarily minor equipment leakages, tank overflows, equipment drains, and floor drainage. When a sump has filled to a preset liquid level, the wastes are automatically pumped to the chemical waste receiver tank. Floor drain sump wastes may also be processed through the clean radwaste system if the wastes are relatively low in conductivity. Laboratory wastes are routed directly to the chemical waste receiving tank. [Reference 3-6, Section 9.2.5.2.1]

The chemical waste receiver and monitor tanks are atmospheric tanks with a capacity of 15,000 gallons and 20,000 gallons, respectively. The receiver tanks have level indicators and annunciators which will be used in monitoring the waste inventory. The monitor tanks have level and temperature indicators and annunciators. Depending on the activity level, the wastes after storage and decay may be released on a controlled basis through the liquid radwaste discharge header to the circulating water discharge canal or further processed. Both the chemical waste receiver and monitor tanks are located in shielded cells to maintain safe operating conditions and minimize radiation exposure to station personnel. [Reference 3-6, Section 9.2.4.2.1]

During operation it is expected that the daily flow from the floor drain sumps will be approximately 5,000 gallons. The drywell floor sump wastes will normally be transferred to the clean radwaste system. The chemical wastes can be pumped through the Thermex filter to remove suspended solids. [Reference 3-6, Section 9.2.4.2.2]

3.2.3.1.3 Miscellaneous Radwaste

Miscellaneous radwastes are those wastes which potentially have high detergent or contaminant level, but are of low radioactivity concentration. [Reference 3-6, Section 9.2.4.3.2]

The miscellaneous waste system collects equipment washdown and decontamination solution wastes, radiochemistry laboratory solution wastes, miscellaneous water waste, and personnel decontamination wastes. The miscellaneous waste system processes and strains these liquid wastes before discharge through the radwaste discharge header into the circulating water discharge canal. The liquid wastes are sampled and analyzed before release and continually monitored during release. [Reference 3-6, Section 9.2.4.3.2]

The miscellaneous waste drain tank collects drainage from floor drains originating in the following areas [Reference 3-6, Section 9.2.4.3.2].

- turbine washdown area
- personnel decontamination areas
- fuel cask decontamination area
- reactor head washdown area
- truck decontamination area
- machine shop wastes
- retube building decontamination area

During normal operation it is expected that the monthly volume of miscellaneous wastes will be approximately 1,000 gallons. When one section of the miscellaneous waste tank is filled, the wastes are sampled and analyzed for radioactivity. The wastes are pumped through a strainer and discharged at a controlled rate through the liquid radwaste discharge header into the circulating water discharge canal. The miscellaneous waste is continuously monitored for activity as it passes through the radwaste discharge header. If necessary, miscellaneous wastes of high radioactivity concentrations and low detergent levels may be transferred to the chemical waste receiver tank for further processing. [Reference 3-6, Section 9.2.4.3.3]

Controls for limiting the release of radiological liquid effluents are described in the ODCM. Controls are based on (1) concentrations of radioactive materials in liquid effluents and projected dose or (2) dose commitment to a hypothetical member of the public. Concentrations of radioactive material that may be released in liquid effluents to unrestricted areas are limited to the concentration specified in 10 CFR 20, Appendix B, Table 2, Column 2, for radionuclides other than dissolved or entrained noble gases. For dissolved or entrained noble gases, the concentration of individual isotopes shall be limited to 2E-04 microcurie/ml [Reference 3-5, Section 3.2.1]. The ODCM dose limits during a calendar quarter are ≤ 1.5 mrem to the total body and ≤ 5 mrem to any organ [Reference 3-5, Section 3.2.2]. During the calendar year, the ODCM dose limits are ≤ 3 mrem to the total body and ≤ 10 mrem to any organ [Reference 3-5, Section 3.2.2]. Radioactive liquid wastes are subject to the sampling and analysis program described in the ODCM.

3.2.3.2 Gaseous Waste Processing Systems and Effluent Controls

The gaseous radwaste system processes gaseous radioactive wastes from the main condenser air ejectors, the startup mechanical vacuum pump, the gland seal condensers, and other minor sources, and controls their release to the atmosphere through the main stack in such a way that the operation and availability of the station is not limited. [Reference 3-6, Section 9.4.1]

3.2.3.2.1 Air Ejector Offgas and Augmented Offgas System

The air ejector and augmented offgas (AOG) system includes the subsystems that process and/or dispose of the gases from the main condenser air ejectors, the startup mechanical vacuum pump, and the gland seal condensers. All such gases from the unit are routed to the main stack for dilution and elevated release to the atmosphere. Discharges from the air ejector, the charcoal vault, and the stack are continuously monitored by radiation monitors. [Reference 3-6, Section 9.4.4.1.1]

Gases routed to the main stack include air ejector and gland seal offgases, and gases from the standby gas treatment system (SGTS). Dilution air input to the stack is supplied by two full capacity fans located in the filter building at the base of the main stack. The stack is designed such that prompt mixing of all gas inlet streams occurs in the base to allow location of sample points as near the base as possible. The stack drainage is routed to the liquid radwaste collection system. [Reference 3-6, Section 9.4.4.1.1]

The AOG system provides for the controlled recombination of radiolytic hydrogen and oxygen, followed by chilling of the gas mixture to strip the condensable water vapor and reduce the volume and relative humidity of the remaining noncondensables, principally inleakage air with traces of the radioactive noble gases krypton and xenon, which are delayed by an adsorption process using activated charcoal. The offgas passes through the charcoal vessels and is then discharged to the environs via the main stack. The delay time created by the charcoal adsorption process allows for the continued decay of the krypton and xenon radioactivity to a point where the ultimate release of the offgas results in a site boundary gamma radiation dose that meets the definition of ALARA (As Low As Reasonably Achievable). The radioactivity of the gas mixture is

monitored immediately downstream of the steam jet air ejectors, representing the inlet conditions to AOG, and at the discharge from the AOG system. [Reference 3-6, Section 9.4.4.1]

The offgas system is provided with flow, temperature, and radiation instrumentation to ensure proper operation and control. Hydrogen analyzer instrumentation is also provided to ensure that hydrogen concentration is maintained below the flammable limit. [Reference 3-6, Section 9.4.4.1.2]

The offgas radiation monitoring is divided into two subsystems. One subsystem (pre-treatment) takes a continuous sample from the offgas line prior to the delay and adsorption treatment process. The other subsystem (post-treatment) takes a continuous sample from the offgas line just before discharge to the main stack. [Reference 3-6, Section 9.4.4.1.2]

3.2.3.2.2 Turbine Sealing and Mechanical Vacuum Pump Systems

The gland seal holdup system collects and processes, by delay, the noncondensable exhaust from the main turbine gland seal condenser. During startup operation the discharge of the condenser mechanical vacuum pump is routed through the gland seal holdup system. The effluent of the gland seal holdup system is routed to the main station stack where it is continuously monitored by the main stack radiation monitoring system before discharge to the environment. [Reference 3-6, Section 9.4.4.2.1]

During normal operation of the gland seal holdup system, a 2,200 lb/hr saturated air-water vapor mixture containing trace amounts of hydrogen, oxygen, and radioactive gases is exhausted from the turbine generator gland seal condenser and enters the 16-inch diameter holdup line. After being delayed for a period of approximately 1.75 minute, the effluent is routed to the main stack where it is mixed with the AOG system effluent and the discharge of the main stack dilution fans before release to the environment. [Reference 3-6, Section 9.4.4.2.1]

The gland seal holdup system shares with the AOG system the main stack, dilution fans, and the main stack radiation monitoring system. During normal operation, the amount of radioactive activation and fission gases associated with the gland seal holdup system is extremely small. The radioactivity that is collected and processed by the gland seal holdup system is proportional to the amount of main steam utilized in the main turbine sealing system. This amount of steam is less than 0.1% of the full power rated steam flow. In addition to the small amount of radioactivity processed, there is a correspondingly small amount of radiolytic hydrogen and oxygen which are well below the explosive limits. [Reference 3-6, Section 9.4.4.2.2]

3.2.3.2.3 Miscellaneous Gaseous Effluents (Low Release Potential Effluents)

Miscellaneous gaseous effluents are categorized into two classes, those from areas having a negligible or low potential for the release of airborne radioactivity, and those from areas likely to experience radioactive contamination. Below is a list of station areas which fall into these categories and which are exhausted directly to the environment. [Reference 3-6, Section 9.4.4.3.1]

- diesel generator building

- administration building
- machine shop
- battery room and lube oil compartments
- recirculation pump MG set area
- reactor auxiliary bay
- turbine building operating floor and switchgear area

The ventilation air from the first six areas listed above has a negligible potential for the release of radioactive effluents. The turbine building operating floor including the reactor feedwater pump area are considered to have a low potential for release. Any release from the turbine building basement area or the turbine building ground floor to the turbine building operating floor or adjacent areas above elevation 51 feet is precluded since the turbine building basement and ground floor are maintained at a slight negative pressure relative to the turbine building operating floor. [Reference 3-6, Section 9.4.4.3.1]

The airborne radiation concentration levels at elevation 51 feet in the turbine building are routinely monitored by means of the turbine building effluent monitoring system. Airborne activity levels in those areas of the station having a direct release path to the environs not monitored by a process radiation monitoring system will under normal operating conditions be within those levels allowed for in 10 CFR 20, Appendix B, Table I. [Reference 3-6, Section 9.4.4.3.1]

The expected airborne activity on the turbine building operating floor will normally be below the values assumed above and the releases from the turbine building operating floor and the reactor feedwater pump area are expected to be insignificant relative to the releases from the main stack and the reactor building exhaust vent. [Reference 3-6, Section 9.4.4.3.1

3.2.3.2.4 Miscellaneous Gaseous Effluents

Gaseous effluents from areas of potential radioactive contamination are monitored and discharged to the environment through either the main stack or the reactor building exhaust vent. The station ventilation systems are designed to combine the ventilation air flow from these areas and exhaust that air past process radiation monitoring equipment. [Reference 3-6, Section 9.4.4.3.2]

Miscellaneous sources of potential low-level radioactive airborne contaminants in the station which could be released to the environment are listed below [Reference 3-6, Section 9.4.4.3.1].

- primary containment venting
- steam leakage outside the primary containment
- hood vents
- high pressure coolant injection (HPCI) testing

PNPS 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 PNPS 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 and beyond the site boundary is ≤ 500 mrem/yr to the total body, and ≤ 3000 mrem/yr to the skin [Reference 3-5, Section 3.3.1]. For Iodine-131, Iodine-133, tritium and all radionuclides in particulate form with half-lives greater than 8 days, the limit is ≤ 1500 mrem/yr to any organ [Reference 3-5, Section 3.3.1]. The limit for air dose due to noble gases released in gaseous effluents to areas at and beyond the site boundary during a calendar quarter is ≤ 5 mrad for gamma radiation and ≤10 mrad for beta radiation [Reference 3-5, Section 3.3.2]. For a calendar year, the limit is ≤10 mrad for gamma radiation and ≤ 20 mrad for beta radiation [Reference 3-5, Section 3.3.2]. The radioactive gaseous waste sampling and analysis program specifications provided in the ODCM address the gaseous release type, sampling frequency, minimum analysis frequency, type of activity analysis, and lower limit of detection.

3.2.3.3 Solid Waste Processing

The solid waste processing areas are located in the radwaste building, the radwaste truck lock, and the trash compaction facility (TCF). Both wet and dry solid wastes are processed. Wet solid wastes include backwash sludge wastes from the reactor water cleanup system (RWCU); all spent resins and charcoal from radwaste, spent fuel pool, and condensate demineralizers; and thermex and radwaste filter/demineralizer. [Reference 3-6, Section 9.3.4.1]

Dry solid wastes include rags, paper, small equipment parts, solid laboratory wastes, etc. [Reference 3-6, Section 9.3.4.1]

An outdoor low level radwaste storage facility (LLRWSF) is provided on-site for interim storage for up to 5 years of solid radioactive waste prior to disposal off-site or for temporary storage of bulk-dewatered radwaste awaiting shipment to a processing facility for volume reduction prior to burial. The LLRWSF consists of a compacted gravel bed surrounded by a gravel or earth filled modular block shield wall. Dewatered solid wastes contained in high integrity containers are placed in cylindrical, concrete storage modules within the facility. Dry activated waste in steel containers and overpack, as well as other miscellaneous low-level radioactive materials, is also stored in the LLRWSF in rectangular, concrete storage modules. [Reference 3-6, Section 9.3.4.1]

3.2.3.3.1 Reactor Cleanup Sludge

The purpose of the radwaste system for cleanup sludge is to process the highly radioactive backwash waste which is discharged from the RWCU system. The RWCU system includes two filter-demineralizer units each of which are precoated with powdered ion exchange resin (Powdex) supported by filter aid which is in turn retained on a permanent, stainless steel septum. These filter-demineralizer units remove by filtration and ion exchange the suspended and dissolved solids, both radioactive and stable, from the circulating reactor water. Upon

exhaustion of either its filtration or ion exchange capability, the exhausted cleanup demineralizer is taken out of service, backwashed, and precoated anew. The backwash waste as discharged from a cleanup demineralizer is a relatively dilute slurry (1.1% by weight suspended solids) which is highly radioactive. The backwash waste slurry is accumulated in the backwash collector tank from which it is periodically transferred on a batch basis to the radwaste disposal system for subsequent processing. The function of the radwaste disposal system is to reclaim the liquid phase for reuse within the station and to prepare the solid waste for offsite shipment with minimum exposure of the operators to radiation. [Reference 3-6, Section 9.3.4.2.1]

The radwaste disposal system has been modified. A sludge transfer and decant line has been provided for the cleanup sludge storage tanks. The transfer line is used to transfer sludge to the offsite discharge pipe in the radwaste trucklock. This arrangement bypasses the floc-recycle tank (abandoned). The sludge is dewatered in the radwaste trucklock before being stored to await shipment to a burial processor facility or for other processing. A decant line has been installed between the sludge transfer pumps discharge and the clean waste tanks inlet piping. [Reference 3-6, Section 9.3.4.2.1]

3.2.3.3.2 Spent Resin and Miscellaneous Solid Waste System

The purpose of the spent resin and miscellaneous solid waste systems is to process and temporarily store spent resins and miscellaneous solid waste (rags, used clothing, paper, air falters, etc.) on the site in shielded areas as required prior to offsite shipment to a licensed burial ground or other processing facility. [Reference 3-6, Section 9.3.4.3.1]

All spent resins from radwaste, spent fuel pool, thermex and condensate demineralizers are sluiced into a spent resin tank which provides 670 ft^3 capacity. Thermex waste water and miscellaneous waste waters may be added to the tank to utilize remaining capacity of spent resin and allow for reprocessing. This may be done to reduce solid radwaste volume and overboard discharge of contaminated waste water. [Reference 3-6, Section 9.3.4.3.2]

When spent resins accumulate in the spent resin tank to the amount desired for offsite shipment, the spent resins will be pumped from the tank into a processing/shipping container or HIC (High Integrity Container) as required for dewatering and for shipment and offsite disposal/processing. A backflushing system for tank overflow and spent resin retention screens is provided to eliminate or reduce screen plugging with resin fines as much as possible. Sluice water is recycled back to the spent resin tank. [Reference 3-6, Section 9.3.4.3.2]

The contaminated miscellaneous solid wastes, such as air filters, rags, paper, small equipment parts, and solid laboratory wastes, are placed in disposable containers and shipped for processing or disposal. Compressed solid wastes in the disposable containers are stored temporarily on the site for future offsite shipment. [Reference 3-6, Section 9.3.4.3.2]

The clean radwaste effluent is processed through various processing equipment resulting in spent resin/powdered resin (sludge) which is loaded into containers for shipment to an offsite radioactive waste minimization process facility or shipped for burial.

3.2.3.3.3 Trash Compaction Facility

The original purpose of the TCF was to sort, process, and separate contaminated and non-contaminated material generated from normal operating conditions. This process of separating the contaminated materials from the non-contaminated materials has been discontinued and the current use for the TCF is for storage of contaminated equipment which is used within the plant.

3.2.3.3.3.1 Contaminated Material

Contaminated materials are now stored in one of two locations before they are shipped for disposal. Contaminated dry active waste, metal, and wood are separated and are temporarily stored in either the LLRWSF or the TCF yard in seavans until they are shipped off-site to a radwaste processor.

The compactible radioactive material which will be compacted is transported to the contaminated trash compactor, placed within the compactor, and compacted. The resulting product, which is contained within a steel box specifically designed for handling compacted trash, is transported via forklift truck to the labeling, weighing, and surveying area. [Reference 3-6, Section 9.5.1.6.1]

Radioactive liquid material is segregated, separated, consolidated, and analyzed for disposal in the TCF hazardous material area. Based on analysis results the material is packaged, labeled, and marked for transport to offsite burial, further processing, or interim storage. [Reference 3-6, Section 9.5.1.6.1]

3.2.3.3.3.2 Noncontaminated Material

Material identified as hazardous material is transported to the TCF hazardous material area and surveyed to determine what material is contaminated or not contaminated by predetermined radiological standards. Contaminated hazardous material is segregated and labeled. The non-contaminated hazardous material is accumulated and stored in the 90-day hazardous waste storage area until sufficient quantity is available for disposal, but must be disposed of within 90 days. [Reference 3-6, Section 9.5.1.6.2]

3.2.3.3.4 Decontamination and Trash and Laundry Processing Facility

The decontamination and trash and laundry processing facility is located in the north side of the station services redline building. As a facility to support station operation, it contains equipment for decontamination tools and equipment and also working space for handling trash, metals, wood, and potential HAZMAT being transferred to the TCF. This facility also handles incoming and outgoing shipments of laundry and contains space to permit temporary storage of various dry materials and equipment. [Reference 3-6, Section 9.5.2]

Hazardous material (other than radioactive material), liquids containing radioactive material, or wastes from plant water treatment processes (e.g., spent resin, sludge, and diatomaceous earth) are not stored in the facility. [Reference 3-6, Section 9.5.2]

Both administrative and physical controls are in place to maintain radiation exposure to personnel ALARA and to preclude releases to the environment in excess of the limits set forth in 10 CFR 20. [Reference 3-6, Section 9.5.2]

3.2.4 Transportation of Radioactive Materials

PNPS radioactive waste shipments are packaged in accordance with NRC and U.S. Department of Transportation requirements. The type and quantities of solid radioactive waste generated and shipped at PNPS vary from year to year, depending on plant activities. PNPS currently transports radioactive waste to the Studsvic facility in Irwin, Tennessee, Race facility in Memphis, Tennessee, or the Duratek facility in Oak Ridge, Tennessee, where the wastes are further processed prior to being sent to the Barnwell facility in Barnwell County, South Carolina, or the Envirocare facility in Clive, Utah. On occasion PNPS may also transport material 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 heating boiler blowdown, filter backwash, sludges and other wastes, floor and yard drains, and stormwater runoff. Chemical and biocide wastes are produced from processes used to control the pH in the coolant, to control scale, to control corrosion, and to clean and defoul the main condenser. Waste liquids are typically combined with cooling water discharges. Sanitary wastewater, which is regulated under Groundwater Discharge Permit #2-389 issued from the MDEP, is directed to an onsite septic system where it is transferred to an onsite wastewater treatment facility and ultimately discharged to a leach field.

Non-radioactive 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 the MDEP's air quality standards.

3.2.6 Maintenance, Inspection, and Refueling Activities

Various programs and activities currently exist at PNPS 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), and Appendices G and H, Reactor Vessel Materials;
- meet the requirements of 10 CFR 50.55a, ASME 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. Others are performed during scheduled refueling outages.

3.2.7 Transmission Facilities

The FES [Reference 3-1] identifies two transmission lines that were built to connect PNPS to the electric grid. The 342 line runs approximately 5 miles to the Jordan Road Tap, which connects to the Canal and the Auburn Street Stations via a previously existing line. The 355 line runs on the same towers as the 342 line to the Jordan Road Tap and then beyond for a total of 7.2 miles to the Snake Hill Road Tap, where previously existing lines run to the Bridgewater Station. Therefore, the segments of interest for this report are from PNPS to the Jordan Road Tap for line 342 and from PNPS to the Snake Hill Road Tap for the 355 line. Both lines operate at 345 kv. The transmission corridor is 300 feet wide. Figure 2-2 shows the transmission system of interest.

NSTAR, the current owner and operator of the transmission lines, has approximately 12.2 miles of transmission lines (7.2 miles of corridor) that occupy approximately 260 acres which connect PNPS to the transmission system, in addition to carrying power from other generators. The corridors pass through rolling land that is primarily forested. The major road crossing is Massachusetts Highway Route 3.

The transmission lines were designed and constructed in the late 1960s and early 1970s, in accordance with the National Electrical Safety Code® (NESC) and industry guidance that was current when the lines were built. Ongoing right-of-way surveillance and maintenance of the transmission facilities ensure continued conformance to design standards. These maintenance practices are described in Section 2.4 and Section 4.13.

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 PNPS systems, structures, and components (SSCs) 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 SSCs as required by 10 CFR 54.21 has been completed and is described in the body of the PNPS license renewal application. This evaluation did not identify the need for refurbishment of SSCs 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. There are no plans associated with license renewal to modify the facility or its administrative control procedures other than those procedures necessary to implement the aging management programs described in the Integrated Plant Assessment. The proposed action does not include any modifications directly affecting plant effluents or the environment. Modifications to improve operation of plant SSCs 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 PNPS are described in the body of the PNPS license renewal application. The evaluation of SSCs required by 10 CFR 54.21 identified some new inspection activities necessary to continue operation of PNPS during the additional 20 years beyond the initial license term. These activities are described in the body of the PNPS 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

As of February 2005, the non-outage work force at PNPS consists of approximately 703 persons. There are 574 Entergy employees normally on site or at the offsite training facilities. The remaining 129 persons are baseline contractor employees.

Table 3-1 shows employee and baseline contractor residences by state, county, 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 any significant new aging management programs added at PNPS for license renewal, 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 700-900 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 PNPS.

Table 3-1
Employee Residence Information, PNPS, February 2005

County, State, and City	Employees (Entergy and Baseline Contractors)
BARNSTABLE COUNTY (MASSACHUSETTS)	**137**
Barnstable	21
Bourne	25
Brewster	1
Chatham	1
Dennis	6
Falmouth	9
Harwich	4
Mashpee	13
Sandwich	53
Yarmouth	4
BRISTOL COUNTY (MASSACHUSETTS)	**43**
Acushnet	3
Attleboro	2
Dartmouth	3
Easton	1
Fairhaven	1
Freetown	2
Mansfield	1
New Bedford	12
Norton	1
Raynham	4
Rehoboth	1
Seekonk	1
Swansea	1

Table 3-1
Employee Residence Information, PNPS, February 2005
(Continued)

County, State, and City	Employees (Entergy and Baseline Contractors)
Taunton	9
Westport	1
MIDDLESEX COUNTY (MASSACHUSETTS)	**6**
Ashland	1
Burlington	1
Chelmsford	2
Everett	1
Framingham	1
NORFOLK COUNTY (MASSACHUSETTS)	**57**
Avon	1
Braintree	5
Canton	2
Dedham	1
Franklin	2
Holbrook	1
Medfield	1
Milton	1
Needham	1
Norwood	2
Plainville	1
Quincy	8
Randolph	2
Sharon	5
Stoughton	1
Westwood	1

Table 3-1
Employee Residence Information, PNPS, February 2005
(Continued)

County, State, and City	Employees (Entergy and Baseline Contractors)
Weymouth	21
Wrentham	1
PLYMOUTH COUNTY (MASSACHUSETTS)	**444**
Abington	3
Bridgewater	9
Brockton	5
Carver	25
Duxbury	19
East Bridgewater	5
Halifax	10
Hanover	9
Hanson	5
Hingham	7
Kingston	21
Lakeville	2
Marion	1
Marshfield	27
Middleboro	13
Norwell	3
Pembroke	18
Plymouth	223
Plympton	2
Rochester	8
Rockland	3
Scituate	6

Table 3-1
Employee Residence Information, PNPS, February 2005
(Continued)

County, State, and City	Employees (Entergy and Baseline Contractors)
Wareham	14
West Bridgewater	1
Whitman	5
SUFFOLK COUNTY (MASSACHUSETTS)	**6**
Boston	6
WORCESTER COUNTY (MASSACHUSETTS)	**3**
Milford	1
Shrewsbury	1
Upton	1
PROVIDENCE COUNTY (RHODE ISLAND)	**3**
Cranston	1
Cumberland	1
North Smithfield	1
NEW LONDON COUNTY (CONNECTICUT)	**1**
Griswold	1
MANATEE COUNTY (FLORIDA)	**1**
Bradenton	1
CHESIRE COUNTY (NEW HAMPSHIRE)	**1**
Westmoreland	1
OSWEGO COUNTY (NEW YORK)	**1**
Minetto	1
TOTAL EMPLOYEES = 703	

3.6 References

3-1 U.S. Atomic Energy Commission, Division of Radiological and Environmental Protection, *Final Environmental Statement Related to Operation of Pilgrim Nuclear Power Station*, Docket No. 50 293, Washington, DC, 1972.

3-2 ENSR Corporations, *Redacted Version 316 Demonstration Report - Pilgrim Nuclear Power Station*, Document Number 0970-021-200, prepared for Entergy Nuclear Generation Company, Plymouth, MA, March 2000.

3-3 U.S. Environmental Protection Agency, Water Management Division Region 1, "Modification of Authorization to Discharge Under the National Pollutant Discharge Elimination System, Federal Permit No. MA0003557, Modification No. 1," Boston, MA, August 30, 1994.

3-4 Massachusetts Department of Environmental Protection, Executive Office of Environmental Affairs, Southeast Regional Office, Groundwater Discharge Permit, SE #2-389, Pilgrim Power Station Wastewater Treatment Facility, Lakeville, MA, April 26, 1999.

3-5 Pilgrim Nuclear Power Station, *Pilgrim Nuclear Power Station Offsite Dose Calculation Manual*, Plymouth, MA, October 6, 2003.

3-6 Pilgrim Nuclear Power Station, *Updated Final Safety Analysis Report*, Plymouth, MA.[1]

1. Pilgrim's UFSAR update is done on a page-by-page basis, rather than by entire section or volume. Therefore, several different revisions (up to Revision 24) of the UFSAR update have been used in this ER.

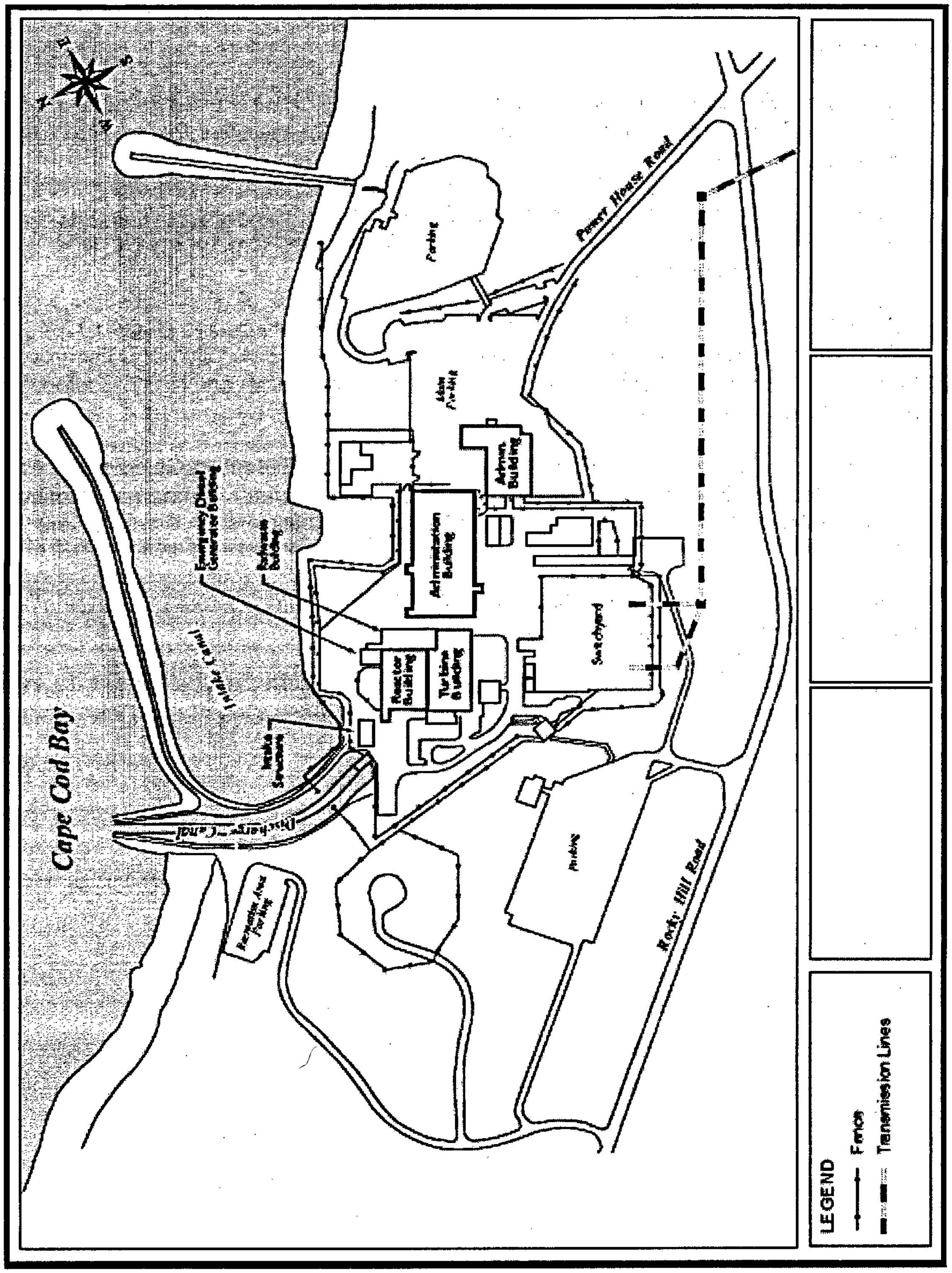

Figure 3-1
Station Layout

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). The NRC designated an issue as Category 1 if, based on the result of its analysis, the following criteria were met:

(1) 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;

(2) 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

(3) 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, the NRC designated the issue Category 2. The NRC requires plant-specific analysis for Category 2 issues. The 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 the NRC resolved using generic findings (10 CFR 51, Subpart A, Appendix B, Table B-1) as described in the GEIS [Reference 4-5]. 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, 13 are not applicable to PNPS because they apply to design or operational features that do not exist at the facility. In addition, because Entergy does not plan to conduct any refurbishment activities, the NRC findings for the seven Category 1 issues that are applicable to refurbishment do not apply. Table 4-1 lists these 20 issues and provides a brief explanation of why they are not applicable to PNPS. Table 4-2 lists the 49 Category 1 issues that Entergy has determined to be applicable to PNPS. Entergy has not identified any new and significant information concerning the impacts addressed by these findings. Therefore, Entergy adopts by reference the NRC findings for these Category 1 issues.

Table 4-1.
Category 1 Issues Not Applicable to PNPS

Surface Water Quality, Hydrology, and Use (for All Plants)	
Impacts of refurbishment on surface water quality	No refurbishment activities planned.
Impacts of refurbishment on surface water use	No refurbishment activities planned.
Altered thermal stratification of lakes	PNPS is not located on a lake.
Eutrophication	PNPS is not located on a lake.
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	PNPS does not use cooling towers.
Impingement of fish and shellfish	PNPS does not use cooling towers.
Heat shock	PNPS does not use cooling towers.
Ground-water Use and Quality	
Impacts of refurbishment on ground-water use and quality	No refurbishment activities planned.
Groundwater use conflicts (potable and service water; plants that use <100 gpm)	PNPS does not use groundwater for potable and service water.
Ground-water quality degradation (Ranney Wells)	PNPS does not use Ranney wells.
Ground-water quality degradation (cooling ponds in salt marshes)	PNPS does not use cooling ponds.
Ground-water quality degradation (saltwater intrusion)	PNPS does not use groundwater for any purpose.
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 tower impacts on crops and ornamental vegetation	PNPS does not use cooling towers.
Cooling tower impacts on native plants	PNPS does not use cooling towers.
Cooling pond impacts on terrestrial resources	PNPS does not use cooling ponds.
Bird collisions with cooling towers	PNPS does not use cooling towers.
Socioeconomics	
Aesthetic impacts (refurbishment)	No refurbishment activities planned.

Table 4-2
Category 1 Issues Applicable to PNPS

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

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

Land Use
Onsite land use (license renewal period)
Power line right of way
Human Health
Noise
Radiation exposures to public (license renewal term)
Occupational radiation exposures (license renewal term)
Socioeconomics
Public services: public safety, social services, and tourism and recreation
Public services, education (license renewal term)
Aesthetic impacts (license renewal term)
Aesthetic impacts of transmission lines (license renewal term)
Postulated Accidents
Design basis accidents
Uranium Fuel Cycle and Waste Management
Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high level waste)
Offsite radiological impacts (collective effects)
Offsite radiological impacts (spent fuel and high level waste disposal)
Non-radiological impacts of the uranium fuel cycle
Low-level waste storage and disposal
Mixed waste storage and disposal
On-site spent fuel
Nonradiological waste
Transportation

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

Decommissioning
Radiation doses
Waste management
Air quality
Water quality
Ecological resources
Socioeconomic impacts

Category 2 License Renewal Issues

The NRC designated 21 issues as Category 2. Sections 4.1 through 4.21 address each of 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 PNPS does not have. In addition, some Category 2 issues (4) apply only to refurbishment activities. If the issue does not apply to PNPS, the section explains the basis.

For the 11 Category 2 issues applicable to PNPS, the corresponding section contains the required analyses. These analyses include conclusions regarding the significance of the impacts relative to the renewal of the operating license for PNPS 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 the 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

The NRC determined that its categorization and impact-finding definitions did not apply to electromagnetic fields (chronic effect) and environmental justice. The 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, the NRC does not require information from applicants, but noted that it will 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* - findings for the issue from Table B-1, Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants, Appendix B to Subpart A.
- *Requirement* - the requirement from 10 CFR 51.53(c)(3)(ii) is restated.
- *Background* - for issues applicable to PNPS, 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 PNPS.
- *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 PNPS specific information.
- *Conclusion* - for issues applicable to PNPS, 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)(kk)(A)

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

4.1.4 Analysis of Environmental Impact

The issue of surface water use conflicts does not apply to PNPS as the plant does not use cooling towers, cooling ponds, or withdraw water from a small river. As Section 3.2.2.1 describes, PNPS uses a once-through cooling system that withdraws water from Cape Cod Bay.

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 Part 125, or equivalent state permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

4.2.4 Background

The effects of entrainment on aquatic resources were considered by the NRC at the time of original licensing and are periodically reconsidered by EPA or state water quality permitting agencies in the development of National Pollutant Discharge Elimination System (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 4-5, Section 4.2.2.1.2].

4.2.5 Analysis of Environmental Impact

As Section 3.2.2.1 describes, PNPS has a once-through heat dissipation system that uses water from Cape Cod Bay for condenser cooling.

Section 316(b) of the Clean Water Act (CWA) requires that any standard established pursuant to Sections 301 or 306 of the CWA shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts (33 USC 1326). Entrainment through the condenser cooling system of fish and shellfish in early life stages is a potential adverse environmental impact that can be minimized by the best technology available.

The EPA Region I is the NPDES permitting authority for Massachusetts. The current PNPS NPDES permit (Federal Permit No. MA0003557) notes the following:

> It has been determined based on engineering judgment that the circulating water intake structures [sic] presently employs the best technology available for minimizing adverse environmental impact. Any change in the location, design, or capacity of the present structure shall be approved by the Regional Administrator and the Director. The present design shall be reviewed for conformity to the regulations pursuant to Section 316(b) of the Act when such are promulgated. [Reference 4-3]

Thus the PNPS NPDES permit, issued August 30, 1994, by EPA Region I, constitutes the current CWA Section 316(b) determination for PNPS. Attachment A contains portions of the permit, including the quoted Section A.1.i.

EPA Region I is requiring all NPDES permittees in the region (to whom CWA Section 316 applies) to submit new Sections 316(a) and 316(b) demonstrations. EPA Region I is reviewing an Entergy application for renewal of the PNPS NPDES Permit and, as described in Section 2.2, a new combined Section 316 report that evaluates more than 25 years of entrainment and impingement data [Reference 4-2]. This new Section 316 demonstration report concludes that the PNPS cooling water intake system has not resulted in adverse impacts to the integrity of Cape Cod Bay fish and shellfish populations, including a number of Representative Important

Species (e.g., American lobster, winter flounder, rainbow smelt, cunner, alewife, and Atlantic silverside).

On July 9, 2004, the EPA published a final rule in the Federal Register (69 FR 41575) [Reference 4-12] addressing cooling water intake structures at existing power plants, such as PNPS. The rule is Phase II in the EPA's development of 316(b) regulations that establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at existing facilities. The national requirements, which are implemented through NPDES permits, provide several compliance alternatives that may be pursued by facilities to meet the entrainment and impingement performance standards in the Rule. Any additional mitigation measures under the new regulations would only further reduce the already small impacts.

4.2.6 Conclusion

EPA Region I has determined based on engineering judgment that the circulating water intake structure presently employs the best technology available for minimizing adverse environmental impact. Because Entergy submitted a timely application for renewal of the PNPS NPDES Permit, the 1994 permit and its Section 316(b) determination remain in effect. For this reason, Entergy concludes that PNPS impacts due to entrainment of fish and shellfish are SMALL and do not warrant mitigation beyond those measures required by the NPDES permit, as periodically amended.

4.3 Impingement of Fish and Shellfish

4.3.1 Description of Issue

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

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

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

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

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

4.3.4 Background

Aquatic organisms that are drawn into the intake with the cooling water 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 4-5, Section 4.2.2.1.3].

4.3.5 Analysis of Environmental Impact

PNPS currently uses various techniques for reducing impingement mortality. The traveling screens are equipped with fish collection buckets and low-pressure sprays for removing impinged organisms. The fish are washed into a fish return sluiceway and returned to the intake embayment at a point sufficiently distant from the intake to avoid re-impingement. If there is an indication that fish are being impinged at a rate exceeding 20 fish per hour, the traveling screens are turned continuously until the impingement rate drops below 20 fish per hour for two consecutive sampling events.

As Section 3.2.2.1 describes, PNPS has a once-through heat dissipation system that uses water from Cape Cod Bay for condenser cooling. Section 4.2 discusses the existing PNPS Section 316(b) determination and the combined Section 316 demonstration completed in March 2000. Attachment A contains relevant portions of the NPDES permit. On July 9, 2004, the EPA published a final rule in the Federal Register (69 FR 41575) (Reference 4-12) addressing cooling water intake structures at existing power plants, such as PNPS. The rule is Phase II in the EPA's development of 316(b) regulations that establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at existing facilities. The national requirements, which are implemented through NPDES permits, provide several compliance alternatives that may be pursued by facilities to meet the entrainment and impingement performance standards in the Rule. Any additional mitigation measures under the new regulations would only further reduce the already small impacts.

4.3.6 Conclusion

EPA Region I has determined based on engineering judgment that the circulating water intake structures presently employs the best technology available for minimizing adverse environmental impact. Because Entergy submitted a timely application for renewal of the PNPS NPDES Permit, the 1994 permit and its Section 316(b) determination remain in effect. For this reason, Entergy

concludes that PNPS impacts due to impingement of fish and shellfish are SMALL and do not warrant mitigation beyond those measures required by the NPDES permit, as periodically amended.

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 Part 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 4-5, Section 4.2.2.1.4].

4.4.5 Analysis of Environmental Impact

As Section 3.2.2.1 describes, PNPS has a once-through heat dissipation system that uses water from Cape Cod Bay for condenser cooling. As discussed below, Entergy also has a Section 316(a) variance for PNPS 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). Boston Edison Company submitted a combined CWA Section 316(a) and (b) demonstration report for PNPS to EPA Region I in 1977 that was accepted by the agency and used in determining facility-specific NPDES discharge temperature limits. That original Section 316 demonstration, based on 3 years (1969-1972) of pre-operational and 5 years (1972-1976) of post-operational engineering, hydrological, and ecological data, concluded that the thermal effluent from PNPS would not result in long-term impacts to the fish and wildlife populations of Cape Cod Bay.

In issuing and renewing the Station's NPDES Permits since that time, the EPA determined that thermal discharges from PNPS were sufficiently protective of the aquatic ecosystem of Cape Cod Bay to satisfy alternative thermal effluent limitations under Section 316(a) of the CWA. Those determinations were based on the original combined Section 316 Demonstration and on-going ecological monitoring programs.

In recent years, EPA Region I has required all NPDES permittees in the region (to whom CWA Section 316 applies) to submit new Section 316(a) and 316(b) demonstrations. EPA Region I is reviewing an Entergy application for renewal of the PNPS NPDES Permit and, as described in Section 2.2, a new combined Section 316 report that evaluates more than 25 years of data on potential thermal impacts [Reference 4-2]. This new Section 316 demonstration report concludes the following:

> Existing thermal discharges, essentially unchanged since operation of the Station, affect only a small area in the immediate vicinity of PNPS, and have resulted in no adverse impacts to the [Representative Important Species] populations or to the integrity of the aquatic ecosystem of Cape Cod Bay. Therefore, the thermal discharge does not adversely affect the propagation or protection of a balanced, indigenous population of fish, shellfish, and wildlife in Cape Cod Bay. [Reference 4-2, page 7-6]

4.4.6 Conclusion

As noted previously, Entergy has submitted a timely application for renewal of the PNPS NPDES Permit. The current NPDES Permit (provided in Attachment A) 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 <u>Groundwater Use Conflicts (Plants Using >100 gpm of Groundwater)</u>

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

The issue of groundwater use conflicts at plants that pump more than 100 gallons per minute of groundwater does not apply to PNPS. As Sections 3.2.2.1 and 3.2.2.2 describe, the plant obtains all its cooling and process water from Cape Cod Bay, and gets its potable and reactor makeup water from the Town of Plymouth.

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

The issue of groundwater use conflicts does not apply to PNPS because the plant does not use cooling towers or cooling ponds and does not withdraw water from a small river. PNPS uses a once-through cooling system that withdraws and discharges water to Cape Cod Bay.

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

PNPS does not utilize Ranney wells. Potable water is supplied by the town of Plymouth and cooling water is taken from Cape Cod Bay for a once-through cooling system that discharges water to Cape Cod Bay. Therefore, this issue is not applicable to PNPS 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

PNPS is not an inland site and does not utilize cooling ponds. PNPS utilizes a once-through cooling system that withdraws water from and discharges to Cape Cod Bay. Therefore, this issue is not applicable to PNPS 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 PNPS license renewal. Therefore this issue is not applicable to PNPS 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

The NRC did not reach a conclusion about the significance of potential impacts to threatened and endangered species in the GEIS because (1) the significance of impacts on such species cannot be assessed without site- and project-specific information that will not be available until the time of license renewal and (2) additional species that are threatened with extinction and that may be adversely affected by plant operations may be identified between the present and the time of license renewal [Reference 4-5, Section 3.9].

4.10.5 Analysis of Environmental Impacts

Section 2.2 of this ER describes the aquatic communities of western Cape Cod Bay and discusses population trends in recreationally, socially, and commercially important populations, including the American lobster and winter flounder. Section 2.4 describes important terrestrial habitats at PNPS and along the associated PNPS-to-Snake Hill Road transmission corridor. As discussed in Section 2.4, the transmission corridor crosses an area designated as critical habitat for the endangered northern red-bellied cooter, but the PNPS-to-Snake Hill Road transmission line is not owned or maintained by Entergy. The PNPS site does contain a priority habitat for the state-listed Species of Special Concern, the spotted turtle. Section 2.5 discusses threatened or endangered species that occur or may occur at PNPS, along this transmission corridor, or in Cape Cod Bay.

With the exception of the four species identified in Section 2.5, Entergy is not aware of any threatened or endangered terrestrial species that could occur at the PNPS site or along the associated transmission corridor. Current operations of PNPS and NSTAR vegetation management practices along transmission line rights-of-way do not adversely affect any listed terrestrial species or its habitat (see Section 2.4). Furthermore, station operations and transmission line maintenance practices are not expected to change significantly during the license renewal term. Therefore, no adverse impacts to threatened or endangered terrestrial species from current or future operations are anticipated.

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

Boston Edison and Entergy have conducted extensive population studies of fish and shellfish in the vicinity of PNPS since 1969. No state- or federally-listed fish species has been collected or observed in more than 30 years of monitoring.

As noted in Section 2.5, a number of threatened and endangered marine species (five whales and five sea turtles) pass Cape Cod during seasonal migrations and sometimes forage in semi-enclosed Cape Cod Bay. Most of the great whales (the minke, finback, and right whales are exceptions) live and forage over the continental shelf, approaching the coastline only during seasonal migrations. Although whales are regularly observed in summer months in the eastern portion of Cape Cod Bay and the Stellwagen Bank area, they do not normally feed in the western portion of the Bay or in the vicinity of PNPS. Because whales do not move into the shallow waters immediately offshore of PNPS, they are not affected by operation of the PNPS cooling water intake system or by the station's thermal discharge. There is no evidence that operation of PNPS has had an effect on whales in Cape Cod Bay.

Sea turtles are more likely to move inshore and feed in shallow coastal waters (particularly the green sea turtle, which actually comes ashore to bask), but reports of sea turtles foraging in extreme western Cape Cod Bay are rare. As discussed in Section 2.5, small numbers of sea turtles are stranded every year on Cape Cod beaches, but strandings on the western shore of the Bay (the mainland) are rare. No sea turtles have been impinged at PNPS, and none have been rescued from the PNPS intake canal. There are no records of sea turtles congregating in the area of the PNPS discharge canal, and no indication that the thermal effluent has disrupted normal seasonal movement or migration of turtles.

Entergy wrote to the MDFW, the FWS, and the NMFS requesting information on any listed species or critical habitats that might occur on the PNPS site or along the associated transmission corridor, with particular emphasis on species that might be adversely affected by continued operation over the license renewal period. Agency responses are provided in Attachment B of this ER. The FWS is in agreement regarding the transitory nature of the three listed bird species, as well as to the nature of the red-bellied cooter turtle habitat on the transmission lines. NMFS did recommend that Entergy address any impact on sea turtles in preparing this application. As was stated previously in Section 2.5 of this ER, in the thirty-three years that PNPS has been in operation no sea turtles have ever been observed in the intake or discharge canal or along the PNPS waterfront. In the twenty-five years that Mass Audubon has been documenting the numbers and locations of sea turtle strandings in Massachusetts, only one sea turtle stranding has been recorded in the town of Plymouth [Reference 4-10] and that stranding was not attributable to PNPS operations.

MDFW stated, "If there are no plans to expand the footprint or to alter current operations over the license period, then it would not seem likely that there would be an adverse affect on state-protected wildlife species." However, MDFW was unable to provide an official determination unless a full environmental review was conducted.

4.10.6 Conclusion

As discussed in Section 3.3, Entergy has no plans to conduct refurbishment or construction activities at PNPS during the license renewal term. Therefore, there will be no impact to threatened and endangered species from refurbishment activities.

Because Entergy has no plans to alter current operations and resource agencies contacted by Entergy evidenced no serious concerns about license renewal impacts, Entergy concludes that impacts to threatened or endangered species from license renewal would be SMALL and do not warrant further mitigation.

Renewal of the operating license for PNPS is not expected to result in the taking of any threatened or endangered species. Renewal of the license is not likely to jeopardize the continued existence of any threatened or endangered species or result in the destruction or adverse modifications of any critical habitat.

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 PNPS. Therefore, this issue is not applicable to PNPS 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, canals, 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 $3.15\text{x}10^{12}$ ft^3/year ($9\text{x}10^{10}$ 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

The issue of thermophilic organisms does not apply to PNPS because the plant does not use a cooling pond, lake, canal, or discharge to a small river. PNPS uses a once-through cooling system that withdraws from and discharges water into Cape Cod Bay. Therefore, this issue is not applicable to PNPS 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 4-5, Sections 4.5.4 and 4.5.4.1].

4.13.5 Analysis of Environmental Impact

In the case of PNPS, *there have been no previous* NRC or NEPA *analyses of transmission-line-*induced-current hazards. Therefore, this section provides an analysis of the station's transmission lines' conformance with the NESC standard. The analysis is based on computer modeling of electric field strength under the lines.

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

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

In 1977, the NESC adopted a provision that describes an additional criterion to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98-kV alternating current to ground.[1] The clearance must limit the steady-state induced current[2] to 5 milliamperes if the largest anticipated truck, vehicle, or equipment were short-circuited to ground. By way of comparison, the setting of ground fault circuit interrupters used in residential wiring (special breakers for outside circuits or those with outlets around water pipes) is 4 to 6 milliamperes..

As described in Section 3.2.7, two 345-kV lines were specifically constructed to distribute power from PNPS to the electric grid. Entergy's analysis of these transmission lines began by identifying the limiting case for each line. The limiting case is the location along each line where the potential for current-induced shock would be greatest. Because in the region of interest the two transmission lines share towers, there was only one limiting location to be considered. For convenience and conservatism, the limiting case selected was the hypothetical location with minimum clearance allowed by the Commonwealth of Massachusetts for 345-kV lines. All spans on these lines have greater clearance than the limiting case.

Once the limiting case was identified, NSTAR, the lines' owner, calculated the electric field strength underneath the lines, allowing for contribution from both lines simultaneously. NSTAR used the Electric Power Research Institute (EPRI) code, ENVIRO, to determine electric field strength [Reference 4-9].

Finally, Entergy calculated the induced current based on the distribution of electric field strength. Entergy used methods described in EPRI's Transmission Line Reference Book [Reference 4-4]. The analysis assumed the maximum vehicle allowed by the Commonwealth of Massachusetts, which is a tractor-trailer 60 feet long, 8 feet wide, and a maximum of 13.5 feet high.

Entergy determined that the combined effect of the two lines does not have the capacity to induce as much as 5 milliamperes in a vehicle parked beneath the lines. The Entergy-calculated induced current would be 4.5 milliamps [Reference 4-11]. Therefore, the PNPS transmission line designs conform to the NESC provisions for preventing electric shock from induced current.

NSTAR conducts surveillance and maintenance to ensure that design ground clearances do not change. These procedures include routine aerial inspections on a regular basis. These aerial patrols of all corridors include checks for encroachments, broken conductors, broken or leaning structures, and signs of trees burning, any of which would be evidence of clearance problems. Ground inspections include examination for clearance at questionable locations, integrity of structures, and surveillance for dead or diseased trees which might fall on the transmission lines. The results of these observations and inspections are reviewed by NSTAR Asset Management engineers and follow-up inspections are scheduled if necessary. The completed reviews are evaluated and prioritized based upon safety and structural integrity. Work orders are created in

1. Part 2, Rules 232C1c and 232D3c.
2. The NESC and the GEIS use the phrase "steady-state current," whereas 10 CFR 51.53(c)(3)(ii)(H) uses the phrase "induced current." The phrases mean the same here.

NSTAR's work management system for those observations which require action and the responsible operating divisions are notified to schedule the corrective action.

4.13.6 Conclusion

Entergy's assessment concludes that electric shock is of SMALL significance for the PNPS transmission lines. 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 4-5, Section 3.7.2].

4.14.5 Analysis of Environmental Impact

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

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

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

As noted in 10 CFR 51, Subpart A, Appendix B, Table B-1, the NRC concluded that impacts to housing are expected to be of small significance at plants located in high population areas where growth control measures are not in effect. As of February 2005, the PNPS site has approximately 703 full time workers (Entergy employees and baseline contractors) during normal plant operations. As described in Section 2.6, PNPS is located in a high population area. As described in Section 3.5, Entergy does not plan to add any additional permanent employees during the license renewal term. Entergy's analysis of the Plymouth and Barnstable County planning tools, such as zoning and redevelopment incentives, determined that the tools are designed to guide growth, but not to limit it.

4.14.6 Conclusion

As noted in Section 3.3, there are no major refurbishment activities required for PNPS 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 4-5, 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 PNPS license renewal. Therefore, there will be no impact to public utilities from refurbishment activities and therefore no further analysis is needed.

PNPS demand for water is not expected to change during the license renewal period. Section 2.9.1 notes that average daily water withdrawals exceed authorized withdrawal limits (capacities) in some areas. The region overall has excess capacity, but is expected to eventually experience water shortages in several of the larger municipalities of Plymouth and Barnstable Counties [Reference 4-1]. However, Entergy does not anticipate a need for additional workers during the period of extended operation. There will be no impact to public utilities from additional plant workers living in the two-county area near the plant where the majority of employees live.

4.15.6 Conclusion

Although future water shortages are a concern for the region, their occurrence would be independent of the license renewal process. Therefore, Entergy concludes that impacts to the

public water supply from plant-related population growth and plant demand would be SMALL and mitigation would not be warranted.

4.16 Education Impacts from Refurbishment

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 PNPS license renewal. Therefore this issue is not applicable to PNPS and no analysis is required.

4.17 Offsite Land Use—Refurbishment

4.17.1 Description of Issue

Offsite Land Use (effects of refurbishment activities)

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

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

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

An assessment of the impact of the proposed action on... land-use...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 PNPS license renewal. Therefore, there will be no impacts from refurbishment activities and no analysis is required.

4.18 Offsite Land Use—License Renewal Term

4.18.1 Description of Issue

Offsite Land Use (effects of license renewal)

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

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

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

An assessment of the impact of the proposed action on ...land-use...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, "...population-driven land use changes during the license renewal term at all nuclear plants will be small...." Regulatory Guide 4.2 further states, "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:

- the size of the plant's tax payments relative to the community's total revenues,
- the nature of the community's existing land use pattern, and
- 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 4-5, Section 4.7.4.2].

4.18.5 Analysis of Environmental Impact

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

4.18.5.1 Population-Driven Land Use Changes

Entergy agrees with the GEIS conclusion that new population-driven land use changes at PNPS during the license renewal term would be SMALL [Reference 4-5, Section 4.7.4.2]. Entergy does not anticipate that additional workers will be employed at PNPS during the period of extended operations. Therefore there will be no adverse impact to the offsite land use from plant-related population growth.

4.18.5.2 Tax-Driven Land Use Changes

The NRC has determined that the significance of tax payments as a source of local government revenue would be small if the payments are less than 10% of revenue [Reference 4-5, Section 3.7.3]. The NRC further determined that, if a plant's tax payments are projected to be small relative to the community's total revenue (i.e., less than 10% of revenue), new tax-driven land-use changes would be small.

The NRC defined the magnitude of land-use changes as follows [Reference 4-5, Section 4.7.4]:

- Small - very little new development and minimal changes to an area's land-use pattern;
- Moderate - considerable new development and some changes to land-use pattern;

- Large - large-scale new development and major changes in land-use pattern.

Table 2-4 compares the tax payments made by Entergy to the Town of Plymouth with the Town's annual property tax revenues. Entergy's tax payments to the Town of Plymouth represent approximately 2 to 3% of the Town's total annual property tax revenues. Using the NRC's criteria, Entergy's tax payments are of small significance to the Town of Plymouth. As described in Section 3.3, Entergy does not anticipate refurbishment or construction during the license renewal period. Therefore, Entergy does not anticipate any increase in the assessed value of PNPS due to refurbishment-related improvements, or any related tax-increase-driven changes to offsite land-use and development patterns.

Additionally, Section 2.8 describes the Town of Plymouth's land-use patterns, which reflect the use of planning tools, such as zoning, to prohibit new construction in selected areas and encourage growth in others. Section 2.9 describes public facilities. Because infrastructure is limited in some areas and accessible in others, zoning guidelines encourage growth in areas where infrastructure already exists. New infrastructure construction is less likely to occur. Therefore, growth is encouraged, but limited to pre-selected areas. During the summer months, tourism creates a large surge in population and the overflow is absorbed by existing temporary housing accommodations. This surge does not, however, affect overall permanent residential housing patterns or capacities.

4.18.6 Conclusion

Because Entergy's tax payments are small, and the Town of Plymouth has pre-established patterns of development and has been able to provide adequate public services to support and guide ongoing development, Entergy concludes that impacts to offsite land use from plant-related tax impacts would be SMALL and mitigation would not be warranted.

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 4-5, Section 3.7.7].

4.19.5 Analysis of Environmental Impact

As described in Section 3.3, no refurbishment is planned and no refurbishment impacts to local transportation are anticipated. No further evaluation is necessary.

During the license renewal term, as described in Section 3.5, Entergy does not intend to add any additional employees above the existing reactor workforce of approximately 703 during normal operations of the license renewal term and an outage workforce of as many as 1,600 workers (including permanent employees and contractors for the outage).

4.19.6 Conclusion

As discussed in Section 3.3, no refurbishment is planned and no refurbishment impacts to local transportation are anticipated. Also, Entergy does not intend to add any additional license renewal term employees above the existing reactor workforce and outage workforce. 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 4-5, Section 3.7.7].

4.20.5 Analysis of Environmental Impact

As described in Section 2.11, no archaeological or historic sites of significance were identified during surveys prior to station construction. Entergy does not plan any refurbishment activities, so no refurbishment-related impacts are anticipated.

Local archaeological, State Register of Historic sites, and National Historic Register sites of significance have been identified. Although a number of archaeological and historical sites are located on or near the station and its transmission line corridors, PNPS is not aware of any adverse effects or detrimental impacts on these sites caused by the operation of PNPS. Therefore, Entergy concludes that the continued operation of PNPS would have SMALL adverse impacts on historic or archaeological resources; hence, there would be no impacts to mitigate.

PNPS corresponded with the SHPO regarding the potential effect of the proposed license renewal of PNPS. The SHPO confirmed that LR at PNPS is unlikely to affect significant historic or archaeological resources.

4.20.6 Conclusion

As noted in Section 3.3, there are no major refurbishment activities required for license renewal at PNPS. In addition, based on consultation with the State Historic Preservation Officer (see Attachment C), no prehistoric or historic resources would be affected by operation of the plant during the license renewal period. Therefore, the potential impact of continued operation of PNPS 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 4-5, Section 5.5.2.5].

4.21.5 Analysis of Environmental Impact

The method used to perform the Severe Accident Mitigation Analysis (SAMA) was based on the handbook used by the NRC to analyze benefits and costs of its regulatory activities [Reference 4-6].

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 factor of 7.0%).

- 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 factor of 7.0%.

- 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 factor 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 factor of 7.0%. 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 General Electric (GE) Advanced Boiling Water Reactor (ABWR) design;

- NRC and industry documentation discussing potential plant improvements;

- PNPS 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

- PNPS PSA model risk significant contributors.

(3) Phase I - Preliminary Screening

Potential SAMA candidates were screened out if they modified features not applicable to PNPS, if they had already been implemented at PNPS, 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 PNPS since they were developed in the past and no credit was taken for inflation when applying them to PNPS. 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) Sensitivity Analyses

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 27-year period for remaining plant life. The other sensitivity analysis was to investigate the sensitivity of each analysis case to the discount rate of 3.0%.

The SAMA analysis for PNPS 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 PNPS PSA model and the MACCS2 consequence analysis software code. The PSA model used for the SAMA analysis (PNPS Revision 1, April 2003) is an internal events risk model.

4.21.5.1.1 The PSA 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 the PNPS (PNPS Revision 1, April 2003). This current model is an updated version of the model used in the 1992 IPE and subsequently modified in 1995 to answer an RAI and reflects the PNPS configuration and design changes as of September 2001. It also uses component failure and unavailability data as of December 2001, and resolves all findings and observations during the industry peer review of the model, conducted in March 2000. The PNPS 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 1.62. This analysis is presented in Section E.1.1 of Attachment E.1.

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

The PNPS fire analysis was performed using the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology for qualitative and quantitative screening of fire areas and for fire analysis of areas that did not screen. The FIVE methodology is primarily a screening approach used to identify plant vulnerabilities due to fire initiating events. The end result of PNPS IPEEE fire analysis identified the CDF for significant fire areas. A number of administrative procedures were revised to improve combustible and flammable material control.

4.21.5.1.3 The 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 PNPS PSA model, site meteorological data, projected population distribution (within 50-mile radius) for the year 2032, emergency response evacuation modeling, and economic data. The MACCS2 input data are described in Section E.1.5 of Attachment E.1.

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 PNPS at-power internal events [Reference 4-6].

<u>Off-Site Exposure Costs</u>

The Level 3 baseline analysis resulted in an annual off-site exposure risk of 13.6 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 4-6]. 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 7.0% discount rate, assuming FA is zero, and the baseline CDF of 6.41E-06/year resulted in the monetary equivalent value of $292,751. 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 $45,900. This value was discounted in the same manner as the public health risks in accordance with the following equation:

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

where

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

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

F = accident frequency (events/year);

S = status quo (current conditions);

A = after implementation of proposed action;

r = discount rate (%); and

t_f = license renewal period (years).

Using previously defined values, the resulting monetary equivalent is $494,017. 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 4-6]. 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 PNPS's accident risk is

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

$$W_{IO} = 3,300 \times F_S \times \$2,000 \times \frac{1 - e^{-0.07 \times 20}}{0.07}$$

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

For the baseline CDF, 6.41 x 10^{-6}/year,

$$W_{IO} = \$455$$

Long-Term Dose

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

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 PNPS's accident risk is

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

$$W_{LTO} = (F_S \times 20,000)\$2,000 \times \frac{1-e^{-0.07 \times 20}}{0.07} \times \frac{1-e^{-0.07 \times 10}}{0.07 \times 10}$$

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

For the CDF for the baseline, 6.41 x 10^{-6}/year,

W_{LTO} = \$1,985.

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

$$AOE_B = W_{IO} + W_{LTO} = \$455 + \$1,985 = \$2,440$$

The resulting monetary equivalent of \$2,440 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 4-6] to be \$1.5 x 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);

r = discount rate (%).

Based upon the values previously assumed,

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

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

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

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

where,

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

Based upon the values previously assumed,

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

Replacement Power Costs

Replacement power costs were estimated in accordance with the *Regulatory Analysis Technical Evaluation Handbook* [Reference 4-6]. 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:

$$PV_{RP} = \left(\frac{\$1.2x10^8}{r}\right)(1 - e^{-rt_f})^2$$

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 $\$1.2x10^8$ 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 4-6] for discount rates between 5% and 10% only.

Based upon the values previously assumed,

$$PV_{RP} = \left(\frac{\$1.2x10^8}{r}\right)(1 - e^{-rt_f})^2 = \left(\frac{\$1.2x10^8}{0.07}\right)(1 - e^{-(0.07)(20)})^2 = \$9.73x10^8$$

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

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

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,

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

Total On-Site Property Damage Costs

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

$$AOSC = \Delta F(U_{CD} + U_{RP}) = \Delta F(\$1.16\text{x}10^{10} + \$7.89\text{x}10^9) = \Delta F(\$1.95\text{x}10^{10})$$

where

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

For the baseline CDF, $6.41\text{x}10^{-6}$/year,

AOSC = \$125,086.

The resulting monetary equivalent of \$125,086 is presented in Table 4-3.

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

Parameter	Present Dollar Value ($)
Off-site exposure costs	$292,751
Off-site economic costs	$494,017
On-site exposure costs	$2,440
On-site economic costs	$125,086
Total	**$914,294**

4.21.5.2 Identify SAMA Candidates

Based on a review of industry documents, an initial list of SAMA candidates was identified. Since PNPS is a typical GE boiling water reactor design, considerable attention was paid to the SAMA candidates from SAMA analyses for other plants with a GE boiling water reactor design. 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 PNPS IPE and IPEEE. In both the IPE and IPEEE, several enhancements 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 current PNPS 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 model 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 of Attachment E.1. The comprehensive list contained a total of 281 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 PNPS. Potential SAMA candidates were screened out if they modified features not applicable to PNPS or if they had already been implemented at PNPS. 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, 222 of the 281 initial SAMA candidates were eliminated, leaving 59 SAMA candidates for further analysis. The list of original 281 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 (COE). The benefit was defined as the sum of the reduction in dollar equivalents for each severe accident impact area (off-site exposure, off-site economic costs, occupational exposure, and on-site economic costs). If the expected implementation cost exceeded the estimated benefit, the SAMA was not considered to be 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.2.

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 dealt with installing digital large break LOCA protection; the bounding calculation estimated the benefit of this improvement by total elimination of risk due to large break LOCA (see the Phase II analysis of SAMA 52 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 4-6] 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 calculated by applying a multiplier of six 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 IPEEE analyses using the FIVE methodology and seismic PSA provide quantitative, but conservative results. Therefore, the results were combined as described below to represent the total external events risk.

The conservative EPRI FIVE methodology was used for the PNPS IPEEE fire analysis. The fire analysis was done as a screening analysis only and not as a determination of the fire CDF at PNPS. Since fire zone conditional core damage probability is estimated by failing all equipment

in the fire zone, a SAMA that reduces internal events CDF may not reduce fire CDF for a zone. Thus the resulting benefit value is inflated and therefore, overly conservative.

The sum of the fire zone CDF values (Table E.1-12) is approximately 1.91 x 10^{-5} per reactor-year. This value is lower than the originally published fire CDF value of 2.20 x 10^{-5} due to updated equipment failure probability and unavailability values. As described above, this fire CDF is only a screening value. A more realistic fire CDF may be about a factor of three less than this value [Reference 4-8]. With a factor of three reduction, the fire CDF is about 6.37 x 10^{-6} per reactor-year.

The seismic PSA analysis is also a conservative analysis. Therefore, its results should not be compared directly with the best-estimate internal events results. Conservative assumptions in the seismic PSA analysis include the following.

- Each of the sequences in the seismic PSA assumes unrecoverable loss of off-site power. If off-site power were 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.

- Each of the sequences in the seismic PSA assumes unrecoverable loss of the nitrogen system and the fire water crosstie to the RHR system.

- Each of the sequences in the seismic PSA assumes unrecoverable loss of the CSTs water source for the high pressure injection systems.

- 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.

- Dual initiators are included in the seismic small LOCA, medium LOCA, large LOCA, and ISLOCA event trees. For example, the seismic small LOCA initiating event frequency is a combination of the probability that the seismic event induced a small LOCA and the probability that a small LOCA will occur due to a random event during the 24-hour mission time.

- The ATWS event tree was conservatively simplified so that all conditions which lead to a failure to scram result in core damage, without the benefit of standby liquid control (SLC) or other mitigating systems.

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

The seismic CDF in the IPEEE was conservatively estimated to be 5.82x10^{-5} per reactor-year. The seismic CDF has recently been re-evaluated to reflect the updated Gothic computer code room heat up calculations that predict no room cooling requirements for HPCI, RCIC, core spray,

and RHR areas; to update random component failure probabilities; and to model replacement of certain relays with a seismically rugged model. The new seismic CDF is 3.22×10^{-5} per reactor-year. As described above, this is a conservative value. Engineering judgment indicates that a more realistic value would be at least a factor of two less than this value. With a factor of two reduction, the seismic CDF is 1.61×10^{-5} per year.

Combination of the reduced fire and seismic CDF values results in an external events risk estimate of 2.25×10^{-5} per year, which is 3.51 times higher than the internal events CDF. This would justify use of a multiplier of four on the averted cost estimates (for internal events) to represent the additional SAMA benefits in external events.

CDF uncertainty calculations resulted in a factor of 1.62 (Table E.1-3). Since 3.51 x 1.62 = 5.69, a multiplier of six would be reasonable to account for both external events and uncertainties.

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 six times the internal events estimated benefit to account for external events and uncertainty is conservative.

The expected Cost of Implementation (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
- Dresden 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 59 Phase II SAMA candidates is presented in Table E.2-1 of Attachment E.2.

4.21.5.5 Sensitivity Analysis

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 27-year period for remaining plant life (i.e. seven years on the original plant license plus the 20-year license renewal period). The 20-year licensing renewal period was used in the base case. The resultant monetary equivalent for internal event was calculated by using 27 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.2.

4.21.6 Conclusion

This analysis addressed 281 SAMA candidates for mitigating severe accident impacts. Phase I screening eliminated 222 SAMA candidates from further consideration, based on either inapplicability to PNPS's design or features that had already been incorporated into PNPS's current design, procedures and/or programs. During the Phase II cost benefit evaluation of the

remaining 59 SAMA candidates, an additional 54 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 (30, 34, 56, 57, and 58) presented in Table 4-4 were found to be potentially cost beneficial for mitigating the consequences of a severe accident for PNPS.

- A plant modification and procedural change was recommended to install keylocked control switches to enable AC bus cross-ties to enhance the reliability of AC power system (SAMA candidate 30).
- A plant procedural enhancement was recommended to use DC bus cross-ties to enhance the reliability of DC power system (SAMA candidate 34).
- A plant modification was recommended to install additional fuses in panel C7 to enable the DTV valve function during loss of containment heat removal accident sequences (SAMA candidate 56).
- A plant procedural enhancement was recommended to allow use of the hydro turbine in the event that EDG A or fuel oil transfer pump P-141A is unavailable (SAMA candidate 57).
- A plant procedural enhancement was recommended to allow alternately feeding B1 loads via B3 when A3 is available and alternately feeding B2 loads via B4 when A4 is available (SAMA candidate 58).

These SAMA candidates do not relate to adequately managing the effects of aging during the period of extended operation. In addition, since the SAMA analysis is conservative and is not a complete engineering project cost-benefit analysis, it does not estimate all of the benefits or all of the costs of a SAMA. For instance, it does not consider increases or decreases in maintenance or operation costs following SAMA implementation. Also, it does not consider the possible adverse consequences of procedure changes, such as additional personnel dose. Therefore, the above, potentially cost-beneficial SAMAs have been submitted for engineering project cost-benefit analysis.

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

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
030	9.g. Enhance procedures to make use of AC bus cross-ties.	SAMA would provide increased reliability of AC power system and reduce core damage and release frequencies.	11.10%	8.47%	$78,902	$473,410	$146,120
	Basis for Conclusion: The CDF contribution due to loss of MCC B17, B18, and B15 was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $146,120 by engineering judgment.						
034	10.d. Enhance procedures to make use of DC bus cross-ties.	This SAMA would improve DC power availability.	4.65%	1.91%	$19,761	$118,568	$13,000
	Basis for Conclusion: The CDF contribution due to loss of DC buses D16 and D17 was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $13,000 by engineering judgment.						
056	Provide redundant DC power supplies to DTV valves.	This SAMA would improve reliability of the DTV valves and enhance containment heat removal capability.	8.81%	3.51%	$36,773	$220,639	$112,400
	Basis for Conclusion: The CDF contribution from sequences involving DC power supply failures to the direct torus vent valves was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $112,400 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
057	Proceduralize use of the diesel fire pump hydro turbine in the event of EDG A failure or unavailability.	This SAMA would increase capability to provide makeup to the fire pump day tank to allow continued operation of the diesel fire pump, without dependence on electrical power.	2.25%	3.14%	$29,213	$175,279	$26,000
	Basis for Conclusion: The CDF contribution from sequences involving loss of offsite power and failure of either EDG A, or the EDG A fuel oil transfer oil pump, was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $26,000 by engineering judgment.						
058	Proceduralize the operator action to feed B1 loads via B3 When A5 is unavailable post-trip. Similarly, feed B2 loads via B4 when A6 is unavailable post trip.	This SAMA would provide the direction to restore B15 and B17 loads upon loss of A5 initiating events as long as A3 is available. Additionally, it would provide the direction to restore B14 and B18 loads upon loss of A6 initiating events as long as A4 is available.	4.92%	3.14%	$31,799	$190,797	$50,000
	Basis for Conclusion: The CDF contribution from sequences involving loss of 4160VAC safeguard bus A5 was conservatively eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $50,000 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 (NRR) 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.

NRR Office Letter No. 906, Revision 2 [Reference 4-7] 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 PNPS license; thus, no disproportionate impact on minority or low income populations would occur from the proposed action. If replacement of the electricity generated by PNPS with fossil-fuel sources was considered as an alternative to the proposed action, the environmental justice ramifications of that alternative's air emissions and other environmental impacts would need to be considered. 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 of this ER 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 the environmental impacts of renewing the PNPS license are small. 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.

Because all impacts are small, and because there are few low-income or minority populations in the environmental impact area, 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 PNPS license.

4.23 References

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4-11 TetraTech NUS, "Calculation of Induced Current for the License Renewal Environmental Report - Pilgrim Nuclear Power Station," Aiken, SC, April 23, 2001.

4-12 U.S. Environmental Protection Agency, "National Pollutant Discharge Elimination System – Final Regulations to Establish Requirement for Cooling Water Intake Structures at Phase II Existing Facilities," 69 FR 41576, July 9, 2004.

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 implemented a process 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 leads to an impact finding different from that codified in the regulation.

The term "significant" is not specifically defined by the NRC. 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 the 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 PNPS. 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 responsible for environmental matters, with assistance from 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; and
  - environmental issues are reviewed and evaluated for applicability by the nuclear corporate support group.
- If the issue is applicable to the Entergy 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 PNPS license renewal include the following:

- review of documents related to environmental issues at PNPS;
- review of internal procedures for reporting to the NRC events that could have environmental impacts; and
- 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 PNPS 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 PNPS operating license and has concluded that all impacts would be small and would not require mitigation. This ER documents the basis for Entergy's conclusion. Section 4 incorporates by reference NRC findings for the 49 Category 1 issues that apply to PNPS, all of which have impacts that are small (Table 4-2). The rest 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 PNPS license renewal would have on resources associated with Category 2 issues.

6.2 Mitigation

6.2.1 Requirement [10 CFR 51.53(c)(3)(iii)]

"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."

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 PNPS

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.** This issue does not apply because PNPS does not use cooling ponds or cooling towers withdrawing water from a small river.
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.** PNPS has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements.
Impingement of fish and shellfish 10 CFR 51.53(c)(3)(ii)(B)	**SMALL.** PNPS has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements.
Heat shock 10 CFR 51.53(c)(3)(ii)(B)	**SMALL.** PNPS has a current NPDES permit which constitutes compliance with CWA Section 316(a) requirements.
Ground-water Use and Quality	
Groundwater use conflicts (plants using >100 gpm of ground-water) 10 CFR 51.53(c)(3)(ii)(C)	**NONE.** This issue does not apply because PNPS uses <100 gpm of groundwater. PNPS's potable water is supplied by the Town of Plymouth.
Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river) 10 CFR 51.53(c)(3)(ii)(A)	**NONE.** This issue does not apply because PNPS does not use cooling towers withdrawing water from a small river.
Groundwater use conflicts (Ranney Wells) 10 CFR 51.53(c)(3)(ii)(C)	**NONE.** PNPS does not use Ranney Wells. Consideration of mitigation is not required.
Degradation of groundwater quality 10 CFR 51.53(c)(3)(ii)(D)	**NONE.** PNPS does not use cooling ponds. Consideration of mitigation is not required.
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.

Table 6-1
Environmental Impacts Related to License Renewal at PNPS
(Continued)

Threatened or Endangered Species (for All Plants)	
Threatened or endangered species 10 CFR 51.53(c)(3)(ii)(E)	**SMALL.** No major refurbishment activities have been identified and no significant issues have been identified by any of the environmental agencies that were consulted.
Air Quality	
Air quality during refurbishment 10 CFR 51.53(c)(3)(ii)(F)	**NONE.** No impacts are expected because PNPS has *no plans to undertake refurbishment.*
Human Health	
Microbiological (Thermophilic) Organisms 10 CFR 51.53(c)(3)(ii)(G)	**NONE.** The issue does not apply because PNPS does not discharge to a lake or use cooling towers or cooling ponds discharging to a small river.
Electromagnetic fields – Acute effects 10 CFR 51.53(c)(3)(ii)(H)	**SMALL.** The largest modeled induced current under the PNPS transmission lines would be less than 5.0 milliamperes, which is the National Electric Safety Code® standard for preventing electric shock from induced current.
Socioeconomics	
Housing impacts 10 CFR 51.53(c)(3)(ii)(I)	**SMALL.** PNPS is located in a high-population area that does not have growth control measures. Therefore, in accordance with NRC standards, housing impacts would be 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 PNPS. 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 PNPS 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 PNPS
(Continued)

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.** No plant-induced changes to offsite land use are expected from license renewal.
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 identified adverse impacts or detrimental effects on identified historic and archaeological properties. 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, 10 CFR 51, Subpart A, Appendix B, and information specific to PNPS.

This review and analysis did not identify any significant adverse environmental impacts associated with the continued operation of PNPS. 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 PNPS 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 PNPS 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;
- land required to dispose of spent nuclear fuel and low-level radioactive wastes generated as a result of plant operations;
- elemental materials that will become radioactive; and
- materials used for the normal industrial operations of PNPS 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 PNPS 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 at PNPS was established when the station began operation in 1972. PNPS's FES [Reference 6-1] evaluated the impacts of constructing and operating PNPS. Initially, approximately 500 acres were acquired for the station. The land had been a private, mostly wooded, estate. PNPS and associated facilities cover about one-third of this acreage. When Boston Edison was considering constructing a second reactor on the PNPS site, the company purchased approximately 1,100

additional acres inland of the original 500-acre tract. Approximately 1,500 acres of the approximately 1,600 acres owned by Entergy is managed as timberland.

This greenspace in a populated and growing area between two large urban areas provides habitat for plants and animals. After operations cease, most of the land occupied by the station and ancillary facilities could be restored to terrestrial habitat or used for other industrial purposes. Long-term productivity of the terrestrial and aquatic habitats in the vicinity of PNPS is not adversely affected by the station or its operations. Continued operations for an additional 20 years would not alter this conclusion.

6.6 References

6-1 U.S. Atomic Energy Commission, Division of Radiological and Environmental Protection, *Final Environmental Statement Related to Operation of Pilgrim Nuclear Power Station*, Docket No. 50-293, Washington, DC, 1972.

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*, Washington, DC, 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]. 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

PNPS operated at a capacity factor of 98.5% in 2004 and is rated at approximately 715 gross MWe. The proposed action is to renew the operating license for PNPS which would provide the opportunity for Entergy to continue to operate PNPS 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. Entergy concludes that the environmental impacts of extended PNPS operation would be small.

7.3 No-Action Alternative

The "no-action alternative" to the proposed action is not to renew the operating license for PNPS. In this alternative, it is expected that PNPS will continue to operate up to the end of the existing operating license, at which time plant operation would cease, and decommissioning would begin. Because PNPS constitutes a significant block of base load capacity, it is reasonable to assume that a decision not to renew the PNPS licenses would necessitate the replacement of its approximately 715 gross MWe with other sources of generation. The environmental impacts of the no-action alternative would be

- the environmental impacts from decommissioning the PNPS 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 PNPS 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 PNPS 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 PNPS and, therefore, bounds decommissioning activities that Entergy would conduct at PNPS.

As the GEIS notes, the 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. The 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 PNPS; license renewal would only postpone decommissioning for 20 years. The 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 Subpart A, 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 generic environmental impact statement [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 PNPS site since it was concluded that there was not enough land to build a coal-fired unit and a coal yard on the existing site (brownfield). 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. PNPS is situated on 140 acres and is rated at approximately 715 gross MWe. Therefore for the 620 gross MWe coal-fired plant used in this analysis, approximately 1,054 acres of land would be needed.

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

- Nuclear generation at an alternate site (Section 8.1.3). Entergy did not consider nuclear generation at the PNPS site (brownfield) since it was concluded that there was not enough land to build a nuclear unit. Based on Table 8.1 of the GEIS, it would take approximately 0.5 to 1.0 acres of land per MWe to construct a nuclear plant. PNPS is situated on 140 acres and is rated at approximately 715 gross MWe. Therefore for a 715 gross MWe nuclear plant, approximately 357.5 to 715 acres of land would be needed.

Entergy's experience indicates that, although customized unit sizes can be built, using standardized sizes is more economical. For example, a standard-sized gas-fired combined cycle plant has a net capacity of 585 MWe. The plant consists of two 189-MWe gas turbines and 207 MWe of heat recovery capacity. For comparability, Entergy set the net power of the hypothetical coal-fired unit equal to the hypothetical gas-fired plant (585 MWe). Although both provide less capacity than PNPS (715 MWe), this ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other methods.

These alternatives are presented (Sections 8.1.1, 8.1.2, and 8.1.3, respectively) as if such plants were constructed at the PNPS site, 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. Although PNPS does own an additional 1,500 acres of forest land, it is a greenfield site as it is not part of the PNPS facility site. This additional land is zoned as rural residential.

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 PNPS site.

The potential for using purchased power is discussed in Section 8.1.4. Purchased power is considered feasible, but would result in the transfer of environmental impacts from the current region in Massachusetts to some other location in Massachusetts, 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]. 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, and hydroelectric) would require a large area of land and would thus require a greenfield siting plan. This would result in a greater environmental impact than continued operation of PNPS.

- *Low capacity factors*

  Some of the technologies identified above (wind, solar, and hydroelectric) are not capable of producing the nearly 715 gross MWe of power at high capacity factors. These generation technologies are used as peaking power sources, as opposed to base-load power sources, and for this reason are not reasonable alternatives.

- *Geographic availability of the resource*

  Some of the technologies are not feasible because there is no feasible location in the area served by PNPS.

- *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 purchased power.

7.6 References

7-1 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.

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 715 gross 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 2012 through 2032.
- 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 PNPS in 2004 was 98.5%. 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

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 8-14]. Below is a discussion of the supply side alternative energy technologies that Entergy could utilize if the license for PNPS is not renewed. These alternatives are within the range of alternatives capable of meeting the goal of approximately 715 gross MWe as base-load generation (replacement power for PNPS).

Conventional coal-fired, natural gas-fired combined cycle, and advanced light water reactor are currently available conventional base-load technologies considered to replace PNPS generation upon its termination of operation. These sources are considered viable alternatives based upon current Entergy planning strategies.

The environmental impacts discussed in this chapter are for the construction and operation of these generation facilities. Impacts are evaluated for a greenfield case (building on a new, pristine condition site) and a brownfield case (constructing new generation on the existing PNPS site, in the case of a gas-fired unit).

The continued operation of PNPS 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, as described below.

8.1.1 Coal-Fired Generation

The NRC has evaluated coal-fired generation alternatives in each of the plant-specific supplements to the GEIS. For the Oconee boiling-water reactors, the NRC analyzed 2,500 MWe of coal-fired generation capacity [Reference 8-15]. Entergy has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed substantially more generating capacity than the 620 gross MWe from coal-fired generation discussed in this analysis. In defining the PNPS coal-fired alternative, Entergy has used site-specific input and has scaled from the NRC analysis, where appropriate.

Tables 8-1, 8-2, and 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 8-7]. For the purposes of analysis, Entergy assumed that coal and lime (calcium hydroxide) would be delivered by barge to a newly constructed receiving dock on site.

The coal-fired alternative that Entergy has defined would be located at an alternative site.

Table 8-1
Coal-Fired Alternative Emission Control Characteristics

Characteristic	Basis
Unit size = 585 MWe ISO rating net[1]	Calculated to be < PNPS gross capacity (715 MWe)
Unit size = 620 MWe ISO rating gross[1]	Calculated based on 6% onsite power use
Number of units = 1	
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxide emissions (Reference 8-7, Table 1.1-3)
Fuel type = bituminous, pulverized coal	Typical for coal used in Massachusetts
Fuel heating value = 12,464 Btu/lb	2000 value for coal used in Massachusetts (Reference 8-6, Table 25)
Fuel ash content by weight = 8.2%	2000 value for coal used in Massachusetts (Reference 8-6, Table 25)
Fuel sulfur content by weight = 0.69%	2000 value for coal used in Massachusetts (Reference 8-6, Table 25)
Uncontrolled NO_x emission = 10 lb/ton Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (Reference 8-7, Table 1.1-3)

Table 8-1
Coal-Fired Alternative Emission Control Characteristics (Continued)

Characteristic	Basis
Heat rate = 10,200 Btu/kWh	Typical for coal-fired, single-cycle steam turbines (Reference 8-5, page 108)
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 8-7, Table 1.1-3)
Particulate control = fabric filters (baghouse-99.9% removal efficiency)	Best available for minimizing particulate emissions (Reference 8-7, pp. 1.1-6 and -7)
SO_x control = Wet scrubber – lime (95% removal efficiency)	Best available for minimizing SO_x emissions (Reference 8-7, Table 1.1-1)
1. The difference between "net" and "gross" is electricity consumed by auxiliary equipment and environmental control devices (Reference 8-5, page 107).	
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 < = less than

Table 8-2
Air Emissions from Coal-Fired Alternative

Parameter	Calculation	Result
Annual coal consumption	$\frac{620\text{MW}}{\text{unit}} \times \frac{10,200\text{Btu}}{\text{kw} \times \text{hr}} \times \frac{1,000\text{kW}}{\text{MW}} \times \frac{\text{lb}}{12,464\text{Btu}} \times \frac{24\text{hr}}{\text{day}} \times \frac{365\text{day}}{\text{yr}} \times \frac{\text{ton}}{2,000\text{lb}} \times 0.85$	1,888,980 tons of coal per year
SO_x [1,2]	$\frac{1,888,980\text{tons}}{\text{yr}} \times \frac{38 \times 0.69\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2,000\text{lb}} \times \frac{100-95}{100}$	1,238 tons SO_x per year
NO_x [2,3]	$\frac{1,888,980\text{tons}}{\text{yr}} \times \frac{10\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2,000\text{lb}} \times \frac{100-95}{100}$	472 tons NO_x per year
CO[2]	$\frac{1,888,980\text{tons}}{\text{yr}} \times \frac{0.5\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2,000\text{lb}}$	472 tons CO per year
TSP	$\frac{1,888,980\text{tons}}{\text{yr}} \times \frac{10 \times 8.2\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2,000\text{lb}} \times \frac{100-99.9}{100}$	77 tons TSP per year
PM_{10} [4]	$\frac{1,888,980\text{tons}}{\text{yr}} \times \frac{2.3 \times 8.2\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2,000\text{lb}} \times \frac{100-99.9}{100}$	18 tons PM_{10} per year

1. Reference 8-7, Table 1.1-1
2. Reference 8-7, Table 1.1-3
3. Reference 8-7, Table 1.1-2
4. Reference 8-7, Table 1.1-4

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

Table 8-3
Solid Waste from Coal-Fired Alternative

Parameter	Calculation	Result
Annual SO_x generated[1]	$\frac{1{,}888{,}980 \text{ tons coal}}{\text{yr}} \times \frac{0.69 \text{ tons}}{100 \text{ tons coal}} \times \frac{64.1 \text{ tons } SO_2}{32.1 \text{ tons S}}$	26,027 tons of SO_x per year
Annual SO_x removed	$\frac{26{,}027 \text{ tons } SO_2}{\text{yr}} \times \frac{95}{100}$	24,726 tons of SO_x per year
Annual ash generated	$\frac{1{,}888{,}980 \text{ tons coal}}{\text{yr}} \times \frac{8.2 \text{ tons ash}}{100 \text{ tons coal}} \times \frac{99.9}{100}$	154,741 tons of ash per year
Annual lime consumption[2]	$\frac{26{,}027 \text{ tons } SO_2}{\text{yr}} \times \frac{56.1 \text{ tons CaO}}{64.1 \text{ tons } SO_2}$	22,779 tons of CaO per year
Calcium sulfate[3]	$\frac{24{,}726 \text{ tons } SO_2}{\text{yr}} \times \frac{172 \text{ tons Ca } SO_4 \bullet 2H_2O}{64.1 \text{ tons } SO_2}$	66,347 tons of $CaSO_4 \cdot 2H_2O$ per year
Annual scrubber waste[4]	$\frac{22{,}779 \text{ tons CaO}}{\text{yr}} \times \frac{100-95}{100} + 66{,}347 \text{ tons } CaSO_4 \bullet 2H_2O$	67,486 tons of scrubber waste per year
Total volume of scrubber waste[5]	$\frac{67{,}486 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{144.8 \text{ lb}}$	37,285,083 ft^3 of scrubber waste
Total volume of ash[6]	$\frac{154{,}741 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	123,792,800 ft^3 of ash
Total volume of solid waste	$37{,}285{,}083 \text{ ft}^3 + 123{,}792{,}800 \text{ ft}^3$	161,077,883 ft^3 of solid waste
Waste pile area (acres)	$\frac{161{,}077{,}883 \text{ ft}^3}{30 \text{ ft}} \times \frac{\text{acre}}{43{,}560 \text{ ft}^2}$	123.3 acres of solid waste
Waste pile area (ft x ft square)	$\sqrt{161{,}077{,}883 \text{ ft}^3/30 \text{ ft}}$	2,317 feet by feet square of solid waste

Based on annual coal consumption of 1,888,980 tons per year (Table 8-2).
1. Calculations assume 100% combustion of coal.
2. Lime consumption is based on total SO_2 generated.
3. Calcium sulfate generation is based on total SO_2 removed.
4. Total scrubber waste includes scrubbing media carryover.
5. Density of $CaSO_4 \cdot 2H_2O$ is 144.8 lb/ft3.
6. Density of coal bottom ash is 100 lb/ft3 [Reference 8-10].

S = sulfur
SO_2 = sulfur dioxide
SO_x = oxides of sulfur
CaO = calcium oxide (lime)
$CaSO_4 \cdot 2H_2O$ = calcium sulfate dihydrate

8.1.1.1 Closed-Cycle Cooling System

The overall impacts at an alternate greenfield site of the coal-fired generating system using a closed-cycle cooling system with cooling towers are discussed in the following sections. The magnitude of impacts for the alternate site will depend on the location of the particular site selected. PNPS currently uses once-through cooling systems. For the purposes of comparison with an alternative site, it is assumed that the replacement coal-fired plant sited at an alternate site would use a closed-cycle cooling system.

The environmental impacts of building a coal-fired generation facility with a closed-cycle cooling system at an 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 620 gross MWe coal-fired plant utilized in this analysis, it would take approximately 1,054 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 8-14]. Therefore, for the 620 gross MWe coal-fired plant utilized in this analysis, it would take approximately 13,640 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 PNPS. In the GEIS, the staff estimated that approximately 1 acre per MWe would be affected for mining and processing the uranium during the operating life of a nuclear power plant [Reference 8-14]. Therefore, for the 715 gross MWe plant (PNPS) utilized in this analysis, it would take approximately 715 acres of land.

The impact of a coal-fired generating unit with a closed-cycle 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 1,054 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.

Use of cooling makeup water from a nearby surface water body could have adverse impacts on aquatic resources. If needed, construction and maintenance of an electric power transmission line and a rail spur would have ecological impacts. There would be some impact on terrestrial ecology from water drift from the cooling towers. Overall, the ecological impacts of constructing a coal-fired plant with a closed-cycle cooling system at an alternate site are considered to be MODERATE to LARGE.

8.1.1.1.3 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. Depending on the water source, the impacts of water use for cooling system makeup water and the effects on water quality caused by cooling tower blowdown could have noticeable impacts. Therefore, the impacts of a new coal-fired plant utilizing a closed-cycle cooling system at an alternate site are considered SMALL to MODERATE.

Groundwater

Impacts of groundwater withdrawal would be SMALL if only used for potable water. If groundwater is used to supply makeup water, then the impacts could be MODERATE to LARGE. Therefore, groundwater impacts from a coal-fired plant on the aquifer would be site-specific and dependent on aquifer recharge and other withdrawals. The overall impacts would be SMALL to LARGE.

8.1.1.1.4 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 (SO_x), nitrogen oxides (NO_x), particulate matter, and carbon monoxide, all of which are regulated pollutants. As already stated, Entergy has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. Entergy estimates the coal-fired alternative emissions to be as follows (from Table 8-2).

- Oxides of sulfur = 1,238 tons per year
- Oxides of nitrogen = 472 tons per year
- Carbon monoxide = 472 tons per year

- Particulates:

  -Total suspended particulates = 77 tons per year

  -PM_{10} (particulates having a diameter of less than 10 microns) = 18 tons per year

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

The NRC did not quantify coal-fired emissions in the GEIS, but implied that air impacts would be substantial. The 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. The NRC also mentioned global warming and acid rain as potential impacts. Entergy concludes that federal legislation and large-scale concerns, such as global warming and acid rain, are indications of concerns about destabilizing important attributes of air resources. However, SO_x emission allowances, NO_x emission offsets, low NO_x burners with overfire air and selective catalytic reduction, fabric filters or electrostatic precipitators, and scrubbers are provided as mitigation measures. As such, Entergy concludes that the coal-fired alternative would have MODERATE impacts on air quality; the 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 1,889,000 tons of coal having an ash content of 8.2%. After combustion, 99.9% of this ash (approximately 155,000 tons per year) would be collected and disposed of at either an onsite or offsite landfill. In addition, approximately 67,500 tons of scrubber waste would be disposed of each year (based on annual calcium hydroxide usage of approximately 23,000 tons). Entergy estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 123 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 8-14]. 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 8-11].

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 620 gross MWe coal-fired plant utilized in this analysis, it would take approximately three years to construct the plant with the workforce ranging from approximately 744 to 1,550.

Communities around the new site would have to absorb the impacts of a large, temporary work force (up to 1,550 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 124 workers for the 620 gross 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

Alternative site locations could reduce the aesthetic impact of coal-fired generation if siting were in an area that was already industrialized. In such a case, however, the introduction of tall stacks and cooling towers would probably still have a MODERATE incremental impact. Locating at other, largely undeveloped sites could show a LARGE impact.

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 8-4
Summary of Environmental Impacts from Coal-Fired Generation Using Closed-Cycle Cooling at an Alternate Greenfield Site

Impact Category	Impact	Comments
Land Use	MODERATE to LARGE	Approximately 1054 acres, including transmission lines and rail line for coal delivery.
Ecology	MODERATE to LARGE	Impact will depend on ecology of site.
Water Use and Quality:		
- Surface Water	SMALL to MODERATE	Impact will depend on volume and other characteristics of receiving water.
- Groundwater	SMALL to LARGE	Impact will depend on site characteristics and availability of groundwater.
Air Quality	MODERATE	SO_x – 1,238 MT/yr – allowances required NO_x – 472 MT/yr – allowances required Particulate – 77 MT/yr (filterable) – 18 MT/yr (unfilterable) Carbon monoxide – 472 MT/yr Trace amounts of mercury, arsenic, chromium, beryllium and selenium
Waste	MODERATE	Total waste volume would be estimated around 222,200 tons per year 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 1,550 workers at the peak of construction) and a permanent work force of approximately 124 workers. Impacts at a rural site would be larger. Transportation-related impacts associated with commuting construction workers would be site dependent.

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

Impact Category	Impact	Comments
Aesthetics	MODERATE 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 Once-Through Cooling System

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

Table 8-5
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	Compared with a closed-cycle cooling system, less land would be required because cooling towers and associated infrastructure not needed.
Ecology	MODERATE to LARGE	Slightly reduced environmental impacts because there are no cooling towers; however, increased water withdrawal may impact aquatic resources.
Water Use and Quality:		
- Surface Water	SMALL to MODERATE	Impact would depend on surface water body characteristics, volume of water withdrawn, and characteristics of the discharge.
- Groundwater	SMALL to LARGE	Impact would depend on site characteristics and availability of groundwater. It is unlikely that groundwater would be used for once-through cooling, but could be used for sanitary water.
Air Quality	MODERATE	No change.
Waste	MODERATE	No change.
Human Health	SMALL	No change.
Socioeconomics	SMALL to LARGE	No change.
Aesthetics	MODERATE to LARGE	Reduced aesthetic impact because cooling towers would not be used.
Historic and Archaeological Resources	SMALL	Less land impacted.

8.1.2 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.

The NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. The NRC has evaluated the environmental impacts of constructing and operating four 440-MWe combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal [Reference 8-14]. This analysis would bound the gas-fired alternative analysis for PNPS because Entergy has defined a reasonable gas alternative for PNPS as a 608-MWe combined-cycle plant. Entergy has adopted the rest of the NRC analysis with necessary Entergy-specific modifications noted. 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.

Table 8-6
Gas-Fired Alternative Emission Control Characteristics

Characteristic	Basis
Unit size = 585 MWe ISO rating net[1] Two 189-MWe combustion turbines and a 207-MWe heat recovery boiler	Manufacturer's standard size gas-fired combined cycle plant that is <PNPS gross capacity (715 MWe)
Unit size = 608 MWe ISO rating gross[a]	Calculated based on 4% onsite power
Number of units = 1	
Fuel type = natural gas	Assumed
Fuel heating value = 1,042 Btu/ft^3	2000 value for gas used in Massachusetts [Reference 8-6, Table 25]
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available [Reference 8-8, Table 3.1-2a]
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_x emissions [Reference 8-8, Table 3.1 Database]
Fuel NO_x content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas-fired units with water injection [Reference 8-8, Table 3.1 Database]
Fuel CO content = 0.0023 lb/MMBtu	Typical for large SCR-controlled gas-fired units [Reference 8-8, Table 3.1]
Heat rate = 6,204 Btu/kWh	Manufacturer's listed heat rate for this unit.
Capacity factor = 0.85	Typical for large gas-fired base load units (Entergy experience)

1. The difference between "net" and "gross" is electricity consumed by auxiliary equipment and environmental control devices [Reference 8-5, page 107].

Btu = British thermal unit
ft^3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60% relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt-hour
MM = million
MW = megawatt
NO_x = nitrogen oxides
< = less than
SCR = selective catalytic reduction

Table 8-7
Air Emissions from Gas-Fired Alternative

Parameter	Calculation	Result
Annual gas consumption	$\frac{608\text{ MW}}{\text{unit}} \times \frac{6{,}204\text{ Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\text{ kW}}{\text{MW}} \times 0.85 \times \frac{\text{ft}^3}{1{,}042\text{ Btu}} \times \frac{24\text{ hr}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}}$	26,954,462,833 ft^3 per year
Annual Btu input	$\frac{26{,}954{,}462{,}833\text{ ft}^3}{\text{yr}} \times \frac{1{,}042\text{ Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\text{Btu}}$	28,086,550 MMBtu per year
SO_x[1]	$\frac{0.0034\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{28{,}086{,}550\text{ MMBtu}}{\text{yr}}$	47.7 tons SO_x per year
NO_x[2]	$\frac{0.0109\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{28{,}086{,}550\text{ MMBtu}}{\text{yr}}$	153.1 tons NO_x per year
CO[2]	$\frac{0.0023\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{28{,}086{,}550\text{ MMBtu}}{\text{yr}}$	32.2 tons CO per year
TSP[1]	$\frac{0.0019\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{28{,}086{,}550\text{ MMBtu}}{\text{yr}}$	26.7 tons filterable TSP per year
PM_{10}[1]	$\frac{26.7\text{ tons TSP}}{\text{yr}}$	26.7 tons filterable PM_{10} per year

1. Reference 8-8
2. Reference 8-8

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

8.1.2.1 Closed-Cycle Cooling System

The overall impacts of the natural-gas-generating system with a closed-cycle cooling system located at the PNPS 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

Gas-fired generation at the PNPS site would require converting the existing industrial site to a gas plant. Almost all the converted land would be used for the power block and associated facilities. Additional land would be disturbed during pipeline construction. Some additional land would also be required for backup oil storage tanks. The nearest gas pipeline tie-in is located in Plymouth, Massachusetts (Algonquin Gas Transmission Line), 5.5 miles from the PNPS site. Therefore, gas-fired generation land use impacts at the existing PNPS site are SMALL to MODERATE; the impacts would noticeably alter the habitat, but would not destabilize important attributes of the resource.

In addition to the land required for the gas-fired plant, construction at a greenfield site could *impact approximately 20 to 50 acres for offices, roads, parking areas, and a switchyard.* The power block could require 60 acres. Some additional land would also be required for backup oil storage. In addition, it is assumed that additional acreage may be necessary for transmission lines (assuming the plant is sited 10 miles from the nearest inter-tie connection) although this would depend on the actual plant location. Plants of this type are usually built very close to existing natural gas pipelines. Including the land required for pipeline construction, a greenfield site could require approximately 500 acres. Depending on the transmission-line routing, the greenfield site alternative could result in SMALL to MODERATE land-use impacts.

8.1.2.1.2 Ecology

Siting gas-fired generation at the existing PNPS site would have MODERATE ecological impacts because the facility would be constructed on previously disturbed areas and would disturb relatively little acreage at the site. Habitat would be disrupted by pipeline construction. Ecological impacts could be reduced by using the existing intake and discharge system. Past operational monitoring of the effects of the cooling systems at PNPS has not shown significant negative impacts to the Cape Cod Bay, 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. Therefore, in this case, the appropriate characterization of gas-fired generation ecological impacts is SMALL.

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 PNPS intake and discharge structures as part of a closed-cycle cooling system; therefore, water quality impacts would continue to be SMALL.

Water quality impacts from sedimentation during construction are 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 3.2.2.2 of this ER, PNPS does not have its own groundwater wells for potable water purposes, but rather purchases potable water from the Town of Plymouth. 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 = 47.7 tons per year
- Oxides of nitrogen = 153.1 tons per year
- Carbon monoxide = 32.2 tons per year
- Filterable Particulates = 26.7 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 PNPS 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 any greenfield site located in Massachusetts would be in 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 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

It is assumed that gas-fired construction would take place while PNPS continues operation, with completion of the replacement plant at the time that the nuclear plant would halt operations. Construction of the gas-fired alternative would take much less time than constructing other plants. During the time of construction, the surrounding communities would experience demands

on housing and public services that could have MODERATE impacts. After construction, the communities would be impacted by the loss of jobs, construction workers would leave, PNPS nuclear plant workforce would decline through a decommissioning period to a minimal maintenance size, and the gas-fired plant would introduce a replacement tax base of about 100 new jobs.

The GEIS concluded that socioeconomic impacts from constructing a gas-fired plant would not be very noticeable and that the small operational workforce would have the lowest socioeconomic impacts (local purchases and taxes) of nonrenewable technologies. Compared to the coal-fired alternative, the smaller size of the construction workforce, the shorter construction time frame, and the smaller size of the operations workforce would reduce some of the socioeconomic impacts. For these reasons, the socioeconomic impacts of gas-fired-generation socioeconomic impacts would be SMALL to MODERATE. That is, depending on other growth in the area, socioeconomic effects could be noticed, but they would not destabilize important attributes of the resource.

Construction at another site would relocate some socioeconomic impacts, but would not eliminate them. The community around the PNPS site would still experience the impact of the loss of PNPS operational jobs and the tax base. The communities around the new site would have to absorb the impacts of a temporary workforce and a small permanent workforce. Therefore, the impacts would be MODERATE to LARGE, based on net job and tax-base losses in the PNPS. However, the reduction in staff would be mitigated by PNPS' proximity to the Boston area. This impact is about the same in the PNPS area as in the no-action alternative.

8.1.2.1.8 Aesthetics

The combustion turbines and heat-recovery boilers would be relatively low structures and would be screened from most offsite vantage points by intervening woodlands. The steam turbine building would be taller and together with the exhaust stacks, could be visible offsite. However, the visual impacts would be comparable to those from the existing PNPS facilities.

The GEIS analysis noted that land-related impacts, such as aesthetic impacts, would be small unless site-specific factors indicate a particular sensitivity. As in the case of the coal-fired alternative, aesthetic impacts from the gas-fired alternative would be noticeable. However, because the gas-fired structures are shorter than the coal-fired structures and more amenable to screening by vegetation, it was determined that the aesthetic resources would not be destabilized by the gas-fired alternative. For these reasons, aesthetic impacts from a gas-fired plant would be SMALL to MODERATE. The impacts would be clearly noticeable, but would not destabilize this important resource.

Alternative locations could reduce the aesthetic impact of gas-fired generation if siting was in an area that was already industrialized. In such a case, however, the introduction of the steam generator building, stacks, and cooling tower plumes would probably still have a SMALL to MODERATE incremental impact.

8.1.2.1.9 Historic and Archaeological Resources

The GEIS analysis noted, as for the coal-fired alternative, that cultural resource impacts of the gas-fired alternative would be SMALL unless important site-specific resources were affected. Gas-fired alternative construction at the PNPS site would affect a smaller area within the footprint of the coal-fired alternative. Therefore, cultural resource impacts would be SMALL. That is, cultural resource impacts would not be detectable or would be so minor that they would neither destabilize nor noticeably alter important attributes of the resource.

Construction at another site could necessitate instituting cultural resource preservation measures, but impacts can generally be managed and maintained as SMALL. Cultural resource surveys would be required for the pipeline construction and other areas of ground disturbance associated with this alternative.

Table 8-8
Summary of Environmental Impacts from Gas-Fired Generation Using Closed-Cycle Cooling at PNPS or at Alternate Greenfield Site

Impact Category	PNPS Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Land Use	SMALL to MODERATE	Approximately 60 acres required for power block, 150 acres disturbed for pipeline construction, additional land for backup oil storage tanks.	SMALL to MODERATE	Up to 500 acres required for site, pipelines, transmission line connection; additional land for backup oil storage tanks.
Ecology	SMALL to MODERATE	Constructed on land within PNPS site. Possible habitat loss due to pipeline construction.	SMALL to MODERATE	Impact depends on location and ecology of site; potential habitat loss and fragmentation; reduced productivity and biological diversity.
Water Use and Quality: Surface Water	SMALL	Uses existing intake and discharge structures and cooling system.	SMALL to MODERATE	Impact depends on volume and characteristics of receiving water body.

Table 8-8
Summary of Environmental Impacts from Gas-Fired Generation Using Closed-Cycle Cooling at PNPS or at Alternate Greenfield Site
(Continued)

Impact Category	PNPS Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Water Use and Quality: Groundwater	SMALL	PNPS does not have its own groundwater system	SMALL to LARGE	Groundwater impacts would depend on uses and available supply.
Air Quality	MODERATE	Primarily nitrogen oxides. Impacts could be noticeable, but not destabilizing.	MODERATE	Same impacts as PNPS site.
Waste	SMALL	Small amount of ash produced.	SMALL	Same impacts as PNPS site.
Human Health	SMALL	Impacts considered minor.	SMALL	Same impacts as PNPS site.
Socioeconomics	SMALL to MODERATE	Additional workers during construction period, followed by reduction from current PNPS workforce.	MODERATE to LARGE	Construction impacts would be relocated. Community near PNPS would still experience workforce reduction.
Aesthetics	SMALL to MODERATE	Visual impact of stacks and equipment would be noticeable, but not as significant as coal option.	SMALL to MODERATE	Alternate location could reduce aesthetic impact if siting is in an industrial area.
Historic and Archaeological Resources	SMALL	Only previously disturbed and adjacent areas would be affected.	SMALL	Alternate location would necessitate cultural resource studies.

8.1.2.2 Once-Through Cooling System

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

Table 8-9
Summary of Environmental Impacts from Gas-Fired Generation Using Once-Through Cooling at PNPS or at an Alternate Greenfield Site

Impact Category	PNPS Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Land Use	SMALL to MODERATE	25 to 30 acres less land required because cooling towers and associated infrastructure are not needed.	SMALL to MODERATE	25 to 30 acres less land required because cooling towers and associated infrastructure are not needed.
Ecology	SMALL	Less terrestrial habitat lost and cooling tower effects eliminated. Increased water withdrawal, but aquatic impact would be similar to current PNPS operations.	SMALL to MODERATE	Impact would depend on ecology at the site. No impact to terrestrial ecology from cooling tower drift. Increased water withdrawal and possible greater impact to aquatic ecology.
Water Use and Quality: Surface Water	SMALL to MODERATE	No discharge of cooling tower blowdown containing dissolved solids. Increased water withdrawal and more thermal load on receiving body of water.	SMALL to MODERATE	No discharge of cooling tower blowdown containing dissolved solids. Increased water withdrawal and more thermal load on receiving body of water.

Table 8-9
Summary of Environmental Impacts from Gas-Fired Generation Using Once-Through Cooling at PNPS or at an Alternate Greenfield Site

Impact Category	PNPS Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Water Use and Quality: Groundwater	SMALL	No change.	SMALL to LARGE	Groundwater impacts would depend on uses and available supply. It is unlikely that groundwater would be used for once-through cooling, but could be used for sanitary water.
Air Quality	MODERATE	No change.	MODERATE	No change.
Waste	SMALL	No change.	SMALL	No change.
Human Health	SMALL	No change.	SMALL	No change.
Socioeconomics	SMALL to MODERATE	No change.	MODERATE to LARGE	No change.
Aesthetics	SMALL to MODERATE	Reduced aesthetic impact because cooling towers would not be used.	SMALL to MODERATE	Reduced aesthetic impact because cooling towers would not be used.
Historic and Archaeological Resources	SMALL	Less land affected.	SMALL	Less land affected.

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 the 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 8-17, 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 PNPS or at an alternate site. The impacts shown in Table S-3 are for a 1000-MWe reactor and would need to be adjusted to reflect replacement of PNPS, which has a capacity of 715 gross MWe. The environmental impacts associated with transporting fuel and waste to and from a light-water cooled nuclear power reactor are summarized in Table S-4 of 10 CFR 51.52. The summary of the NRC's findings on NEPA issues for license renewal of nuclear power plants in 10 CFR 51 Subpart A, Appendix B, Table B-1 is also relevant, although not directly applicable, for consideration of environmental impacts associated with the operation of a replacement nuclear power plant [Reference 8-17, Section 8.2.3].

8.1.3.1 Closed-Cycle Cooling System

The environmental impacts of constructing a nuclear power plant at an alternate site using closed-cycle cooling are summarized in Table 8-10.

8.1.3.1.1 Land Use

Land use requirements at an alternate site would require land for the nuclear power plant plus the possible need for land for a new transmission line. In addition, it may be necessary to construct a rail spur to an alternate site to bring in equipment during construction. Depending on transmission line routing, siting a new nuclear plant at an alternate site would result in MODERATE to LARGE land use impacts, and probably would be LARGE for a greenfield site [Reference 8-17, Section 8.2.3.1].

8.1.3.1.2 Ecology

At an alternate site, there would be construction impacts and new incremental operational impacts. Even assuming siting at a previously disturbed area, the impacts would alter the ecology. Impacts could include wildlife habitat loss, reduced productivity, habitat fragmentation,

and a local reduction in biological diversity. Use of cooling water from a nearby surface water body could have adverse aquatic resource impacts. Construction and maintenance of the transmission line would have ecological impacts. Overall, the ecological impacts at an alternate site would be MODERATE to LARGE [Reference 8-17, Section 8.2.3.1].

8.1.3.1.3 Water Use and Quality

Surface Water

For a replacement reactor located at an alternate site, new intake structures would need to be constructed to provide water needs for the facility. Impacts would depend on the volume of water withdrawn for makeup, relative to the amount available from the intake source and the characteristics of the surface water. Plant discharges would be regulated by the State of Massachusetts or other state jurisdiction. Some erosion and sedimentation may occur during construction. The impacts would be SMALL to MODERATE.

Groundwater

A nuclear power plant sited at an alternate site may use groundwater. The impacts of such a withdrawal rate on an aquifer would be site specific and dependent on aquifer recharge and other withdrawal rates from the aquifer. Therefore, the overall impacts would be SMALL to LARGE.

8.1.3.1.4 Air Quality

Construction of a new nuclear plant at 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, house-heating boilers, and similar minor emission points. These emissions would be regulated. Emissions for a plant sited in Massachusetts would be regulated by the MDEP. Overall, emissions and associated impacts are considered SMALL [Reference 8-17, Section 8.2.3.1].

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. In addition to the impacts shown in Table B-1, construction-related debris would be generated during construction activities and removed to an appropriate disposal site. Overall, waste impacts are considered SMALL [Reference 8-17, Section 8.2.3.1].

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 are considered SMALL [Reference 8-17, Section 8.2.3.1].

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 2,500. Since PNPS's current reactor is rated at 715 gross MWe, construction period and peak workforce may be less, but impacts are expected to be consistent with that of the 1,000 MWe reactor.

Construction of a replacement nuclear power plant at an alternate site would relocate some socioeconomic impacts, but would not eliminate them. The communities around the PNPS site would still experience the impact of PNPS operational job loss (although potentially tempered by projected economic growth), and the communities around the new site would have to absorb the impacts of a large, temporary work force (up to 2,500 workers at the peak of construction) and a permanent work force of approximately 704 workers. In the GEIS, the NRC noted that socioeconomic impacts at a rural site would be larger than at an urban site because more of the peak construction work force would need to move to the area to work. Alternate sites would need to be analyzed on a case-by-case basis. Socioeconomic impacts at rural sites could be LARGE [Reference 8-17, Section 8.2.3.1].

Transportation-related impacts associated with commuting workers at an alternate site are site dependent, but could be MODERATE to LARGE. Transportation impacts related to commuting of plant operating personnel would also be site dependent, but can be characterized as SMALL [Reference 8-17, Section 8.2.3.1].

8.1.3.1.8 Aesthetics

At an alternate site, depending on placement, there would be an aesthetic impact from the buildings. There would also be a significant aesthetic impact associated with construction of a new transmission line to connect to other lines to enable delivery of electricity. Noise and light from the plant would be detectable offsite. The impact of noise and light would be mitigated if the plant were 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 8-17, Section 8.2.3.1].

8.1.3.1.9 Historic and Archeological 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 8-10
Summary of Environmental Impacts from Nuclear Power Generation Closed-Cycle Cooling at Alternate Greenfield Site

Impact Category	Alternative Greenfield Site	
	Impact	**Comments**
Land Use	MODERATE to LARGE	Requires 376 to 715 acres for the plant and 715 acres for uranium mining.
Ecology	MODERATE to LARGE	Impact depends on location and ecology of the site, surface water body used for intake and discharge, and transmission line routes; potential habitat loss and fragmentation; reduced productivity and biological diversity.
Water Use and Quality: Surface Water	SMALL to MODERATE	Impact will depend on the volume of water withdrawn and discharged and the characteristics of the surface water body.
Water Use and Quality: Groundwater	SMALL to LARGE	Groundwater impacts would depend on uses and available supply.
Air Quality	SMALL	Fugitive emissions and emissions from vehicles and equipment during construction. Small amount of emissions from diesel generators and possibly other sources during operation. Emissions are similar to current releases at PNPS site.
Waste	SMALL	Waste impacts for an operating nuclear power plant are set out in 10 CFR 51, Subpart A, Appendix B, Table B-1. Debris would be generated and removed during construction.
Human Health	SMALL	Human health impacts for an operating nuclear power plant are set out in 10 CFR 51, Subpart A, Appendix B, Table B-1.
Socioeconomics	SMALL to LARGE	Construction impacts depend on location. Impacts at a rural location could be LARGE. Surrounding community would experience loss of tax base and employment with MODERATE impacts. Transportation impacts associated with construction workers could be MODERATE to LARGE. Transportation impacts of commuting workers during operations would be SMALL.
Aesthetics	SMALL to LARGE	Impacts would depend on the characteristics of the alternate site. Impacts would be SMALL if the plant is located adjacent to an industrial area. New transmission lines would add to the impacts and could be MODERATE. If a greenfield site is selected, the impacts could be LARGE.

Table 8-10
Summary of Environmental Impacts from Nuclear Power Generation
Closed-Cycle Cooling at Alternate Greenfield Site
(Continued)

Impact Category	Alternative Greenfield Site	
	Impact	Comments
Historic and Archaeological Resources	SMALL	Potential impacts can be effectively managed.

8.1.3.2 Once-Through Cooling System

The environmental impacts of constructing a nuclear power plant that uses once-through cooling at an alternate site are similar to the impacts for a nuclear power plant using closed-cycle cooling with cooling towers. However, there are some differences in the environmental impacts between the closed-cycle and once-through cooling systems. In those impact categories related to land-area requirements, such as land use, terrestrial ecology, and cultural resources, the impacts are likely to be smaller if the site uses a once-through cooling system rather than a closed-cycle cooling system. However, the impacts of a plant with a once-through cooling system are likely to be greater than a plant with a closed-cycle cooling system in the areas of water use and aquatic ecology because of the need for greater quantities of cooling water. Table 8-11 summarizes the incremental differences.

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

Impact Category	Alternative Greenfield Site	
	Impact	Comments
Land Use	MODERATE to LARGE	Requires 376 to 715 acres for the plant and 715 acres for uranium mining.
Ecology	MODERATE to LARGE	Impact would depend on ecology of the site. No impact to terrestrial ecology from cooling tower drift. Increased water withdrawal with possible greater impact to aquatic ecology.
Water Use and Quality: Surface Water	SMALL to MODERATE	No discharge of cooling tower blowdown. Increased water withdrawal and more thermal load on receiving body of water.

Table 8-11
Summary of Environmental Impacts from Nuclear Power Generation Using Once-Through Cooling at Alternate Greenfield Site (Continued)

Impact Category	Alternative Greenfield Site	
	Impact	Comments
Water Use and Quality: Groundwater	SMALL to LARGE	No change.
Air Quality	SMALL	No change.
Waste	SMALL	No change.
Human Health	SMALL	No change.
Socioeconomics	MODERATE to LARGE	No change.
Aesthetics	SMALL to LARGE	Reduced aesthetic impact because cooling towers would not be used, but impacts could still be large if lengthy transmission line is required.
Historic and Archaeological Resources	SMALL	Less land impacted

8.1.4 Purchased Electrical Power

If available, purchased power from other sources could potentially obviate the need to renew PNPS. "Purchased power" is power purchased and transmitted from electric generation plants that the applicant does not own and that are located elsewhere within the region, nation, Canada, or Mexico.

In theory, purchased power is a feasible alternative to PNPS license renewal. There is no assurance, however, that sufficient capacity or energy would be available in the 2012 through 2032 time frame to replace the 715 gross MWe base-load generation. For example, EIA projects that total gross U.S. imports of electricity from Canada and Mexico will gradually increase from 38.4 billion kWh in year 2001 to 47.2 billion kWh in year 2010 and then gradually decrease to 28.94 billion kWh in year 2020 [Reference 8-2, page 149]. On balance, it appears unlikely that electricity purchased from Canada or Mexico would be able to replace the PNPS generating capacity.

More importantly, regardless of the technology used to generate purchased power, the generating technology would be one of those described in this ER and in the GEIS (probably coal, natural gas, nuclear, or hydroelectric). The GEIS description of other technology impacts is

representative of purchased power impacts related to PNPS license renewal alternatives [Reference 8-16].

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 715 gross MWe of electricity as a base-load supply using these technologies is not technologically feasible, except for oil, which is not economically feasible.

8.2.1 Wind

In the entire six-state New England region, only two wind projects are in operation: the 6 MW Searsburg project in Vermont and a 320 kW project in Massachusetts owned by Princeton Municipal Light. There is also an additional project under active development in southern Vermont (Equinox) [Reference 8-4]. Wind turbines typically operate at a 25 to 35% capacity factor compared to 80 to 95% for a base load plant. This low capacity factor results from the high degree of intermittence of wind energy in many locations. Current energy storage technologies are too expensive to permit wind power plants to serve as large base load plants.

According to the Wind Energy Resource Atlas of the United States (Reference 8-18), areas suitable for wind energy applications must be wind power class 3 or higher. Approximately 50% of the land area in Massachusetts has a wind power classification of 3 or higher and, therefore may be suitable for wind energy applications. However, land-use conflicts such as urban development, farmland, and environmentally sensitive areas reduce the amount of land suitable for wind energy applications to about 16% of the land area in the state (Reference 8-9).

The GEIS estimates a land use of 150,000 acres per 1,000 MWe for wind power (Reference 8-14, Section 8.3.1). Therefore, to replace the 715 gross MWe of electricity generated by PNPS, approximately 107,250 acres would be required. The areas having ideal conditions are located on mountaintops and adjacent to the coast. There is insufficient area on the coast for replacing the PNPS generating capacity. Therefore the wind alternative would require a large Greenfield site located on mountaintops, which would result in a LARGE adverse environmental impact.

Also, new easements, road building, and some clearing for towers and blades would be required. This eliminates the possibility of co-locating a wind-energy facility with a retired nuclear power plant. A siting plan would be required. Construction of several hundred wind turbines would also require extensive construction of transmission lines to bring the power and the energy to market. This would have a LARGE impact upon much of the natural environment in the affected areas.

Wind power could be included in a combination of alternatives to replace PNPS. The environmental impacts of a large-scale wind farm are described in the GEIS [Reference 8-14]. 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

The average capacity factor for this technology is estimated to be between 25 and 40% annually. This technology has high capital costs and lacks base-load capability unless combined with natural gas backup. It requires very large energy-storage capabilities. Based upon solar energy resources, the most promising region of the country for this technology is the West [Reference 8-16, Section 8.2.4.2].

There are also substantial impacts to natural resources (wildlife habitat, land-use, and aesthetic impacts) from construction of solar-generating facilities. As stated in the GEIS, land requirements are high. Based on the land requirements of 14 acres for every 1 MWe generated, approximately 10,010 acres would be required to replace the 715 gross MWe produced by PNPS. There is not enough land for either type of solar electric system (photovoltaic or thermal) at the existing PNPS 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

Hydroelectric power has an average annual capacity factor of 46%. Section 8.3.4 of the GEIS, indicates that the percentage of the U.S. electrical generation consisting of hydroelectricity is expected to decline because hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and destruction of natural river courses. Section 8.3.4 of the GEIS estimates land use of 1 million acres per 1,000 MWe (or 1,000 acres per MWe) for hydroelectric power, resulting in a LARGE environmental impact. Due to the lack of locations for siting a hydroelectric facility large enough to replace PNPS, local hydropower is not a feasible alternative to PNPS license renewal [Reference 8-16, Section 8.2.4.3].

According the U.S. Hydropower Resource Assessment for Massachusetts (Reference 8-12), there are no remaining sites in Massachusetts that would be environmentally suitable for a large hydroelectric facility.

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 8-16, Section 8.2.4.4]. This technology is not applicable to the region where the replacement of 715 gross MWe is needed. There are no high temperature geothermal sites in Massachusetts.

8.2.5 Wood Energy

A wood-burning facility can provide base-load power and operate with an average annual capacity factor of around 70 to 80% and with 20 to 25% efficiency. The cost of the fuel required for this type of facility is highly variable and very site-specific. The 53 MW McNeil Station, the largest wood-fired generator in the world when it came on line, was developed with great promise as an in-state generating source, a market for low-grade wood to aid Vermont forest management, insulation from volatile oil prices, and a significant employer generating other associated economic benefits [Reference 8-19]. However, since the plant opened in June 1984, McNeil's fuel price of about 3.5 cents/kWh was not competitive with the post-1986 regime of low oil prices [Reference 8-19]. Among the factors influencing costs are the environmental considerations and restrictions that are influenced by public perceptions, easy access to fuel sources, and environmental factors. In addition, the technology is expensive and inefficient. Current conditions still do not allow McNeil to operate as a base load facility as originally envisioned, but instead gives its owners a price ceiling on the market prices they face [Reference 8-19]. Like many other large plants that came on line at the time of high oil prices, interest rates, and other capital costs, McNeil was an investment that looked better then than it does today [Reference 8-19]. Therefore, economics alone eliminate biomass technology as a reasonable alternative.

Estimates in the GEIS suggest that the overall level of construction impact per MW of installed capacity should be approximately the same as that for a coal-fired plant, although facilities using wood waste for fuel would be built at smaller scales [Reference 8-14]. Like coal-fired plants, wood-waste plants require large areas for fuel storage and processing and involve the same type of combustion equipment. Because of uncertainties associated with obtaining sufficient wood and wood waste to fuel a base load generating facility, ecological impacts of large-scale timber cutting (e.g., soil erosion and loss of wildlife habitat), and relatively low energy conversion efficiency, Entergy has determined that wood waste is not a feasible alternative to renewing the PNPS operating license.

8.2.6 Municipal Solid Waste

The initial capital costs for this technology are much greater than the comparable steam-turbine technology found at wood-waste facilities. This is due to the need for specialized municipal solid waste-handling and waste-separation equipment and stricter environmental emissions controls. The decision to burn municipal waste to generate energy is usually driven by the need for an alternative to landfills, rather than by energy considerations. High costs prevent this technology from being economically competitive. Thus, municipal solid waste generation is not a reasonable alternative [Reference 8-16, Section 8.2.4.6].

Currently, there are approximately 89 waste-to-energy plants operating in the United States. These plants generate approximately 2,500 MWe, or an average of approximately 28 MWe per plant [Reference 8-13]. Therefore, approximately 26 typical waste-to-energy plants would be required to replace the 715 gross MWe base load capacity of PNPS. Therefore, the generation of electricity from municipal solid waste would not be a feasible alternative to renewal of the PNPS operating license.

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). 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 PNPS. For these reasons, such fuels do not offer a feasible alternative to PNPS license renewal. In addition, these systems have LARGE impacts on land use [Reference 8-16, Section 8.2.4.7].

8.2.8 Oil

Oil is not considered a stand-alone fuel because it is not cost-competitive when natural gas is available. The cost of an oil-fired operation is about eight times as expensive as a nuclear or coal-fired operation. In addition, future increases in oil prices are expected to make oil-fired generation increasingly more expensive than coal-fired generation. For these reasons, oil-fired generation is not a feasible alternative to PNPS license renewal, nor is it likely to be included in a mix with other resources except as a back-up fuel [Reference 8-16, Section 8.2.4.8].

8.2.9 Fuel Cells

Phosphoric acid fuel cells are the most mature fuel-cell technology, but they are only in the initial stages of commercialization. Two hundred turnkey plants have been installed in the U.S.

feasible for storage of sufficient electricity to meet the base-load generating requirements. This is a very expensive source of generation, which prevents it from being competitive. This technology also has a high land use impact, which, like wind technology, results in a LARGE impact to the natural environment. It is estimated that 35,000 acres of land would be required to generate 1,000 MWe of electricity. Therefore, fuel cells are not considered a feasible alternative to license renewal [Reference 8-16, Section 8.2.4.10].

As market acceptance and manufacturing capacity increase, natural-gas-fueled fuel cell plants in the 50- to 100-MW range are projected to become available. At the present time, however, fuel cells are not economically or technologically competitive with other alternatives for base load electricity generation, and progress in market growth and cost reduction has been slower than alternatives anticipated [Reference 8-1]. Fuel cells are, consequently, not a feasible alternative to renewal of the PNPS operating license.

8.2.10 Delayed Retirement

Even without retiring any Entergy owned or non-Entergy owned generating units, it is expected that additional capacity will be required in the near future. Thus, even if substantial capacity were scheduled for retirement and could be delayed, some of the delayed retirement would be needed just to meet load growth.

PNPS would be required, in part, to offset any actual retirements that occur. Delayed retirement of other Entergy or non-Entergy generation units is unlikely to displace the need for 650 gross MWe of capacity over the twenty years of extended operation and therefore, would not be a feasible alternative to PNPS 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 8-16, Section 8.2.4.1.2].

Market and regulatory conditions in the deregulated environment can be described as follows:

- a decline in generation costs, due primarily to technological advances that have reduced the cost of constructing new generating units (e.g., combustion turbines);
- national energy legislation, which has encouraged wholesale competition through open access to the generation of electrical energy, as well as state legislation designed to facilitate retail competition.

Consistent with these changes, the electricity generation planning environment features lower capacity and lower energy prices than during earlier periods, shorter planning horizons, lower

reserve margins, and increased reliance on market prices to direct utility resource planning. These have greatly reduced the number of cost-effective DSM alternatives.

Another significant change includes the adoption of increasingly stringent national appliance standards for most major energy-using equipment and the adoption of energy efficiency requirements in state building codes. These mandates have further reduced the potential for cost-effective generator-sponsored measures.

The environmental impacts of an energy conservation program would be SMALL, but the potential to displace the entire generation at PNPS solely with conservation is not realistic. Therefore, the conservation option by itself is not considered a reasonable replacement for the PNPS operating license renewal alternative.

8.2.12 Combination of Alternatives

The 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, the 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 8-14, 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 for PNPS. 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 PNPS 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 PNPS. 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 PNPS 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 PNPS site. Therefore, the no-action alternative would have negative net environmental benefits.

The environmental impacts associated with the proposed action (the continued operation of PNPS) 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 PNPS 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 PNPS from the decision not to pursue license renewal.

The *Joint DOE-Electric Power Research Institute Strategic Research and Development Plan to Optimize US 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 US domestic electricity supply system, expanding US 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 8-3]. The renewal of the PNPS operating license is consistent with these goals.

8.4 Summary

The proposed action is the renewal of the PNPS operating license. The proposed action would provide the continued availability of approximately 715 gross MWe of base-load power generation through 2032.

CO_2 emissions from power generation are a major contributor to anthropogenic greenhouse gas emissions and climate change. These emissions result from the efficiency of the technologies used to produce and deliver the energy and the carbon content of the fuel being used. The table below shows a comparison of the CO_2 content of various fuels: (Reference 8-20)

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	0.0
Renewable sources	0.0

The following table provides an estimate of the CO_2 emissions that would result if other fuel technologies were used to supply the electricity that currently is being produced by PNPS: 715 MWe and an estimated 92% capacity factor. The technologies, fuels, and production efficiencies

shown are based upon "Greenfield plants" that have recently been permitted as having "Best Available Control Technologies" under the New Source Review Permit program (Reference 8-21).

Technology	Fuel	Heat Rate (BTU/KWh)	Electricity (MWH/yr)	CO_2 Emissions (metric tons CO_2/yr)
Pulverized coal	Bituminous coal	9,928	5,762,328	5,327,479
Pulverized coal	Subbituminous coal	9,700	5,762,328	5,392,749
Combined cycle gas turbine	Natural gas	6,814	5,762,328	2,085,595

The environmental impacts of the continued operation of PNPS, providing approximately 715 gross MWe of base-load power generation through 2032, are less than impacts associated with the best case among reasonable alternatives. The continued operation of PNPS would create significantly less environmental impact than the construction and operation of new base-load generation capacity.

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

8.5 References

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8-3 U.S. Department of Energy - Electric Power Research Institute, *Joint DOE-EPRI Strategic Research and Development Plan to Optimize U.S. Nuclear Power Plants*, Volume 1, March 20, 1998.

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8-14 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.

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8-21 U.S. Environmental Protection Agency, RACT/BACT/LAER Clearinghouse (RBLC), available at http://cfpub.epa.gov/RBLC/htm/bl02.cfm, accessed on October 15, 2005.

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 9-2 provides a list of the environmental permits held by PNPS 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. Other than routine renewals required at frequencies specified by the permits in Table 9-1, no state, federal, or local environmental permits have been identified as being required for re-issuance to support the extension of the PNPS operating license.

9.2.1 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 office of Nuclear Reactor Regulation has issued guidance to its staff regarding compliance with the Act [Reference 9-3, Appendix E]. This guidance acknowledges that Massachusetts has an approved coastal zone management program. PNPS, located in Plymouth County, is within the Massachusetts coastal zone [Reference 9-1]. Concurrent with submitting the *Applicant's Environmental Report - Operating License Renewal Stage* to the NRC, Entergy will submit a copy of the report to the Commonwealth in fulfillment of the regulatory requirement for submitting a copy of the coastal zone consistency certification to the state.

9.2.2 Water Quality (401) Certification

With respect to applicants for a federal license to conduct an activity that might result in a discharge into navigable waters, section 401 of the CWA establishes certain requirements for

certifications from the state that the discharge will comply with certain CWA requirements (33 USC 1341). On July 31, 1970, the Massachusetts Water Resources Commission provided a water quality certification reflecting its receipt of reasonable assurance that operation of the Pilgrim Station will not violate applicable water quality standards. Massachusetts provided a further water quality certification on April 15, 1971. Copies of these certifications are provided in Attachment A. In addition, the NPDES permit, which was issued jointly by the EPA pursuant to the CWA and the Commonwealth of Massachusetts pursuant to Massachusetts General Law Chap. 21, § 43, reflects continued compliance with applicable CWA standards. Excerpts of this permit are also included in Attachment A.

9.3 Environmental Permits - Discussion of Compliance

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

PNPS has an onsite wastewater treatment plant. Sanitary wastewater that does not contain radioactive materials is processed in the wastewater treatment facility and discharged through a permitted drain field to the groundwater. This is regulated through the MDEP, Groundwater Discharge Permit #2-389.

Entergy has measures in place to ensure those 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. Therefore, planned projects or changes in plant operations would be required to undergo an environmental review and evaluation prior to implementation, with appropriate permits obtained or modified as necessary.

Table 9-1
Environmental Authorizations for PNPS License Renewal

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License Renewal	Environmental Report submitted in support of license renewal application
U.S. Fish and Wildlife Service and National Marine Fisheries Service	Endangered Species Act Section 7 (16 USC 1636)	Consultation	Requires Federal agency issuing a license to consult with FWS and NMFS. (Attachment B)

Table 9-1
Environmental Authorizations for PNPS License Renewal

Agency	Authority	Requirement	Remarks
Commonwealth of Massachusetts Division of Fisheries and Wildlife	Endangered Species Act Section 7 (16 USC 1636)	Consultation	Requires Federal agency issuing a license to consult with FWS at the state level. (Attachment B)
Massachusetts Department of Environmental Protection	Clean Water Act Section 401 (16 USC 470f)	Certification	Requires Commonwealth certification that discharge would comply with CWA standards
Massachusetts Historical Commission	National Historic Preservation Act Section 106	Consultation	Requires Federal agency issuing a license to consider cultural impacts and consult with the SHPO. (Attachment C)
Massachusetts Office of Coastal Zone Management	Federal Coastal Zone Management Act (16 USC 1451 et seq.)	Certification	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. (Attachment D)

Table 9-2
Environmental Authorizations for Current PNPS Operations

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal Requirements for License Renewal					
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to Operate	DPR – 35	Issued 09/15/72 Expires 06/08/12	Operation of Unit 1
U.S. Nuclear Regulatory Commission	Atomic Energy Act Section 161, (42 USC 2201), 10 CFR 40 and 70	Material License	20-07626-04	Issued 02/10/03 Expires 02/28/13	Contamination on reactor components
U.S. Department of Transportation	49 CFR 107, Subpart G	Registration	062601551001J	Issued 05/16/05 Expires 06/30/06 This permit is renewed on an annual basis.	Radioactive and hazardous materials shipments
U.S. Environmental Protection Agency and Massachusetts Department of Environmental Protection	Clean Water Act (33 USC 1251 et seq.), M.G.L. Chapter 21, Section 43(2)	NPDES Permit	Federal Permit: MA0003557 Massachusetts Permit: 359	Issued 04/29/91 Modified 08/30/94 Expired 04/29/96 (remains in effect pending EPA and Commonwealth action on renewal applications submitted 10/25/95 and 12/01/99)	Plant discharges to Cape Cod Bay

Table 9-2
Environmental Authorizations for Current PNPS Operations

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
U.S. Fish and Wildlife Service	Migratory Bird Treaty Act, 16 USC 703-712	Depredation Permit	MB831184-0	Issued 07/08/2005 Expires 06/30/2006 This permit is renewed on an annual basis.	Removal of birds and nests from utility structures
State Requirements for License Renewal					
Massachusetts Department of Public Health	M.G.L. Chapter 111, Section 5N	Material License	07-6262	Issued 4/22/03 Expires 4/30/08	Contamination on reactor components
Massachusetts Department of Public Health	M.G.L. Chapter 111, Section 5N	Material License	49-0078	Issued 10/11/02 Expires 5/31/06	Contamination on reactor components
Massachusetts Department of Public Safety	M.G.L. Chapter 148, Section 13	Registration	Not applicable	This registration is renewed annually on April 1.	Storing flammable materials in tanks
Massachusetts Department of Environmental Protection	310 CMR 7.02(11) 310 CMR 7.02(11)(e)	50% Facility Emission Cap		Issued 7/18/2005	Emissions from various small combustion sources

Table 9-2
Environmental Authorizations for Current PNPS Operations

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Massachusetts Department of Environmental Protection	M.G.L. Chapter 21, Sections 26-53	Groundwater Discharge Permit	#2-389	Issued 4/20/99 Expires 4/20/04 Renewal application submitted 10/14/03. Administratively continued pending review of application	Treated effluent discharges to groundwater from wastewater treatment facility
State Requirements for License Renewal (continued)					
Massachusetts Department of Environmental Protection	M.G.L. Chapter 21C 310 CMR 30	Large Quantity Generator	MAR000014167	Issued 10/06/99	Hazardous waste generation
South Carolina Department of Health and Environmental Control	South Carolina Radioactive Waste Transportation and Disposal Act (SC ST SEC 13-7-110 et seq.)	Radioactive Waste Transport Permit	0007-20-01	Issued 12/17/04 Expires 12/31/05 This permit is renewed on an annual basis.	Transportation of radioactive waste to disposal facility in South Carolina

Table 9-2
Environmental Authorizations for Current PNPS Operations

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Tennessee Department of Environment and Conservation	TCA 68-202-206	Radioactive Waste License-for-Delivery	T-MA004-L01	Issued 12/08/04 Expires 12/31/05 This permit is renewed on an annual basis.	Shipment of radioactive waste to disposal/ processing facility in Tennessee

CFR - Code of Federal Regulations
USC - United States Code
M.G.L. - Massachusetts General Laws
CMR - Code of Massachusetts Regulations
TCA - Tennessee Code Annotated
SC ST - South Carolina Statutes

9.4 References

9-1 Massachusetts Coastal Zone Management, "Massachusetts Coastal Zone Management," Boston, MA, 2001, available at http://www.state.ma.us/czm/czm.htm, accessed April 23, 2001.

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Attachment A

NPDES Permit and Water Quality Certification

- Title page and section relevant to the Clean Water Act Section 316(a) and (b)5
- Section 401 Water Quality Certification, April 15, 1971
- Section 401 Water Quality Certification, July 31, 1970

MODIFICATION OF
AUTHORIZATION TO DISCHARGE UNDER THE
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Federal Clean Water Act, as amended, (33 U.S.C. §§1251 et seq.; the "CWA"), and the Massachusetts Clean Waters Act, as amended, (M.G.L. Chap. 21, §§26-53),

Boston Edison Company
Pilgrim Nuclear Power Station
800 Boylston Street
Boston, Massachusetts 02199

is authorized to discharge in accordance with effluent limitations, monitoring requirements and other conditions set in the previous permit, except as set forth herein and listed as follows:

1. Page 9, Par. I.A.4 has been changed for the new flow rate for Discharge 003.
2. Page 9a, Par. I.A.4a has been added for the new Discharge 008.
3. Page 2, Par. I.A.1.a.(2) change word from "daily" to "monthly" (typographical error).
4. Page 5, Par. I.A.m. delete "shall" and "circulating" (typographical errors) and add " 'no more than' 20,000 gallon batches " (clarification).
5. Page 7, Par I.A.2.e add "from April 1 to November 30 each year" (clarification).
6. Page 12, Par. I.A.7.i clarify Discharge #005 contents.

This modifies the permit issued on April 29, 1991.

This permit modification shall become effective on the date of issuance.

This permit modification and the authorization to discharge shall expire at midnight, April 29th, 1996.

Signed this 30th day of August 1994

Edward K. McSweeney
Director
Water Management Division
Environmental Protection Agency
Region I
Boston, MA

Director of the Office of Watershed Management
Department of Environmental Protection
Commonwealth of Massachusetts
Boston, MA

d. The term "EPA" means the Regional Administrator of Region I of the U. S. Environmental Protection Agency or his designee and the term "State" means the Director of the Divison of Water Pollution Control of the Massachusetts Department of Environmental Protection or his designee.

e. There shall be no discharge of polychlorinated biphenyl compounds commonly used for transformer fluid.

f. There shall be no discharge of treated or untreated chemicals which result from cleaning or washing of condensers or equipment wherein heavy metals may be discharged.

g. The rate of change of Discharge 001 Delta-T shall not exceed: (1) a 3 °F rise or fall in temperature for any 60-minute period during normal steady state plant operation and (2) a 10 °F rise or fall in temperature for any 60-minute period during normal load cycling. Variation in inlet temperature shall not be considered as an operational rise or fall of temperature. Normal startup temperature rise shall not exceed the maximum allowed in Subparagraph I.A.2.a below. In the event of a reactor emergency shutdown, the allowable decrease of 10° F/hour may be exceeded. In such an event, the permittee shall report the occurrence in the next monthly DMR to EPA and the State.

h. The thermal plumes from the station:

(1) shall not deleteriously interfere with the natural movements, reproductive cycles, or migratory pathways of the indigenous populations within the water body segment;

(2) shall have minimal contact with the surrounding shorelines.

i. It has been determined, based on engineering judgment, that the circulating water intake structures presently employs the best technology available for minimizing adverse environmental impact. Any change in the location, design or capacity of the present structure shall be approved by the Regional Administrator and the Director. The present design shall be reviewed for conformity to regulations pursuant to Section 316(b) of the Act when such are promulgated.

j. The effluent shall not contain materials in concentrations or combinations which are hazardous or toxic to aquatic life or which would impair the uses designated by the classification of the receiving waters.

from the
NPDES permit

1.9.9

The Commonwealth of Massachusetts
Water Resources Commission
Leverett Saltonstall Building, Government Center
100 Cambridge Street, Boston 02202

OFFICE OF THE DIRECTOR
DIVISION OF WATER POLLUTION CONTROL

April 15, 1971

Mr. Claude A. Pursel
Assistant Vice President-Nuclear
Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199

Re: State Certification
Pilgrim Station
Boston Edison Company

02152 0629

Dear Mr. Pursel:

In response to your request in letter dated February 17, 1971, this Division has reviewed your application for a permit to construct and operate a wastewater discharge outlet from a nuclear power plant at Plymouth, Massachusetts, known as the Pilgrim Station.

In accordance with the provisions of Section 21(b)(1) of the Federal Water Quality Improvement Act of 1970 (Public Law 91-224), this Division hereby certifies that, based on information and investigations, there is reasonable assurance that the proposed activity will be conducted in a manner which will not violate applicable water quality standards adopted by this Division under authority of Section 27(4) of Chapter 21 of the Massachusetts General Laws, said water quality standards having been filed with the Secretary of State of the Commonwealth on March 6, 1967.

Should any pollution arise through or because of the operation of the proposed facility or through failure to comply with this Division's Rules and Regulations pertaining to waste disposal, the Division will direct that the condition be corrected. Non-compliance on the part of the licensee will be cause for this Division to recommend the revocation of the license issued therefor or to take such other action as is authorized by the General Laws of the Commonwealth.

Very truly yours,

Thomas C. McMahon
Director

TCM-MAS/lma

cc: Chief, Permits Branch, Operations Division, Corps of Engineers,
424 Trapelo Road, Waltham, Mass. 02154

Associate Commissioner, Waterways Division, Department of Public Works,
100 Nashua Street, Boston, Mass. 02114

RECEIVED
APR 21 1971
PILGRIM PROJECT

OFFICE OF THE DIRECTOR
DIVISION OF WATER POLLUTION CONTROL

The Commonwealth of Massachusetts
Water Resources Commission
State Office Building, Government Center
100 Cambridge Street, Boston 02202

1.9.7
Copies to:
EWO
EFK
L. Schvetan
Stol Co. Afteron

July 31, 1970

Mr. Claude Pursel
Assistant Vice-President - Nuclear
Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199

RE: Pilgrim Nuclear Station
Plymouth, Massachusetts

Dear Mr. Pursel:

This is to certify that the Division has received reasonable assurance that operation of the proposed Pilgrim Station will not violate applicable water quality standards. These assurances have been provided in a preliminary engineering report submitted by the Boston Edison Company, and during subsequent meetings with the company and with the Administrative-Technical Advisory Committee pertaining to ecological and radiological studies before and after operation.

The Division has issued an interim permit for a new waste discharge outlet for this facility. This permit is valid for a period of three years from date of start-up. Should the before and after study indicate a need for further controls and/or treatment of the plant effluents such controls will be provided by Boston Edison.

The foregoing certification is to comply with Section 21 (B) (1) of the Federal Water Quality Improvement Act of 1970 (Public Law 91-224).

Very truly yours,

Thomas C. McMahon

Thomas C. McMahon
Director

TCM:JRZ:mlw

Attachment B

Special Status Species Correspondence

- Letter from Stephen Bethay, Entergy, to Mike Bartlett, FWS, dated February 3, 2005
- Letter from Michael J. Amaral, FWS, to Stephen Bethay, Entergy, dated March 9, 2005
- Letter from Stephen Bethay, Entergy, to Christopher Mantzaris, NMFS, dated February 3, 2005
- Letter from Mary A. Colligan, NMFS, to Stephen Bethay, Entergy, dated March 4, 2005
- Letter from Stephen Bethay, Entergy, to Jenna Garvey, MDFW, dated February 3, 2005
- Letter from Thomas W. French, PhD, MDFW, to Stephen Bethay, Entergy, dated April 8, 2005
- Letter from Christine Vaccaro, MDFW, to Phil Moore, TtNUS, dated July 6, 2001 (This letter is in response to Entergy's request for information on protected species in the vicinity of PNPS)

Entergy

Entergy Nuclear Generation Company
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

February 3, 2005

Mr. Mike Bartlett
Project Leader
U.S. Fish and Wildlife Service
New England Field Office
70 Commercial Street
Suite 300
Concord, NH 03301-5208

SUBJECT: Pilgrim Nuclear Power Station
Request for Information on Threatened or Endangered Species

Dear Mr. Bartlett:

Entergy Nuclear Generation Company (Entergy) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Pilgrim Nuclear Power Station (PNPS). The current operating license for the Station expires in June 2012. As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10CFR51.53). The NRC will request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

Entergy and Boston Edison Company, the previous owner of the Station, have operated PNPS since 1972. The Station lies on the western shore of Cape Cod Bay in Plymouth County, Massachusetts, just east of the Town of Plymouth (see attached Figure 2-1). Entergy purchased PNPS from Boston Edison Company in 1999. When Entergy purchased PNPS, it did not purchase the transmission facilities. While divesting itself of fossil and nuclear generating facilities, NSTAR (the parent company of Boston Edison) retained ownership of transmission facilities. Two transmission lines were built in the early 1970s to connect PNPS to the regional electric grid. These 345 KV transmission lines, which share a single corridor, run south from PNPS to the Snake Hill Road Tap approximately 6 miles south of the station (see attached Figure 2-2).

Based on a review of company documents (surveys and monitoring studies) and information on the Massachusetts Geographic Information System and Massachusetts Division of Fisheries & Wildlife websites, Entergy believes that no Federally listed terrestrial species occur on the PNPS site proper or within/along the associated 7.2 mile-long transmission corridor. The PNPS-to-Snake Hill Road transmission corridor crosses habitat designated critical (at 50 CFR 17.95) for the endangered Northern Red-Bellied Cooter (*Pseudemys rubiventris bangsi*), but the part of the critical habitat crossed by the transmission corridor appears to be a buffer area for the population rather than high-quality turtle habitat. Northern Red-Bellied Cooters have never been observed by Boston Edison, Entergy, or NSTAR biologists in this transmission corridor. As noted above, Entergy does not own or maintain the transmission lines that run from PNPS to the Snake Hill Road Tap, and is not involved in vegetation management in the right-of-way.

Several listed terrestrial species are known to occur in the general vicinity of the PNPS site, however, and cannot be ruled out as occasional visitors to the PNPS site and environs. These include the bald eagle, piping plover, and roseate tern. Bald eagles are present year-round in Massachusetts and congregate in significant numbers in wintering areas along the coast of Cape Cod and Buzzard's Bay. Bald eagles have been observed foraging in the general vicinity of PNPS, but are not believed to nest in the area. Piping plovers nest in summer on sandy coastal beaches along the Massachusetts coast. No suitable piping plover nesting habitat is found on the PNPS site (the shoreline in the area is rocky); however, individual birds may move through the PNPS area when migrating to breeding areas further north of Plymouth Bay and returning to wintering areas along the south Atlantic and Gulf coasts. Like the piping plover, the roseate tern nests in colonies along the Massachusetts coast in summer. The roseate tern nests in dune areas with thick vegetative cover, always in association with the common tern. Although suitable nesting habitat has not been identified at PNPS, migrating terns may move through the site in late spring (en route to nesting areas in Maine and Nova Scotia) and late summer (en route to wintering areas in the West Indies and Latin America).

PNPS, a one-unit nuclear plant with a total rated output of 688 MWe (megawatts electrical), uses a once-through cooling water system that withdraws from and discharges to Cape Cod Bay. A recently-prepared Clean Water Act Section 316 Study[1] that was submitted to EPA Region I in 2000 concluded that the PNPS cooling water intake system has not resulted in adverse impacts to the integrity of Cape Cod Bay fish and shellfish populations, including a number of Representative Important Species (e.g., American lobster, winter flounder, rainbow smelt, cunner, alewife, and Atlantic silverside).

Boston Edison and Entergy have monitored the marine fishes of western Cape Cod Bay since 1969 to assess possible impacts of PNPS operations. These monitoring studies also suggest that PNPS operations have not had a significant effect on local and regional fish populations. Trends in abundance of groundfish, pelagic fish, and shellfish (lobsters in particular) in western Cape Cod Bay mirror population trends in the larger Gulf of Maine and western North Atlantic and do not appear to be influenced by PNPS operations.

A number of listed marine species (including 5 great whales and 5 sea turtles) are known to use Cape Cod Bay at certain times of the year, but none of these species is believed to forage, feed, rest, or reproduce in the shallow waters adjacent to PNPS. Federally listed whales known to migrate along the coast of Massachusetts include the Sei whale, right whale, blue whale, finback whale, and humpback whale. These great whales pass Cape Cod during seasonal migrations and sometimes forage in Cape Cod Bay. Five sea turtle species (loggerhead, green, leatherback, hawksbill, and Kemp's ridley) occur along the Massachusetts coast, but sightings are uncommon and limited for the most part to sub-adult "wanderers." Young sea turtles are occasionally stranded on Cape Cod beaches.

Because whales do not move into the shallow waters immediately offshore of PNPS, they are not affected by operation of the PNPS cooling water intake system or by the station's thermal discharge. No sea turtles have been observed in the vicinity of the station, and none have been impinged since operational monitoring began in the 1970s. There are no records of sea turtles congregating in the area of the PNPS discharge canal, and no indication that the thermal effluent

[1]ENSR, 2000, "Combined 316 Demonstration Report – Pilgrim Nuclear Power Station," Prepared for Entergy Nuclear Generation Company. March.

has disrupted normal seasonal movement or migration of turtles.

Entergy is committed to the conservation of significant natural habitats and protected species, and expects that operation of the Station through the license renewal period (an additional 20 years) would not adversely affect any listed species. Entergy has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. We therefore request your concurrence with our determination that license renewal would have no effect on threatened or endangered species (including candidate species and species proposed for listing) and that formal consultation is not necessary.

Please do not hesitate to call me at 508-830-7832 if you have any questions or require any additional information. After your review, we would appreciate your sending a letter detailing any concerns you may have about any listed species in the area or confirming Entergy's conclusion that operation of PNPS over the license renewal term would have no effect on any threatened or endangered species under the jurisdiction of the U.S. Fish and Wildlife Service. 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 PNPS license renewal application.

Sincerely,

Stephen Bethay

Stephen Bethay
Director, Nuclear Assessment
Pilgrim Nuclear Power Station
Entergy Nuclear Generation Company

Enclosure: Figures 2-1 and 2-2 from ER

Cc: Fred Mogolesko, Entergy
Jacob Scheffer, Entergy
Jack Alexander, Entergy
Jack Fulton, Entergy
David Lach, Entergy

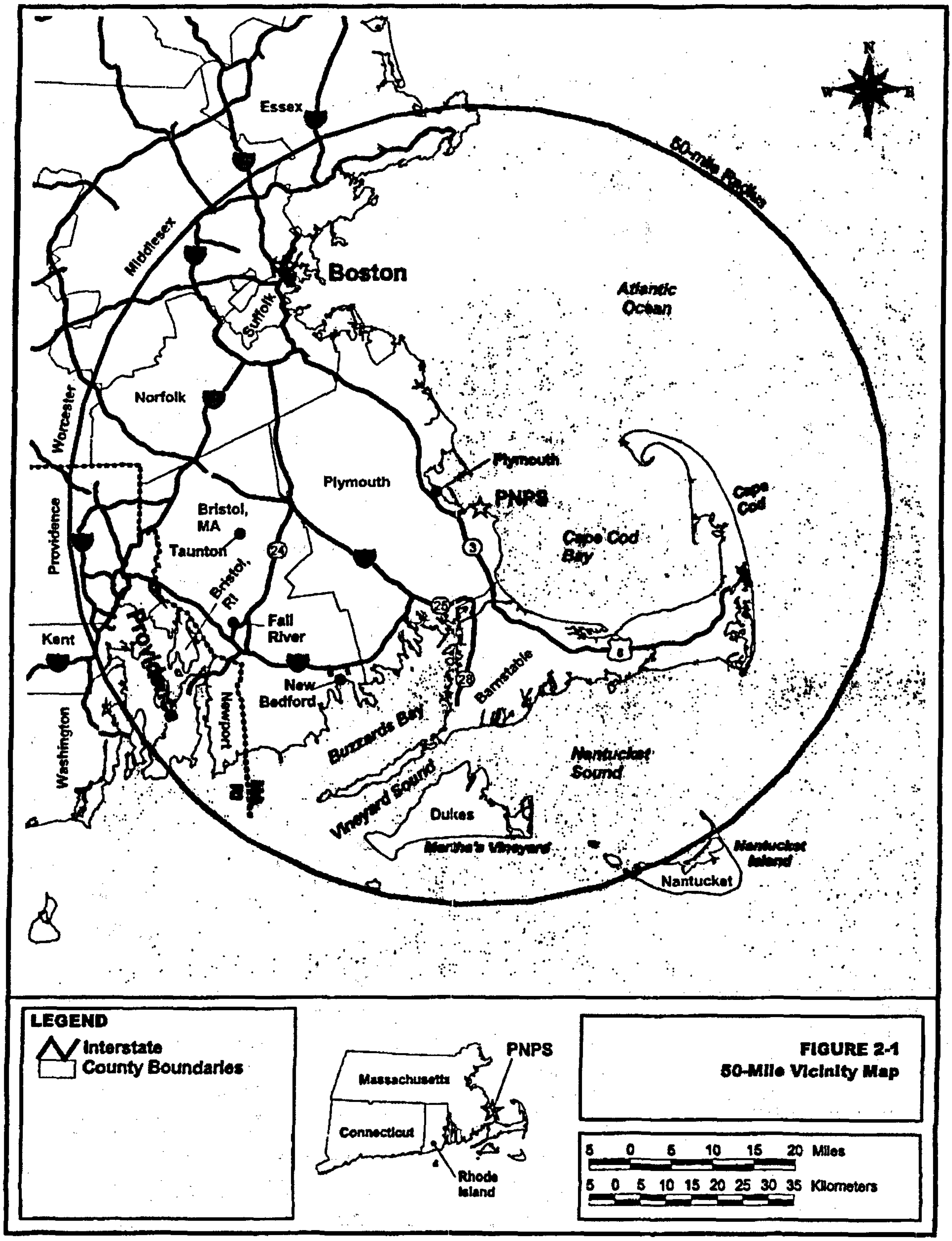


FIGURE 2-1
50-Mile Vicinity Map

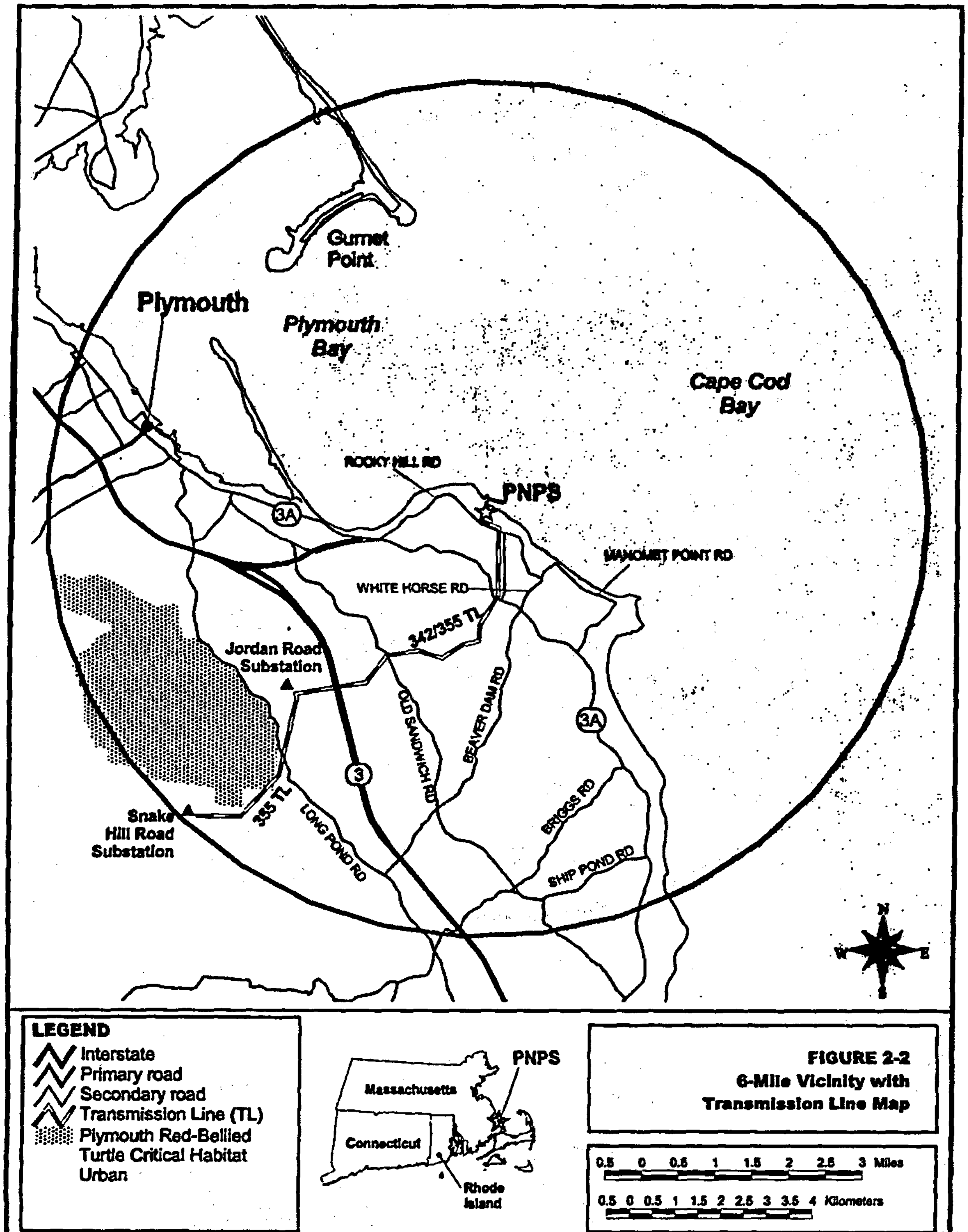


FIGURE 2-2
6-Mile Vicinity with Transmission Line Map

United States Department of the Interior

FISH AND WILDLIFE SERVICE
New England Field Office
70 Commercial Street, Suite 300
Concord, New Hampshire 03301-5087

March 9, 2005

Stephen Bethay
Entergy Nuclear Generation Company
600 Rocky Hill Road
Plymouth, MA 02360

Dear Mr. Bethay:

We are in receipt of your February 3, 2005 letter regarding the license renewal process for the Pilgrim Nuclear Power Station (PNPS), Plymouth, Massachusetts. The following comments are provided in accordance with Section 7 of the Endangered Species Act (ESA) of 1973, as amended (16 U.S.C. 1531-1543).

The federally-threatened piping plover (*Charadrius melodus*) and federally-endangered roseate tern (*Sterna dougallii*) are known to occur along Plymouth Beach, just north of the PNPS. Occasional wintering bald eagles (*Haliaeetus leucocephalus*) are also sometimes present in the area. According to our records, none of the above-listed species are known to frequent the immediate vicinity of PNPS and, therefore, the presence of these species near the power station is probably transient in nature.

As stated in your letter, the PNPS-to-Snake Hill Road transmission corridor crosses critical habitat for the endangered red-bellied cooter (*Pseudemys rubriventris*). We concur with your determination that the area crossed by the transmission line does not provide the specific biological habitat needs for the red-bellied cooter. However, turtles may traverse the transmission line corridor and the area is considered critical based on its value to buffer against activities that may degrade water quantity and quality in ponds occupied by the species.

Information was provided regarding several marine mammals and turtles. Jurisdiction for those species resides with the National Marine Fisheries Service. We suggest you contact them at their Gloucester, Massachusetts office at 978-281-9300 with regard to the relicensing of the PNPS.

Since no expansion of existing facilities is planned and no additional land disturbance is anticipated, we concur with your determination that license renewal for PNPS is not likely to adversely affect federally-listed species subject to the jurisdiction of the U.S. Fish and Wildlife Service, and that formal consultation with us is not required.

Thank you for your coordination. Please contact us at 603-223-2541 if we can be of further assistance.

Sincerely yours,

Michael J. Amaral

Michael J. Amaral
Endangered Species Specialist
New England Field Office

Entergy

Entergy Nuclear Generation Company
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

February 3, 2005

Mr. Christopher Mantzaris
Asst. Regional Administrator for Protected Resources
National Marine Fisheries Service
Northeast Regional Office
One Blackburn Drive
Gloucester, MA 01930-2298

SUBJECT: Pilgrim Nuclear Power Station
Request for Information on Threatened or Endangered Species

Dear Mr. Mantzaris:

Entergy Nuclear Generation Company (Entergy) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Pilgrim Nuclear Power Station (PNPS). The current operating license for the Station expires in June 2012. As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10CFR51.53). The NRC will request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

Entergy and Boston Edison Company, the previous owner of the Station, have operated PNPS since 1972. The Station lies on the western shore of Cape Cod Bay in Plymouth County, Massachusetts, just east of the Town of Plymouth (see attached Figure 2-1). Semi-enclosed Cape Cod Bay has a surface area of 430 square nautical miles, or 365,000 acres, and connected to a much larger body of water, the Gulf of Maine, which is bounded on the west by the shorelines of Massachusetts, New Hampshire, Maine, and New Brunswick and on the east by the undersea landforms (Georges Banks being perhaps the most notable) that separate the Gulf of Maine from the rest of the North Atlantic.

PNPS, a one-unit nuclear plant with a total rated output of 688 MWe (megawatts electrical), uses a once-through cooling water system that withdraws from and discharges to Cape Cod Bay. A recently-prepared Clean Water Act Section 316 Study[1] that was submitted to EPA Region I in 2000 concluded that the PNPS cooling water intake system has not resulted in adverse impacts to the integrity of Cape Cod Bay fish and shellfish populations, including a number of Representative Important Species (e.g., American lobster, winter flounder, rainbow smelt, cunner, alewife, and Atlantic silverside).

Boston Edison and Entergy have monitored the marine fishes of western Cape Cod Bay since 1969 to assess possible impacts of PNPS operations. These monitoring studies also suggest that PNPS operations have not had a significant effect on local and regional fish populations. Trends in abundance of groundfish, pelagic fish, and shellfish (lobsters in particular) in western Cape

[1]ENSR, 2000, "Combined 316 Demonstration Report – Pilgrim Nuclear Power Station," Prepared for Entergy Nuclear Generation Company. March.

Cod Bay mirror population trends in the larger Gulf of Maine and western North Atlantic and do not appear to be influenced by PNPS operations.

In more than 30 years of monitoring the aquatic populations of western Cape Cod Bay, Entergy, Boston Edison Company, and their contractors have never collected a listed marine species. No listed species have been observed in the PNPS intake canal or discharge canal. None have been impinged or entrained in the Station's cooling water.

A number of listed marine species (including 5 great whales and 5 sea turtles) are known to use Cape Cod Bay at certain times of the year, but none of these species is believed to forage, feed, rest, or reproduce in the shallow waters adjacent to PNPS. Federally listed whales known to migrate along the coast of Massachusetts include the Sei whale, right whale, blue whale, finback whale, and humpback whale. These great whales pass Cape Cod during seasonal migrations and sometimes forage in Cape Cod Bay. Five sea turtle species (loggerhead, green, leatherback, hawksbill, and Kemp's ridley) occur along the Massachusetts coast, but sightings are uncommon and limited for the most part to sub-adult "wanderers." Young sea turtles are occasionally stranded on Cape Cod beaches.

Because whales do not move into the shallow waters immediately offshore of PNPS, they are not affected by operation of the PNPS cooling water intake system or by the station's thermal discharge. No sea turtles have been observed in the vicinity of the station, and none have been impinged since operational monitoring began in the 1970s. There are no records of sea turtles congregating in the area of the PNPS discharge canal, and no indication that the thermal effluent has disrupted normal seasonal movement or migration of turtles.

Entergy is committed to the conservation of significant natural habitats and protected species, and expects that operation of the Station through the license renewal period (an additional 20 years) would not adversely affect any listed marine species. Entergy has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. We therefore request your concurrence with our determination that license renewal would have no effect on threatened or endangered marine species (including candidate species and species proposed for listing) and that formal consultation is not necessary.

Please do not hesitate to call me at 508-830-7832 if you have any questions or require any additional information. After your review, we would appreciate your sending a letter detailing any concerns you may have about any listed species in the area or confirming Entergy's conclusion that operation of PNPS over the license renewal term would have no effect on any threatened or endangered species under the jurisdiction of the National Marine Fisheries Service. 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 PNPS license renewal application.

Sincerely,

Stephen Bethay

Stephen Bethay
Director, Nuclear Assessment
Pilgrim Nuclear Power Station
Entergy Nuclear Generation Company

Enclosure: Figure 2-1 from ER

Cc: Fred Mogolesko, Entergy
Jacob Scheffer, Entergy
Jack Alexander, Entergy
Jack Fulton, Entergy
David Lach, Entergy

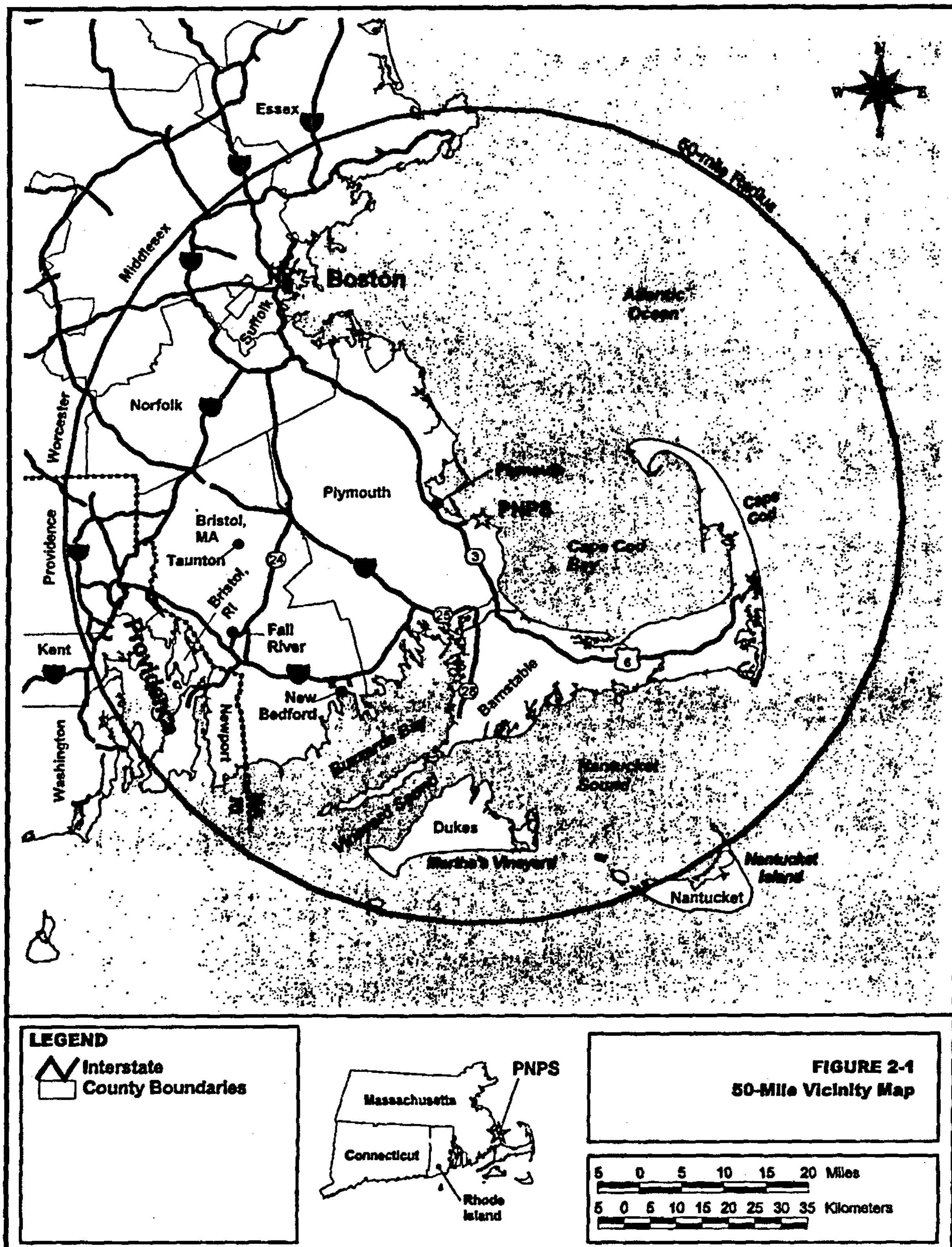


FIGURE 2-1
50-Mile Vicinity Map

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
NORTHEAST REGION
One Blackburn Drive
Gloucester, MA 01930-2298

MAR -4 2005

Stephen Bethay
Director, Nuclear Assessment
Entergy Nuclear Generation Company
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

Re: Pilgrim Nuclear Power Station, Protected Species

Dear Mr. Bethay,

This is in response to your letter dated February 3, 2005, requesting information on the presence of any federally threatened or endangered species under the jurisdiction of the National Marine Fisheries Service (NMFS) in the vicinity of the Pilgrim Nuclear Power Station (PNPS), located on the western shore of Cape Cod Bay in Plymouth County, MA. Entergy Nuclear Power Station is currently preparing an application to the U.S. Nuclear Regulatory Commission (NRC) for the renewal of the operating license for PNPS, as the current operating license expires in June 2012, the information requested is to assist with the application process.

As mentioned in your letter, four species of federally threatened or endangered sea turtles and three species of endangered whales may be found in the waters of Cape Cod. The sea turtles in northeastern nearshore waters are typically small juveniles with the most abundant being the federally threatened loggerhead (*Caretta caretta*) followed by the federally endangered Kemp's ridley (*Lepidochelys kempi*). Loggerhead turtles have been found to be relatively abundant off the Northeast coast (from near Nova Scotia, Canada to Cape Hatteras, North Carolina). Loggerheads and Kemp's ridleys have been documented in waters as cold as 11°C, but generally migrate northward when water temperatures exceed 16°C. These species are typically present in Massachusetts waters from June – October. Federally endangered leatherback sea turtles (*Dermochelys coriacea*) are located in Massachusetts waters during the warmer months as well. While leatherbacks are predominantly pelagic, they may occur close to shore, especially when pursuing their preferred jellyfish prey. Green sea turtles *(Chelonia mydas)* may also occur sporadically in Massachusetts waters, but those instances would be rare.

Federally endangered North Atlantic right whales (*Eubalaena glacialis*), humpback whales (*Megaptera novaeangliae*), and fin whales (*Balaenoptera physalus*) may all also be found seasonally in Massachusetts waters. North Atlantic right whales have been documented in the nearshore waters of Massachusetts from December through June. Humpback whales feed during the spring, summer, and fall over a range that encompasses the eastern coast of the United States. Fin whales are common in waters of the United States Exclusive Economic Zone, principally offshore from Cape

Hatteras northward. While these whale species are not considered residents of the Cape Cod Bay area, it is possible that transients may enter the area during seasonal migrations.

It is the understanding of NMFS that there have been no interactions or impingements of sea turtles at PNPS in the past 30 years of monitoring at PNPS. However, since the entrainment and impingement of sea turtles at several nuclear power plants on the East Coast has been documented, and as sea turtles may be seasonally present in the vicinity of the intakes associated with the PNPS, NMFS recommends that this impact be fully addressed in the application being prepared.

Section 7(a)(2) of the Endangered Species Act (ESA) of 1973, as amended, states that each Federal agency shall, in consultation with the Secretary, insure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat. Any discretionary federal action that may affect a listed species must undergo Section 7 consultation. As listed species may be present in the project area, the federal action agency, in this case the NRC, is responsible for determining whether the proposed action is likely to affect any listed species. The NRC should then submit their determination along with a request for concurrence, to the attention of the Endangered Species Coordinator, NOAA Fisheries, Northeast Regional Office, Protected Resources Division, One Blackburn Drive, Gloucester, MA 01930. After reviewing this information, NOAA Fisheries would then be able to conduct a consultation under section 7 of the ESA.

Should you have any questions about these comments or about the section 7 consultation process in general, please contact Sara McNulty at (978) 281-9328 ext. 6520.

Sincerely,

Mary Colligan

Mary A. Colligan
Assistant Regional Administrator
for Protected Resources

Cc: Boelke, F/NER4

File Code: Sec 7, Pilgrim Nuclear Power Station, Spp. Pres.

Entergy

Entergy Nuclear Generation Company
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

February 3, 2005

Ms. Jenna Garvey
Environmental Review Assistant
Massachusetts Division of Fisheries & Wildlife
Natural Heritage & Endangered Species Program
Route 135
Westborough, MA 01581

SUBJECT: Pilgrim Nuclear Power Station
Request for Information on Threatened and Endangered Species

Dear Ms. Garvey:

Entergy Nuclear Generation Company (Entergy) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Pilgrim Nuclear Power Station (PNPS). The current operating license for the Station expires in June 2012. As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10CFR51.53). The NRC will consult with the U.S. Fish and Wildlife Service under Section 7 of the Endangered Species Act and may also seek your assistance in the identification of important species and habitats in the project areas. By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

Entergy and Boston Edison Company, the previous owner of the Station, have operated PNPS since 1972. The Station lies on the western shore of Cape Cod Bay in Plymouth County, Massachusetts, just east of the Town of Plymouth (see attached Figure 2-1). Entergy purchased PNPS from Boston Edison Company in 1999. When Entergy purchased PNPS, it did not purchase the transmission facilities. While divesting itself of fossil and nuclear generating facilities, NSTAR (the parent company of Boston Edison) retained ownership of transmission facilities. Two transmission lines were built in the early 1970s to connect PNPS to the regional electric grid. These 345 KV transmission lines, which share a single corridor, run south from PNPS to the Snake Hill Road Tap approximately 6 miles south of the station (see attached Figure 2-2).

Entergy is committed to the conservation of significant natural habitats and protected species, and believes that operation of PNPS and its transmission lines since 1972 has had no adverse impact on any threatened or endangered species. Based on our review of the various Natural Heritage and Endangered Species Program data layers (downloaded from MassGIS) and the list you provided (Vaccaro, Division of Fisheries and Wildlife, to Moore, Tetra Tech NUS, July 6, 2001), no state-listed species occurs on the PNPS site property, the area owned and managed by Entergy. A number of federally-listed species occur seasonally in Plymouth County in the general vicinity of PNPS, but the likelihood of adverse impacts to these species is small. For example, piping plovers and roseate terns could move through the PNPS site during spring and fall migrations, but would not nest in the area or be affected by plant operations. A

number of great whale and sea turtle species occur in Cape Cod Bay, but none has been observed in the shallow waters offshore of PNPS by Boston Edison or Entergy biologists conducting studies of fish and shellfish.

Entergy has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. As a consequence, we believe that operation of the plant, including maintenance of the transmission lines, over the license renewal period (an additional 20 years) would not adversely affect any threatened or endangered species.

After your review, we would appreciate your sending a letter detailing any concerns you may have about any listed species in the project area or confirming Entergy's conclusion that the operation of Pilgrim Nuclear Power Station over the license renewal term would have no effect on any state- or federally-listed species.

We will include a copy of your July 6, 2001 letter and any additional correspondence from your office in the license renewal application that we submit to the NRC.

Please do not hesitate to call me at 508-830-7832 if you have any questions or require any additional information.

Sincerely,

Stephen Bethay

Stephen Bethay
Director, Nuclear Assessment
Pilgrim Nuclear Power Station
Entergy Nuclear Generation Company

Encls: Figure 2-1
Figure 2-2

Cc: Fred Mogolesko, Entergy
Jacob Scheffer, Entergy
Jack Alexander, Entergy
Jack Fulton, Entergy
David Lach, Entergy

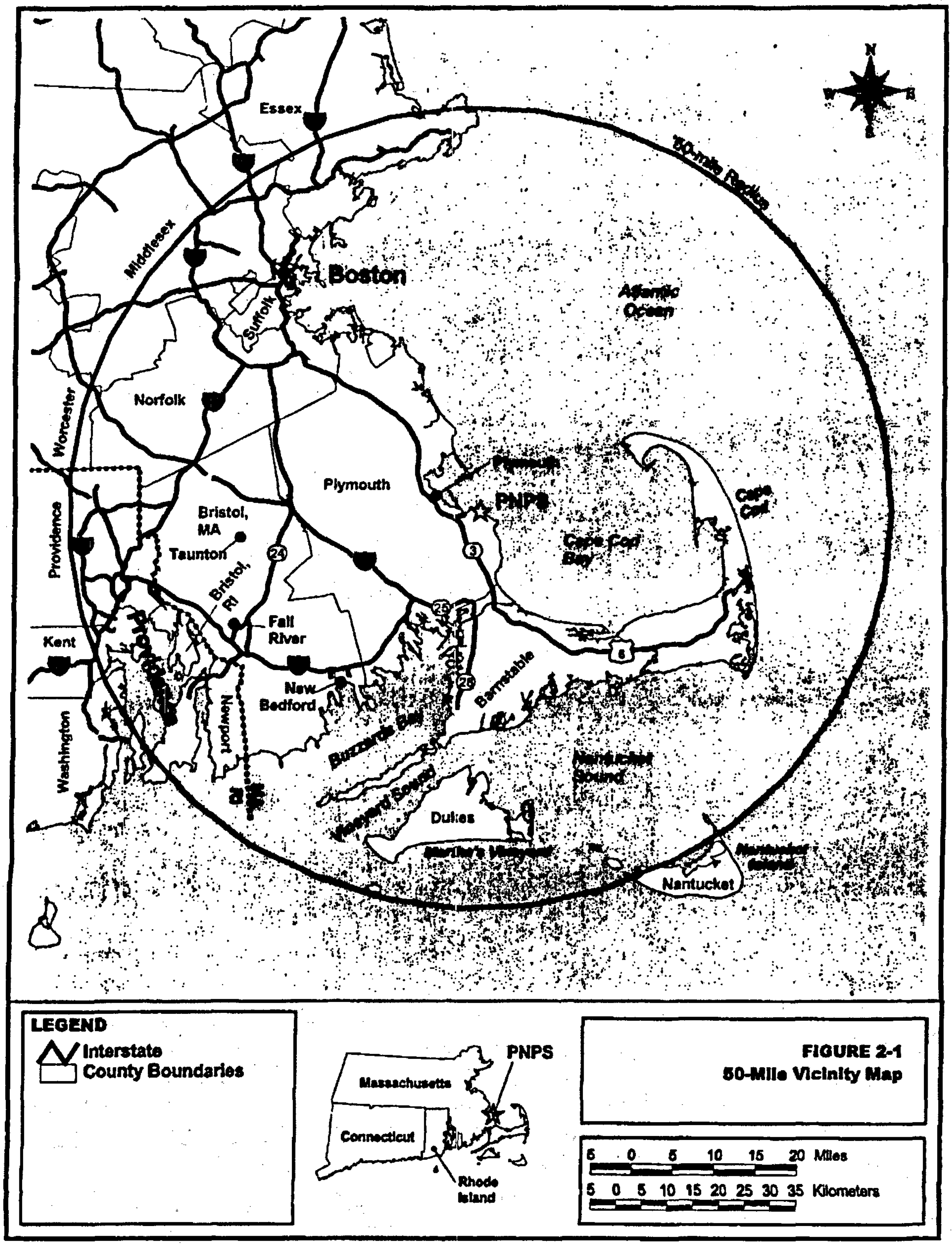


FIGURE 2-1
50-Mile Vicinity Map

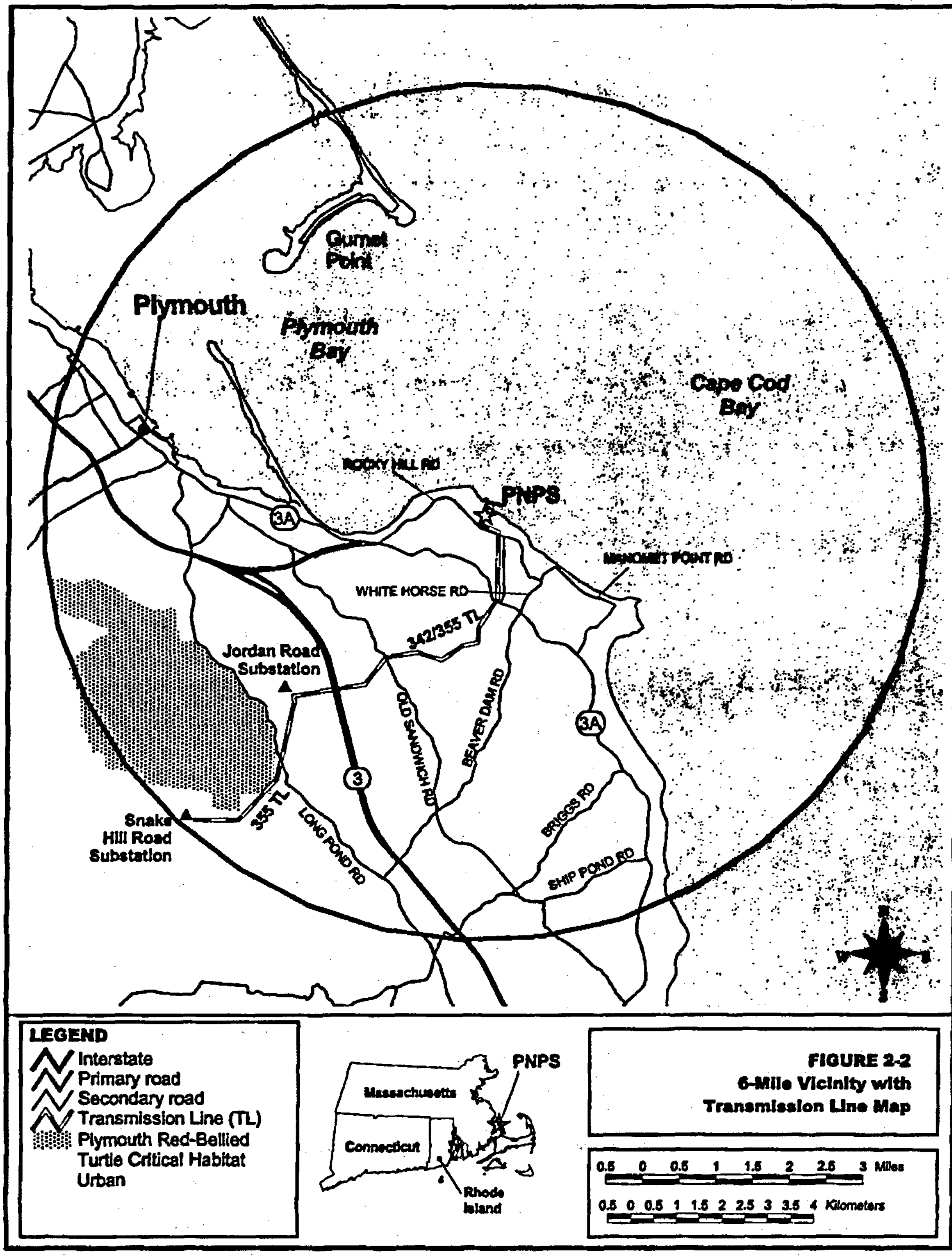


FIGURE 2-2
6-Mile Vicinity with Transmission Line Map

Commonwealth of Massachusetts

Division of Fisheries & Wildlife

MassWildlife

Wayne F. MacCallum, *Director*

April 8, 2005

Entergy Nuclear Generation Company
Pilgrim Nuclear Power Station
Attn: Stephen Bethay
600 Rocky Hill Road
Plymouth, MA 02360

RE: Pilgrim Nuclear Power Plant
Plymouth, MA
Renewal of Operating License
NHESP File No. 04-16063

Dear Mr. Bethay,

Thank you for contacting the Natural Heritage and Endangered Species Program (NHESP) of the MA Division of Fisheries and Wildlife for information regarding state-listed rare species at the above referenced site.

As you are aware from our previous letters, there are state-protected rare species that occur within proximity to the above site. According to the 11th edition of the Massachusetts Natural Heritage Atlas, a majority of *Priority Habitat 1320* (PH 1320) and *Estimated Habitat 148* (WH 148) falls within a half mile radius to the subject project location. The Spotted Turtle (*Clemmys guttata*), a state-listed species of Special Concern is located in this Estimated Habitat polygon.

This species is protected under the Massachusetts Endangered Species Act (MESA) (M.G.L. c. 131A) and its implementing regulations (321 CMR 10.00). State-listed wildlife are also protected under the state's Wetlands Protection Act (WPA) (M.G.L. c. 131, s. 40) and its implementing regulations (310 CMR 10.37 and 10.59). Fact sheets for this species can be found on our website http://www.nhesp.org

With regard to determining the potential impacts this project would have on this and other state-listed species, it is not something that can be assessed without more specific information regarding the details associated with the operation of the power plant. If there are no plans to expand the footprint or to alter current operations over the license period, then it would not seem likely that there would be an adverse affect on state-protected wildlife species. However, the NHESP can not at this time officially make this determination unless we were to receive more detailed information in order to conduct a full environmental review. If you have any further questions, please contact Jenna Garvey, Environmental Review Assistant at: (508) 792-7270, extension 303.

Sincerely,

Thomas W. French

Thomas W. French, Ph.D.
Assistant Director

cc: Plymouth Conservation Commission

Attachment C

Massachusetts Historical Commission Correspondence

- Letter from Stephen Bethay, Entergy, to Brona Simon, Massachusetts Historical Commission, dated February 17, 2005
- Letter from Eric S. Johnson, Massachusetts Historical Commission, to Stephen Bethay, Entergy, dated March 14, 2005

Entergy

Entergy Nuclear Generation Company
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

February 17, 2005

Brona Simon
Assistant Director
Massachusetts Historical Commission
220 Morrissey Blvd.
Boston, MA 02125

Subject: PILGRIM NUCLEAR POWER STATION LICENSE RENEWAL REQUEST FOR INFORMATION ON HISTORIC / ARCHAEOLOGICAL RESOURCES

Dear Ms. Simon:

Entergy Corporation is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Pilgrim Nuclear Power Station (PNPS), which expires in 2012. Entergy intends to submit this application for license renewal in December 2005. As part of the license renewal process, the NRC requires license applicants to "assess whether any historic or archaeological properties will be affected by the proposed project." The NRC may also request an informal consultation with your office at a later date under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470) and the Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

Pilgrim Nuclear Power Station (PNPS) is located in the Town of Plymouth, Plymouth County, Massachusetts, on the rocky western shoreline of Cape Cod Bay. This location is latitude 41° 56' 69" North and longitude 70° 34' 74" West (latitude +41.9444 and longitude –70.5794). The site consists of approximately 1700 acres. Less than 200 acres, between Rocky Hill Road and Cape Cod Bay, are developed with a nuclear reactor containment building, turbine and auxiliary buildings, intake and discharge structures, a diesel generator building, the switchyard, and associated transmission lines. The remainder of the site is in a forest management trust (see Figure 2-3).

The area within 6 miles of the site is completely within Plymouth County and includes the Town of Plymouth, the center of which is about 4 miles northwest of PNPS and has a population of 51,701 (Bureau of the Census 2000) (see Figure 2-2). The nearest major metropolitan cities are Boston, Massachusetts (36 miles to the northwest), and Providence, Rhode Island (44 miles to the west).

An examination of the archaeological site files and maps maintained by the Office of the State Archaeologist at the Massachusetts Historical Commission revealed approximately 130 archaeological (pre-historic and historic) sites within a 6-mile radius of the station. While Entergy does not own the transmission lines and is not responsible for maintaining the transmission corridors rights-of-way, NRC regulations (10 CFR 51) require the utility seeking license renewal to evaluate the impact to transmission corridors from license renewal. Four sites (#84, #813, #815, and #816) appear to fall within or near the Jordan Road transmission line corridor right-of-way (see Figure 2-2). Beyond the Jordan Road

tap, site # 361 appears to fall near the corridor. Original surveys of the site property identified several archaeological sites, however they were ultimately determined to be insignificant (AEC 1974).

Currently, 92 "above-ground" locations are listed in the National Register of Historic Places for Plymouth County (U. S. Department of the Interior 2001). The attached table lists the 18 sites located within the Town of Plymouth. The State Register of Historic Places 2000, a report published by the Massachusetts Historical Commission, states that the Town of Plymouth is home to 21 sites of historic significance (Massachusetts Historical Commission 2000).

Entergy has no plans to alter current operations over the license renewal period. No major expansion of existing facilities is planned, and no major structural modifications have been identified for the purposes of supporting license renewal. No additional land disturbance is anticipated.

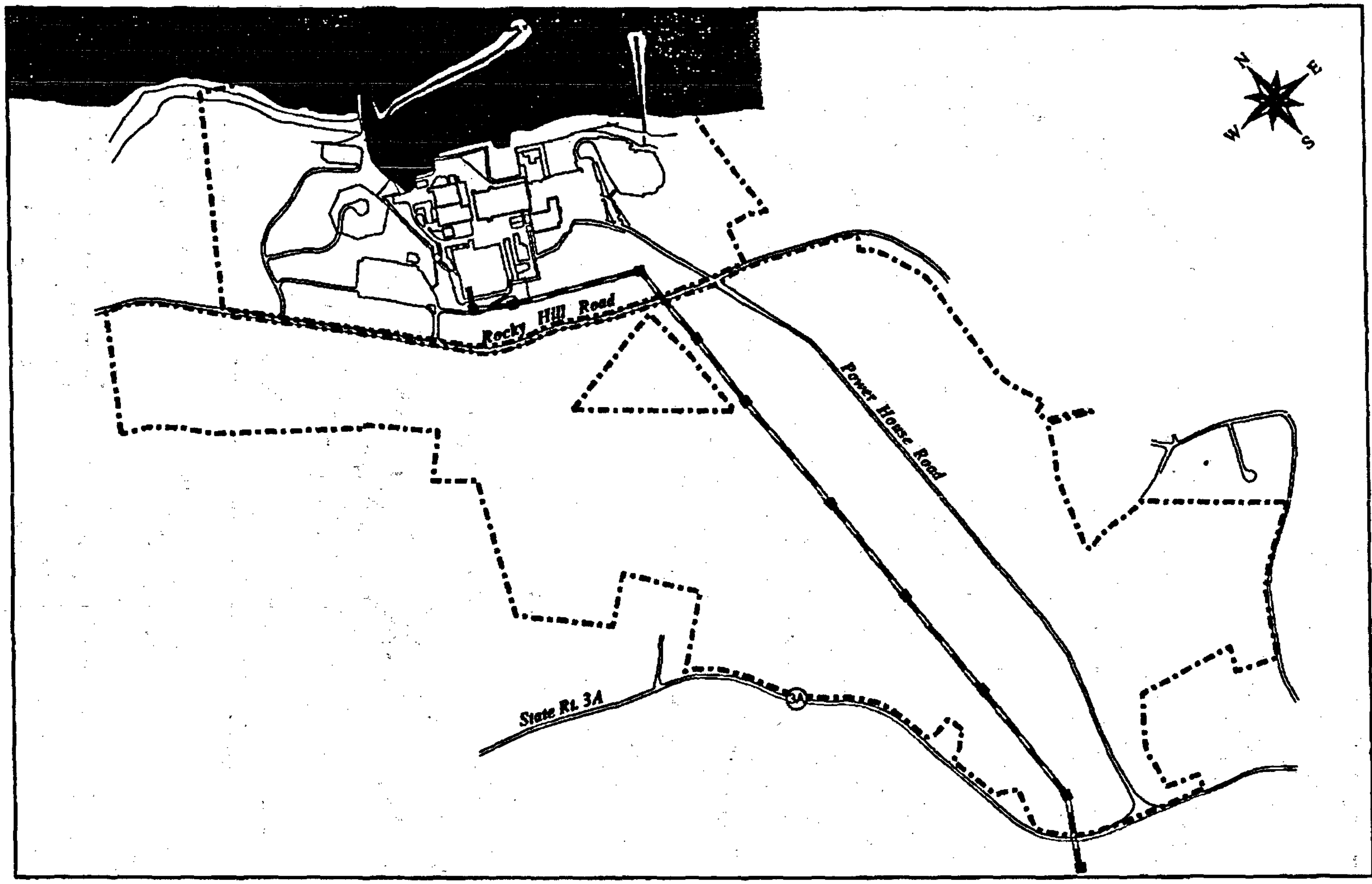
We would appreciate your sending us a letter by March 15, 2005 detailing any concerns you may have about historic/archaeological resources in the area and/or a concluding statement that the operation of the Pilgrim Nuclear Power Station over the license renewal term would have no effect on any historic or archeological properties. This will enable us to meet our application preparation schedule. Entergy will include a copy of this letter and your response in the license renewal application that we submit to the NRC. Please call Fred Mogolesko at 508-830-7832 if you have any questions or require any additional information to review the proposed action.

Sincerely,

Stephen J Bethay

Stephen Bethay
Director, Nuclear Assessment
Pilgrim Nuclear Power Station
Entergy Nuclear Generation Company

encl. Figure 2-3
Figure 2-2
Table
Citation List



LEGEND

Site Boundary

Transmission Lines

200 0 200 600 1000 Feet

FIGURE 2-3
Site Boundary

Utility\Pilgrim\Gr\A2-3 Pilgrim Bndry.ai

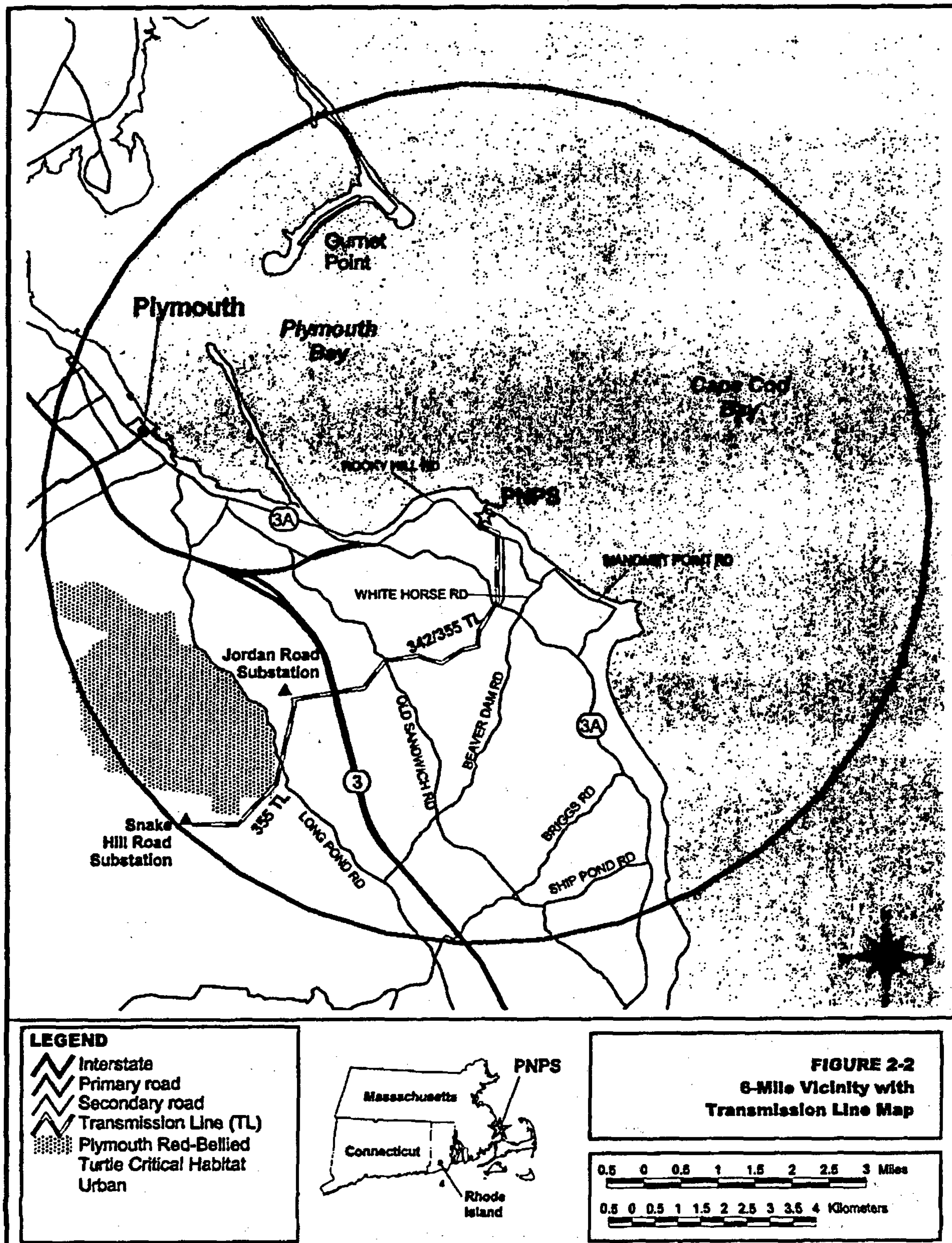


FIGURE 2-2
6-Mile Vicinity with Transmission Line Map

Town of Plymouth, Massachusetts
Sites Listed in the National Register of Historic Places

Site Name	Location
Bartlett-Russell-Hedge House	32 Court Street
Bradford-Union Street Historic District	Bradford, Union, Emerald, Water Cure, and Freedom Streets
Clifford-Warren House	East of Plymouth at 3 Clifford Road
Cole's Hill	Carver Street
Harlow Old Fort House	119 Sandwich Street
Sgt. William Harlow Family Homestead	8 Winter Street
Hillside	230 Summer Street
Jabez Howland House	33 Sandwich Street
National Monument to the Forefathers	Allerton Street
Old County Courthouse	Leyden and Market Streets
Parting Ways Archaeological District	Address Restricted
Pilgrim Hall	75 Court Street
Plymouth Antiquarian House	126 Water Street
Plymouth Post Office Building	5 Main Street
Plymouth Rock	Water Street
Plymouth Village Historic District	Roughly bounded by Water, Main, and Brewster Streets
Richard Sparrow House	42 Summer Street
Town Brook Historic and Archaeological District	Address Restricted

Source: U. S. Department of the Interior 2005.

CITATIONS IN SHPO CORRESPONDENCE

AEC (U.S. Atomic Energy Commission). 1974. Final Environmental Statement related to the Proposed Pilgrim Nuclear Power Station, Unit 2. Division of Radiological and Environmental Protection. Washington DC.

Massachusetts Historical Commission, 2003. *State Register of Historic Places 2000.*

U.S. Census Bureau. 2000. "Census 2000 Redistricting Data (Public Law 94-171) Summary File." Available at http://factfinder.census.gov/servlet/DTGeoSearchByListServlet?ds_name=DEC_2000_PL_U&state=dt&_lang=en. Accessed June 1, 2001.

U.S. Department of the Interior. 2005. Plymouth County, Massachusetts Listing of Sites on the National Register of Historic Places. Available at http://www/nr/nps/gov. Accessed January 17, 2005.

The Commonwealth of Massachusetts

William Francis Galvin, Secretary of the Commonwealth
Massachusetts Historical Commission

March 14, 2005

Stephen Bethay
Director, Nuclear Assessment
Pilgrim Nuclear Power Station
Entergy Nuclear Generation Company

RE: Pilgrim Nuclear Power Station License Renewal, Plymouth, MHC #RC.36661

Dear Mr. Bethay:

Thank you for submitting information to the Massachusetts Historical Commission regarding the proposed project referenced above. Staff of the MHC have reviewed the information you submitted and have the following comments.

MHC understands from your letter that Entergy has no plans to alter current operations at the power station, to expand existing facilities, or to undertake ground-disturbing activities over the license renewal period.

In addition to the five archaeological sites mentioned in your letter, review of MHC's Inventory of the Historic and Archaeological Assets of the Commonwealth indicates that there is one additional recorded archaeological site within the project area, which consists of the existing power station and transmission line corridor. This site (MHC site #19-68), located within the transmission line corridor north of Rocky Hill Road, is associated with the Native American settlement of the Plymouth area. After review of MHC's files and the information you submitted, MHC staff have determined that the proposed license renewal as currently described is unlikely to affect significant historic or archaeological resources.

Should plans change and if activities involving ground disturbance are contemplated, MHC requests the opportunity to review project plans in order to assess potential effects to historic and archaeological resources and to determine whether an archaeological survey is warranted for project impact areas.

These comments are offered in compliance with Section 106 of the National Historic Preservation Act of 1966, as amended (36 CFR 800) and Massachusetts General Laws, Chapter 9, Sections 26-27C (950 CMR 71). If you have any questions concerning this review, please feel free to contact me at this office.

Sincerely,

Eric S. Johnson

Eric S. Johnson
Archaeologist/Preservation Planner
Massachusetts Historical Commission

xc: Plymouth Historical Commission
Cheryl Andrews-Maltais, THPO, WTGHA

220 Morrissey Boulevard, Boston, Massachusetts 02125
(617) 727-8470 • Fax: (617) 727-5128
www.state.ma.us/sec/mhc

Attachment D

Coastal Zone Management Consistency Certification

Federal Consistency Certification for Federal Permit and License Applicants[1]

This is the Entergy Nuclear Generation Company (Entergy) certification to the U. S. Nuclear Regulatory Commission (NRC) that the renewal of the Pilgrim Nuclear Power Station (PNPS) 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, Massachusetts enforceable coastal resource protection policies and PNPS compliance status, and summary findings.

CONSISTENCY CERTIFICATION

Entergy certifies to the NRC that renewal of the PNPS operating license complies with the enforceable policies of Massachusetts' approved coastal zone management program and will be conducted in a manner consistent with such program. Entergy expects PNPS operations during the license renewal term to be a continuation of current operations as described below, with no station changes that would change effects on Massachusetts' 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 an 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 [915 CFR 930.51(b)(1)]. NOAA approved the Massachusetts coastal zone management program in 1978. In Massachusetts, the approved program is the Massachusetts Coastal Zone Management (MCZM) Program, Massachusetts General Laws (M.G.L.) Chapter 21A, Sections 2 and 4A, with regulations at 301 Code of Massachusetts Regulations (CMR) 20 – 26.

MCZM Program regulations require review of federal activities that are listed or that could reasonably be expected to affect the coastal zone (301 CMR 21.04). NRC licensing is a listed activity [301 CMR 21.07(2)(a)(6)] and the PNPS location at the coastline and withdrawal from and discharge to coastal waters could reasonably be expected to affect the coastal zone. The State regulation requires certification of compliance with the MCZM Program policies [301 CMR 21.07(3)(a)(1)] and the regulation lists the policies (301 CMR 21.98). Attachment D-1 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 PNPS license to operate for an additional 20 years beyond the current expiration date of June 8, 2012. Entergy expects PNPS operations during the license renewal term to be a continuation of current operations as described in the following paragraphs, with no changes that would affect the Massachusetts coastal zone. Entergy certifies that license renewal complies with the program policies of the Massachusetts approved coastal management program and will be conducted in a manner consistent with such policies.

Background Information

PNPS is located on the western shore of Cape Cod Bay in the Town of Plymouth, Plymouth County, Massachusetts. Approximately 60 percent of the area within a 50-mile radius is the open water of Cape Cod Bay and Plymouth Bay. Two transmission lines were built to connect PNPS to the electric grid. Both lines share a 300-foot wide transmission corridor that runs approximately 5 miles inland to the Jordan Road Tap. The inland boundary of the coastal zone is 100 feet inland of Route 3A, therefore, the area of interest includes the plant property and the transmission corridor to 100 feet west of the Route 3A crossing. Figures 2-1 and 2-2 are PNPS 50-mile and 6-mile vicinity maps, respectively.

PNPS is a single-unit plant with a boiling water reactor and turbine generator licensed for an output of 2,028 megawatts-thermal (MWt), and an electric rating of 715 megawatts-electric (MWe) gross.

PNPS is equipped with a once-through heat dissipation system that withdraws cooling water from and discharges to Cape Cod Bay. Two pumps in the intake structure provide a continuous supply (311,000 gallons per minute [gpm]) of condenser cooling water. Also housed in the intake structure are five service water pumps that supply 10,000 gpm cooling water, with four pumps in operation and one on standby, to the service water system. After moving through the condensers, cooling water is discharged into a 900-foot long discharge channel. At low tide the water in the discharge channel is several feet higher than sea level and the discharge is rapid and turbulent. At high tide the velocity is much lower. The increase in water temperature across the condensers ranges from 27 to 30°F; the plant is permitted for as much as a 32°F temperature change. Entergy holds a National Pollutant Discharge Elimination System (NPDES) permit for this and other plant/stormwater discharges. In accordance with permit requirements, Entergy monitors discharge characteristics and reports the results to the U.S. Environmental Protection Agency (EPA) and the Massachusetts Department of Environmental Protection. The PNPS NPDES permit, issued August 30, 1994, by EPA Region I, constitutes the current CWA Section 316(b) determination for PNPS. Because Entergy submitted a timely application for renewal of the PNPS NPDES permit, the 1994 permit has been administratively continued.

PNPS has an onsite wastewater treatment plant. Sanitary wastewater that does not contain radioactive materials is processed in the wastewater treatment facility and discharged through a permitted drain field to the groundwater. The treated wastewater discharge cannot exceed an average of 37,500 gallons per day.

Entergy employs a permanent workforce of approximately 700 employees (including baseline permanent contractors) at PNPS. The majority of the PNPS workforce (approximately 83%) lives in Plymouth or Barnstable Counties. PNPS is on a 24-month refueling cycle. During

refueling outages, site employment increases above the 700 person permanent workforce by as many as 700 to 900 workers for temporary (30 to 40 days) duty.

Environmental Impacts

The NRC has prepared a Generic Environmental Impact Statement (NRC 1996) 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:

> Small – 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 PNPS 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 49 [2] applicable Category 1 issues.

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 PNPS[4], and like the

[2] The remaining Category 1 issues do not apply to PNPS either because they are associated with design or operational features that PNPS does not have (e.g., cooling towers) or to an activity, refurbishment, that PNPS 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 Category 2 issues do not apply to PNPS either because they are associated with design or operational features that PNPS does not have (e.g., cooling towers) or to an activity, refurbishment, that PNPS will not undertake.

Category 1 issues, could potentially involve impacts to the coastal zone. The applicable issues and Entergy's impact conclusions are listed below.

- Aquatic ecology
  - Entrainment of fish and shellfish in early life stages – This issue addresses mortality of organisms small enough to pass through the plant's circulating cooling water system. Entergy and Boston Edison (former owner/operator of PNPS)have conducted studies of the impacts of entrainment under direction of the EPA and the Commonwealth and, in issuing the plant's discharge permit, EPA and the Commonwealth have approved the plant's intake structure as the best technology available to minimize impact. Entergy concludes that these impacts are small during current operations and has no plans that would change this conclusion for the license renewal term.
  - Impingement of fish and shellfish – 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 studies and permit discussed above also address impingement. Entergy concludes that these impacts are small during current operations and has no plans that would change this conclusion for the license renewal term.
  - Heat shock – This issue addresses mortality of aquatic organisms by exposure to heated plant effluent. Entergy and Boston Edison (former owner/ operator of PNPS) have conducted studies of this issue under the direction of the EPA and the Commonwealth and, in issuing the plant's discharge permit, EPA and the Commonwealth have determined 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 has no plans that would change this conclusion for the license renewal term.
- Threatened or endangered species

This issue address effects that PNPS 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 Commonwealth of Massachusetts law (Table D-1). Although several species of whales and sea turtles occur in Cape Cod Bay, none have ever been observed in the vicinity of the plant. Several other terrestrial species could occur on the PNPS site, or along associated transmission corridors, although none have been observed. Entergy's and NSTAR's (the company responsible for the transmission lines) environmental protection programs have identified no adverse impacts to such species and Entergy consultation with cognizant Federal and Commonwealth agencies has identified no impacts of concern. Entergy concludes that PNPS impacts to these species are small during current operations and has no plans that would change this conclusion for the license renewal term.

- Human health

Electromagnetic fields, acute effects (electric shock) – 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
  - <u>Housing</u> – This issue addresses impacts that PNPS employees required to support license renewal could have on local housing availability. The NRC concluded, and Entergy concurs, that impacts would be small for plants located in high population areas with no growth control measures. Using the NRC definitions and categorization methodology, PNPS is located in a high population area and locations where additional employees would probably live do not have growth control measures. In addition, as Entergy does not intend to add additional permanent employees to the PNPS workforce, Entergy has concluded that impacts during the PNPS license renewal term would be small.
  - <u>Public services; public utilities</u> – This issue address impacts that adding license renewal workers could have on public water supply systems. Entergy has analyzed the availability of public water supplies in candidate locales and has found no limitations that would suggest that additional PNPS workers would cause impacts. As Entergy does not intend to add additional permanent employees to the PNPS workforce, Entergy has concluded that impacts during the PNPS license renewal term would be small.
  - <u>Offsite land use</u> – This issue addresses impacts that local government spending of plant property tax dollars can have on land use patterns. PNPS property taxes comprise 2-3 percent of the Town of Plymouth'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 PNPS license renewal term would be small.
  - <u>Public services; transportation</u> – This issue addresses impacts that adding license renewal workers could have on local traffic patterns. As Entergy does not intend to add additional employees to the permanent workforce for the license renewal term, this would result in small impacts.
  - <u>Historic and archaeological resources</u> – This issue address impacts that license renewal activities could have on resources of historic or archaeological significance. Although a number of archaeological or historic sites have been identified on or near the PNPS site or associated transmission lines, Entergy is not aware of any adverse or detrimental impacts to these sites from current operations and Entergy has no plans for license renewal activities that would disturb these resources. Entergy correspondence with the Massachusetts Historical Commission, State Historic Preservation Officer identified no issues of concern.
  - <u>Severe accidents</u> – Results from the Entergy severe accident mitigation alternatives (SAMA) analysis have not identified additional cost beneficial ways 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 PNPS. The SAMAs, however, are unrelated to aging management issues that are the subject of the license renewal analysis and, therefore are not related to the consistency certification for license renewal.

State Program

The Massachusetts Coastal Zone Management Program is administered by the Massachusetts Office of Coastal Zone Management within the Massachusetts Executive Office of Environmental Affairs. The office maintains a website that describes the program in general terms (Reference D-3). The Massachusetts Coastal Zone Management Program (Reference D-4) contains details about the state's enforceable policies and management principles. Attachment D-1 lists these policies and management principles and discusses for each item the applicability to PNPS and, where applicable, the status of PNPS compliance.

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 PNPS.
2. For Category 2 issues applicable to PNPS, Entergy has determined that the environmental impacts are small.
3. To the best of Entergy's knowledge, PNPS is in compliance with Massachusetts licensing and permitting requirements and is in compliance with its Commonwealth-issued licenses and permits.
4. Entergy's license renewal and continued operation of PNPS would be consistent with the enforceable provisions of the Massachusetts Coastal Zone Management Program.

STATE NOTIFICATION

By this certification that PNPS license renewal is consistent with Massachusetts' coastal zone management program, the Commonwealth of Massachusetts 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 301 CMR 21.07(3)(e), if the Commonwealth of Massachusetts 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 Commonwealth's concurrence, objection, or notification of review status shall be sent to:

Robert Schaaf
U.S. Nuclear Regulatory Commission
One White Flint North
11555 Rockville Pike
Rockville, MD 020852-2738

Stephen J. Bethay
Director, Nuclear Assessment
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

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. Massachusetts Coastal Zone Management, "Massachusetts Coastal Zone Management," Boston, MA, 2001, available at http://www.state.ma.us/czm/czm.htm, accessed April 23, 2001.

D-4. Code of Massachusetts Regulations, Chapter 301, Sections 20-26, Coastal Zone Management Program.

D-5. U.S. Fish & Wildlife Service, Threatened and Endangered Species System (TESS); Listings by State and Territory as of 02/23/2005: Massachusetts, February 23, 2005, Available at http://ecos.fws.gov/tess_public/TESSWebpageUsaLists?state=MA.

D-6. Massachusetts Division of Fisheries and Wildlife, "Rare Species by County: Plymouth," Boston, MA, March 1, 2003, Available at http://www.mass.gov/dfwele/dfw/nhesp/plym.htm, Accessed January 11, 2005.

D-7. Massachusetts Division of Fisheries and Wildlife, "Massachusetts List of Endangered, Threatened and Special Concern Species," Boston, MA, June 18, 2004, Available at http://www.mass.gov/dfwele/dfw/nhesp/nhrare.htm, Accessed February 23, 2005.

D-8. Massachusetts Division of Fisheries & Wildlife, National Heritage & Endangered Species Program, BioMap and Living Waters: Guiding Land Conservation for Biodiversity in Massachusetts, Core Habitats of Plymouth, Westborough, MA, 2004.

Table D-1
Massachusetts Coastal Zone Management Program's
Program Policies and Management Principles

The Massachusetts Coastal Zone Management Program is codified in the Massachusetts General Laws and the Code of Massachusetts Regulations and requires persons seeking approval for activities which may impact the Coastal Zone to demonstrate that the activity is consistent with all applicable policies in 301 CMR 21.98, Policy Appendix. Entergy is seeking renewal of the operating license for PNPS. The following table details the policies and management principles of 301 CMR 21.98 and provides the Entergy demonstration that PNPS license renewal would be consistent with 301 CMR 21.98.

POLICY	JUSTIFICATION/ CONSISTENCY
WATER QUALITY POLICIES	
WATER QUALITY POLICY #1: Ensure that point-source discharges in or affecting the coastal zone are consistent with federally-approved state effluent limitations and water quality standards.	PNPS operations are consistent with its NPDES permit requirements which are based on federally approved water quality standards.
WATER QUALITY POLICY #2: Ensure that nonpoint pollution controls promote the attainment of state surface water quality standards in the coastal zone.	PNPS's storm water runoff is covered by its NPDES permit.
WATER QUALITY POLICY #3: Ensure that activities in or affecting the coastal zone conform to applicable state requirements governing sub-surface waste discharges and sources of air and water pollution and protection of wetlands.	PNPS's activities conform to requirements set forth in its: • Groundwater Permit • Air Quality Emissions Cap • NPDES Permit • Applicable Wetlands Order of Conditions
HABITAT POLICIES	
HABITAT POLICY #1: Protect wetland areas including salt marches, shellfish beds, dunes, beaches, barrier beaches, salt ponds, eel grass beds, and freshwater wetlands for their role as natural habitats.	PNPS does maintain onsite man-made freshwater wetlands areas.
HABITAT POLICY #2: Promote the restoration of degraded or former wetland resources in coastal areas and ensure that activities in coastal areas do no further wetland degradation, but instead take advantage of opportunities to engage in wetland restoration.	PNPS operations do not degrade wetlands in the coastal areas.
PROTECTED AREAS POLICIES	
PROTECTED AREAS POLICY #1: Assure preservation, restoration, and enhancement of complexes of coastal resources of regional or	PNPS is not located in an Area of Critical Environmental Concern.

statewide significance through the Areas of Critical Environmental Concern (ACEC) Program.	
PROTECTED AREAS POLICY #2: Protect state and locally designated scenic rivers and state classified scenic rivers in the coastal zone.	PNPS is not located on a river.
PROTECTED AREAS POLICY #3: Review proposed developments in or near designated or registered historic districts or sites to ensure that the preservation intent is respected by federal, state, and private activities and that potential adverse effects are minimized.	Entergy is aware of no PNPS impacts on designated or registered historic districts or sites and license renewal will not alter this. Entergy has been in contact with the Massachusetts Historical Commission which is in agreement that license renewal for PNPS is unlikely to affect historic sites or districts.
COASTAL HAZARDS POLICIES	
COASTAL HAZARD POLICY #1: Preserve, protect, restore, and enhance the beneficial functions of storm damage prevention and flood control provided by natural coastal landforms, such as dunes, beaches, barrier beaches, coastal banks, land subject to coastal storm flowage, salt marshes, and land under the ocean.	Entergy is aware of no PNPS impacts on these areas and of no reason for license renewal to alter this.
COASTAL HAZARD POLICY #2: Ensure construction in water bodies and contiguous land areas will minimize interference with water circulation and sediment transport. Approve permits for flood or erosion control projects only when it has been determined that there will be no significant adverse effects on the project site or adjacent or downcoast areas.	PNPS license renewal will necessitate no construction.
COASTAL HAZARD POLICY #3: Ensure that state and federally funded public works projects proposed for location within the coastal zone will: • Not exacerbate existing hazards or damage natural buffers or other natural resources; • Be reasonably safe from flood and erosion related damage; • Not promote growth and development in hazard-prone or buffer areas, especially in Velocity zones and ACECs; and • Not be used on Coastal Barrier Resource Units for new or substantial reconstruction of structures in a manner inconsistent with the	PNPS is a privately owned facility and its license renewal is not a state or federally funded public works project

Coastal Barrier Resource/Improvement Acts.	
COASTAL HAZARD POLICY #4: Prioritize public funds for acquisition of hazardous coastal areas for conservation or recreation use, and relocation of structures out of coastal high hazard areas, giving due consideration to the effects of coastal hazards at the location to the use and the manageability of the area.	PNPS is a privately owned facility and is not involved in the spending/ prioritizing of public funds.
PORT AND HARBOR INFRASTRUCTURE POLICIES	
PORTS POLICY #1: Ensure that dredging and disposal of dredged material minimize adverse effects on water quality, physical processes, marine productivity, and public health.	PNPS is not a port or harbor infrastructure project.
PORTS POLICY #2: Promote the widest possible public benefit from channel dredging, ensuring that designated ports and developed harbors are given highest priority in the allocation of federal and state dredging funds. Ensure that this dredging is consistent with marine environmental policies.	PNPS is not a port or harbor infrastructure project.
PORTS POLICY #3: Preserve and enhance the capacity of Designated Port Areas (DPAs) to accommodate water-dependent industrial uses, and prevent the exclusion of such uses from tidelands and any other DPA lands over which a state agency exerts control by virtue of ownership, regulatory authority, or other legal jurisdiction.	PNPS is not a port or harbor infrastructure project.
PORTS AND HARBOR INFRASTRUCTURE MANAGEMENT PRINCIPLES	
PORTS MANAGEMENT PRINCIPLE #1: Encourage, through technical and financial assistance, expansion of water dependent uses in designated ports and developed harbors, re-development of urban waterfronts, and expansion of visual access.	PNPS is not a port or harbor infrastructure project.
PUBLIC ACCESS MANAGEMENT PRINCIPLES	
PUBLIC ACCESS MANAGEMENT PRINCIPLE #1: Improve public access to coastal recreation facilities and alleviate auto traffic and parking problems through improvements in public transportation. Link existing coastal recreation sites to each other or to nearby coastal inland facilities via trails for bicyclists, hikers, and equestrians, and via rivers for boaters.	Due to the heightened security environment, PNPS has closed it's shorefront area and nature trails to public access.

PUBLIC ACCESS MANAGEMENT PRINCIPLE #2: Increase capability of existing recreation areas by facilitating multiple use and by improving management, maintenance, and public support facilities. Resolve conflicting uses whenever possible through improved management rather than through exclusion of uses.	Due to the heightened security environment, PNPS has closed it's shorefront area and nature trails to public access.
PUBLIC ACCESS MANAGEMENT PRINCIPLE #3: Provide technical assistance to developers of private recreational facilities and sites that increase public access to the shoreline.	PNPS is a privately owned facility and is not involved in external activities of shorefront development. In addition, due to the heightened security environment, PNPS has closed it's shorefront area and nature trails to public access.
PUBLIC ACCESS MANAGEMENT PRINCIPLE #4: Expand existing recreation facilities and acquire and develop new public areas for coastal recreational activities. Give highest priority to expansions or new acquisitions in regions of high need or limited site availability. Assure that both transportation access and the recreational facilities are compatible with social and environmental characteristics of surrounding communities.	PNPS is a privately owned facility and is not involved in external activities of shorefront development.
ENERGY POLICY	
ENERGY POLICY #1: For coastally dependent energy facilities, consider siting in alternative coastal locations. For non-coastally dependent energy facilities, consider siting in areas outside of the coastal zone. Weigh the environmental and safety impacts of locating proposed energy facilities at alternative sites.	PNPS is an existing facility.
ENERGY MANAGEMENT PRINCIPLE	
ENERGY MANAGEMENT PRINCIPLE #1: 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 Commonwealth.	PNPS is a privately owned power generation facility that plays an important role as a generator and as a means for maintaining grid stability in Southeastern Massachusetts.
OCEAN RESOURCES POLICIES	
OCEAN RESOURCES POLICY #1: Support the development of environmentally sustainable aquaculture, both for commercial and enhancement (public shellfish stocking) purposes. Ensure that the review process regulating aquaculture facility sites (and access routes to those areas) protects ecologically	Entergy is aware of no aquaculture near the site. Entergy is aware of no PNPS impacts on aquaculture and no reason for license renewal to alter this. PNPS sponsors a pilot phase winter flounder hatchery in Chatham, MA. PNPS has

significant resources (salt marshes, dunes, beaches, barrier beaches, and salt ponds) and minimizes adverse impacts upon the coastal and marine environment.	conducted post release survival studies which indicate this is a viable restoration technique.
OCEAN RESOURCES POLICY #2: Extraction of marine minerals will be considered in areas of state jurisdiction except where prohibited by the Massachusetts Ocean Sanctuaries Act, where and when the protection of fisheries, air and marine water quality, marine resources, navigation, and recreation can be assured.	PNPS operation and license renewal do not involve extraction of marine minerals.
OCEAN RESOURCES POLICY #3: Accommodate offshore sand and gravel mining needs in areas and in ways that will not adversely affect shoreline areas due to alteration of wave direction and dynamics, marine resources, and navigation. Mining of sand and gravel, when and where permitted, will be primarily for the purpose of beach nourishment.	PNPS operations and license renewal do not involve sand or gravel mining.
GROWTH MANAGEMENT PRINCIPLES	
GROWTH MANAGEMENT PRINCIPLE #1: Encourage, through technical assistance and review of publicly funded development, compatibility of proposed development with local community character and scenic resources.	PNPS is a privately owned facility and renewal of its operating license is not a state or federally funded public works project
GROWTH MANAGEMENT PRINCIPLE #2: Ensure that state and federally funded transportation and wastewater projects primarily serve existing developed areas, assigning highest priority to projects that meet the needs of urban and community development centers.	PNPS is a privately owned facility and renewal of its operating license is not a state or federally funded public works project
GROWTH MANAGEMENT PRINCIPLE #3: Encourage the revitalization and enhancement of existing development centers in the coastal zone through technical assistance and federal and state financial support for residential, commercial, and industrial development.	PNPS is a privately owned facility and renewal of its operating license is not a state or federally funded public works project

Table D-2
Endangered and Threatened Species that Occur in the Vicinity of PNPS or in Plymouth County, MA

Scientific Name	Common Name	Federal Status[a]	State Status[a]
Mammals			
Balaenoptera borealis	Sei whale	E	E
Balaena glacialis	Right Whale	E	E
Balaenoptera musculus	Blue Whale	E	E
Balaenoptera physalus	Finback Whale	E	E
Megaptera novaeangliae	Humpback Whale	E	E
Birds			
Ammodramus savannarum	Grasshopper Sparrow	-	T
Bartramia longicauda	Upland Sandpiper	-	E
Botaurus lentiginosus	American Bittern	-	E
Charadrius melodus[b]	Piping Plover	T	T
Circus cyaneus	Northern Harrier	-	T
Haliaeetus leucocephalus	Bald Eagle	T	E
Ixobrychus exilis[b]	Least Bittern	-	E
Parula americana	Northern Parula	-	T
Podilymbus podiceps	Pied-Billed Grebe	-	E
Rallus elegans	King Rail	-	T
Sterna dougallii dougallii[b]	Roseate Tern	E	E
Reptiles			
Caretta caretta	Loggerhead Sea Turtle	T	T
Chelonia mydas	Green Sea Turtle	T	T
Dermochelys coriacea	Leatherback Sea Turtle	E	E
Emydoidea blandingii	Blanding's Turtle	-	T
Eretmochelys imbricata	Hawksbill Sea Turtle	E	E
Lepidochelys kempii	Kemp's Ridley Sea Turtle	E	E
Malaclemys terrapin	Diamondback Terrapin	-	T
Pseudemys rubriventris[b]	Northern Red-Bellied Cooter	E	E
Amphibians			
Ambystoma opacum	Marbled Salamander	-	T
Scaphiopus holbrookii	Eastern Spadefoot Toad	-	T
Invertebrates			
Acronicta albarufa	Barrens Daggermoth	-	T
Alasmidonta heterodon	Dwarf Wedgemussel	E	E
Cicinnus melsheimeri	Melsheimer's Sack Bearer	-	T
Cycnia inopinatus	Unexpected Cycnia	-	T
Enallagma recurvatum[b]	Pine Barrens Bluet	-	T
Erynnis persius persius[b]	Persius Duskywing	-	E
Hypomecis buchholzaria	Buchholz's Gray	-	E
Lampsilis cariosa	Yellow Lampmussel	-	E
Metarranthis apiciaria	Barrens Metarranthis Moth	-	E
Nicrophorus americanus	American Burying Beetle	E	-
Papaipema appassionata	Pitcher Plant Borer Moth	-	T
Papaipema stenocelis	Chain Fern Borer Moth	-	T

Scientific Name	Common Name	Federal Status[a]	State Status[a]
Papaipema sulphurata[b]	Water-Willow Stem Borer	-	T
Somatochlora kennedyi	Kennedy's Emerald	-	E
Zanclognatha martha	Pine Barrens Zanclognatha	-	T
Vascular plants			
Agalinis acuta	Sandplain Gerardia	E	-
Aristida purpurascens	Purple Needlegrass	-	T
Asclepias verticillata	Linear-Leaved Milkweed	-	T
Bidens hyperborean var. *hyperborea*	Estuary Beggarticks	-	E
Calamagrostis pickeringii	Reed Bentgrass	-	E
Cardamine longii	Long's Bittercress	-	E
Carex polymorpha	Variable Sedge	-	E
Carex striata var. *brevis*	Walter's Sedge	-	E
Crassula aquatica	Pygmyweed	-	T
Cyperus houghtonii	Houghton's Flatsedge	-	E
Dichanthelium mattamuskeetense	Mattamuskeet Panic-Grass	-	E
Elatine americana	American Waterwort	-	E
Eriocaulon parkeri	Estuary Pipewort	-	E
Eupatorium aromaticum	Lesser Snakeroot	-	E
Eupatorium leucolepis var. *novae-angliae*[b]	New England Boneset	-	E
Isoetes acadiensis	Acadian Quillwort	-	E
Isotria medeoloides	Small Whorled Pogonia	T	-
Linum medium var. *texanum*	Rigid Flax	-	T
Lipocarpha micrantha	Dwarf Bulrush	-	T
Ludwigia sphaerocarpa	Round-Fruited False-Loosestrife	-	E
Lycopus rubellus	Gypsywort	-	E
Mertensia maritima	Oysterleaf	-	E
Ophioglossum pusillum	Northen adder's-tongue	-	T
Panicum rigidulum var. *Pubescens*	Long-Leaved Panic-Grass	-	T
Platanthera flava var. *herbiola*	Pale Green Orchid	-	T
Polygonum setaceum var. *interjectum*	Strigose Knotweed	-	T
Prenanthes serpentaria	Lion's Foot	-	E
Ranunculus micranthus	Tiny-Flowered Buttercup	-	E
Ranunculus pensylvanicus	Bristly Buttercup	-	T
Rhynchospora inundata[b]	Inundated Horned-Sedge	-	T
Rhynchospora nitens[b]	Short-Beaked Bald-Sedge	-	T
Rhynchospora torreyana[b]	Torrey's Beak-Sedge	-	E
Rumex pallidus	Seabeach Dock	-	T
Sabatia campanulata	Slender Marsh Pink	-	E
Sagittaria subulata var. *subulata*	River Arrowhead	-	E
Sanicula canadensis	Canadian Sanicle	-	T
Scirpus longii	Long's Bulrush	-	T

Scientific Name	Common Name	Federal Status[a]	State Status[a]
Senna hebecarpa	Wild Senna	-	E
Spartina cynosuroides	Salt Reedgrass	-	T
Sphenopholis pensylvanica	Swamp Oats	-	T
Symphyotrichum concolor	Eastern Silvery Aster	-	E
Triosteum perfoliatum	Broad Tinker's Weed	-	E
Viola brittoniana	Britton's Violet	-	T

a. E = Endangered; T = Threatened; - = Not listed.
b. Species reported by the Massachusetts NHESP as occurring within six miles of PNPS.
Source: References D-6, D-7, and D-8

Table D-3
Environmental Authorizations for Current PNPS Operations

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal Requirements to License Renewal					
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to Operate	DPR – 35	Issued 09/15/72 Expires 06/08/12	Operation of Unit 1
U.S. Nuclear Regulatory Commission	Atomic Energy Act Section 161, (42 USC 2201), 10 CFR 40 and 70	Material License	20-07626-04	Issued 02/10/03 Expires 02/28/2013	Contamination on reactor components
U.S. Department of Transportation	49 CFR 107, Subpart G	Registration	062601551001J	Issued 05/16/05 Expires 06/30/06 This permit is renewed on an annual basis.	Radioactive and hazardous materials shipments
U.S. Environmental Protection Agency and Massachusetts Department of Environmental Protection	Clean Water Act (33 USC 1251 et seq.), MGL c21, Section 43(2)	NPDES Permit	MA0003557	Issued 04/29/91 Modified 08/30/94 Expired 04/29/96 (remains in effect pending EPA and Commonwealth action on renewal applications submitted 10/25/95 and 12/01/99)	Plant discharges to Cape Cod Bay
U.S. Fish and Wildlife Service	Migratory Bird Treaty Act, 16 USC 703-712	Depredation Permit	MB831184-0	Issued 07/08/05 Expires 06/30/06 This permit is renewed on an annual basis.	Removal of birds and nests from utility structures

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
State Requirements to License Renewal					
Massachusetts Department of Public Health	MGL c111, Section 5N	Material License	07-6262	Issued 4/22/03 Expires 4/30/08	Contamination on reactor components
Massachusetts Department of Public Health	MGL c111, Section 5N	Material License	49-0078	Issued 10/11/02 Expires 5/31/06	Contamination on reactor components
Massachusetts Department of Public Safety	MGL c148, Section 13	Registration	Not applicable	Expires 04/01/2006 This registration is renewed on an annual basis.	Storing flammable materials in tanks
Massachusetts Department of Environmental Protection	MGL c21, Sections 26-53	Groundwater Discharge Permit	#2-389	Issued 04/20/99 Expires 4/20/04 Renewal Application submitted 10/14/03. Administratively continued pending review of application	Treated effluent discharges to groundwater from wastewater treatment facility
Massachusetts Department of Environmental Protection	310 CMR 7.02(15) 310 CMR 7.02(15)(e)	50% Facility Emission Cap		Issued 07/18/2005	Emissions from various small combustion sources
Massachusetts Department of Environmental Protection	MGL c21C 310 CMR 30	Large Quantity Generator	MAR000014167	Issued 10/06/99	Hazardous waste generation

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
State Requirements to License Renewal					
South Carolina Department of Health and Environmental Control	South Carolina Radioactive Waste Transportation and Disposal Act (SC ST SEC 13-7-110 et seq.)	Radioactive Waste Transport Permit	0007-20-01	Issued 12/17/04 Expires 12/31/05 This permit is renewed on an annual basis.	Transportation of radioactive waste to disposal facility in South Carolina
Tennessee Department of Environment and Conservation	TCA 68-202-206	Radioactive Waste License-for-Delivery	T-MA004-L01	Issued 12/08/04 Expires 12/31/05 This permit is renewed on an annual basis.	Shipment of radioactive waste to disposal/ processing facility in Tennessee
CFR - Code of Federal Regulations USC - United States Code MGL - Massachusetts General Laws CMR - Code of Massachusetts Regulations TCA - Tennessee Code Annotated					

Table D-4
Environmental Authorizations for Pilgrim Nuclear Power Station License Renewal

Agency	Authority	Requirement	Activity Covered
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License Renewal	Environmental Report submitted in support of license renewal application
U.S. Fish and Wildlife Service and National Marine Fisheries Service	Endangered Species Act Section 7	Consultation	Requires Federal agency issuing a license to consult with FWS and NMFS.
Commonwealth of Massachusetts Division of Fisheries and Wildlife	Endangered Species Act Section 7	Consultation	Requires Federal agency issuing a license to consult with FWS at the state level.
Massachusetts Department of Environmental Protection	Clean Water Act Section 401	Certification	Requires Commonwealth certification that discharge would comply with CWA standards
Massachusetts Historical Commission	National Historic Preservation Act Section 106	Consultation	Requires Federal agency issuing a license to consider cultural impacts and consult with the SHPO.
Massachusetts Coastal Zone Management Program	Federal Coastal Zone Management Act (16 USC 1451 et seq.)	Certification	Requires an applicant to provide certification to the federal agency issuing the license that the 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.

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 Pilgrim Nuclear Power Station (PNPS) PSA Level 1 and Level 2 models. This section provides the description of PNPS PSA Levels 1, 2, and 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 PNPS (Revision 1, April 2003) [Reference E.1-1]. The PNPS PSA model and documentation has been updated to reflect the current plant operating configuration and design changes as of September 2001. The current PSA model reflects the accumulation of additional plant operating history and component failure and unavailability data as of December 2001. The PSA model also resolves all findings and observations during the industry peer review of the model, conducted in March 2000 [Reference E.1-1]. The PNPS model adopts the small event tree/ large fault tree approach and uses the CAFTA code for quantifying CDF. The Level 1 and Level 2 PNPS PSA analyses were originally developed and submitted to the NRC in September 1992 as the Pilgrim Nuclear Power Station Individual Plant Examination (IPE) Submittal [Reference E.1-2].

The PSA model has been updated since the IPE due to the following.

- In 1995, the original IPE model was changed in response to the NRC Request for Additional Information (RAI) received in April 1995 [Reference E.1-3]. Overall CDF was reduced from 5.85E-5/yr to 2.84E-5/yr. The reduction in CDF was due to removal of HPCI room cooling dependency, revised ADS success criteria, and improved HPCI/RCIC performance.

- 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.1-2 [Reference E.1-1].

The current PNPS 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.1-3 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 PNPS PSA model and the SAMAs evaluated in Section E.2.

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.1-1.

Table E.1-1
Core Damage Frequency Uncertainty

Confidence	CDF (\RY)
Mean value	6.68E-6
5th percentile	4.30E-6
50th percentile	5.93E-6
95th percentile	1.08E-5

The values in Table E.1-1 reflect the uncertainties associated with the data distributions used in the analysis. The ratio of the 95th percentile to the mean is about 1.62. This uncertainty factor is included in the factor of 6 used to determine the upper bound estimated benefit described in Appendix E, Section 4.21.5.4.

Table E.1-2
PNPS PSA Model CDF Results by Major Initiators

IE Type	IE Description	CDF (/RY)	Percentage of CDF
TDC	Loss of DC Power Buses	3.06E-06	47.77%
LOOP	Loss of Offsite Power	1.29E-06	20.12%
TAC	Loss of AC Power Buses	8.83E-07	13.78%
LSSW	Loss of Salt Service Water	3.91E-07	6.10%
TRAN	Transients	3.60E-07	5.62%
LOCA	Loss of Coolant Accident	1.75E-07	2.73%
SBO	Station Blackout	1.46E-07	2.28%
ATWS	Anticipated Transient Without Scram	5.30E-08	0.83%
ISLOCA	Interfacing System LOCA	3.64E-08	0.57%
FLOOD	Internal Flooding	1.28E-08	0.20%
Total		**6.41E-06**	**100.00%**

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
IE-T1	6.70E-02	1.337	Loss of offsite power (LOOP)	This term represents the LOOP initiating event. Industry efforts over the last twenty years have led to a significant reduction in plant scrams from all causes. 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 025, 026, 027, 028, 029, 030, 033, and 035 for enhancing AC or DC system reliability or to cope with LOOP and SBO events were evaluated.
IE-TDCB	2.63E-03	1.319	Transient caused by loss of 125VDC bus B	This term represents an initiating event caused by a complete loss of 125VDC buses D-17, D5, and D37 and random failures of battery D-2. Phase I SAMAs to improve battery charging capability and replace existing batteries with more reliable ones have already been installed. Phase II SAMAs 025, 026, 027, 031, 032, 033, 034, and 035 for enhancing DC system availability and reliability were evaluated.
IE-TDCA	2.63E-03	1.304	Transient caused by loss of 125VDC bus A	This term represents an initiating event caused by a complete loss of 125VDC buses D-16, D4, and D36, and random failures of battery D-1. Phase I SAMAs to improve battery charging capability and replace existing batteries with more reliable ones have already been installed. Phase II SAMAs 025, 026, 027, 031, 032, 033, 034, and 035 for enhancing DC system availability and reliability were evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
FXT-XHE-FO-V4T2	2.31E-02	1.121	Operator fails to align fire water crosstie for reactor pressure vessel (RPV) injection via LPCI (transient)	This term represents operator failure to align fire water via the LPCI injection path for alternate RPV vessel injection. 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 SAMAs 057 and 059, which recommend proceduralizing use of the diesel fire pump hydroturbine following EDG A failure, and providing a redundant path from fire water pump discharge to LPCI loops A and B cross-tie, were evaluated.
AC2-PHN-PE-23kV	5.00E-01	1.079	Loss of shutdown transformer 23kV feed	This term represents loss of the shutdown transformer 23kV feed to 4.16kV bus A8. 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 025, 026, 027, 028, 029, 030, 033, and 035 for enhancing AC or DC system reliability or to cope with LOOP and SBO events were evaluated.
IE-TSSW	6.85E-05	1.065	Loss of salt service water (SSW) system	This term represents an initiating event caused by a complete loss of the service water system. Phase I SAMAs were implemented to improve service water system reliability by enhancing screen wash, adding redundant DC control power for SSW pumps, and increasing seismic integrity of the partition wall between the SSW pumps. Phase II SAMA 055 to improve SSW system reliability by reducing common dependencies was evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
IE-TAC6	2.63E-03	1.059	Transient caused by loss of 4160VAC bus A6	This term represents loss of 4.16kV bus A6. Phase I SAMAs to improve 4.16kV bus cross-tie capability and revise procedures to repair or replace failed 4.16kV breakers have already been implemented. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035 for enhancing AC or DC system reliability or to cope with LOOP and SBO events were evaluated.
CIV-XHE-FO-DTV	3.01E-03	1.057	Operator fails to vent containment using direct torus vent (DTV)	This term represents operator failure to recognize the need to vent the torus for pressure reduction during loss of containment heat removal accident sequences. 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 053 to control containment venting within a narrow pressure band to prevent rapid containment depressurization during venting was evaluated.
IE-TAC5	2.63E-03	1.052	Transient caused by loss of 4160VAC bus A5	This term represents an initiating event caused by loss of 4.16kV bus A5. Phase I SAMAs to improve 4.16kV bus cross-tie capability and revise procedures to repair or replace failed 4.16kV breakers have already been implemented. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035 for enhancing AC or DC system reliability or to cope with LOOP and SBO events were evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
RHR-MAI-MA-HTXAP	4.08E-04	1.051	RHR heat exchanger E-207A unavailable due to maintenance	This term represents RHR heat exchanger E-207A 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 venting via DTV path to reduce containment pressure. Phase II SAMAs 001, 009, 014, 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.
RBC-MAI-MA-LOOPA	3.71E-04	1.046	RBCCW loop A out for maintenance	This term represents RBCCW loop A unavailable due to maintenance. A Phase I SAMA was implemented to improve RBCCW system reliability by making component cooling water trains separate. Phase II SAMA 055 to improve RBCCW system reliability by reducing common dependencies was evaluated.
FXT-XHE-FO-DWS	2.21E-02	1.046	Operator fails to align fire water cross-tie for drywell spray	This term represents operator failure to align fire water via the LPCI injection path for alternate drywell spray to remove containment heat. 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 SAMAs 057 and 059, which recommend proceduralizing use of the diesel fire pump hydroturbine following EDG A failure, and providing a redundant path from fire water pump discharge to LPCI loops A and B cross-tie, were evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
AC8-CBR-CO-204	9.50E-05	1.044	480V circuit breaker 52-204 fails to remain closed	This term represents random failure of 480V circuit breaker 52-204, leading to loss of power to 480V motor control center (MCC) B14 and its associated loads. A Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 030 and 058 to improve 480V bus availability were evaluated.
AC8-CBR-CO-103	9.50E-05	1.044	480V circuit breaker 52-103 fails to remain closed	This term represents random failure of 480V circuit breaker 52-103, leading to loss of power to 480V MCC B15 and its associated loads. A Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 030 and 058 to improve 480V bus availability were evaluated.
FXT-ENG-FR-P140	1.92E-02	1.043	Diesel fire pump P-140 fails to run	This term represents diesel fire pump P-140 failure to run. Phase II SAMA 045, to add a diverse injection system and provide an injection source other than fire water, was evaluated.
LCI-HTX-VF-E207A	3.24E-04	1.04	Loop B heat exchanger E-207A failure	This term represents random failure of RHR heat exchanger E-207A, 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 venting via DTV path to reduce containment pressure. Phase II SAMAs 001, 009, 014, 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.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
LCI-HTX-VF-E207B	3.24E-04	1.039	Loop A heat exchanger E-207B failure	This term represents random failure of RHR heat exchanger E-207B, leading to loop B 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 venting via DTV path to reduce containment pressure. Phase II SAMAs 001, 009, 014, 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.
IE-T2	8.90E-02	1.038	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. Phase II SAMA 038, to improve MSIV design and mitigate the consequences of this event, was evaluated.
RHR-MAI-MA-HTXBP	2.69E-04	1.032	RHR heat exchanger E-207B unavailable due to maintenance	This term represents RHR heat exchanger E-207B unavailable due to maintenance, leading to loop B 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 venting via DTV path to reduce containment pressure. Phase II SAMAs 001, 009, 014, 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.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
RBC-MAI-MA-LOOPB	2.36E-04	1.029	RBCCW loop B out for maintenance	This term represents RBCCW loop B unavailable due to maintenance. A Phase I SAMA was implemented to improve RBCCW system reliability by making component cooling water trains separate. Phase II SAMA 055 to improve RBCCW system reliability by reducing common dependencies was evaluated.
DWS-XHE-FO-W2	2.85E-04	1.026	Operator fails to align drywell spray mode of RHR	This term represents operator failure to align the drywell spray mode of RHR for containment pressure reduction. 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. No additional Phase II SAMAs were recommended for this subject.
SPC-XHE-FO-W1	1.54E-04	1.026	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, 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. No additional Phase II SAMAs were recommended for this subject.
LCS-CCF-PG-STNRS	2.22E-05	1.024	Common cause failure of strainers BS-8002A&B plugged	This term represents common cause failure of the core spray and RHR suction strainers. A Phase I SAMA, installing improved passive emergency core cooling system (ECCS) suction strainers, has been implemented. Phase II SAMAs 042, 044, and 045, which recommend addition of independent injection systems to mitigate this failure event, were evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
DC1-CBR-CO-7216A	5.11E-05	1.023	125VDC circuit breaker 72-16A fails to remain closed	This term represents random failure of 125VDC circuit breaker 72-16A, leading to loss of DC power to bus D-16. Phase I SAMAs to improve battery charging capability and replace existing batteries with more reliable ones have already been installed. Phase II SAMAs 025, 026, 027, 031, 032, 033, 034, and 035 for enhancing DC system availability and reliability were evaluated.
ADS-XHE-FO-X1T2	6.88E-04	1.023	Operator fails to perform emergency depressurization (transient)	This term represents operator failure to manually open the SRVs for depressurization during transients. 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. No additional Phase II SAMAs were recommended for this subject.
DC1-CBR-CO-72165	5.11E-05	1.023	125VDC circuit breaker 72-165 fails to remain closed	This term represents random failure of DC circuit breaker 72-165 to provide power to DTV valve AO 5025, causing failure of the valve to open on demand, resulting in loss of containment venting capability. Phase II SAMA 056 to improve DTV valve availability was evaluated.
OSP-SBO	7.64E-02	1.023	Operator fails to start or align station blackout (SBO) diesel to either bus A5 or A6	This term represents operator failure to start or align the SBO diesel to either bus A5 or A6 during a LOOP event. 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.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
DC1-CBR-CO-7217A	5.11E-05	1.023	125VDC circuit breaker 72-17A fails to remain closed	This term represents random failure of 125VDC circuit breaker 72-17A, leading to loss of DC power to bus D-17. Phase I SAMAs to improve battery charging capability and replace existing batteries with more reliable ones have already been installed. Phase II SAMAs 025, 026, 027, 031, 032, 033, 034, and 035 for enhancing DC system availability and reliability were evaluated.
OSP-14	4.10E-02	1.022	Failure to recover offsite power within 14 hours	This term represents operator failure to recover offsite power within 14 hours during a LOOP event. 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.
IE-T3A	8.60E-01	1.022	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 SAMA 038 to improve MSIV design and mitigate the consequences of this event was evaluated.
FXT-MAI-MA-P140	9.22E-03	1.019	Diesel driven fire water pump P-140 unavailable due to maintenance	This term represents diesel fire pump P-140 in maintenance. Phase II SAMA 045, to add a diverse injection system and provide an injection source other than fire water, was evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
AC4-RCK-NO-604	2.51E-03	1.019	4.16kV circuit breaker 152-604 control circuit no output	This term represents failure of the control circuit of 4.16kV circuit breaker 152-604, leading to LOOP to safety bus A6. Phase I SAMAs to improve 4.16kV bus cross-tie capability and revise procedure to repair or replace failed 4.16kV breakers have already been installed. In addition, a Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035 for enhancing AC or DC system reliability or to cope with LOOP and SBO events were evaluated.
DC1-CBR-CO-72175	5.11E-05	1.018	125VDC circuit breaker 72-175 fails to remain closed	This term represents random failure of DC circuit breaker 72-175 to provide power to DTV valve AO 5042B, causing failure of the valve to open on demand, resulting in loss of containment venting capability. Phase II SAMA 056 to improve DTV valve availability was evaluated.
CIV-RCK-NO-5042B	2.50E-03	1.018	SV 5042B control circuit failure	This term represents random failure of the control circuit of DTV valve AO 5042B, causing failure of the valve to open on demand, resulting in loss of containment venting capability to control containment pressure. Phase II SAMA 056 to improve DTV valve availability was evaluated.
CIV-RCK-NO-A5025	2.50E-03	1.018	AO 5025 control circuit failure	This term represents random failure of the control circuit of DTV valve AO 5025, causing failure of the valve to open on demand, resulting in loss of containment venting capability to control containment pressure. Phase II SAMA 056 to improve DTV valve availability was evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
AC4-RCK-NO-504	2.51E-03	1.017	4.16kV circuit breaker 152-504 control circuit no output	This term represents failure of the control circuit of 4.16kV circuit breaker 152-504, leading to LOOP to safety bus A5. Phase I SAMAs to improve 4.16kV bus cross-tie capability and revise procedures to repair or replace failed 4.16kV breakers have already been installed. In addition, a Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035 for enhancing AC or DC system reliability or to cope with LOOP and SBO events were evaluated.
SSW-MDP-FS-P208D	2.02E-03	1.017	SSW pump P-208D fails to start on demand	This term represents random failure of SSW pump P-208D to start. Phase I SAMAs were implemented to improve service water system reliability by enhancing screen wash, adding redundant DC control power for SSW pumps, and increasing seismic integrity of the partition wall between the SSW pumps. Phase II SAMA 055 to improve SSW system reliability by reducing common dependencies was evaluated.
SSW-CCF-FS-3P208	2.26E-05	1.017	Common cause failure of 3 SSW pumps to start	This term represents common cause failure of 3 service water pumps to start. Phase I SAMAs were implemented to improve service water system reliability by enhancing screen wash, adding redundant DC control power for SSW pumps, and increasing seismic integrity of the partition wall between the SSW pumps. Phase II SAMA 055 to improve SSW system reliability by reducing common dependencies was evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
SSW-MDP-FS-P208E	2.02E-03	1.016	SSW pump P-208E fails to start on demand	This term represents random failure of SSW pump P-208E to start. Phase I SAMAs were implemented to improve service water system reliability by enhancing screen wash, adding redundant DC control power for SSW pumps, and increasing seismic integrity of the partition wall between the SSW pumps. Phase II SAMA 055 to improve SSW system reliability by reducing common dependencies was evaluated.
IE-S1	3.00E-04	1.015	Medium LOCA	This term represents the medium LOCA initiating event. Several 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, 041, 042, 043, 044, and 054 were evaluated to reduce the CDF contribution from medium LOCA.
LCS-STR-PG-8002A	1.20E-04	1.014	ECCS strainer BS-8002A plugged	This term represents failure of core spray and RHR suction strainer BS-8002A. A Phase I SAMA was implemented to install improved passive ECCS suction strainers. Phase II SAMAs 042, 044, and 045, which recommend addition of independent injection systems to mitigate this failure event, were evaluated.
LCS-STR-PG-8002B	1.20E-04	1.014	ECCS strainer BS-8002B plugged	This term represents failure of core spray and RHR suction strainer BS-8002B. A Phase I SAMA was implemented to install improved passive ECCS suction strainers. Phase II SAMAs 042, 044, and 045, which recommend addition of independent injection systems to mitigate this failure event, were evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
ADS-XHE-FO-X1S1	7.40E-03	1.013	Operator fails to perform emergency depressurization during medium LOCA	This term represents operator failure to manually open the SRVs for depressurization during medium LOCA. 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. No additional Phase II SAMAs were recommended for this subject.
EDG-ENG-FR-EDGB	6.10E-03	1.013	Emergency diesel generator -B (EDG) fails to continue to run	This term represents random failure of EDG-B, leading to an SBO event. Phase I SAMAs to improve availability and reliability of the EDGs by creating a cross-tie of EDGs fuel oil supply and installing a backup SBO diesel generator have already been implemented. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
AC8-CBR-CO-104	9.50E-05	1.013	480V circuit breaker 52-104 fails to remain closed	This term represents random failure of 480V circuit breaker 52-104, leading to loss of power to 480V MCC B17 and its associated loads. A Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 030 and 058 to improve 480V bus availability were evaluated.
HCI-MAI-MA-HCITM	1.62E-02	1.013	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 setpoints and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 040, 041, 042, 043, 044, and 045.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
SSW-CCF-FR-3P208	5.59E-06	1.012	Common cause failure of 3 SSW pumps to run	This term represents common cause failure of 3 service water pumps to continue to run Phase I SAMAs were implemented to improve service water system reliability by enhancing screen wash, adding redundant DC control power for SSW pumps, and increasing seismic integrity of the partition wall between the SSW pumps. Phase II SAMA 055 to improve SSW system reliability by reducing common dependencies was evaluated.
AC8-CBR-CO-205	9.50E-05	1.012	480V circuit breaker 52-205 fails to remain closed	This term represents random failure of 480V circuit breaker 52-205, leading to loss of power to 480V MCC B18 and its associated loads. A Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 030 and 058 to improve 480V bus availability were evaluated.
IE-T3C	4.40E-02	1.012	Inadvertently opened relief valve	This term represents an initiating event caused by inadvertent opening of a relief valve. Improvement of the SRV design and SRV reseat reliability, to reduce the probability and consequences of this initiating event, were evaluated in Phase II SAMAs 046 and 050.
RBC-CCF-CC-4MOVS	1.13E-05	1.012	Common cause failure of RBCCW heat exchanger A & B side MOVs (4) to open	This term represents common cause failure of RBCCW heat exchanger A & B side MOVs to open. A Phase I SAMA was implemented to improve RBCCW system reliability by making component cooling water trains separate. Phase II SAMA 055 to improve RBCCW system reliability by reducing common dependencies was evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
OSP-24	1.41E-02	1.011	Failure to recover offsite power within 24 hours	This term represents operator failure to recover offsite power within 24 hours during a LOOP event. 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.
SSW-RCI-FE-3828X	3.00E-04	1.01	Pressure switch PS-3828X coil fails to energize	This term represents random failure of SSW pressure switch PS-3828X, resulting in loss of SSW system loop A. Phase I SAMAs were implemented to improve service water system reliability by enhancing screen wash, adding redundant DC control power for SSW pumps, and increasing seismic integrity of the partition wall between the SSW pumps. Phase II SAMA 055 to improve SSW system reliability by reducing common dependencies was evaluated.
EDG-MAI-MA-EDGA	6.41E-03	1.01	EDG-A out for maintenance	This term represents EDG-A out for maintenance, leading to an SBO event. Phase I SAMAs to improve availability and reliability of the EDGs by creating a cross-tie of EDGs fuel oil supply and installing a backup SBO diesel generator have already been implemented. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
EDG-ENG-FR-EDGA	6.10E-03	1.01	EDG-A fails to continue to run	This term represents random failure of EDG-A, leading to an SBO event. Phase I SAMAs to improve availability and reliability of the EDGs by creating a cross-tie of EDGs fuel oil supply and installing a backup SBO diesel generator have already been implemented. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.
SSW-MOV-OO-V3805	6.62E-04	1.009	SSW TBCCW A heat exchanger outlet MOV MO-3805 fails to go 90% closed	This term represents random failure of SSW MOV MO-3805 to go 90% closed, resulting in loss of SSW to RBCCW loop B. A Phase I SAMA was implemented to improve RBCCW system reliability by making component cooling water trains separate. Phase II SAMA 055 to improve RBCCW system reliability by reducing common dependencies was evaluated.
SSW-MDP-FS-P208B	2.02E-03	1.009	SSW pump P-208B fails to start on demand	This term represents random failure of SSW pump P-208B to start. Phase I SAMAs were implemented to improve service water system reliability by enhancing screen wash, adding redundant DC control power for SSW pumps, and increasing seismic integrity of the partition wall between the SSW pumps. Phase II SAMA 055 to improve SSW system reliability by reducing common dependencies was evaluated.
SSW-MDP-FS-P208A	2.02E-03	1.009	SSW pump P-208A fails to start on demand	This term represents random failure of SSW pump P-208A to start. Phase I SAMAs were implemented to improve service water system reliability by enhancing screen wash, adding redundant DC control power for SSW pumps, and increasing seismic integrity of the partition wall between the SSW pumps. Phase II SAMA 055 to improve SSW system reliability by reducing common dependencies was evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
C	5.80E-06	1.009	Reactor Protection System (RPS) failure	This term represents failure of the RPS. Several Phase I SAMAs to minimize the risks associated with anticipated transient without scram (ATWS) scenarios have already been installed. No Phase II SAMAs were evaluated to further improve reliability of RPS. However, Phase II SAMA 048 to enhance reliability of the standby liquid control system and improve capability to mitigate the consequences of an ATWS event was evaluated.
AC4-RCK-NO-605	2.51E-03	1.009	4.16kV circuit breaker 152-605 control circuit no output	This term represents failure of the control circuit of 4.16kV circuit breaker 152-605, leading to loss of power to safety bus A6. Phase I SAMAs to improve 4.16kV bus cross-tie capability and procedures to repair or replace failed 4.16kV breakers have already been installed. In addition, a Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035 for enhancing AC or DC system reliability or to cope with LOOP and SBO events were evaluated.
RCI-TDP-RS-P206	1.52E-02	1.009	RCIC turbine driven pump P-206 fails to restart after clear high level signal	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 setpoints and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 040, 041, 042, 043, 044, and 045.
FXT-RCK-NO-P140	2.50E-03	1.009	Diesel fire pump P-140 control circuit no output	This term represents diesel fire pump P-140 control circuit failure. Phase II SAMA 045, to add a diverse injection system and provide an injection source other than fire water, was evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
AC4-RCK-NO-508	2.51E-03	1.008	4.16kV circuit breaker 152-508 control circuit no output	This term represents failure of the control circuit of 4.16kV circuit breaker 152-508, leading to loss of power to 480V load center B1. Phase I SAMAs to improve 4.16kV bus cross-tie capability and revise procedures to repair or replace failed 4.16kV breakers have already been implemented. In addition, a Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035 for enhancing AC or DC system reliability or to cope with LOOP and SBO events were evaluated.
AC8-RCK-NO-101	2.50E-03	1.008	480V circuit breaker 52-101 control circuit no output	This term represents random failure of 480V circuit breaker 52-101, leading to loss of power to 480V load center B1 and its associated loads. A Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 030 and 058 to improve 480V bus availability were evaluated.
EDG-MAI-MA-EDGB	4.09E-03	1.008	EDG-B out for maintenance	This term represents EDG-B out for maintenance, leading to an SBO event. Phase I SAMAs to improve availability and reliability of the EDGs by creating a cross-tie of EDGs fuel oil supply and installing a backup SBO diesel generator have already been implemented. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035, for enhancing AC or DC system reliability or to cope with LOOP and SBO events, were evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
HCI-TDP-FS-PM205	7.53E-03	1.008	HPCI turbine driven pump P-205 fails to start on demand	This term represents random failure of the HPCI system. Phase I SAMAs to improve availability and reliability of the HPCI system that have already been implemented include raising backpressure trip setpoints and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 040, 041, 042, 043, 044, and 045.
RBC-CCF-FS-4PUMP	7.35E-06	1.008	Common cause failure of four RBCCW pumps to start	This term represents common cause failure of four RBCCW pumps to start. A Phase I SAMA was implemented to improve RBCCW system reliability by making component cooling water trains separate. Phase II SAMA 055 to improve RBCCW system reliability by reducing common dependencies was evaluated.
AC4-RCK-NO-505	2.51E-03	1.007	4.16kV circuit breaker 152-505 control circuit no output	This term represents failure of the control circuit of 4.16kV circuit breaker 152-505, leading to loss of power supply to safety bus A5. Phase I SAMAs to improve 4.16kV bus cross-tie capability and revise procedures to repair or replace failed 4.16kV breakers have already been installed. In addition, a Phase I SAMA was implemented to proceduralize operator action to manually close the circuit breaker. Phase II SAMAs 025, 026, 027, 028, 029, 030, 033, and 035 for enhancing AC or DC system reliability or to cope with LOOP and SBO events were evaluated.
FXT-XVM-CC-511	5.00E-04	1.007	Manual valve 10-HO-511 fails to open	This term represents random failure of manual valve 10-HO-511 to open to provide fire water to LPCI loops A and B. This failure leads to loss of fire water backup for reactor vessel injection and drywell spray. Phase II SAMA 059 to enhance availability of the fire water system was evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
FXT-XVM-CC-8I56	5.00E-04	1.007	Manual valve 8-I-56 fails to open	This term represents random failure of manual valve 8-I-56 to open to provide fire water to LPCI loops A and B. This failure leads to loss of fire water backup for reactor vessel injection and drywell spray. Phase II SAMA 059 to enhance availability of the fire water system was evaluated.
RCI-MAI-MA-RCITM	1.97E-02	1.007	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 setpoints and proceduralizing intermittent operation. Additional improvements were evaluated in Phase II SAMAs 040, 041, 042, 043, 044, and 045.
CIV-AOV-CC-5042B	1.00E-03	1.007	AO 5042B fails to open on demand	This term represents random failure of DTV valve AO 5042B to open on demand, resulting in loss of containment venting capability to control containment pressure. Phase II SAMAs 001, 009, 014, 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 for containment pressure control.
CIV-AOV-CC-A5025	1.00E-03	1.007	AO 5025 fails to open on demand	This term represents random failure of DTV valve AO 5025 to open on demand, resulting in loss of containment venting capability to control containment pressure. Phase II SAMAs 001, 009, 014, 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 for containment pressure control.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
CM	3.30E-01	1.006	RPS mechanical failure	This term represents random failure of the RPS. Several Phase I SAMAs to minimize the risks associated ATWS scenarios have already been installed. No Phase II SAMAs were evaluated to further improve reliability of RPS. However, Phase II SAMA 048 to enhance reliability of the standby liquid control system and improve ATWS capability to mitigate the consequences of this event was evaluated.
RBC-MAI-MA-P202E	6.71E-03	1.006	RBCCW pump 202E out for maintenance	This term represents RBCCW pump 202E unavailable due to maintenance. A Phase I SAMA was implemented to improve RBCCW system reliability by making component cooling water trains separate. Phase II SAMA 055 to improve RBCCW system reliability by reducing common dependencies was evaluated.
RBC-MAI-MA-P202F	6.44E-03	1.006	RBCCW pump 202F out for maintenance	This term represents RBCCW pump 202F unavailable due to maintenance. A Phase I SAMA was implemented to improve RBCCW system reliability by making component cooling water trains separate. Phase II SAMA 055 to improve RBCCW system reliability by reducing common dependencies was evaluated.
IE-TDC-CCF	3.66E-08	1.006	Common cause failure of 125VDC buses A&B	This term represents an initiating event caused by a complete loss of 125VDC buses D-16 and D-17 or random failure of batteries D-1 and D-2. Phase I SAMAs to improve battery charging capability and replace existing batteries with more reliable ones have already been installed. Phase II SAMAs 025, 026, 027, 031, 032, 033, 034, and 035 for enhancing DC system availability and reliability were evaluated.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
SPC-MAI-MA-SPCA	3.01E-03	1.005	Suppression pool cooling loop A out for maintenance	This term represents RHR suppression pool cooling loop A unavailable due to maintenance. Phase I SAMAs to improve availability and reliability of the RHR suppression pool cooling mode that have already been implemented include using drywell spray mode and fire protection cross-tie to provide redundant containment heat removal capability. Additional improvements were evaluated in Phase II SAMAs 001 and 014.
SPC-MAI-MA-SPCB	2.91E-03	1.005	Suppression pool cooling loop B out for maintenance	This term represents RHR suppression pool cooling loop B unavailable due to maintenance. Phase I SAMAs to improve availability and reliability of the RHR suppression pool cooling mode that have already been implemented include using drywell spray mode and fire protection cross-tie to provide redundant containment heat removal capability. Additional improvements were evaluated in Phase II SAMAs 001 and 014.
DWS-MAI-MA-DWSA	3.18E-03	1.005	Drywell spray loop A out for maintenance	This term represents RHR drywell spray loop A unavailable due to maintenance. Phase I SAMAs to improve availability and reliability of the RHR drywell spray mode that have already been implemented include using suppression pool cooling mode and fire protection cross-tie to provide redundant containment heat removal capability. Additional improvements were evaluated in Phase II SAMA 009.

Table E.1-3
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs

Event Name	Probability	RRW	Event Description	Disposition
ADS-XHE-FO-X1S2	1.45E-03	1.005	Operator fails to perform emergency depressurization during small LOCA	This term represents operator failure to manually open the SRVs for depressurization during a small LOCA. 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. No additional Phase II SAMAs were recommended for this subject.

E.1.2 PSA Model – Level 2 Analysis

E.1.2.1 Containment Performance Analysis

The PNPS 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 [References E.1-2 and E.1-3]. The Level 2 PSA model used for the SAMA analysis, Revision 1, reflects the PNPS operating configuration and design changes as of September 2001. Specifically, the Level 2 model has been updated to incorporate insights from the independent BWROG peer review.

The PNPS 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.1-4] 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

Table E.1-4
Summary of PNPS PSA Core Damage Accident Class

PDS Group	Simplified Description	Point Estimate	% of Total CDF
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 PDS, late injection and containment heat removal are available.	1.16E-7	1.80
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.	2.43E-7	3.79
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.	1.48E-7	2.31
VSL_RUPT	Vessel rupture event resulting in LOCA beyond ECCS capability. All PDS result in core damage at low reactor pressure with late injection available.	4.00E-9	0.06
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/SV with early core melt subsequent to containment overpressure failure. Late injection and containment heat removal are available.	3.39E-8	0.53
ISLOCA	Large and small break interfacing system LOCA outside containment. Core damage results at low or high reactor pressure with a bypassed containment.	4.00E-9	0.06
TW	Containment decay heat removal systems are not available and coolant recirculation to the torus over pressurizes the containment to failure or venting. The torus is saturated.	5.86E-6	91.45
	Total	**6.41E-06**	**1.00E+00**

Table E.1-5
Notation and Definitions for PNPS 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.
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.

Table E.1-5
Notation and Definitions for PNPS CET Functional Nodes Description (Continued)

CET Node	CET Functional Node Description
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.

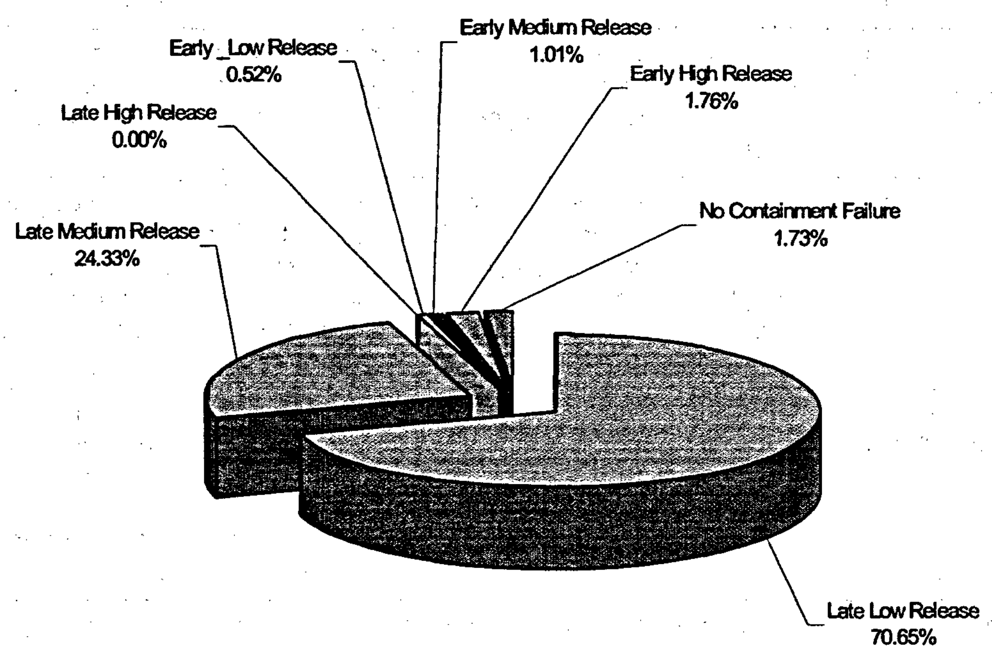

Figure E.1-1
PNPS Radionuclide Release Category Summary

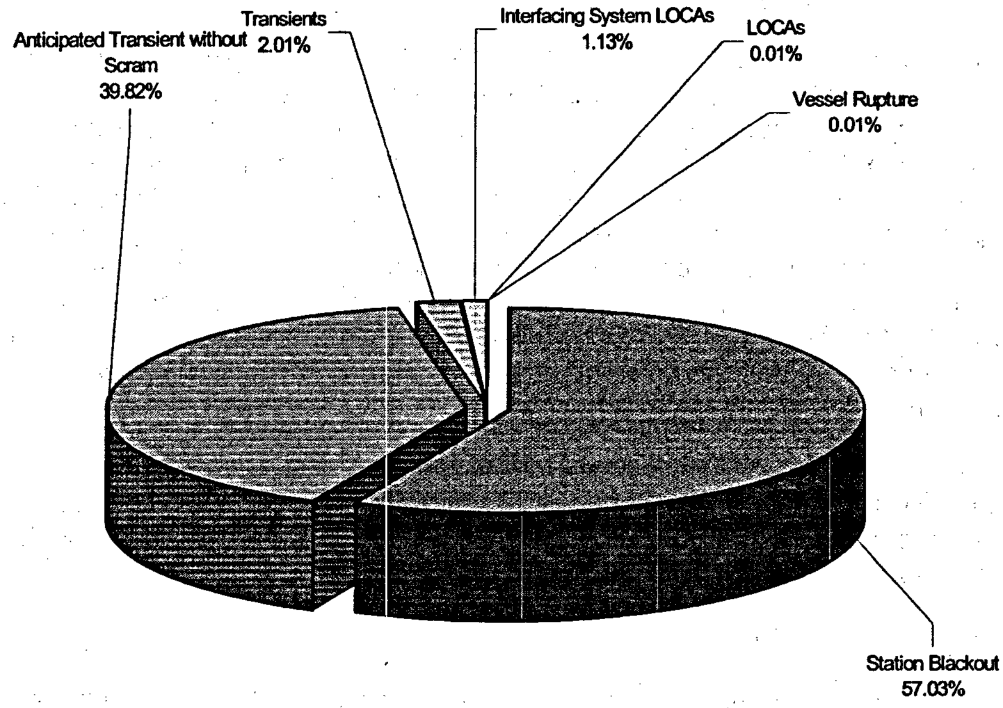

Figure E.1-2
PNPS Plant Damage State Contribution to LERF

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 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.1-4].

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. PNPS 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, PNPS expects that an Emergency Action Level (as defined by the PNPS 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.1-5]. 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:

(1) High (HI) - 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.1-5].[1]

(2) Medium (MED) - 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.1-5].[2]

(3) Low (LO) - 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.

(4) Negligible (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.

E.1.2.2.4 Release Category Bin Assignments

Table E.1-6 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.1-7.

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1. Once the CsI source term exceeds 0.1, 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%, the number of latent fatalities is found to be at least 10% of the latent fatalities for the highest release.

Table E.1-6
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.1-7
PNPS Release Categories

Timing of Release	Magnitude of Release			
	Low	Medium	High	
Early	Early/Low	Early/Med	Early/High	NCF
Late	Late/Low	Late/Med	Late/High	

E.1.2.2.5 Mapping of Level 1 Results into the Various Release Categories

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 2 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.1-8 provides a description of the PNPS PDS that are used to summarize the Level 1 results.

Table E.1-8
Summary of PNPS Core Damage Accident Sequences Plant Damage States

PDS	Description	Point Estimate	% 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.	1.05E-11	<0.001

Table E.1-8
Summary of PNPS Core Damage Accident Sequences Plant Damage States (Continued)

PDS	Description	Point Estimate	% of CDF
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.	8.68E-08	1.35
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	<0.001
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.	0.00E+00	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.	0.00E+00	0.00
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.	1.12E-09	0.08
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.	4.43E-09	0.07

Table E.1-8
Summary of PNPS Core Damage Accident Sequences Plant Damage States
(Continued)

PDS	Description	Point Estimate	% of CDF
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 SSW system, containment venting, and containment heat removal are available.	3.64E-09	0.06%
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 SSW 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 SSW 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.	2.37E-08	0.37
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.	3.75E-06	58.5
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.	1.52E-07	2.37
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.	5.07E-08	0.79

Table E.1-8
Summary of PNPS Core Damage Accident Sequences Plant Damage States (Continued)

PDS	Description	Point Estimate	% of CDF
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.	4.89E-09	0.08
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.	2.53E-09	0.04
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.	1.56E-06	24.40
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.	5.24E-07	8.18
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.	6.78E-11	0.001
PDS-21	Short-term transients (IORV) with loss of core cooling. Core damage results at low primary system pressure. Late injection and containment heat removal are available.	8.18E-09	0.13
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.	1.08E-09	0.02
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.	0.00E+00	0.00
PDS-24	Similar to PDS-23, except that containment venting is not available.	4.98E-09	0.08

Table E.1-8
Summary of PNPS Core Damage Accident Sequences Plant Damage States (Continued)

PDS	Description	Point Estimate	% of CDF
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.	2.57E-09	0.04
PDS-26	Similar to PDS-25, except that containment venting is not available.	1.24E-08	0.19
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	4.40E-11	0.001
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.	1.10E-09	0.02
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.	1.41E-07	2.21
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.	0.00E+00	0.00
PDS-31	Long-term SBO sequence involving a loss of high-pressure injection due to one stuck-open safety relief valve or long-term failure of HPCI and 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.	2.60E-09	0.04
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 and 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.	4.00E-09	0.06

Table E.1-8
Summary of PNPS Core Damage Accident Sequences Plant Damage States (Continued)

PDS	Description	Point Estimate	% of CDF
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.	4.00E-09	0.06
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 and SVs 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.	1.95E-08	0.31
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.	0.00E+00	0.00
PDS-39	Similar to PDS-38 except that containment heat removal from the RHR system is not available.	2.32E-09	0.04
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

Table E.1-8
Summary of PNPS Core Damage Accident Sequences Plant Damage States (Continued)

PDS	Description	Point Estimate	% of CDF
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.	1.34E-11	<0.001
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.	0.00E+00	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 following a loss of reactivity control. Late injection and containment venting are available.	3.39E-08	0.53
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 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.	3.22E-09	0.05
PDS-48	Unisolated LOCA outside containment with early core melt at low RPV pressure.	7.73E-10	0.01

The PDS designators listed in Table E.1-8 represent the core damage end state categories from the Level 1 analysis that 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.1-7. Note, however, that since not all the Level 2 sequences associated with each Level 1 core damage class 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.

E.1.2.2.6 Collapsed Accident Progression Bins Source Terms

The source term analysis results in hundreds of source terms for internal initiators, making calculation with the MACCS2 consequence model cumbersome. Therefore, the source terms were grouped into a much smaller number of source term groups defined in terms of similar properties, with a frequency weighted mean source term for each group.

The consequence analysis source terms groups are represented by collapsed accident progression bins (CAPB). The CAPB were generated by sorting the accident progression bins for each of the forty-eight PDS on attributes of the accident: the occurrence of core damage, the occurrence of vessel breach, primary system pressure at vessel breach, the location of containment failure, the timing of containment failure, and the occurrence of core-concrete interactions. Descriptions of the CAPB are presented in Table E.1-9.

Table E.1-9
Collapsed Accident Progression Bins (CAPB) Descriptions

CAPB Number	Description
CAPB-1	[CD, No VB, No CF, No CCI] Core damage (CD) occurs, but timely recovery of RPV injection prevents vessel breach (No VB). Therefore, containment integrity is not challenged (No CF) and core-concrete interactions are precluded (No CCI). However, the potential exists for in-vessel release to the environment due to containment design leakage.
CAPB-2	[CD, VB, No CF, No CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment does not fail structurally and is not vented (No CF). Ex-vessel releases are recovered, precluding core-concrete interactions (No CCI). Although containment does not fail, vessel breach does occur, therefore the potential exists for in- and ex-vessel releases to the environment due to containment design leakage. RPV pressure is not important because, even though high pressure induced severe accident phenomena (such as direct containment heating [DCH]) occurs, containment does not fail.
CAPB-3	[CD, VB, No CF, CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment does not fail structurally and is not vented (No CF). However, ex-vessel releases are not recovered in time, and therefore core-concrete interactions occur (CCI). RPV pressure is not important because, even though high pressure induced severe accident phenomena (such as direct containment heating [DCH]) occurs, containment does not fail, nor is the vent limit reached.
CAPB-4	[CD, VB, Early CF, WW, RPV pressure >200 psig at VB, No CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails either before core damage, during core damage, or at vessel breach (Early CF). Containment failure occurs in the torus (WW), above the water level. RPV pressure is greater than 200 psig at time of vessel breach (this implies that high pressure induced severe accident phenomena [DCH] are possible). There are no core concrete interactions (No CCI) due to the presence of an overlying pool of water.

Table E.1-9
Collapsed Accident Progression Bins (CAPB) Descriptions
(Continued)

CAPB Number	Description
CAPB-5	[CD, VB, Early CF, WW, RPV pressure <200 psig at VB, No CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails either before core damage, during core damage, or at vessel breach (Early CF). Containment failure occurs in the torus (WW), above the water level. RPV pressure is less than 200 psig at time of vessel breach; precluding high pressure induced severe accident phenomena. There are no core concrete interactions (No CCI) due to the presence of an overlying pool of water.
CAPB-6	[CD, VB, Early CF, WW, RPV pressure >200 psig at VB, CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails either before core damage, during core damage, or at vessel breach (Early CF). Containment failure occurs in the torus (WW), above the water level. RPV pressure is greater than 200 psig at time of vessel breach (this implies that high pressure induced severe accident phenomena [DCH] are possible). Following containment failure, core-concrete interactions occur (CCI).
CAPB-7	[CD, VB, Early CF, WW, RPV pressure <200 psig at VB, CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails either before core damage, during core damage, or at vessel breach (Early CF). Containment failure occurs in the torus (WW), above the water level. RPV pressure is less than 200 psig at time of vessel breach; precluding high pressure induced severe accident phenomena. Following containment failure, core-concrete interactions occur (CCI).
CAPB-8	[CD, VB, Early CF, DW, RPV pressure >200 psig at VB, No CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails either before core damage, during core damage, or at vessel breach (Early CF). Containment failure occurs in the drywell or below the torus water line (DW). RPV pressure is greater than 200 psig at time of vessel breach (this implies that high pressure induced severe accident phenomena [DCH] are possible). There are no core concrete interactions (No CCI) due to the presence of an overlying pool of water.

Table E.1-9
Collapsed Accident Progression Bins (CAPB) Descriptions
(Continued)

CAPB Number	Description
CAPB-9	[CD, VB, Early CF, DW, RPV pressure <200 psig at VB, No CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails either before core damage, during core damage, or at vessel breach (Early CF). Containment failure occurs in the drywell or below the torus water line (DW). RPV pressure is less than 200 psig at time of vessel breach; precluding high pressure induced severe accident phenomena. There are no core concrete interactions (No CCI) due to the presence of an overlying pool of water.
CAPB-10	[CD, VB, Early CF, DW, RPV pressure >200 psig at VB, CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails either before core damage, during core damage, or at vessel breach (Early CF). Containment failure occurs in the drywell or below the torus water line (DW). RPV pressure is greater than 200 psig at time of vessel breach (this implies that high pressure induced severe accident phenomena [DCH] are possible). Following containment failure, core-concrete interactions occur (CCI).
CAPB-11	[CD, VB, Early CF, DW, RPV pressure <200 psig at VB, CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails either before core damage, during core damage, or at vessel breach (Early CF). Containment failure occurs in the drywell or below the torus water line (DW). RPV pressure is less than 200 psig at time of vessel breach; precluding high pressure induced severe accident phenomena. Following containment failure, core-concrete interactions occur (CCI).
CAPB-12	[CD, VB, Late CF, WW, No CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails late due to loss of containment heat removal (Late CF). Containment failure occurs in the torus (WW), above the water level. RPV pressure is not important because high-pressure severe accident phenomena (such as DCH) did not fail containment. There are no core concrete interactions (No CCI) due to the presence of an overlying pool of water.

Table E.1-9
Collapsed Accident Progression Bins (CAPB) Descriptions
(Continued)

CAPB Number	Description
CAPB-13	[CD, VB, Late CF, WW, CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails late (late CF) due to core-concrete interactions (CCI) after vessel breach. Containment failure occurs in the torus (WW), above the water level. RPV pressure is not important because high-pressure severe accident phenomena (such as DCH) did not fail containment.
CAPB-14	[CD, VB, Late CF, DW, No CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails late due to loss of containment heat removal (Late CF). Containment failure occurs in the drywell or below the torus water level (DW). RPV pressure is not important because high-pressure severe accident phenomena did not fail containment. There are no core concrete interactions (No CCI) due to the presence of an overlying pool of water.
CAPB-15	[CD, VB, Late CF, DW, CCI] Core damage (CD) occurs followed by vessel breach (VB). Containment fails late (late CF) due to core-concrete interactions (CCI) after vessel breach. Containment failure occurs in the drywell or below the torus water level (DW). RPV pressure is not important because high-pressure severe accident phenomena did not fail containment.
CAPB-16	[CD, VB, BYPASS, RPV pressure >200 psig, No CCI] Small break interfacing system LOCA outside containment occurs. Core damage (CD) and subsequent vessel breach (VB) results at high RPV pressure with a bypassed containment. There are no core concrete interactions (No CCI) due to the presence of an overlying pool of water.
CAPB-17	[CD, VB, BYPASS, RPV pressure <200 psig, No CCI] Large break interfacing system LOCA outside containment occurs. Core damage (CD) and subsequent vessel breach (VB) results at low RPV pressure with a bypassed containment. There are no core concrete interactions (No CCI) due to the presence of an overlying pool of water.

Table E.1-9
Collapsed Accident Progression Bins (CAPB) Descriptions
(Continued)

CAPB Number	Description
CAPB-18	[CD, VB, BYPASS, RPV pressure >200 psig, CCI] Small break interfacing system LOCA outside containment occurs. Core damage (CD) and subsequent vessel breach (VB) results at high RPV pressure with a bypassed containment. Following vessel breach, core-concrete interaction occurs (CCI).
CAPB-19	[CD, VB, BYPASS, RPV pressure <200 psig, CCI] Large break interfacing system LOCA outside containment occurs. Core damage (CD) and subsequent vessel breach (VB) results at low RPV pressure with a bypassed containment. Following vessel breach, core-concrete interaction occurs (CCI).

Based on the above binning methodology, the salient Level 2 results are summarized in Tables E.1-10 and E.1-11 respectively. 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. Table E.1-11 provides the frequency, time, duration, energy, and elevation of release for each CAPB.

Table E.1-10
Summary of PNPS Containment Event Tree Quantification

Release Category (Timing/Magnitude)	Release Frequency (/RY)
Late Low	4.53E-06
Late Medium	1.56E-06
Late High	0.00E-00
Early Low	3.32E-08
Early Medium	6.48E-08
Early High	1.13E-07
No Containment Failure	1.11E-07

<u>*Nomenclature*</u>

Timing

L (Late) - Greater than 24 hours
E (Early) - Less than 24 hours

Magnitude

NCF	(Little to no release)	- Less than 0.001% CsI
LO	(Low)	- 0.001 to 1% CsI
MED	(Medium)	- 1 to 10% CsI
HI	(High)	- Greater than 10% CsI

Table E.1-11
Collapsed Accident Progression Bin (CAPB) Source Terms

	CAPB	CAPB Frequency (/year)	Warning Time (sec)	Elevation (m)	Release Start (sec)	Release Duration (sec)	Release Energy (W)
1	CAPB-1	9.51E-08	3.98E+03	3.00E+01	2.20E+04	9.00E+03	2.61E+05
2	CAPB-2	1.27E-08	3.96E+03	3.00E+01	2.20E+04	9.00E+03	2.50E+05
3	CAPB-3	2.39E-09	3.96E+03	3.00E+01	2.20E+04	9.00E+03	2.50E+05
4	CAPB-4	3.29E-09	7.96E+03	3.00E+01	1.83E+04	3.56E+03	1.10E+07
5	CAPB-5	2.73E-09	1.31E+04	3.00E+01	2.53E+04	7.93E+03	8.34E+06
6	CAPB-6	7.95E-09	1.33E+04	3.00E+01	2.56E+04	8.11E+03	8.23E+06
7	CAPB-7	7.93E-09	1.38E+04	3.00E+01	2.61E+04	8.46E+03	8.03E+06
8	CAPB-8	2.06E-08	9.18E+03	3.00E+01	2.00E+04	4.59E+03	1.04E+07
9	CAPB-9	9.25E-09	9.21E+03	3.00E+01	2.44E+04	8.87E+03	4.18E+06
10	CAPB-10	8.53E-08	1.37E+04	3.00E+01	2.60E+04	8.40E+03	8.06E+06
11	CAPB-11	4.35E-08	1.37E+04	3.00E+01	2.60E+04	8.40E+03	8.06E+06
12	CAPB-12	1.70E-06	2.84E+04	3.00E+01	4.64E+04	9.00E+03	7.59E+06
13	CAPB-13	2.30E-09	9.14E+03	3.00E+01	2.71E+04	9.00E+03	1.80E+06
14	CAPB-14	2.26E-06	2.66E+04	3.00E+01	4.46E+04	9.00E+03	7.08E+06
15	CAPB-15	2.12E-06	2.81E+04	3.00E+01	4.62E+04	9.00E+03	7.60E+06
16	CAPB-16	1.18E-09	3.96E+03	3.00E+01	2.12E+04	9.00E+03	2.50E+05
17	CAPB-17	6.91E-09	3.96E+03	3.00E+01	2.14E+04	9.00E+03	2.50E+05
18	CAPB-18	4.61E-10	3.96E+03	3.00E+01	2.12E+04	9.00E+03	2.50E+05
19	CAPB-19	2.43E-08	3.96E+03	3.00E+01	2.18E+04	9.00E+03	2.50E+05

Table E.1-11
Collapsed Accident Progression Bin (CAPB) Source Terms
(continued)

	Release Fractions								
	NG	I	Cs	Te	Sr	Ru	La	Ce	Ba
1	1.99E-07	1.85E-07	1.85E-07	0.00E+00	1.24E-09	8.00E-09	5.01E-11	8.43E-11	1.70E-08
2	9.97E-05	4.81E-05	4.66E-05	1.76E-07	3.97E-07	4.00E-06	1.65E-08	5.15E-08	4.87E-06
3	9.97E-05	5.37E-05	4.97E-05	1.76E-06	5.80E-07	4.00E-06	2.37E-08	1.57E-07	4.95E-06
4	1.00E+00	4.90E-02	2.62E-02	4.18E-05	2.46E-05	3.66E-04	8.97E-07	3.04E-06	1.92E-04
5	9.85E-01	7.86E-02	3.68E-02	4.28E-05	4.10E-05	3.66E-04	1.56E-06	6.79E-06	3.44E-04
6	1.00E+00	4.02E-02	2.32E-02	1.48E-03	3.19E-04	3.66E-04	6.50E-06	7.17E-05	3.23E-04
7	9.76E-01	6.11E-02	2.94E-02	1.26E-03	2.30E-04	3.66E-04	9.10E-06	1.06E-04	4.52E-04
8	1.00E+00	2.98E-01	2.72E-01	3.07E-05	9.89E-04	2.23E-02	4.49E-05	6.57E-05	1.15E-02
9	5.97E-01	7.61E-02	7.07E-02	1.41E-05	9.72E-04	1.09E-02	3.69E-05	7.63E-05	1.02E-02
10	1.00E+00	2.80E-01	2.49E-01	1.11E-02	3.07E-03	1.81E-02	7.95E-05	5.81E-04	1.03E-02
11	9.79E-01	1.73E-01	1.41E-01	9.97E-03	3.13E-03	1.78E-02	1.22E-04	9.39E-04	1.72E-02
12	2.01E-01	5.84E-05	4.37E-05	1.25E-07	2.36E-07	1.72E-06	8.04E-09	2.56E-08	2.99E-06
13	9.97E-01	7.99E-03	5.99E-03	1.76E-04	3.63E-05	3.66E-04	2.15E-06	1.41E-05	4.52E-04
14	7.75E-01	2.88E-02	2.67E-02	2.47E-05	2.05E-04	2.13E-03	8.49E-06	2.27E-05	2.61E-03
15	9.97E-01	2.76E-01	2.68E-01	1.27E-03	2.27E-03	2.25E-02	9.33E-05	3.00E-04	2.74E-02
16	1.00E+00	6.71E-02	3.26E-02	4.06E-04	9.11E-05	2.21E-02	1.45E-06	1.65E-05	4.27E-05
17	9.72E-01	3.62E-01	3.37E-01	1.34E-03	2.37E-03	2.20E-02	9.90E-05	1.62E-04	8.57E-03
18	1.00E+00	9.76E-02	6.25E-02	2.09E-02	4.67E-03	2.27E-02	7.45E-05	8.50E-04	2.12E-03
19	9.72E-01	4.03E-01	3.77E-01	6.87E-02	9.58E-03	2.26E-02	3.00E-04	2.33E-03	1.20E-02

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 versus time (time of containment failure is determined by comparing these values with the nominal containment capability);
- radionuclide release time and magnitude for a large number of radioisotopes; and
- release fractions for twelve radionuclide species.

E.1.3 IPEEE Analysis

E.1.3.1 Seismic Analysis

PNPS performed a seismic PRA following the guidance of NUREG-1407, *Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities*, June 1991. The seismic PRA model was performed in conjunction with the SQUG program in 1994 as part of the IPEEE submittal report [Reference E.1-6]. The seismic, high wind, and external flooding analyses determined that the plant is adequately designed to protect against the effects of these natural events.

A number of plant improvements were identified in Table 2.4 of NUREG-1742, *Perspectives Gained from the IPEEE Program*, Final Report, April 2002 [Reference E.1-8]. These improvements were implemented.

The seismic CDF in the IPEEE was conservatively estimated to be 5.82×10^{-5} per reactor-year. The seismic CDF has recently been re-evaluated to reflect the updated Gothic computer code room heat up calculations that predict no room cooling requirements for HPCI, RCIC, Core Spray, and RHR areas; to update random component failure probabilities; and to model replacement of certain relays with a seismically rugged model. The updated seismic CDF of 3.22×10^{-5} per reactor-year was used in estimation of the factor of 6 used to determine the upper bound estimated benefit described in Section 4.21.5.4.

E.1.3.2 Fire Analysis

The PNPS internal fire risk model was performed in 1994 as part of the IPEEE submittal report [Reference E.1-6]. The PNPS fire analysis was performed using the conservative EPRI's Fire Induced Vulnerability Evaluation (FIVE) methodology for qualitative and quantitative screening of fire areas and for fire analysis of areas that did not screen [Reference E.1-7]. The FIVE methodology is primarily a screening approach used to identify plant vulnerabilities due to fire initiating events.

Table E.1-12 presents the results of the PNPS IPEEE fire analysis. The values presented in Table E.1-12 are taken from NUREG-1742 [Reference E.1-8]. These values are the same as the original IPEEE fire CDF results (2.20E-5 per reactor-year) [Reference E.1-6] after the response to NRC questions/issues regarding fire-modeling progression. A revised fire zone CDF of 1.91E-5 per reactor-year, generated to reflect updated equipment failure probability and unavailability values was used in estimation of the factor of 6 used to determine the upper bound estimated benefit described in Section 4.21.5.4.

The significant fire scenarios involve fires occurring in the train B switchgear room, turbine building heater bay, vital motor generator set room, and train A switchgear room.

Table E.1-12
PNPS Fire Updated Core Damage Frequency Results

Fire Compartment Sub-Area	Description	CDF/year	New Estimate CDF/year
1E	Reactor Building West, El. 21	9.7E-07	8.25E-07
2B	Turbine Building Heater Bay	2.1E-06	2.74E-06
3A	Train B RBCCW/TBCCW Pump and Heat Exchanger Room	2.0E-06	1.31E-06
4A	Train A RBCCW/TBCCW Pump and Heat Exchanger Room	9.8E-07	2.95E-07
6	Control Room	1.6E-06	8.90E-07
7	Cable Spreading Room	9.5E-07	7.85E-07
9	Vital Motor Generator Set Room	2.4E-06	2.38E-06
12	Train A Switchgear Room	3.1E-06	2.30E-06
13	Train B Switchgear Room	6.1E-06	6.85E-06
26	Main Transformer	1.5E-06	7.60E-07
		2.2E-05	**1.91E-05**

E.1.3.3 Other External Hazards

The PNPS IPEEE submittal [Reference E.1-6], 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 PNPS.

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 expected not to impact the conclusions of this SAMA evaluation.

E.1.4 PSA Model Peer Review and Difference between Current PSA Model and 1995 Update IPE

E.1.4.1 PSA Model Peer Review

The original IPE PSA model was peer reviewed on March 2000 using the BWROG PSA Peer Review Certification Implementation Guidelines. Facts and Observation sheets documented the certification teams' insights and potential level of significance. As part of the update of the IPE PSA models, all major issues and observations from the BWROG Peer Review (i.e., Level A, B, C, and D observations) have been addressed and incorporated into the current IPE PSA model, April 2003 [Reference E.1-1].

For the current IPE/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 PNPS 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 and Appendix P of the Pilgrim Nuclear Power Station Individual Plant Examination for Internal Events update report, April 2003 [Reference E.1-1].

E.1.4.2 Major Differences between the Updated IPE PSA Model and 1995 Update IPE Model

E.1.4.2.1 Core Damage – Comparison to the PNPS 1995 Update IPE Model

The current PNPS IPE/PSA update model was completely revised in response to the BWROG Peer Review of March 2000 [Reference E.1-1]. The updated model is based upon all procedures and plant design as of September 30, 2001, and plant data as of December 31, 2001. The results yield a measurably lower CDF (point estimate CDF - 6.41E-6/reactor year) than the original IPE (point estimate CDF - 5.85E-5/yr) [Reference E.1-2] and 1995 PSA model update (point estimate CDF - 2.84E-5/yr) [Reference E.1-3]. (The 1995 update was performed to answer NRC questions following the IPE submittal.) The improved results are due to improved plant performance, replacement of switchyard breakers, more realistic success criteria based on MAAP runs, and more sophisticated data handling. Major changes are summarized as follows.

A. Initiating Event

The initiating event frequencies were updated to include current plant data and recent NRC publication information. For example, the LOOP frequency decreased significantly from the original IPE frequency of 0.475/yr to the current value of 0.067/yr [Reference E.1-1], which reflects the decreased occurrence of LOOP events since 1990 and replacement of switchyard breakers. In addition, fault tree models were developed to calculate support system initiating event frequencies.

B. Accident Sequence Evaluation

Event trees from the original IPE were completely revised. BWROG certification findings and observations were incorporated into the revised event trees. Major facts and observations include the following.

(1) LOOP Event Tree

The LOOP event was completely revised to account for failure modes of HPCI/RCIC beyond 8 hours of operation; RPV depressurization on HCTL; and transfer to the SBO tree to address such items as premature battery depletion and AC recovery at 30 minutes and beyond.

(2) *SBO Event Tree*

Current update reflects GE load shed calculations and use of plant SBO procedures for DC load shedding.

(3) *Inadvertent Stuck Open Relief Valve (IORV) Event Tree*

The IORV event tree was modified to include RPV depressurization with two SRVs given high-pressure injection failure.

(4) *LOCAs Event Trees*

The update considers both HPCI and RCIC for small break LOCAs.

Large and medium LOCAs and subsequent ATWS are modeled as core damage end states in the updated model. Small break LOCAs and ATWS are treated as similar to transient-induced ATWS.

The vapor suppression system is considered during large LOCAs events.

(5) *ATWS Event Tree*

The revised ATWS tree reflects the potential for MSIV closure on low RPV level.

The revised ATWS model takes into consideration "inhibit ADS" and MSIV bypass issues. In addition, HRA values take into consideration ATWS accident progressions for RPV and containment conditions predicted by MAAP.

(6) *Loss-of-Containment Heat Removal Sequences*

The revised event trees model the potential impact from containment venting on low-pressure system operation. For example, no credit is given for core spray and LPCI if containment venting is required. In addition, other containment related phenomena, such as high torus temperatures (HPCI) and high containment pressures (RCIC, SRVs) are reflected in the updated event trees.

The update model only considers the DTV path for containment venting.

(7) *ISLOCA Event Tree*

NSAC-154 [Reference E.1-10] and NUREG/CR-5124 [Reference E.1-11] were used to reassess the ISLOCA analysis.

Success criteria for low-pressure injection during an ISLOCA are consistent with those used for small LOCAs.

The revised ISLOCA event tree credits use of condensate or fire water for large ISLOCA events provided that LPCI or core spray operation had previously occurred to provide initial RPV reflood.

(8) Other Changes

The revised event trees credit use of feedwater when appropriate.

Control Rod Drive system flow into the RPV is credited for sequences that involve loss of containment heat removal and subsequent requirement to control containment pressure with direct torus containment venting.

Consistent success criteria were employed for RPV depressurization for transients, medium LOCAs, and small LOCAs.

The revised PNPS IPE models are based on the BWROG EPGs/SAGs Revision 4 of the BWROG EPGs [Reference E.1-1].

Core damage definition has been revised to be consistent with the EPRI PSA Applications Guide [Reference E.1-12]. That is, core damage occurs when peak clad temperature exceeds 2200°F.

HPCI and RCIC use is based on a 24-hour mission time.

C. <u>Thermal - Hydraulic (T-H) Analysis</u>

T-H analysis has been completely revised and improved to better support the success criteria. The MAAP4 computer code [Reference E.1-4] was used to update and address the many issues raised by the BWROG certification team, such as the following.

- A basis was provided for the timing and discharge pressure (flow) adequacy when using the fire water system for successful mitigation during transients and small LOCAs.
- Success criteria for SORV are same as for non-SORV cases (2 SRVs are required for successful RPV depressurization).
- Consistent success criteria are used for RPV depressurization for transients, medium LOCAs, and small LOCAs.
- Plant specific calculations were performed to identify the plant response for single or double recirculation pump trip failures.
- The appropriateness of the core damage definition used in the update was verified.

- In addition to the MAAP4 code, the GOTHIC code [Reference E.1-13] was used to predict various room heatup rates for the reactor building, turbine building, switchgear room, and battery room.

D. *System Analysis*

System fault tree models from the original IPE were completely revised to reflect the as-built plant configuration. MAAP analyses were clearly identified to support the success criteria of these Level 1 models. More detailed modeling for the logic interlock was included in the system models. A detailed fault tree for the RPS was developed based on NUREG/CR-5500 [Reference E.1-9], which decreased the failure-to-scram probability from 3.0E-5/yr to 5.8E-6/yr.

E. *Data Analysis*

Component failure data, both generic and plant-specific, were reviewed and updated with more recent experience (the performance of risk significant systems HPCI and RCIC has greatly improved since the original IPE). Plant-specific data were adjusted for industry experience using Bayesian updates. Maintenance unavailability values were updated based on maintenance rule records from the system engineers. More recent common cause failure data and approach NUREG/CR-5497 [Reference E.1-14] were factored into this update. In particular, a more detailed and refined common-cause failure methodology (Alpha model) has been applied in this update. In addition, more common-cause equipment failure groups such as fans, dampers, transformers, DC power panels, and circuit breakers have been included in the analysis.

F. *HRA*

A complete revision of the HRA was performed to identify, quantify, and document the pre-initiator and post-initiator human errors (including recoveries). The updated HRA was performed using NUREG/CR-1278 [Reference E.1-15], also referred to as THERP. Screening values were only used for low-significance human errors. In addition, a detailed analysis was performed to treat dependencies between post-initiator errors.

G. *Dependency Analysis*

A complete revision of the internal flooding analysis was developed to systematically address spatial dependencies.

Dependency between pre-initiator human errors (such as miscalibration of instruments) was modeled. In addition, dependencies between multiple post-accident operator actions appearing in the same accident sequence were evaluated.

Detailed component dependency tables were developed to address the support systems associated with the modeled systems and components.

H. Structural Response

The ISLOCA frequency was revised.

RPV overpressure and capability of the reactor building were included in the Level 2 assessment.

I. Quantification

The truncation value was lowered to 1.0E-11.

Human Error Probability (HEP) dependencies and recovery actions in the cutsets were evaluated.

ATWS contribution decreased due to lower probability of failure to scram based on NUREG/CR-5500 [Reference E.1-9].

The HRA was completely revised to address a comment from the PSA Certification [Reference E.1-16] that many of the HEPs were not realistic using the previous methodology. In many cases (e.g., failure to perform DTV), the previous HEPs were judged to be overly conservative.

J. Internal Flooding Analysis

The internal flooding analysis from the original IPE was completely revised to include a detailed, systematic examination of the flood source and progression for each of the analyzed flooding scenarios. In addition, the updated internal flooding analysis considers the effects of spray on equipment.

K. Uncertainty Analysis

An uncertainty analysis was performed for this update.

E.1.4.2.2 Containment Performance – Comparison to the Original PNPS IPE Model

Containment performance analysis models were completely revised from the original IPE. Propagation of Level 1 cutsets to the Level 2 CET was developed. A detailed LERF model was developed to ensure that LERF calculations are consistent with the PSA Applications Guide and NRC requirements for RG 1.174 [Reference E.1-17]. Other salient items incorporated are the following.

- CET fault models were revised to ensure that mitigating systems were not degraded in the Level 1 sequence.
- CET fault tree models allowed credit for AC power recovery post 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.

- Shell melt-through phenomena were considered where applicable.
- Operator responses to key actions were reassessed to incorporate the probability for success given the containment conditions and Emergency Operating Procedure directions.
- Direct torus venting was considered post core damage.
- PNPS-specific primary containment structural evaluation was included in the CET. This also included a structural evaluation of torus failure due to dynamic loading during ATWS scenarios, torus break below the water line, and bellows seal capability.
- A reactor building bypass fault tree model was developed to assess the impact on the Level 2 analysis.

E.1.5 <u>The MACCS2 Model - Level 3 Analysis</u>

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 MACCS2 [Reference E.1-18] was created for PNPS. 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 PNPS was estimated for the year 2032, the end of the proposed license renewal period, for each spatial element by combining total resident population projections with transient population data obtained from Massachusetts and Rhode Island. 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	0	0	0	0	80474	80474
NNE	3	0	0	0	0	3
NE	3	0	0	0	0	3
ENE	3	0	33121	0	0	33124
E	5	0	33121	23185	0	56311
ESE	23	0	49682	92740	0	142445
SE	950	9936	115925	23185	0	149996
SSE	13289	69555	82803	0	0	165647
S	23695	99364	132485	84383	43397	383324
SSW	23695	49762	23696	23185	21699	142037
SW	23695	71088	277374	349491	114546	836194
WSW	23695	71088	277374	349491	183037	904685
W	22818	71088	277374	388324	286370	1045974
WNW	16494	71088	118481	303450	390150	899663
NW	11269	71088	195075	1529212	405561	2212205
NNW	5599	35544	43350	31295	321894	437682
Total	165236	619601	1659861	3197941	1847128	7489767

The 2000 U.S. Census Bureau data, together with Massachusetts and Rhode Island population projection data, was used to project county-level resident populations to the year 2032. Seasonal peak transient population was conservatively used to establish a transient/resident population ratio for each county within the 50-mile radius. The ratio was found to be decreasing over time. For purposes of this study, the total county level population values were estimated by

summing the year 2000 peak transient population of each county and the projected year 2032 permanent population of that county to obtain the 2032 total county population.

E.1.5.2.2 Land Fraction

The land fraction for each spatial element was estimated from the PNPS Emergency Planning Zone maps for radii of 2, 5, and 50 miles [Reference E.1-20].

E.1.5.2.3 Watershed Class

There are two watershed types in the 50-mile zone surrounding PNPS: ocean and land (watersheds) drained by rivers. There are no major lakes. The watershed index assigns "1" to any spatial element having a non-zero land fraction and "2" to all elements over the Atlantic Ocean or its bays.

E.1.5.2.4 Regional Economic Data

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.

Regional Economic Data

County level economic data were obtained from the U.S. Department of Agriculture. The Census of Agriculture is conducted every five years and data from 1997 and 1992 were used to project the farm-related economic data for 2002.

VALWF - Value of Farm Wealth

MACCS2 requires an average value of farm wealth (dollars/hectare) for the 50-mile radius area around PNPS. The county-level farmland property value was used as a basis for deriving this value. VALWF is $23,578/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 $189,041/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.1-18 with the consumer price index of 177.1, which is the average value for the year 2001, as appropriate.

Variable	Description	Value
EVACST	Daily cost for a person who has been evacuated ($/person-day)	42.3
POPCST	Population relocation cost ($/person)	7840
RELCST	Daily cost for a person who is relocated ($/person-day)	42.3
CDFRM0	Cost of farm decontamination for the various levels of decontamination ($/hectare)	881 1959
CDNFRM	Cost of non-farm decontamination for the various levels of decontamination ($/person)	4700 12540
DLBCST	Average cost of decontamination labor ($/person-year)	54800
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 New England Agricultural Statistics, 2001. The crops listed for each of the two states, Massachusetts and Rhode Island, were 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 PNPS site meteorological monitoring system and the Automated Surface Observatory System (ASOS) at Plymouth Airport.

Site Specific Data

Site specific meteorological data is available from two meteorological towers, one located off the main parking lot and the second located west of the old I&S building, the "lower" and "upper" towers respectively. The upper tower is the designated data source for MACCS2 input. Data from the lower tower was used only if measurements from the upper tower were missing for a specific hour.

Year 2001 hourly data from the upper tower was used in this analysis. The data was more than 98% complete. Missing data was obtained either from the lower tower or from estimates based on adjacent valid measurements of the missing hour.

Accumulated Precipitation

The nearest source of hourly precipitation data to PNPS is the ASOS at Plymouth Airport. The data was converted to MACCS2 input format to provide precipitation in hundredths of an inch.

Regional Mixing Height Data

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. PNPS mixing height data, given in Reference E.1-19, was used for MACCS2 analysis.

E.1.5.2.7 Emergency Response Assumptions

Details of the evacuation time estimates including supporting assumptions regarding population, alarm criteria, delay times, areas, speed, distance, and routes are contained in the PNPS Emergency Plan [Reference E.1-20].

Evacuation Delay Time

The elapsed time between siren alert and the beginning of evacuation is 40 minutes. A sensitivity case that assumes 2 hours for evacuees to begin evacuation was considered in this study to evaluate consequence sensitivities due to uncertainties in delay time.

Evacuation Speed

The worst case for PNPS evacuation is during the winter, under adverse weather conditions, since snow removal can add up to an hour and a half to the evacuation time. The radius of the Emergency Planning Zone is 10 miles. Assuming that the net movement of the entire population is 10 miles, the time required for evacuation ranges from 3 hours 35 minutes to 6 hours 30 minutes, and the average evacuation speed ranges from 2.79 miles/hour in clear weather to 1.54 miles/hour under adverse weather conditions. The average evacuation speed is 2.17 miles/hour, or 0.97 meter/second.

A sensitivity case that assumes a lower evacuation speed of 0.69 meter/second was considered in this study to evaluate consequence sensitivities due to uncertainties in evacuation speed.

E.1.5.2.8 Core Inventory

The estimated PNPS core inventory (Table E.1-14) used in the MACCS2 input is based on a power level of 2028 MW(t).

Table E.1-14
PNPS Core Inventory (Becquerels)

Nuclide	Inventory	Nuclide	Inventory
Co-58	1.15E+16	Te-131m	2.87E+17
Co-60	1.37E+16	Te-132	2.80E+18
Kr-85	1.88E+16	I-131	1.94E+18
Kr-85m	6.84E+17	I-132	2.85E+18
Kr-87	1.24E+18	I-133	4.07E+18
Kr-88	1.68E+18	I-134	4.45E+18
Rb-86	1.05E+15	I-135	3.83E+18
Sr-89	2.08E+18	Xe-133	4.07E+18
Sr-90	1.47E+17	Xe-135	9.68E+17
Sr-91	2.71E+18	Cs-134	3.17E+17
Sr-92	2.83E+18	Cs-136	8.51E+16
Y-90	1.58E+17	Cs-137	1.90E+17
Y-91	2.54E+18	Ba-139	3.75E+18
Y-92	2.84E+18	Ba-140	3.70E+18
Y-93	3.23E+18	La-140	3.77E+18
Zr-95	3.34E+18	La-141	3.48E+18
Zr-97	3.44E+18	La-142	3.35E+18
Nb-95	3.16E+18	Ce-141	3.36E+18
Mo-99	3.65E+18	Ce-143	3.27E+18
Tc-99m	3.15E+18	Ce-144	2.18E+18
Ru-103	2.77E+18	Pr-143	3.20E+18
Ru-105	1.85E+18	Nd-147	1.43E+18
Ru-106	7.52E+17	Np-239	4.26E+19
Rh-105	1.38E+18	Pu-238	2.96E+15
Sb-127	1.74E+17	Pu-239	7.51E+14
Sb-129	6.06E+17	Pu-240	9.41E+14
Te-127	1.69E+17	Pu-241	1.62E+17
Te-127m	2.27E+16	Am-241	1.65E+14
Te-129	5.68E+17	Cm-242	4.35E+16
Te-129m	1.49E+17	Cm-244	2.35E+15

Source: derived from Reference E.1-21 for a power level of 2028 MW(t)

E.1.5.2.9 Source Terms

Twelve release categories, corresponding to internal event sequences, were part of the MACCS2 input. Details of the source terms for postulated internal events are available in on-site documentation. 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 40 minute delay and 0.97 meter/sec speed of evacuation. Sensitivity case 1 is the base case with delayed evacuation of 2 hours. Sensitivity case 2 is the base case with an evacuation speed of 0.69 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 PNPS are 13.6 person-rem/yr and $45,900/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)
CAPB-1	9.51E-08	4.66E-01	3.82E+06	4.43E-06[2]	3.63E-01
CAPB-2	1.27E-08	9.96E+01	6.40E+06	1.26E-04	8.10E-02
CAPB-3	2.39E-09	1.06E+02	6.48E+06	2.53E-05	1.55E-02
CAPB-4	3.29E-09	1.38E+04	4.28E+09	4.54E-03	1.41E+01
CAPB-5	2.73E-09	1.81E+04	5.30E+09	4.94E-03	1.45E+01
CAPB-6	7.95E-09	1.51E+04	3.51E+09	1.20E-02	2.79E+01
CAPB-7	7.93E-09	1.67E+04	4.42E+09	1.32E-02	3.51E+01
CAPB-8	2.06E-08	4.10E+04	1.47E+10	8.44E-02	3.03E+02
CAPB-9	9.25E-09	2.37E+04	8.33E+09	2.19E-02	7.70E+01
CAPB-10	8.53E-08	4.31E+04	1.54E+10	3.68E-01	1.31E+03
CAPB-11	4.35E-08	3.45E+04	1.15E+10	1.50E-01	5.00E+02
CAPB-12	1.70E-06	9.72E+01	4.63E+06	1.65E-02	7.88E+00
CAPB-13	2.30E-09	7.30E+03	6.53E+08	1.68E-03	1.50E+00
CAPB-14	2.26E-06	1.58E+04	4.14E+09	3.57E+00	9.36E+03
CAPB-15	2.12E-06	4.31E+04	1.59E+10	9.14E+00	3.37E+04
CAPB-16	1.18E-09	1.86E+04	5.50E+09	2.19E-03	6.48E+00
CAPB-17	6.91E-09	4.81E+04	1.71E+10	3.32E-02	1.18E+02
CAPB-18	4.61E-10	2.38E+04	7.86E+09	1.10E-03	3.62E+00
CAPB-19	2.43E-08	5.31E+04	1.88E+10	1.29E-01	4.56E+02
			Totals	**1.36E+01**	**4.59E+04**

1. 1 sv = 100 rem
2. 4.43E-06 (person-rem/yr) = 9.51E-08 (/yr) x 4.66E-01 (person-sv) x 100 (rem/sv)

Results of sensitivity analyses indicate that a delayed evacuation or a lower evacuation speed would not have 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 2% between the base case population dose and the Sensitivity Case 2 population dose for release mode CAPB-8.

Table E.1-16
Summary of Offsite Consequence Sensitivity Results

	Population Dose (person-sv)			Offsite Economic Cost ($)		
Release Mode	**Base Case**	**2-Hr Delayed Evacuation**	**Lower Speed of Evacuation**	**Base Case**	**2-Hr Delayed Evacuation**	**Lower Speed of Evacuation**
CAPB-1	4.66E-01	4.66E-01	4.67E-01	3.82E+06	3.82E+06	3.82E+06
CAPB-2	9.96E+01	9.97E+01	9.97E+01	6.40E+06	6.40E+06	6.40E+06
CAPB-3	1.06E+02	1.06E+02	1.06E+02	6.48E+06	6.48E+06	6.48E+06
CAPB-4	1.38E+04	1.39E+04	1.39E+04	4.28E+09	4.28E+09	4.28E+09
CAPB-5	1.81E+04	1.82E+04	1.82E+04	5.30E+09	5.30E+09	5.30E+09
CAPB-6	1.51E+04	1.51E+04	1.51E+04	3.51E+09	3.51E+09	3.51E+09
CAPB-7	1.67E+04	1.68E+04	1.68E+04	4.42E+09	4.42E+09	4.42E+09
CAPB-8	4.10E+04	4.16E+04	4.17E+04	1.47E+10	1.47E+10	1.47E+10
CAPB-9	2.37E+04	2.38E+04	2.39E+04	8.33E+09	8.33E+09	8.33E+09
CAPB-10	4.31E+04	4.34E+04	4.36E+04	1.54E+10	1.54E+10	1.54E+10
CAPB-11	3.45E+04	3.48E+04	3.49E+04	1.15E+10	1.15E+10	1.15E+10
CAPB-12	9.72E+01	9.75E+01	9.78E+01	4.63E+06	4.63E+06	4.63E+06
CAPB-13	7.30E+03	7.30E+03	7.31E+03	6.53E+08	6.53E+08	6.53E+08
CAPB-14	1.58E+04	1.58E+04	1.59E+04	4.14E+09	4.14E+09	4.14E+09
CAPB-15	4.31E+04	4.33E+04	4.35E+04	1.59E+10	1.59E+10	1.59E+10
CAPB-16	1.86E+04	1.87E+04	1.88E+04	5.50E+09	5.50E+09	5.50E+09
CAPB-17	4.81E+04	4.83E+04	4.86E+04	1.71E+10	1.71E+10	1.71E+10
CAPB-18	2.38E+04	2.39E+04	2.40E+04	7.86E+09	7.86E+09	7.86E+09
CAPB-19	5.31E+04	5.33E+04	5.37E+04	1.88E+10	1.88E+10	1.88E+10

E.1.6 References

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E.1-21 U.S. Nuclear Regulatory Commission, NUREG/CR-4551, Vol. 2, Rev. 1, Part 7, *Evaluation of Severe Accident Risks: Quantification of Major Input Parameters, 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 PNPS is a conventional GE nuclear power reactor design, 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), and
- Arkansas Nuclear 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's 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), and
- NUREG/CR-5474, Assessment of Candidate Accident Management Strategies (Reference E.2-16).

In addition to SAMA candidates from review of industry documents, additional SAMA candidates were obtained from plant-specific sources, such as the PNPS IPE (Reference E.2-17) and IPEEE (Reference E.2-18). In both the IPE and IPEEE, several enhancements related to severe accident insights were recommended and implemented. These enhancements are included in the comprehensive list of phase I SAMA candidates as numbers 248 through 281. The current PNPS PSA model was also used to identify plant-specific modifications for inclusion in the comprehensive list of SAMA candidates. The risk-significant terms from the current 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 were listed in Table E.1-2.

The comprehensive list, available in on-site documentation, contained a total of 281 phase I SAMA candidates.

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 PNPS. Potential SAMA candidates were screened out if they modified features not applicable to PNPS, if they had already been implemented at PNPS, 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, 63 of the phase I SAMA candidates were screened out because they were not applicable to PNPS, 4 of the phase I SAMA candidates were screened out because they were similar in nature and could be combined with another SAMA candidate, and 155 of the phase I SAMA candidates were screened out because they had already been implemented at PNPS, leaving 59 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 59 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),
- Dresden SAMA Analysis (Reference E.2-6),
- ANO-2 SAMA Analysis (Reference E.2-7), and

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 PNPS, the following estimated costs for each potential element of the proposed SAMA implementation are 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 59 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 large break LOCA protection system. The bounding calculation estimated the benefit of this improvement by total elimination of risk due to large break LOCA (see analysis in phase II SAMA 052 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.

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 $261,832. This analysis case was used to model the benefit of phase II SAMAs 1 and 14.

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 $264,219. This analysis case was used to model the benefit of phase II SAMA 9.

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. Reducing the releases from the vent path resulted in no benefit. This analysis case was used to model the benefit of phase II SAMAs 2 and 19.

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 $61,701. This analysis case was used to model the benefit of phase II SAMAs 3 and 47.

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 $2,620,551. This analysis case was used to model the benefit of phase II SAMAs 4, 5, 8, and 23.

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 an upper bound benefit of approximately $12,915. This analysis case was used to model the benefit of phase II SAMAs 6, 18, and 20.

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 an upper bound benefit of approximately $64,577. This analysis case was used to model the benefit of phase II SAMAs 7, 13, and 21.

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 (DCH, steam explosions, late over-pressurization) to zero in the level 2 PSA model, which resulted in an upper bound benefit of approximately $1,233,428. This analysis case was used to model the benefit of phase II SAMAs 10, 15, 16, and 24.

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 $25,831. This analysis case was used to model the benefit of phase II SAMA 11.

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 $19,373. This analysis case was used to model the benefit of phase II SAMA 12.

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 no benefit. This analysis case was used to model the benefit of phase II SAMA 17.

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 $1,226,971. This analysis case was used to model the benefit of phase II SAMA 22.

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 extended

from 14 hours to 24 hours to simulate additional 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 14 hours to 24 hours during SBO scenarios in the level 1 PSA model. This resulted in an upper bound benefit of approximately $146,356. This analysis case was used to model the benefit of phase II SAMAs 25, 26, 28, 33, and 35.

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 DC buses D16 and D17 to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $118,568. This analysis case was used to model the benefit of phase II SAMAs 27 and 34.

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 SBO diesel generator to zero in level 1 PSA model, which resulted in an upper bound benefit of approximately $265,687. This analysis case was used to model the benefit of phase II SAMA 29.

Improve AC Power System

This analysis case was used to evaluate the change in plant risk from improving AC power system cross-tie capability to enhance the availability and reliability of the AC power system. A bounding analysis was performed by setting the loss of MCCs B17, B18, and B15 to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $473,410. This analysis case was used to model the benefit of phase II SAMA 30.

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 bus D17 initiator, and one division of DC power, to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $903,025. This analysis case was used to model the benefit of phase II SAMAs 31 and 32.

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 $16,497. This analysis case was used to model the benefit of phase II SAMA 36.

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 $24,148. This analysis case was used to model the benefit of phase II SAMA 37.

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 no benefit. This analysis case was used to model the benefit of phase II SAMA 38.

Diesel to 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 and 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 no benefit. This analysis case was used to model the benefit of phase II SAMA 39.

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 $110,212. This analysis case was used to model the benefit of phase II SAMAs 40, 41, 42, 44, and 45.

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 $76,025. This analysis case was used to model the benefit of phase II SAMA 43.

SRVs 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 to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $63,599. This analysis case was used to model the benefit of phase II SAMA 46.

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 an upper bound benefit of approximately $12,915. This analysis case was used to model the benefit of phase II SAMA 48.

Reliability of SRVs

This analysis case was used to evaluate the change in plant risk from installing additional signals to automatically open the SRVs. This improvement would reduce the likelihood of SRVs failing to open, thereby reducing the consequences of medium LOCAs. A bounding analysis was performed by setting the probability of SRVs failing to open when required by reactor pressure vessel overpressure conditions to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $31,799. This analysis case was used to model the benefit of phase II SAMA 49.

Improve SRV Design

This analysis case was used to evaluate the change in plant risk from improving the SRV design to increase the reliability of opening, thus increasing the likelihood that accident sequences could be mitigated using low pressure injection systems. A bounding analysis was performed by setting the probability of SRVs failing to open during RPV depressurization to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $194,378. This analysis case was used to model the benefit of phase II SAMA 50.

Self-Cooled ECCS Pump Seals

This analysis case was used to evaluate the change in plant risk from providing self-cooled ECCS pump seals to eliminate dependence on the component cooling water system. A bounding analysis was performed by setting the CDF contribution from sequences involving RHR pump failures to zero in the level 1 PSA model, which resulted in an upper bound benefit of approximately $29,412. This analysis case was used to model the benefit of phase II SAMA 51.

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 an upper bound benefit of approximately $14,109. This analysis case was used to model the benefit of phase II SAMA 52.

Controlled Containment Venting

This analysis case was used to evaluate the change in plant risk from changing the design of the containment vent valves and 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 $137,237. This analysis case was used to model the benefit of phase II SAMA 53.

ECCS Low Pressure Interlock

This analysis case was used to evaluate the change in plant risk from installing a bypass switch to allow operator to bypass the ECCS low pressure interlock circuitry that inhibits opening of the RHR low pressure injection and core spray injection valves following sensor or logic failure. A bounding analysis was performed by setting the CDF contribution due to sensor failure, low pressure permissive logic failure, and miscalibration to zero in the level 1 PSA model. This resulted in an upper bound benefit of approximately $21,761. This analysis case was used to model the benefit of phase II SAMA 54.

Improve the Reliability of SSW and RBCCW Pumps

This analysis case was used to evaluate the change in plant risk from providing a separate pump train to eliminate common cause failure of SSW and RBCCW pumps. A bounding analysis was performed by setting the CDF contribution due to common cause failures of SSW and RBCCW pumps to zero in the level 1 PSA model. This resulted in an upper bound benefit of approximately $356,310. This analysis case was used to model the benefit of phase II SAMA 55.

Redundant DC Power Supplies to DTV Valves

This analysis case was used to evaluate the change in plant risk from installing additional fuses to two DTV valve control circuits to enable the DTV function. A bounding analysis was performed by setting the CDF contribution due to DC power supply failures to DTV valves AO-5042B and AO-5025 to zero in the level 1 PSA model. This resulted in an upper bound benefit of approximately $220,639. This analysis case was used to model the benefit of phase II SAMA 56.

Proceduralize the Use of Diesel Fire Pump Hydroturbine

This analysis case was used to evaluate the change in plant risk from revising the procedure to allow use of hydroturbine if EDG X-107A or diesel driven fire water pump P-140 is unavailable. A bounding analysis was performed by setting the CDF contribution from the sequences involving a LOOP and failure of either EDG A or fuel oil transfer oil pump (P-141) to zero in the level 1 PSA model. This resulted in an upper bound benefit of approximately $175,279. This analysis case was used to model the benefit of phase II SAMA 57.

Proceduralize Alignment of Bus B3 to Feed Bus B1 Loads or Bus B4 to Bus B2

This analysis case was used to evaluate the change in plant risk from providing a procedure to direct the operator to restore 480V MCCs B15 and B17 loads upon loss of 4.16kV bus A5 provided that 4.16kV bus A3 is available. The same is true for restoring 480V MCCs B14 and B18 loads upon loss of 4.16kV bus A6 provided that 4.16kV bus A4 is available. A bounding analysis was performed by setting the CDF contribution from the sequences involving a loss of the 4.16 kV bus A5 to zero in the level 1 PSA model. This resulted in an upper bound benefit of approximately $190,797. This analysis case was used to model the benefit of phase II SAMA 58.

Redundant Path from Fire Water Pump Discharge to LPCI Loops A and B Cross-tie

This analysis case was used to evaluate the change in plant risk from installing a redundant path from fire protection water pump discharge to LPCI loops A and B cross-tie. A bounding analysis was performed by setting the CDF contribution from the sequences involving fire water into LPCI loops A and B cross-tie failure to zero in the level 1 PSA model. This resulted in an upper bound benefit of approximately $929,797. This analysis case was used to model the benefit of phase II SAMA 59.

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 27-year period for remaining plant life (i.e. seven 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 27 years remaining until end of facility life to investigate the impact on each analysis case. Changing this assumption does not cause any additional SAMAs to be cost-beneficial.

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. Changing this assumption does not cause any additional SAMAs to be cost-beneficial.

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 U.S. Nuclear Regulatory Commission, NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Calvert Cliffs Nuclear Power Plant*, Supplement 1, 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 U.S. Nuclear Regulatory Commission, 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, May 1996.

E.2-10 U.S. Nuclear Regulatory Commission, NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*, Volume 1, 5.36, Listing of SAMDAs considered for the Comanche Peak Steam Electric Station, May 1996.

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.

E.2-12 Nunn, D. E., (TVA) to NRC Document Control Desk, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDA) - Response to Request for Additional Information (RAI) - (TAC Nos. M77222 and M77223)," letter dated October 7, 1994.

E.2-13 Liparulo, N. J., (Westinghouse Electric Corporation) to NRC Document Control Desk, "Submittal of Material Pertinent to the AP600 Design Certification Review," letter dated December 15, 1992.

E.2-14 U.S. Nuclear Regulatory Commission, NUREG-0498, *Final Environmental Statement related to the operation of Watts Bar Nuclear Plant, Units 1 and 2,* Supplement No. 1, April 1995.

E.2-15 U.S. Nuclear Regulatory Commission, NUREG-1560, *Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance*, Volume 2, December 1997.

E.2-16 U.S. Nuclear Regulatory Commission, NUREG/CR-5474, *Assessment of Candidate Accident Management Strategies*, March 1990.

E.2-17 Pilgrim Nuclear Power Station, Individual Plant Examination (IPE) Report, September 1992

E.2-18 Pilgrim Nuclear Power Station, Individual Plant Examination of External Events (IPEEE) Report, July 1994.

E.2-19 U.S. Nuclear Regulatory Commission, NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook*, January 1997.

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
Improvements Related to Accident Mitigation Containment Phenomena								
001	Install an independent method of suppression pool cooling.	SAMA would decrease the probability of loss of containment heat removal.	4.70%	4.60%	$43,639	$261,832	$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 PNPS.							
002	Install a filtered containment vent to provide fission product scrubbing. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber	SAMA would provide an alternate decay heat removal method for non-ATWS events, with fission product scrubbing.	0.00%	0.00%	$0	$0	$3,000,000	Not cost effective
	Basis for Conclusion: Successful torus venting accident progression source terms are 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. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
003	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.	0.50%	1.19%	$10,283	$61,701	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							
004	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%	48.62%	$436,759	$2,620,551	>$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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
005	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%	48.62%	$436,759	$2,620,551	$19,000,000	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 at ANO-2 was estimated to be $19 million. Therefore, this SAMA is not cost effective for PNPS.							
006	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%	0.07%	$2,153	$12,915	>$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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
007	Enhance fire protection system and SGTS hardware and procedures.	SAMA would improve fission product scrubbing in severe accidents.	0.00%	1.16%	$10,763	$64,577	>$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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
008	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%	48.62%	$436,759	$2,620,551	>$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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
009	Install a passive containment spray system.	SAMA would decrease the probability of loss of containment heat removal.	5.05%	4.70%	$44,037	$264,219	$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 PNPS.							
010	Strengthen primary and secondary containment.	SAMA would reduce the probability of containment over-pressurization failure.	0.00%	26.10%	$205,571	$1,233,428	$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 at an ABWR was estimated to be $12 million. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
011	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%	0.43%	$4,305	$25,831	>$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 PNPS.							
012	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%	0.22%	$3,229	$19,373	$2,500,000	Not cost effective
	Basis for Conclusion: The probability of vessel failure was modified to account for potential ex-vessel cooling of the vessel bottom head region 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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
013	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%	1.16%	$10,763	$64,577	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							
014	2.g. Dedicated Suppression Pool Cooling	SAMA would decrease the probability of loss of containment heat removal.	4.70%	4.60%	$43,639	$261,832	$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 PNPS.							
015	3.a. Create a larger volume in containment.	SAMA increases time before containment failure and increases time for recovery.	0.00%	26.10%	$205,571	$1,233,428	$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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
016	3.b. Increase containment pressure capability (sufficient pressure to withstand severe accidents).	SAMA minimizes likelihood of large releases.	0.00%	26.10%	$205,571	$1,233,428	$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 at an ABWR was estimated to be $12 million. Therefore, this SAMA is not cost effective for PNPS.							
017	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.	0.00%	0.00%	$0	$0	>$1,000,000	Not cost effective
	Basis for Conclusion: Vacuum breaker failures and suppression pool scrubbing 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. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
018	3.d. Increase the temperature margin for seals.	This SAMA would reduce the potential for containment failure under adverse conditions.	0.00%	0.07%	$2,153	$12,915	$12,000,000	Not cost effective
	Basis for Conclusion: Containment 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 at an ABWR were estimated to be $12 million and was judged to exceed the attainable benefit, even without a detailed cost estimate. Therefore, this SAMA is not cost effective for PNPS.							
019	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%	0.00%	$0	$0	$3,000,000	Not cost effective
	Basis for Conclusion: Successful torus venting accident progressions source terms are 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. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
020	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%	0.07%	$2,153	$12,915	>$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 PNPS.							
021	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%	1.16%	$10,763	$64,577	>$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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
022	14.a. Provide a means of flooding the rubble bed.	SAMA would allow the debris to be cooled.	0.00%	22.48%	$204,495	$1,226,971	$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 PNPS.							
023	14.b. Install a reactor cavity flooding system.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.	0.00%	48.62%	$436,759	$2,620,551	$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 PNPS.							
024	Add ribbing to the containment shell.	This SAMA would reduce the chance of containment buckling under reverse pressure loading.	0.00%	26.10%	$205,571	$1,233,428	$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 at an ABWR was estimated to be $12 million. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	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 Reliability/Availability								
025	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.	1.39%	2.79%	$24,393	$146,356	$500,000	Not cost effective
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 14 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. Therefore, this SAMA is not cost effective for PNPS.							
026	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.	1.39%	2.79%	$24,393	$146,356	>$2,000,000	Not cost effective
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 14 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. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
027	Modification for Improving DC Bus Reliability	SAMA would increase reliability of AC power and injection capability.	4.65%	1.91%	$19,761	$118,568	$500,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of DC buses D16 and D17 was eliminated to 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 PNPS.							
028	2.i. Provide 16-hour SBO injection.	SAMA includes improved capability to cope with longer SBO scenarios.	1.39%	2.79%	$24,393	$146,356	$500,000	Not cost effective
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 14 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. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
029	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.	2.22%	5.06%	$44,281	$265,687	>$2,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to failure of the SBO diesel 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. Therefore, this SAMA is not cost effective for PNPS.							
030	9.g. Enhance procedures to make use of AC bus cross-ties.	SAMA would provide increased reliability of AC power system and reduce core damage and release frequencies.	11.10%	8.47%	$78,902	$473,410	$146,120	Retain
	Basis for Conclusion: The CDF contribution due to loss of MCCs B17, B18, and B15 was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $146,120 by engineering judgment.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
031	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).	24.3%	16.16%	$150,504	$903,025	$3,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of DC Bus 'B' 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 PNPS.							
032	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).	24.3%	16.16%	$150,504	$903,025	$3,000,000	Not cost effective
	Basis for Conclusion: The CDF contribution due to loss of DC Bus 'B' 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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
033	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.	1.39%	2.79%	$24,393	$146,356	>$2,000,000	Not cost effective
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 14 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. Therefore, this SAMA is not cost effective for PNPS.							
034	10.d. Enhance procedures to make use of DC bus cross-ties.	This SAMA would improve DC power availability.	4.65%	1.91%	$19,761	$118,568	$13,000	Retain
	Basis for Conclusion: The CDF contribution due to loss of DC buses D16 and D17 was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $13,000 by engineering judgment.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
035	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.	1.39%	2.79%	$24,393	$146,356	$500,000	Not cost effective
	Basis for Conclusion: The time available to recover offsite power before HPCI and RCIC are lost was changed from 14 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. Therefore, this SAMA is not cost effective for PNPS.							
Improvements in Identifying and Mitigating Containment Bypass								
036	Locate RHR inside containment.	SAMA would prevent ISLOCA outside containment.	0.33%	0.21%	$2,749	$16,497	>$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 PNPS.							
037	Increase frequency of valve leak testing.	SAMA could reduce ISLOCA frequency.	0.54%	0.38%	$4,025	$24,148	$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 $100,000 by engineering judgment. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
038	8.e. Improve MSIV design.	This SAMA would decrease the likelihood of containment bypass scenarios.	0.00%	0.00%	$0	$0	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							
Improvements Related to Core Cooling System								
039	Install an independent diesel for the CST makeup pumps.	SAMA would allow continued inventory in CST during an SBO.	0.00%	0.00%	$0	$0	$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 is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
040	Provide an additional high pressure injection pump with independent diesel.	SAMA would reduce frequency of core melt from small LOCA and SBO sequences.	3.15%	1.97%	$18,369	$110,212	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							
041	Install independent AC high pressure injection system.	SAMA would allow makeup capabilities during transients, small LOCAs, and SBOs.	3.15%	1.97%	$18,369	$110,212	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
042	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.	3.15%	1.97%	$18,369	$110,212	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							
043	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.	2.11%	1.43%	$12,671	$76,025	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
044	2.e. Install an additional active high pressure system.	SAMA will improve reliability of high-pressure decay heat removal by adding an additional system.	3.15%	1.97%	$18,369	$110,212	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							
045	8.c. Add a diverse injection system.	SAMA will improve prevention of core melt sequences by providing additional injection capabilities.	3.15%	1.97%	$18,369	$110,212	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
Improvements Related to ATWS Mitigation								
046	Increase SRV reseat reliability.	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after SLC injection.	1.51%	0.92%	$10,600	$63,599	$2,000,000	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 million at Peach Bottom. Therefore, this SAMA is not cost effective for PNPS.							
047	11.a. Install an ATWS sized vent.	This SAMA would provide the ability to remove reactor heat from ATWS events.	0.50%	1.19%	$10,283	$61,701	>$2,000,000	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. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
048	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.	0.00%	0.02%	$2,153	$12,915	>$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 PNPS.							
Other Improvements								
049	Increase the reliability of SRVs by adding signals to open them automatically.	SAMA reduces the consequences of medium break LOCAs.	0.73%	0.60%	$5,300	$31,799	>$1,500,000	Not cost effective
	Basis for Conclusion: The CDF contribution from SRVs failing to open in medium LOCA sequences was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be greater than $1.5 million by engineering judgment. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
050	8.e. Improve SRV design.	This SAMA would improve SRV reliability thus increasing the likelihood that sequences could be mitigated using low-pressure heat removal.	4.81%	3.51%	$32,396	$194,378	>$2,000,000	Not cost effective
	Basis for Conclusion: The probability of SRV failure to open for vessel depressurization 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. Therefore, this SAMA is not cost effective for PNPS.							
051	Provide self-cooled ECCS pump seals.	SAMA would eliminate ECCS dependency on the component cooling water system.	0.47%	0.55%	$4,902	$29,412	>$200,000	Not cost effective
	Basis for Conclusion: The CDF contribution from sequences involving RHR pump failures 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 PNPS							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
052	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).	0.07%	0.01%	$2,352	$14,109	>$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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
Improvements Related to IPE, IPE Update& IPEEE Insights								
053	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.	3.61%	2.24%	$22,873	$137,237	$300,000	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 $300,000 by engineering judgment. Therefore, this SAMA is not cost effective for PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
054	Install a bypass switch to bypass the low reactor pressure interlocks of LPCI or core spray injection valves	This SAMA would reduce the core damage frequency contribution from the transients with stuck open SRVs or LOCAs cases. Core Spray and LPCI injection valves require a low permissive signal from the same two sensors to open the valves for RPV injection.	0.28%	0.33%	$3,627	$21,761	$1,000,000	Not cost effective
	Basis for Conclusion: The probability of the ECCS low-pressure permissive failing was eliminated to conservatively assess the benefit of this SAMA on CDF. The cost of implementing this SAMA at Dresden was estimated to be $1 million. Therefore, this SAMA is not cost effective for PNPS.							
055	Increase the reliability of SSW and RBCCW pumps.	This SAMA would reduce common cause dependencies from SSW and RBCCW systems and thus reduce plant risk.	4.37%	6.63%	$59,385	$356,310	>$5 million	Not cost effective
	Basis for Conclusion: The CDF contribution from sequences involving common cause failures of SSW and RBCCW 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 PNPS.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
056	Provide redundant DC power supplies to DTV valves.	This SAMA would improve reliability of the DTV valves and enhance containment heat removal capability.	8.81%	3.51%	$36,773	$220,639	$112,400	Retain
	Basis for Conclusion: The CDF contribution from sequences involving DC power supply failures to the DTV valves was eliminated to conservatively assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $112,400 by engineering judgment.							
057	Proceduralize use of the diesel fire pump hydro turbine in the event of EDG A failure or unavailability.	This SAMA would increase capability to provide makeup to the fire pump day tank to allow continued operation of the diesel fire pump, without dependence on electrical power.	2.25%	3.14%	$29,213	$175,279	$26,000	Retain
	Basis for Conclusion: The CDF contribution from sequences involving a LOOP and failure of either EDG A, or the EDG A fuel oil transfer oil pump, was eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $26,000 by engineering judgment.							

Table E.2-1
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation (Continued)

Phase II SAMA ID	SAMA	Result of Potential Enhancement	CDF Reduction	Off-Site Dose Reduction	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Conclusion
058	Proceduralize the operator action to feed B1 loads via B3 When A5 is unavailable post-trip. Similarly, feed B2 loads via B4 when A6 is unavailable post trip.	This SAMA would provide the direction to restore B15 and B17 loads upon loss of A5 initiating events as long as A3 is available. Additionally, it would provide the direction to restore B14 and B18 loads upon loss of A6 initiating events as long as A4 is available.	4.92%	3.14%	$31,799	$190,797	$50,000	Retain
	Basis for Conclusion: The CDF contribution from sequences involving loss of 4160VAC safeguard bus A5 was conservatively eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $50,000 by engineering judgment.							
059	Provide redundant path from fire protection pump discharge to LPCI loops A and B cross-tie.	This SAMA would enhance the availability and reliability of the firewater cross-tie to LPCI loops A and B for reactor vessel injection and drywell spray.	8.77%	17.19%	$154,966	$929,797	$1,956,000	Not cost effective
	Basis for Conclusion: The CDF contribution from sequences involving firewater injection failures was conservatively eliminated to assess the benefit of this SAMA. The cost of implementing this SAMA was estimated to be $1,956,000 by engineering judgment. Therefore, this SAMA is not cost effective for PNPS							

Table E.2-2
Sensitivity Analysis Results

Phase II SAMA ID	SAMA	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Benefit	Upper Bound Estimated Benefit
		Base Line	Base Line		Sensitivity Case 1	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 2
1	Install an independent method of suppression pool cooling.	$43,639	$261,832	$5,800,000	$50,320	$301,920	$59,355	$356,129
2	Install a filtered containment vent to provide fission product scrubbing. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber	$0	$0	$3,000,000	$0	$0	$0	$0
3	Install a containment vent large enough to remove ATWS decay heat.	$10,283	$61,701	>$2,000,000	$11,702	$70,211	$14,207	$85,244
4	Create a large concrete crucible with heat removal potential under the basemat to contain molten core debris.	$436,759	$2,620,551	>$100 million	$492,136	$2,952,813	$610,307	$3,661,845
5	Create a water-cooled rubble bed on the pedestal.	$436,759	$2,620,551	$19,000,000	$498,057	$2,988,339	$610,307	$3,661,845

Table E.2-2
Sensitivity Analysis Results (Continued)

Phase II SAMA ID	SAMA	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Benefit	Upper Bound Estimated Benefit
		Base Line	Base Line		Sensitivity Case 1	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 2
6	Provide modification for flooding the drywell head	$2,153	$12,915	>$1,000,000	$2,425	$14,551	$3,008	$18,048
7	Enhance fire protection system and/or SGTS hardware and procedures.	$10,763	$64,577	>$2,500,000	$12,127	$72,764	$15,040	$90,238
8	Create a core melt source reduction system.	$436,759	$2,620,551	>$5,000,000	$498,057	$2,988,339	$610,307	$3,661,845
9	Install a passive containment spray system.	$44,037	$264,219	$5,800,000	$50,845	$305,069	$59,803	$358,816
10	Strengthen primary/ secondary containment.	$205,571	$1,233,428	$12,000,000	$231,636	$1,389,815	$287,257	$1,723,540
11	Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur	$4,305	$25,831	>$5,000,000	$4,851	$29,105	$6,016	$36,095
12	Provide a reactor vessel exterior cooling system (see #7)	$3,229	$19,373	$2,500,000	$3,638	$21,828	$4,512	$27,071

Table E.2-2
Sensitivity Analysis Results (Continued)

Phase II SAMA ID	SAMA	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Benefit	Upper Bound Estimated Benefit
		Base Line	Base Line		Sensitivity Case 1	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 2
13	Construct a building to be connected to primary/ secondary containment that is maintained at a vacuum	$10,763	$64,577	>$2,000,000	$12,273	$73,640	$15,040	$90,238
14	2.g. Dedicated Suppression Pool Cooling	$43,639	$261,832	$5,800,000	$51,067	$306,400	$59,355	$356,129
15	3.a. Create a larger volume in containment.	$205,571	$1,233,428	$8,000,000	$234,423	$1,406,537	$287,257	$1,723,540
16	3.b. Increase containment pressure capability (sufficient pressure to withstand severe accidents).	$205,571	$1,233,428	$12,000,000	$234,423	$1,406,537	$287,257	$1,723,540
17	3.c. Install improved vacuum breakers (redundant valves in each line).	$0	$0	>$1,000,000	$0	$0	$0	$0
18	3.d. Increase the temperature margin for seals.	$2,153	$12,915	$12,000,000	$2,455	$14,728	$3,008	$18,048
19	5.b/c. Install a filtered vent	$0	$0	$3,000,000	$0	$0	$0	$0

Table E.2-2
Sensitivity Analysis Results (Continued)

Phase II SAMA ID	SAMA	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Benefit	Upper Bound Estimated Benefit
		Base Line	Base Line		Sensitivity Case 1	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 2
20	7.a. Provide a method of drywell head flooding.	$2,153	$12,915	>$1,000,000	$2,455	$14,728	$3,008	$18,048
21	13.a. Use alternate method of reactor building spray.	$10,763	$64,577	>$2,500,000	$12,273	$73,640	$15,040	$90,238
22	14.a. Provide a means of flooding the rubble bed.	$204,495	$1,226,971	$2,500,000	$230,423	$1,382,539	$285,753	$1,714,516
23	14.b. Install a reactor cavity flooding system.	$436,759	$2,620,551	$8,750,000	$498,057	$2,988,339	$610,307	$3,661,845
24	Add ribbing to the containment shell.	$205,571	$1,233,428	$12,000,000	$234,423	$1,406,537	$287,257	$1,723,540
25	Provide additional DC battery capacity.	$24,393	$146,356	$500,000	$27,830	$166,978	$33,598	$201,588
26	Use fuel cells instead of lead-acid batteries.	$24,393	$146,356	>$2,000,000	$28,207	$169,242	$33,598	$201,588
27	Modification for Improving DC Bus Reliability	$19,761	$118,568	$500,000	$23,377	$140,262	$26,044	$156,263
28	2.i. Provide 16-hour SBO injection.	$24,393	$146,356	$500,000	$28,207	$169,242	$33,598	$201,588

Table E.2-2
Sensitivity Analysis Results (Continued)

Phase II SAMA ID	SAMA	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Benefit	Upper Bound Estimated Benefit
		Base Line	Base Line		Sensitivity Case 1	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 2
29	9.b. Provide an alternate pump power source.	$44,281	$265,687	>$2,000,000	$50,546	$303,278	$60,956	$365,738
30	9.g. AC Bus Cross-Ties	$78,902	$473,410	$146,120	$91,662	$549,972	$106,357	$638,142
31	10.a. Add a dedicated DC power supply.	$150,504	$903,025	$3,000,000	$178,405	$1,070,432	$201,864	$1,211,183
32	10.b. Install additional batteries or divisions.	$150,504	$903,025	$3,000,000	$178,405	$1,070,432	$201,864	$1,211,183
33	10.c. Install fuel cells.	$24,393	$146,356	>$2,000,000	$28,207	$169,242	$33,598	$201,588
34	10.d. DC Cross-Ties	$19,761	$118,568	$13,000	$23,377	$140,262	$26,044	$156,263
35	10.e. Extended SBO provisions.	$24,393	$146,356	$500,000	$28,207	$169,242	$33,598	$201,588
36	Locate RHR inside containment.	$2,749	$16,497	>$500,000	$3,213	$19,276	$3,680	$22,077
37	Increase frequency of valve leak testing.	$4,025	$24,148	$100,000	$4,688	$28,127	$5,407	$32,444
38	8.e. Improve MSIV design.	$0	$0	>$2,000,000	$0	$0	$0	$0

Table E.2-2
Sensitivity Analysis Results (Continued)

Phase II SAMA ID	SAMA	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Benefit	Upper Bound Estimated Benefit
		Base Line	Base Line		Sensitivity Case 1	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 2
39	Install an independent diesel for the CST makeup pumps.	$0	$0	$135,000	$0	$0	$0	$0
40	Provide an additional high pressure injection pump with independent diesel.	$18,369	$110,212	>$2,000,000	$21,540	$129,238	$24,477	$146,860
41	Install independent AC high pressure injection system.	$18,369	$110,212	>$2,000,000	$21,902	$131,415	$24,477	$146,860
42	2.a. Install a passive high pressure system.	$18,369	$110,212	>$2,000,000	$21,902	$131,415	$24,477	$146,860
43	2.d. Improved high pressure systems	$12,671	$76,025	>$2,000,000	$14,851	$89,109	$16,894	$101,363
44	2.e. Install an additional active high pressure system.	$18,369	$110,212	>$2,000,000	$21,902	$131,415	$24,477	$146,860
45	8.c. Add a diverse injection system.	$18,369	$110,212	>$2,000,000	$21,902	$131,415	$24,477	$146,860
46	Increase SRV reseat reliability.	$10,600	$63,599	$2,000,000	$12,326	$73,958	$14,270	$85,623
47	11.a. Install an ATWS sized vent.	$10,283	$61,701	>$2,000,000	$11,857	$71,142	$14,207	$85,244

Table E.2-2
Sensitivity Analysis Results (Continued)

Phase II SAMA ID	SAMA	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Benefit	Upper Bound Estimated Benefit
		Base Line	Base Line		Sensitivity Case 1	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 2
48	Diversify explosive valve operation.	$2,153	$12,915	>$200,000	$2,425	$14,551	$3,008	$18,048
49	Increase the reliability of SRVs by adding signals to open them automatically.	$5,300	$31,799	>$1,500,000	$6,163	$36,978	$7,135	$42,811
50	8.e. Improve SRV design.	$32,396	$194,378	>$2,000,000	$37,767	$226,602	$43,483	$260,897
51	Provide self-cooled ECCS pump seals.	$4,902	$29,412	>$200,000	$5,638	$33,829	$6,687	$40,125
52	Provide digital large break LOCA protection.	$2,352	$14,109	>$100,000	$2,688	$16,126	$3,232	$19,391
53	Control containment venting within a narrow band of pressure	$22,873	$137,237	$300,000	$26,653	$159,919	$30,716	$184,299
54	Install a bypass switch to bypass the low reactor pressure interlocks of LPCI or core spray injection valves.	$3,627	$21,761	$1,000,000	$4,163	$24,978	$4,960	$29,758
55	Improve SSW System and RBCCW pump recovery.	$59,385	$356,310	>$5 million	$67,986	$407,918	$81,467	$488,799

Table E.2-2
Sensitivity Analysis Results (Continued)

Phase II SAMA ID	SAMA	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Cost	Estimated Benefit	Upper Bound Estimated Benefit	Estimated Benefit	Upper Bound Estimated Benefit
		Base Line	Base Line		Sensitivity Case 1	Sensitivity Case 1	Sensitivity Case 2	Sensitivity Case 2
56	Provide redundant DC power supplies to DTV valves.	$36,773	$220,639	$112,400	$43,541	$261,247	$48,408	$290,449
57	Proceduralize the use of diesel fire pump hydroturbine in the event of EDG A failure or unavailability.	$29,213	$175,279	$26,000	$33,568	$201,406	$39,901	$239,406
58	Proceduralize the operator action to feed B1 loads via B3 When A5 is unavailable post-trip.	$31,799	$190,797	$50,000	$36,980	$221,878	$42,811	$256,868
59	Provide redundant path from fire protection pump discharge to LPCI loops A and B cross-tie.	$154,966	$929,797	$1,956,000	$176,682	$1,060,091	$213,620	$1,281,720