Applicant's Environmental Report –
Operating License Renewal Stage
Shearon Harris Nuclear Plant
Progress Energy

Unit 1
Docket No. 50-400
License No. NPF-63

Final
November 2006

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ACRONYMS AND ABBREVIATIONS

AEC	U.S. Atomic Energy Commission
AQCR	Air Quality Control Region
BMP	Best management practices
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
cfs	cubic feet per second
CP&L	Carolina Power & Light Company
CSA	Combined Statistical Area
CTMU	Cooling Tower Makeup
CWA	Clean Water Act
DECON	decontamination and dismantlement
DSM	demand-side management
DSHPO	Deputy State Historic Preservation Officer
EA	Environmental Assessment
EPA	U.S. Environmental Protection Agency
ESW	Emergency Service Water
°F	degrees Fahrenheit
FES	Final Environmental Statement
FSAR	Final Safety Analysis Report
FWS	U.S. Fish and Wildlife Service
GEIS	Generic Environmental Impact Statement for License Renewal of Nuclear Plants
gpm	gallons per minute
HEEC	Harris Energy and Environmental Center
HNP	Shearon Harris Nuclear Plant
IPA	Integrated Plant Assessment
IVM	integrated vegetation management
kV	kilovolt
LOCA	loss-of-coolant accident
MSA	Metropolitan Statistical Area
msl	mean sea level
MW	megawatt
MWe	megawatts-electrical
MWt	megawatts-thermal
NAAQS	National Ambient Air Quality Standards
NCDENR	National North Carolina Department of Environment and Natural Resources
NCEMPA	North Carolina Eastern Municipal Power Agency
NCSA	North Carolina State Archaeologist

NCSOA	North Carolina State Office of Archaeology
NCSU	North Carolina State University
NCWRC	North Carolina Wildlife Resources Commission
NEPA	National Environmental Policy Act
NESC®	National Electrical Safety Code®
NMFS	National Marine Fisheries Service
NO_x	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
NSPS	New Source Performance Standard
NWTF	National Wild Turkey Federation
RFES	Revised Final Environmental Statement
ROW	right-of-way
RTP	Research Triangle Park
SAFSTOR	safe storage of the stabilized and defueled facility
SAMA	Severe Accident Mitigation Alternatives
SHPO	State Historic Preservation Office
SMITTR	surveillance, monitoring, inspections, testing, trending, and recordkeeping
SO_2	sulfur dioxide
SO_x	oxides of sulfur
USCB	U.S. Census Bureau
USDOI	U.S. Department of Interior
USGS	U.S. Geological Survey

1.0 INTRODUCTION

1.1 PURPOSE OF AND NEED FOR ACTION

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act of 1954, as amended, and NRC implementing regulations. Progress Energy operates the Shearon Harris Nuclear Plant (HNP), pursuant to NRC Operating License NPF-63. The license will expire October 24, 2026. Progress Energy has prepared this environmental report in conjunction with its application to NRC to renew the HNP operating license, as provided by the following NRC regulations:

> Title 10, Energy, Code of Federal Regulations (CFR), Part 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, Section 54.23, Contents of Application-Environmental Information (10 CFR 54.23) and
>
> Title 10, Energy, CFR, Part 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions, Section 51.53, Postconstruction Environmental Reports, Subsection 51.53(c), Operating License Renewal Stage [10 CFR 51.53(c)].

NRC has defined the purpose and need for the proposed action, the renewal of the operating license for nuclear power plants such as HNP, as follows:

> "...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." (NRC 1996a)

The renewed operating licenses would allow an additional 20 years of plant operation beyond the current HNP licensed operating period of 40 years.

1.2 ENVIRONMENTAL REPORT SCOPE AND METHODOLOGY

NRC regulations for domestic licensing of nuclear power plants require environmental review of applications to renew operating licenses. The NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled *Applicant's Environmental Report - Operating License Renewal Stage*. In determining what information to include in the HNP Environmental Report, Progress Energy has relied on NRC regulations and the following supporting documents that provide additional insight into the regulatory requirements:

- NRC supplemental information in the *Federal Register* (NRC 1996a, 1996b, 1996c, and 1999a)
- *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996d and 1999b)
- Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses (NRC 1996e)
- Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response (NRC 1996f)

Progress Energy has prepared Table 1-1 to verify conformance with regulatory requirements. Table 1-1 indicates where the environmental report responds to each requirement of 10 CFR 51.53(c). In addition, each responsive section is prefaced by a boxed quote of the regulatory language and applicable supporting document language.

1.3 SHEARON HARRIS NUCLEAR PLANT LICENSEE AND OWNERSHIP

Carolina Power & Light Company (CP&L) and North Carolina Eastern Municipal Power Agency are the NRC licensees for HNP. CP&L, now doing business as Progress Energy Carolinas, will submit the HNP license renewal application to the NRC. Progress Energy Carolinas, which serves more than 1.4 million customers in North and South Carolina, is a wholly owned subsidiary of Progress Energy, a diversified energy services company headquartered in Raleigh, North Carolina (Progress Energy 2006).

HNP is co-owned by Progress Energy (83.8 percent) and North Carolina Eastern Municipal Power Agency (16.2 percent) but Progress Energy has exclusive control over operation and maintenance of the facility.

TABLE 1-1
ENVIRONMENTAL REPORT RESPONSES TO LICENSE RENEWAL ENVIRONMENTAL REGULATORY REQUIREMENTS

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(1)		Entire Document
10 CFR 51.53(c)(2), Sentences 1 and 2	3.0	Proposed Action
10 CFR 51.53(c)(2), Sentence 3	7.2.2	Environmental Impacts of Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	7.0	Alternatives to the Proposed Action
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5	Short-Term Use Versus Long-Term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4	Irreversible and Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.2	Mitigation
	7.2.2	Environmental Impacts of Alternatives
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0	Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.1	Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a Small River with Low Flow)
	4.6	Groundwater Use Conflicts (Plants Using Cooling Towers or Cooling Ponds and Withdrawing Makeup Water from a Small River)
10 CFR 51.53(c)(3)(ii)(B)	4.2	Entrainment of Fish and Shellfish in Early Life Stages
	4.3	Impingement of Fish and Shellfish
	4.4	Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.5	Groundwater Use Conflicts (Plants Using >100 gpm of Groundwater)
	4.7	Groundwater Use Conflicts (Plants Using Ranney Wells)
10 CFR 51.53(c)(3)(ii)(D)	4.8	Degradation of Groundwater Quality
10 CFR 51.53(c)(3)(ii)(E)	4.9	Impacts of Refurbishment on Terrestrial Resources
	4.10	Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.11	Air Quality During Refurbishment (Non-Attainment Areas)

TABLE 1-1
ENVIRONMENTAL REPORT RESPONSES TO LICENSE RENEWAL ENVIRONMENTAL REGULATORY REQUIREMENTS (Continued)

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(3)(ii)(G)	4.12	Microbiological Organisms
10 CFR 51.53(c)(3)(ii)(H)	4.13	Electric Shock from Transmission-Line-Induced Currents
10 CFR 51.53(c)(3)(ii)(I)	4.14	Housing Impacts
	4.15	Public Utilities: Public Water Supply Availability
	4.16	Education Impacts from Refurbishment
	4.17	Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.18	Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.19	Historic and Archaeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.20	Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(3)(iv)	6.2	Mitigation
	5.0	Assessment of New and Significant Information
10 CFR 51, Appendix B, Table B-1, Footnote 6	2.6.2	Minority and Low-Income Populations

1.4 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1996a. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." Federal Register. Vol. 61, No. 109. June 5.

NRC (U.S. Nuclear Regulatory Commission). 1996b. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Correction." Federal Register. Vol. 61, No. 147. July 30.

NRC (U.S. Nuclear Regulatory Commission). 1996c. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." Federal Register. Vol. 61, No. 244. December 18.

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

NRC (U.S. Nuclear Regulatory Commission). 1996e. Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses. NUREG-1440. Washington, DC. May.

NRC (U.S. Nuclear Regulatory Commission). 1996f. Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response. Volumes 1 and 2. NUREG-1529. Washington, DC. May.

NRC (U.S. Nuclear Regulatory Commission). 1999a. "Changes to Requirements for Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Final Rule." Federal Register. Vol. 64, No. 171. September 3.

NRC (U.S. Nuclear Regulatory Commission). 1999b. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS). Section 6.3, "Transportation" and Table 9-1, "Summary of findings on NEPA issues for license renewal of nuclear power plants." NUREG-1437. Volume 1, Addendum 1. Washington, DC. August.

Progress Energy. 2006. Progress Energy Data Book. Prepared by Progress Energy, Inc., Raleigh, North Carolina. Available online at http://www.progress-energy.com/investors/overview/databook/databook_fulldocument.pdf.

2.0 SITE AND ENVIRONMENTAL INTERFACES

2.1 LOCATION AND FEATURES

Shearon Harris Nuclear Plant (HNP) is located in the extreme southwest corner of Wake County, North Carolina (Figure 2-1). Portions of the HNP site also lie in southeastern Chatham County. The City of Raleigh, North Carolina is approximately 16 miles northeast of the plant, and the City of Sanford, North Carolina is approximately 15 miles southwest of the plant (Figure 2-2). The Cape Fear River flows in a northwest-to-southeast direction approximately 7.0 miles south of the plant (see Figure 2-1).

CP&L constructed a dam in 1980 on Buckhorn Creek about 2.5 miles north of its confluence with the Cape Fear River to create 4,150-acre Harris Reservoir for cooling tower makeup. Filling of the reservoir began in the fall of 1980, and was completed in early 1983 (NRC 1983, page 4-25; CP&L 1998a). The HNP power block area (reactor building, generating facilities, and switchyard) is located on the northwest shore of the reservoir, about 4.5 miles north of the main dam (HNP FSAR, page 2.1.1-1).

The plant is located on a peninsula that extends into Harris Reservoir from the northwest (Figure 2-3). The Tom Jack Creek arm of the reservoir lies to the west; the Thomas Creek arm of the reservoir lies to the east. The reactor building and generating facilities lie within a nuclear exclusion area, access to which is controlled. The exclusion area is roughly circular, with a radius of approximately 7,000 feet, but is not a perfect circle; its axis ranges from 6,640 feet to 7,200 feet (HNP FSAR, Chapter 2, Figure 2.1.2-1). The distance from the center of the exclusion area to the boundary ranges from 6,640 feet (to the northwest, because US Hwy 1 truncates the circle) to 7,000 feet (east) to 7,200 feet (south). The exclusion area, comprised of both high ground and portions of Harris Reservoir, encompasses approximately 3,535 acres (FSAR, Chapter 2, Figure 2.1.2-1).

The HNP site is a much larger tract of land that includes the exclusion zone, Harris Reservoir, and some surrounding lands (Figure 2-4). It is defined by the boundary of the exclusion area, by the 243 foot contour of the Main Reservoir, and the 260 foot contour of the Auxiliary Reservoir (HNP FSAR, note to Figure 2.1.1-1). It totals 10,744 acres (HNP FSAR, Figure 2.1.1-1; GEIS, Table 2.1). However this acreage is normally reported as “approximately” 10,800 acres (NRC 1983, page 4-20; HNP FSAR, page 2.1.1-1). The larger acreage figure (10,800 acres) will be used throughout this ER for consistency’s sake.

Of the 10,800 or so acres that comprise the HNP site, approximately 4,150 acres were inundated over the 1980-1983 period with the creation of Harris Reservoir. A second, smaller impoundment, the Auxiliary Reservoir (aka “West Auxiliary” Reservoir), was created when the Tom Jack Creek arm of Harris Reservoir was dammed. This 321-acre reservoir, which lies immediately west of the generating facilities, was created to serve as a second source of water for the emergency service water system.

Approximately 1,000 acres of vegetation were cleared during development and construction of the HNP site (NRC 1983, page 4-22). Most borrow areas and laydown yards were planted (or re-planted) in pines in 1981 and 1982. Approximately 440 acres of the site were cleared and graded and are now occupied by generating facilities, parking lots, warehouses, equipment storage and laydown areas (see Figure 3-1). The Wake County Fire/Rescue Training Facility and Cary Police Department Firing Range occupy approximately 20 acres just east of the developed part of the site, across Thomas Creek. Most of the remaining acreage, 5,000 to 6,000 acres, is forested. Upland portions of these forested areas are managed for timber production. Areas along the shore of the Harris Reservoir and buffer zones (i.e., wetlands) are generally left in a natural state.

Section 3.1 describes key features of the plant, including reactor and containment systems, cooling water systems, and transmission facilities.

2.2 AQUATIC RESOURCES

Harris Reservoir

Harris Reservoir was built to supply cooling tower makeup water and auxiliary reservoir makeup water for the 900-MW Harris Nuclear Plant (HNP), which first operated in 1987. It was created by impounding Buckhorn Creek, a tributary of the Cape Fear River (see Figure 2-3). From its headwaters east of HNP near Fuquay-Varina, Buckhorn Creek flows in a southwesterly direction for most of its length, then moves south to its confluence with the Cape Fear. Buckhorn Creek has five tributaries above the Harris Reservoir dam: Tom Jack Creek, Thomas Creek, Little White Oak Creek, White Oak Creek, and Cary Branch (HNP FSAR, Section 2.4.1.2.1.1). Buckhorn Creek and its tributaries drain an area of 76.3 square miles (USGS 2004). Flows in Buckhorn Creek showed dramatic daily and seasonal fluctuations prior to the development of Harris Reservoir, but are now regulated by the Harris Reservoir dam (USGS 2004). From 1981 to 2003, annual mean streamflow (measured at a USGS station 1 mile downstream of the dam) ranged from 2.47 to 137 cubic feet per second.

As noted in Section 2.1, the dam was completed in late 1980 and the reservoir reached full-pool elevation of 220 feet msl in February 1983 (Progress Energy 2003a). The reservoir level is controlled by a spillway, also at the 220 foot elevation, in the Harris Reservoir dam (HNP FSAR, Section 2.4.3.3).

The main body of Harris Reservoir has a surface area of 4,150 acres, a maximum depth of 56 feet, a mean depth of approximately 18 feet, a volume of 8.9×10^7 cubic meters (2.35×10^{10} gallons), and an average residence time of 28 months (Progress Energy 2003a). The Auxiliary Reservoir, which lies immediately west of the developed portion of the site, has a surface area of approximately 321 acres.

The Harris Reservoir shoreline is mostly wooded; the drainage area is mostly rolling hills with land used primarily for silviculture and agriculture (Progress Energy 2003a). Although the immediate watershed is forested, the expanding Towns of Apex and Holly Springs are to its north and east, respectively. Progress Energy holds an NPDES permit for both HNP and the Harris Energy & Environmental Center (HEEC; located northeast of the plant on the Little White Oak Creek arm of the reservoir) and both facilities discharge to the reservoir. The reservoir also receives treated discharge from a wastewater treatment plant in Holly Springs via Utley Creek (a tributary of White Oak Creek), which flows into Harris Reservoir's northeastern-most arm.

A recent analysis of land use coverage showed more than 70 percent of the sub-basin (which includes several watersheds, including the Buckhorn Creek-Harris Reservoir watershed) is forested (NCDENR 2004a). However due to accelerated urban growth especially around the Towns of Holly Springs, Fuquay-Varina, and Sanford the amount of land in pasture, cultivated crops, and forest will probably continue to decrease while the amount of land committed to residential and commercial uses will increase.

Harris Reservoir was classified by North Carolina Department of Environment and Natural Resources' Division of Water Quality as eutrophic in the agency's most recent Basinwide Assessment Report (NCDENR 2004a, pages 89, 93, and 94). The reservoir was most recently sampled by the agency in 2003. At that time, despite heavy rainfall in the watershed, Secchi depths were greater than one meter at all sampling sites. Fecal coliform bacteria concentrations were low. Total phosphorus concentrations were similar to those previously measured. Ammonia concentrations were consistently below detection level at all sites and these concentrations were the lowest ever observed. Aquatic macrophytes, including *Hydrilla* sp., were observed throughout the reservoir. NCDENR classified Harris Reservoir as eutrophic based on calculated North Carolina Trophic State Index scores (which are in turn based on water clarity, algal densities, and phosphorus concentrations); it had received this classification in previous monitoring cycles as well.

Progress Energy has monitored water quality and biological communities in Harris Reservoir since the reservoir filled, in the early 1980s, in an effort to evaluate the waterbody's health, track changes in water quality, document the appearance of non-native plants and animals, and assess the state of the recreational fishery. Water quality (including temperature, dissolved oxygen, pH, and turbidity), water chemistry (including major nutrients and, until 2002, a suite of trace metals), and fish are sampled quarterly; aquatic vegetation is surveyed once a year, in the fall (Progress Energy 2003a, pp. 4-6).

Like several other impoundments in the Research Triangle Area, Harris Reservoir is a biologically productive reservoir. Although it has many of the characteristics of eutrophic southeastern reservoirs (e.g., elevated nutrient concentrations, extensive growth of aquatic vegetation in shallows, oxygen-deficient hypolimnetic water in summer), it also has characteristics of a mesotrophic reservoir, such as good water clarity and low turbidity (Progress Energy 2003a, page 8).

Nutrient concentrations became a concern in Harris Reservoir when phosphorus and nitrogen concentrations showed a pronounced increase in the late 1980s (Progress Energy 2001, p.13). Prior to startup of the plant's cooling system in 1986, the reservoir was moderately productive. The reservoir became more biologically productive when HNP began discharging cooling tower blowdown (and low volumes of other NPDES-permitted wastes) into the reservoir near the main dam via the cooling tower blowdown line (CP&L 1994). The NPDES-permitted discharges that flow into the reservoir from HNP, the HEEC, and the Holly Springs Wastewater Treatment Plant all contain, to one degree or another, nitrogen and phosphorus compounds that stimulate the growth of phytoplankton and aquatic macrophytes. Even after secondary treatment, sewage treatment plant effluent contains these inorganic nutrients, which can accelerate eutrophication in natural waters and produce algae blooms.

In late spring 1989, chlorophyll-*a* concentrations in excess of water quality standards were measured at monitoring stations in Harris Reservoir and the first algal bloom was observed. Increased nutrient loading from both point and non-point sources in the watershed over the 1986-1989 timeframe that accelerated primary productivity were presumed to be the cause. Nutrient concentrations in the reservoir stabilized around 1995, at levels higher than those seen in the early-to-mid 1980s but typical of productive southeastern reservoirs (Progress Energy 2001). The last algal bloom in the reservoir was reported in 1998.

In the early and mid-1980s, prior to operation of HNP, shoreline electrofishing and rotenone samples showed a Harris Reservoir fish population dominated by small (less than 350 mm) largemouth bass and Lepomids (Jones et al. 2000). Black crappie, largemouth bass, and bluegill were the species sought by most anglers. Bluegill was the species most often harvested. Studies of largemouth bass prior to 1987 showed slow growth for this recreationally important species. During 1988 and 1989, as reservoir productivity increased, growth of largemouth bass improved and there was a shift to larger-sized bass (CP&L 1994, pg. 2). The introduction of threadfin shad by North Carolina Wildlife Resources Commission in 1987 also appeared to contribute to improved growth of largemouth bass.

In 2002, Progress Energy biologists collected 19 species of fish in quarterly electrofishing samples. Based on these electrofishing studies, the Harris Reservoir fish community is dominated by four common centrarchids (bluegill, redear sunfish, largemouth bass, black crappie), two minnow species (golden shiner, coastal shiner), and two shad species (gizzard shad, threadfin shad). These eight species are found throughout the reservoir.

Statistical analysis of electrofishing catch rates (number of fish caught per hour) revealed differences among transects (sampling locations) for only one species, the redear sunfish (Progress Energy 2003a, page 10 and Appendix 3). Redear sunfish were captured more often at a transect near the Main Dam and a transect in the Buckhorn Creek arm of the reservoir than at uplake transects. But catch rates for redear sunfish were relatively high at all transects, even at uplake locations.

In 2002, the average number of fish collected at the various sampling locations in Harris Reservoir ranged from 240 fish per hour (Transect V) to 416 fish per hour (Transect H), and averaged 322 fish per hour across all transects. This was the highest catch rate seen over the 1988-2002 period in years in which fish were sampled quarterly (Progress Energy 2003a, page 10). In some years (1992, 1993, and 1998) electrofishing was conducted semi-annually rather than quarterly and these data are not directly comparable to years in which electrofishing was conducted quarterly.

Based on electrofishing samples, the four most abundant fish species are all centrarchids: bluegill (117 fish/hour), redear sunfish (92 fish/hour), largemouth bass (29 fish/hour), and black crappie (21 fish/hour) (Progress Energy 2003a, Appendix 3). These fish made up 80 percent of all fish collected in 2002. The four most important species by weight were largemouth bass (11.3 kilograms/hectare), redear sunfish (6.0 kilograms/hectare), bluegill (3.8 kilograms/hectare), and gizzard shad (3.3 kilograms/hectare) (Progress Energy 2003a, Appendix 4). With the exception of the gizzard shad, these are littoral-zone species that are vulnerable to collection by electrofishing. As a consequence, other species that prefer open waters or deeper waters may have been under-represented in collections. Gizzard shad have less clear-cut habitat preferences and feeding strategies; they may graze on algae-covered rocks in littoral shallows or cruise the pelagic zone, feeding on phytoplankton and zooplankton (Pflieger 1975).

Harris Reservoir offers area anglers a variety of fishing opportunities. Anglers may pursue the reservoir's largemouth bass, which are both plentiful and in good condition, virtually year-round. They may fish for spawning black crappie in the early spring and bedding bluegill in the late spring. Bluegill and redear sunfish are available to anglers all summer, however, and into the fall. Catfish are abundant, and are sought by both casual fishermen fishing from shore and more serious catfish "specialists," who fish dropoffs adjacent to hydrilla beds from boats (Kibler 2002). Channel catfish are sought by most fishermen, but several other species of catfish are present and are occasionally caught by anglers.

Harris Reservoir developed a reputation as a producer of trophy largemouth bass in the early 1990s. When word spread of the large bass being caught, there was a marked increase in fishing pressure. The North Carolina Wildlife Resources Commission carried out creel surveys on Harris Reservoir over a 12-month period in 1997-1998 in an effort to determine the level of fishing effort (pressure), angler preferences, and harvest rates. The estimated fishing effort over the 1997-1998 period was 188,948 hours or 118 hours per hectare, indicating that Harris Reservoir was "heavily fished compared to other Piedmont reservoirs" (Jones et al. 2000). Largemouth bass accounted for 67 percent of all fishing effort. Crappie fishing was a distant second in popularity, accounting for 17 percent of all fishing effort. Although largemouth bass was the species pursued by most anglers, black crappie were harvested at a rate almost ten times that of largemouth bass, suggesting that this species is more easily caught and less likely to be released once caught.

In response to public complaints about the effect of this increased fishing pressure on the largemouth bass population, and on trophy-sized fish in particular, North Carolina Wildlife Resources Commission in 2002 instituted a 16-to-20 inch slot limit on Harris Reservoir largemouth bass (Garitta 2003). At the time the slot limit was imposed, the NCWRC biologist responsible for management of fisheries in District 3, which includes Harris Reservoir, noted that Harris Reservoir was "still a very good fishing lake" and predicted that "the slot limit and the practice of catch and release should help the lake to maintain its trophy fish status" (Garitta 2003).

In summary, Harris Reservoir has evolved from a moderately-productive reservoir with relatively slow-growing gamefish in the 1980s into a more productive reservoir with healthy populations of largemouth bass, "bream" (bluegill and redear sunfish), crappie, and catfish. The reservoir has become more productive as a result of nutrient inputs from the watershed and from HNP that have increased primary and secondary productivity. Gamefish have also benefitted from the introduction of threadfin shad, first stocked by NCWRC in 1987. Based on Progress Energy and NCDENR monitoring, it appears that nutrient inputs have stabilized since the mid-1990s and Harris Reservoir currently supports a healthy, balanced biological community with thriving forage fish and gamefish populations. The fish community is dominated by species native to the southeastern U.S., such as largemouth bass, bluegill, redear sunfish, white catfish, and gizzard shad.

Nuisance Aquatic Organisms

The FES for operation of HNP (NRC 1983) noted that the nuisance aquatic plant hydrilla (*Hydrilla verticillata*) had been found in several Wake County impoundments and predicted it would colonize shallow (up to 10 feet deep) portions of Harris Reservoir. This proved to be prophetic. Hydrilla was discovered in the White Oak Creek arm of Harris Reservoir in 1988, and by 1990 was the dominant aquatic plant of the littoral zone, displacing several native species (CP&L 1994, page 2). Creeping water primrose *(Ludwigia uruquaynensis)*, another non-native plant, appeared a year or so later and quickly established itself in the reservoir. Neither species is unique to Harris Reservoir; both species are regarded as nuisance species by reservoir and pond managers. Hydrilla, in particular, is the bane of reservoir managers and resource agencies in the southeast. None of these nuisance aquatic plants has created operational problems for HNP.

Two new species of invasive aquatic plant, water hyacinth (*Eichohornia crassipes*) and water lettuce (*Pistia stratiotes*), were discovered in 2002 near the Holleman's Crossroads boat ramp (Progress Energy 2003a, page 12). Both are free-floating vascular plants native to South America that are imported for the ornamental pond trade. Progress Energy personnel removed these plants and has found none in follow-up surveys.

2.3 GROUNDWATER RESOURCES

The Shearon Harris Nuclear Plant (HNP) is located in the Piedmont physiographic province near the fall line separating the Coastal Plain from the Piedmont (FSAR p. 2.4.13-1). The site is located within the southeastern portion of the Durham Basin and is underlain by rocks of the Triassic Newark Group. The plant area is covered by residual soils derived from the underlying rock which consists of claystone, shale, siltstone, sandstone, conglomerate, and fanglomerate (FSAR p. 2.4.13-1). The surficial clay soils and saprolite prevent ready recharge to the rocks below (FSAR p. 2.4.13-2).

Flow within the Triassic rocks is controlled by joints and fractures within the rock resulting in low permeability. Groundwater at the plant generally occurs within the jointed rock at depths from approximately 30 to 90 feet beneath the ground surface (FSAR p. 2.4.13-3). Fractures to these depths are common but become less prevalent and tight with depth. The Triassic rocks of the aquifer are quite thick and widespread. However, due to compaction and cementation of individual rock units, it can be regarded only as a minor aquifer. Yield from known wells can range to 20 gallons per minute (gpm) but average approximately 5 gpm (FSAR p. 2.4.13-5). Within the Newark Group larger reserves of groundwater occur in the proximity of diabase dikes; several of which are located within the plant area. Seven wells with a total capacity of 200 gallons per minute were completed at the HNP site in 1973 (HNP FSAR, page 2.4.13-3). Eight more wells with a total capacity of 250 gallons per minute were completed over the 1977-1979 period. Five more wells (no capacity provided in FSAR) were developed in 1980-1981, bringing the total number of production wells developed during the construction phase to 20. As of 2006, none of the twenty wells was being used to produce domestic or process water. HNP uses surface water from Harris Reservoir for all its domestic, process, and cooling tower makeup water.

2.4 CRITICAL AND IMPORTANT TERRESTRIAL HABITATS

The HNP site (Figure 2-4) covers approximately 10,800 acres. The Harris Reservoir, created by a dam on Buckhorn Creek, covers approximately 4,150 acres of the HNP site. The industrial portion of the site occupies approximately 440 acres and consists of generating facilities, warehouses, parking lots, equipment storage, and laydown areas. An additional 700 acres of the site have been leased to Wake County for a Fire/Rescue Training Facility (20 acres) and for Harris Lake County Park (680 acres). Most of the remaining portion of the HNP site (between 5,000 and 6,000 acres) is forested.

Vegetation at most of the HNP site is typical of the eastern Piedmont province of North Carolina (CP&L 1982). Forests at HNP are in various stages of ecological succession and consist of pine forest, hardwood forest, or pine-hardwood mixtures. Loblolly pine (*Pinus taeda*) dominates the pine forests, but shortleaf (*P. echinata*), Virginia (*P. virginiana*), and longleaf (*P. pallustris*) are also found at the site. Hardwood forests at HNP are found primarily in lowland areas along streams. Dominant lowland forest species are sweet gum (*Liquidambar styraciflua*), red maple (*Acer rubrum*), American sycamore (*Platanus occidentalis*), American elm (*Ulnus americana*), and river birch (*Betula nigra*). Most of the upland forests at HNP are a mixture of pines, oaks (*Quercus* spp.) and hickories (*Carya* spp.) (NRC 1983).

Most of the upland forested HNP property is managed for timber production. After timber is removed, sites are replanted with tree species appropriate to the terrain, soils, and drainage characteristics of the area or are allowed to regenerate naturally. Upland areas are generally replanted in loblolly pine or long leaf pine, species that are well suited to the area.

The forested habitats at HNP support a variety of wildlife species typically found in the Piedmont of North Carolina. Forested areas support many species of birds, such as hawks, woodpeckers, warblers, and sparrows, and animals such as white-tailed deer, opossums, raccoons, squirrels, skunks, bobcats, snakes, toads, frogs, and lizards (CP&L 1982).

Harris Reservoir provides some limited marsh habitat in shallow backwaters. These marshes and adjacent shallows are used by waterfowl such as the mallard (*Anas platyrhynchos*), wood duck (*Aix sponsa*), and Canada goose (*Branta canadensis*), and wading birds such as herons and egrets. A great blue heron (*Ardea herodias*) rookery, known to be active during recent breeding seasons, is located at the mouth of Jim Branch in the southeastern portion of Harris Reservoir.

Progress Energy actively works to enhance wildlife habitat at HNP through its forest management practices. Progress Energy has enrolled 14,090 acres around Harris Reservoir in the North Carolina Game Lands Program (NCWRC 2006a). These properties are known collectively as Shearon Harris Game Land, and offer a variety of opportunities for hunting deer, turkey, small game, and waterfowl. Shearon Harris Game Land is open to hunting six days a week during hunting seasons for most species

(NCWRC 2006b). Waterfowl may be hunted on Mondays, Wednesdays, and Saturdays only.

Progress Energy contributed funds to NCWRC for the development of a handicapped-accessible fishing pier at the Park and provided company personnel who assisted in construction of the pier (NCWRC 2002).

Progress Energy cooperates with the North Carolina Waterfowl Association to conserve and enhance waterfowl habitat around Harris Reservoir. Since the late 1980s, 77 wood duck nest boxes have been installed around the shore of the reservoir. Progress Energy volunteers, in cooperation with the Western Wake Ducks Unlimited chapter and Harris Lake County Park, annually inspect and maintain the wood duck boxes to ensure their continued use (Progress Energy 2004a).

Progress Energy has enrolled in the National Wild Turkey Federation's (NWTF) "Energy for Wildlife" program to integrate wildlife management activities into land management program decisions at HNP. For example, fire lanes are planted in a mix of vegetation species (millet, lespedeza, clover) that provide forage opportunities for wildlife.

Timber harvest practices at HNP follow best management practices (BMPs) of the North Carolina Department of Environment and Natural Resources, Division of Forest Resources, including the establishment of Streamside Management Zones, buffer strips of vegetation adjacent to perennial and intermittent streams (at least 50 feet wide on each side of the stream) and water bodies such Harris Reservoir. Land management practices in these Streamside Management Zones that might affect water quality, fish, or other aquatic resources are closely monitored.

As explained in Section 2.1 and shown in Figure 2-4, the HNP site encompasses the exclusion area, the 243-foot msl contour of the Main Reservoir, and the 260-foot msl contour of the auxiliary reservoir. In addition, Progress Energy owns other property that is adjacent to, but not part of, the 10,800-acre HNP site. Progress Energy's land holdings in the vicinity of HNP total approximately 22,850 acres (CP&L 1982). Land management practices, terrestrial habitat types, and associated wildlife species on the adjoining (approximately) 12,000 acres of Progress Energy land are essentially the same as on the onsite 10,800 acres.

Progress Energy property in the vicinity of HNP contains six areas that have been identified by North Carolina Department of Environment and Natural Resources (NCDENR) as significant natural areas (NCDENR 2006a). Small portions of three of these areas (Hollemans Crossroads slopes, Utley Creek slopes, and Jim Branch/Buckhorn Creek forests) lie within the 10,800-acre HNP site, and are briefly described below.

The Hollemans Crossroads slopes are a series of narrow ridges and ravines along the edge of Harris Reservoir just north of Hollemans Crossroads and SR 1130. Most of the slopes support mature hardwoods, and chalk maple (*Acer leucoderme*), which is rare in the eastern Piedmont, but is common here (NCDENR 2006a). The Utley Creek slopes are located immediately south of Utley Creek and east of Hollemans Crossroads slopes. Much of this area consists of mature hardwood forests along north-facing slopes, especially dry oak-hickory forest, which is not usually found in large stands in Wake County. Several slopes contain Virginia spiderwort (*Tradescantia virginiana*), which is rare in Wake County (NCDENR 2006a). The Jim Branch/Buckhorn Creek forests lie approximately two miles south of the Hollemans Crossroads slopes. This natural area consists of two separate portions: slopes along Buckhorn Creek, and slopes along Jim Branch. Both areas contain mature mesic mixed hardwood forest and dry-mesic oak-hickory forests (NCDENR 2006a).

A 1,267-acre parcel of Progress Energy land adjacent to the HNP site known as the Harris Research Tract is used for long-term forest research by North Carolina State University (Blank et al. 2002). Through techniques such as selective cutting and controlled burning, a portion of the Harris Research Tract is being managed as longleaf pine savannah. Pine savannahs are characterized by an open canopy of longleaf pine with a dense ground cover of herbs and shrubs, and have become rare in North Carolina. An experimental population of Michaux's sumac (*Rhus michauxii*), which is federally and state-listed as endangered, was transplanted in this area in 2001 (Blank et al. 2002), and is being monitored by biologists from North Carolina State University.

Section 3.1.3 describes the seven 230-kilovolt transmission lines that connect HNP to the transmission system (Figure 3-2). In total, for the specific purpose of connecting HNP to the transmission system, Progress Energy has approximately 142 miles of corridor that occupy approximately 1,717 acres. The corridors pass through land that is primarily agricultural and forest land. The impact of these corridors on land use is minimal; farmlands that have corridors passing through them generally continue to be used as farmland.

The transmission corridors do not cross any state or federal parks, but do cross North Carolina Game Lands, which encircle the HNP site. The HNP-Ft. Bragg 230 kV line crosses both Shearon Harris and Chatham Game Lands south of the site, while the Cape Fear North and South 230 kV lines cross Shearon Harris and Chatham Game Lands southwest of the site. The HNP-Erwin 230 kV line crosses Shearon Harris Game Land east of the site. The Apex/US 1 230 kV line crosses Shearon Harris Game Land northeast of the site.

Neither HNP nor the transmission corridors that connect the plant to the regional grid contain designated habitats for federally listed species.

2.5 THREATENED OR ENDANGERED SPECIES

Table 2-1 lists the federally- and state-listed threatened and endangered species that are known to occur or historically have occurred in the six counties of interest (Wake, Chatham, Randolph, Lee, Harnett, Cumberland). Of the twelve federally-listed species and one federal-candidate species recorded in these counties, four species (bald eagle, red-cockaded woodpecker, Cape Fear shiner, and Michaux's sumac) have been confirmed in the vicinity of HNP or associated transmission corridors, and only two of these have been observed in recent years. Although 10 CFR 51 only requires applicants to assess impacts of license renewal on listed species, "species of concern" are also listed in Table 2-1. These species have no official status and are not legally protected, but known occurrences are generally taken into consideration by resource agencies during project reviews.

In 1998, CP&L conducted a self-assessment that evaluated more than 50 sensitive plant and animal species that could occur in the vicinity of HNP (based on studies prepared by Pacific Northwest National Laboratory for the NRC, and lists prepared by the U.S. Fish and Wildlife Service and the North Carolina Natural Heritage Program) and evaluated potential threats to these species from activities at HNP (CP&L 1998b).

The self-assessment identified one federally-listed species that could potentially be affected by HNP operations, future facility expansion, or other activities: the red-cockaded woodpecker (*Picoides borealis*). Red-cockaded woodpeckers, federally listed as endangered, are found in mature pine forests (generally longleaf pine) with sparse understory vegetation. There was an active red-cockaded woodpecker colony near in the HNP site in the 1980s, but it was abandoned around 1987. Red-cockaded woodpeckers are known to occur in mature longleaf pine forests crossed by the Harris-Fayetteville transmission corridor. Any activities involving removal of mature longleaf pine would require surveys for this species to ensure that no red-cockaded woodpeckers or cavity trees are impacted.

Federally-threatened bald eagles (*Haliaeetus leucocephalus*) are occasionally seen around Harris Reservoir. An active bald eagle nest was discovered near Harris Reservoir during the 2004-2005 nesting season. Located on private property, the nest is slightly north of state Road 1130 and approximately 2,000 feet from the shoreline of the White Oak Creek arm of the reservoir. HNP operations, future expansions, or other activities are not expected to affect eagles.

Red-cockaded woodpeckers and bald eagles were also identified as occurring in the vicinity of the site in the FES for operation of HNP (NRC 1983, pp. 4-29 and 4-30).

As discussed in Section 2.4, an experimental population of Michaux's sumac (*Rhus michauxii*), which is federally- and state-listed as endangered, was transplanted in the Harris Research Tract near HNP in 2001, and is being monitored by botanists from North Carolina State University. Carolina grass-of-parnassus (*Parnassia caroliniana*; state endangered) occurs in wet savannahs on the Harris-Fayetteville transmission corridor. The Eastern tiger salamander (*Ambystoma tigrinum*), which is state-listed as threatened, is known to occur about 300 feet from the Harris-Wake transmission corridor. The Eastern tiger salamander inhabits burrows in sandy pinewoods near semipermanent ponds in which it breeds. The four-toed salamander (*Hemidactylium scutatum*), which is state-listed as a special concern species, has been recorded as breeding in privately-owned vernal pools outside Progress Energy property south of the Harris reservoir (NCDENR 2006a). This salamander inhabits bogs with mossy seepages or shallow pools. It has not been recorded at the HNP site or near HNP-associated transmission corridors. No other federally- or state-listed threatened or endangered terrestrial plant species are known to occur at HNP or along its transmission corridors. Progress Energy has procedures in place to protect endangered or threatened species, if they are encountered at the plant site or along transmission corridors, and provides training for employees on these procedures (Progress Energy 2002; Progress Energy 2003b).

The federally-endangered Cape Fear shiner (*Notropis mekistocholas*) is endemic to several tributaries of the Cape Fear River in Randolph, Moore, Lee, Hartnett, and Chatham counties (USFWS 2004). Critical habitat for this species has been designated and consists of about 17 river miles in the central Piedmont of North Carolina including: (1) approximately 4 river miles of the Rocky River in Chatham County, (2) approximately 7 river miles of Bear Creek, the Rocky River, and Deep River in Chatham and Lee Counties, and (3) approximately 6 river miles of Fork Creek and the Deep River in Randolph and Moore Counties (Federal Register, Volume 52, Number 186, September 25, 1987). The closest of these to HNP is the Deep River segment, which is approximately 10 miles upstream of the Buckhorn Creek-Cape Fear River confluence.

This species was collected in the Buckhorn Creek drainage in 1972 (AEC 1974, Table 2.24), but was apparently never again collected in Buckhorn Creek or any of its tributaries. One specimen was collected in the Cape Fear River downstream of the site during pre-operational surveys of the river between 1972 and 1980 (NRC 1983, pg. 4-30). No Cape Fear shiners have been collected by CP&L or Progress Energy biologists in Harris Reservoir since monitoring of the reservoir began in the early 1980s.

The Sandhills chub (*Semotilus lumbee*), a state special concern species, is known to occur in a stream that crosses the Harris-Fayetteville corridor. Habitat for this species consists of slow-flowing headwaters, creeks, and small rivers with sand and gravel bottoms and sparse vegetation.

In 1993, CP&L signed a Memorandum of Understanding with the North Carolina Department of Environment, Health, and Natural Resources to preserve and protect rare, threatened, and endangered species and sensitive natural areas occurring on transmission line rights of way (Progress Energy 2003b, pg. 5). The company also follows Best Management Practices for Management of Rare Plants on Progress Energy Rights-of-Way (Progress Energy 2002, pp. 10-14).

2.6 DEMOGRAPHY

2.6.1 REGIONAL DEMOGRAPHY

The GEIS presents a population characterization method that is based on two factors: "sparseness" and "proximity" (NRC 1996, 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: NRC 1996.

"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: NRC 1996.

The GEIS then uses the following matrix to rank the population category as low, medium, or high.

GEIS Sparseness and Proximity Matrix

Proximity

Sparseness		1	2	3	4
	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: NRC 1996, pg. C-159.

Progress Energy used 2000 census data from the U.S. Census Bureau (USCB) website and geographic information system software (ArcView®) to determine most demographic characteristics in the HNP vicinity. As derived from 2000 USCB information, 438,969 people live within 20 miles of HNP (Tetra Tech NUS 2006). Applying the GEIS sparseness measures, HNP has a population density of 349 persons per square mile within 20 miles and falls into the least sparse category, Category 4 (greater than or equal to 120 persons per square mile within 20 miles).

As estimated from 2000 USCB information, 2,035,797 people live within 50 miles of HNP (Tetra Tech NUS 2006). This equates to a population density of 259 persons per square mile. Applying the GEIS proximity measures, HNP is classified as Category 4 (greater than or equal to 190 persons per square mile within 50 miles). According to the GEIS sparseness and proximity matrix, the HNP ranks of sparseness Category 4 and proximity Category 4, resulting in the conclusion that HNP is located in a high population area.

The population distribution within the immediate vicinity of HNP is relatively sparse, however, consistent with the area's rural character (HNP FSAR). The exceptions to this are Apex (8 mi. NE), Fuquay-Varina (8.5 mi. ESE), and Holly Springs (8 mi. E) where the 2000 populations were 20,212, 7,898, and 9,192, respectively (HNP FSAR, Section 2.1.3). The population within a 50-mile radius of HNP contains concentrations of people in the cities of Raleigh (16-28 mi. NE; 2000 population of 276,093), Durham (20–30 mi.

N; 2000 population of 187,035), Fayetteville (37-43 mi. S; 2000 population of 121,015), and Cary (13-18 mi. NE; 2000 population of 94,536) (HNP FSAR, Section 2.1.3). Several other smaller towns and cities have populations greater than 10,000. Outside of these population centers, the region remains largely rural.

All or parts of 26 counties, Raleigh, Durham, Wake Forest, Chapel Hill, and sections of two Combined Statistical Areas (CSAs) and three Metropolitan Statistical Areas (MSAs) are located within 50 miles of HNP (Figure 2-2). The CSAs are Raleigh-Durham-Cary and Greensboro-Winston Salem-High Point. The MSAs are Goldsboro, Fayetteville, and Rocky Mount (USCB 2003a and USCB 2003b).

The Raleigh-Durham-Cary CSA includes the Raleigh-Cary, Durham, and Dunn MSAs (USCB 2003a). From 1990 to 2000, the population of the Raleigh-Durham-Cary CSA increased from 953,547 to 1,314,589, an average annual increase of 3.8 percent (USCB 2003a).

The Greensboro-Winston Salem-High Point CSA includes the Greensboro-High Point, Lexington-Thomasville, Mount Airy, and Winston-Salem MSAs (USCB 2003a). From 1990 to 2000, the population of the Greensboro-Winston Salem-High Point CSA increased from 1,089,859 to 1,283,856, an average annual increase of 1.8 percent (USCB 2003a).

From 1990 to 2000, the Fayetteville MSA population increased from 297,422 to 336,609, an average annual increase of 1.3 percent (USCB 2003b). From 1990 to 2000, the Rocky Mount MSA population increased from 133,235 to 143,026, an average annual increase of 0.7 percent (USCB 2003b). For the same period, the Goldsboro MSA population increased from 104,666 to 113,329, an average annual increase of 0.8 percent (USCB 2003b).

Because more than 80 percent of HNP employees reside in Wake and Lee Counties, they are the counties with the greatest potential to be socioeconomically affected by license renewal (see Section 3.4). Table 2-2 shows population estimates and annual growth rates for these two counties. Values for the State of North Carolina and are provided for comparison's sake. The table is based on U.S. Census Bureau data for 1980, 1990, and 2000, North Carolina Office of State Budget and Management projections through 2030, and a Progress Energy projection to 2050 that is based on linear regression techniques.

Wake County is growing at a faster rate than North Carolina as a whole. From 1990 to 2000, North Carolina's average annual population growth rate was 2.1 percent, while Wake County increased by 4.8 percent. Lee County's growth was similar to statewide growth, as it increased by 1.9 percent.

In 2000, North Carolina reported a population of approximately 8.0 million people, representing approximately 3 percent of the nation's population. North Carolina's population growth rate between 1990 and 2000 was the 9th highest among the 50 states and the District of Columbia (USCB 2001).

In addition to permanent residents who live within 20 and 50 miles of HNP, recreational opportunities draw large transient populations to the area. Recreational land uses which would attract transient concentrations of people within a 50-mile radius of the site are the Harris County Park (2 Mi. SE), Jordan Lake State Recreation Area (5-12 mi. NW), Umstead Lake State Park (20 mi. NE), Raven Rock State Park (13 mi. SSE), Eno River State Park (30 mi. N), and Falls Lake State Recreation Area (30 mi. NNE). On occasions, there are also high concentrations of people at sporting events and functions at the various universities in the area. The North Carolina State Fair, held each October in Raleigh, attracts 700,000 to 850,000 people over a 10-day period (NCDACS 2006).

2.6.2 MINORITY AND LOW-INCOME POPULATIONS

NRC performed environmental justice analyses for previous license renewal applications and concluded that a 50-mile radius could reasonably be expected to contain potential environmental impact sites and that the state was appropriate as the geographic area for comparative analysis. Progress Energy has adopted this approach for identifying the HNP minority and low-income populations that could be affected by HNP operations.

Progress Energy used ArcView® geographic information system software to combine USCB TIGER line data with USCB 2000 census data to determine the minority characteristics by block group. Progress Energy included all block groups if any part of their area lay within 50 miles of HNP. The 50-mile radius includes 1,146 block groups (Table 2-3).

2.6.2.1 Minority Populations

The NRC Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues defines a “minority” population as: American Indian or Alaskan Native; Asian; Native Hawaiian or other Pacific Islander; Black races; all other single; multi-racial; and Hispanic ethnicity (NRC 2004, Appendix D). The guidance indicates that a minority population exists if either of the following two conditions exists:

1. The minority population in the census block group or environmental impact site exceeds 50 percent.

2. The minority population percentage of the environmental impact area 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. Progress Energy used 2000 census data from the USCB website (USCB 2000a, 2000b) to determine the percentage of the total population in North Carolina of each minority category, and in identifying minority populations within 50 miles of HNP.

Progress Energy divided USCB population numbers for each minority population within each block group by the total population of that block group to obtain the percent of the block group's population represented by each minority. For each of the 1,146 block groups within 50 miles of HNP, Progress Energy 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. Progress Energy defines the geographic area for HNP as the State of North Carolina.

USCB data (USCB 2000a) for North Carolina characterizes 1.2 percent of the population as American Indian or Alaskan Native; 1.4 percent Asian; 0.05 percent Native Hawaiian or other Pacific Islander; 21.6 percent Black races; 2.3 percent all other single minorities; 1.3 percent multi-racial; 27.9 percent aggregate of minority races; and 4.7 percent Hispanic ethnicity.

Table 2-3 presents the numbers of block groups in each county in the 50-mile radius that exceed the threshold for minority populations. Figures 2-5 through 2-9 locate the minority block groups among the 50-mile radius.

Four census blocks within the 50-mile radius in Hoke and Robeson Counties have American Indian or Alaskan Native populations that exceed the state average by 20 percent or more (Figure 2-5). Members of the Lumbee and Tuscarora tribes are found in these counties (Stilling 2002; Lumbee Tribe 2006). Of those four block groups, one has an American Indian population that exceeds the 50 percent criterion.

Two hundred and nineteen census blocks within the 50-mile radius have Black Races populations that exceed the state average by 20 percent or more (Figure 2-6). Of those 219 block groups, 156 have Black Races populations of 50 percent or more. These block groups, shown in Figure 2-7, are concentrated in urban areas (Burlington, Cary, Durham, Fayetteville, Raleigh) and the Ft. Bragg area 15 or more miles from the HNP site.

Twelve census blocks within the 50-mile radius have All Other Single Minorities populations that exceed the state average by 20 percent or more.

Two hundred and fifty-three census blocks within the 50-mile radius have Aggregate Minority populations that exceed the state average by 20 percent or more (Figure 2-8). Of those 253 block groups, 234 have Aggregate Minority populations of 50 percent or more.

Thirty-seven census blocks within the 50-mile radius have Hispanic Ethnicity populations that exceed the state average by 20 percent or more. These census blocks are shown in Figure 2-9.

2.6.2.2 Low-Income Populations

NRC guidance defines low-income based on statistical poverty thresholds (NRC 2004, Appendix D). Progress Energy divided USCB low-income households in each census block group by the total households for that block group to obtain the percentage of low-income households per block group. USCB data (USCB 2000b) characterize 12.4

percent of North Carolina as low-income households. A low-income population is considered to be present if:

1. The low-income population in the census block group or the environmental impact site exceeds 50 percent.

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

Table 2-3 identifies the low-income block groups in the region of interest. Figure 2-10 locates the low-income block groups.

Sixty-three census blocks within the 50-mile radius have low-income households that exceed the state average by 20 percent or more. Of these 63 block groups, 15 have 50 percent or more low-income households.

2.7 TAXES

Progress Energy and NCEMPA, the owners of HNP, pay property taxes to both Wake County and Chatham County, but the amounts paid to Chatham County are relatively small. From 2001 to 2004, the amount paid to Chatham County by Progress Energy ranged between $50,000 and $60,000 annually. For the same years, the NCEMPA amount ranged between $40,000 and $50,000 annually.

From 2001 through 2005, Wake County collected between $317 and $389 million annually in total real and personal property tax revenues (see Table 2-4) (Wake County 2006). Each year, Wake County collects these taxes, retains a portion for county operations, and disburses the remainder to the county's 12 cities or municipalities to fund their respective operating budgets (Hepler 2004). Real and personal property tax revenues go into the county's General Fund. In a recent year, the General Fund was disbursed as follows: education - 33.2 percent, human services - 26.6 percent, capital and debt – 20.2 percent, general administration - 6.6 percent, sheriff – 5.7 percent, public safety – 2.7 percent, community services – 2.7 percent, environmental services – 1.0 percent, and other – 1.3 percent (Wake County 2004). For the years 2001 through 2005, Progress Energy's property tax payments have represented 1.9 to 2.6 percent of Wake County's total real and personal property tax revenues (Table 2-4). Over the same period, the NCEMPA's property tax payments have represented less than one percent of Wake County's total real and personal property tax revenues (Table 2-4).

HNP's annual property taxes are expected to remain relatively constant through the license renewal period. With respect to deregulation, the North Carolina General Assembly took no action on restructuring during its 2001 session (EEI 2002). The Study Commission on the Future of Electric Service in North Carolina, which studied electric service choice for more than four years, decided in February 2002 to delay any action for the foreseeable future. Therefore, the potential effects of deregulation are not yet fully known. Progress Energy continues to monitor progress toward a more competitive environment and has actively participated in regulatory reform deliberations in North Carolina. Progress Energy expects that the North Carolina General Assembly will continue to monitor the experiences of states that have implemented electric restructuring legislation (Progress Energy 2006a). In the future, deregulation in North Carolina could affect utilities' tax payments to counties. However, any changes to HNP property tax rates due to deregulation would be independent of license renewal.

2.8 LAND USE PLANNING

This section focuses on Wake County because more than 99 percent of HNP's annual property taxes go to Wake County.

North Carolina has experienced significant population and economic growth since the early 1990s. The state has been one of the fastest growing states in the nation, as a result of in-migration (Brookings Institution 2000). The main reason is the quality of life as characterized by the state's economy, environment, cultural resources and activities, schools, colleges, universities, and recreational opportunities. North Carolina's metropolitan areas frequently show up at the top of lists of the nation's best places to live and work (Brookings Institution 2000).

Wake County is one of the fastest-growing counties in North Carolina. From 1990 to 2000, Wake County's population growth rate averaged 4.8 percent per year, while the population of the state of North Carolina grew an average of 2.1 percent per year (Section 2.6). Over the same period, 1990 to 2000, the number of housing units in Wake County increased by 46.2 percent, while the total number of units in the state increased by 25.0 percent (USCB 1990; USCB 2000c).

Wake County's comprehensive land use plan focuses on growth-related issues and the implementation of conservation efforts to protect natural resources. The plan reflects public involvement in the planning process and the desire to encourage growth while controlling patterns of development. Land use planning tools, such as zoning and population density limits, are used to control development. Wake County encourages growth in areas where public facilities, such as water and sewer systems, exist or are scheduled to be built in the future. Wake County has no growth control measures in the traditional sense. However, the County has created a Growth Management Task Force dedicated to the development of a comprehensive growth management strategy that will retain the quality of life experienced by residents within the region thus far.

Wake County

Portions of Wake County lie within the Research Triangle, an area located between Duke University in Durham, North Carolina State University in Raleigh, and the University of North Carolina at Chapel Hill. Wake County occupies roughly 832 square miles of land area (USCB 2006). Currently, the County is 35 to 40 percent developed. The land use breakdown percentages for Wake County are as follows: 32.8 percent residential, 4.0 percent business/commercial, 2.0 percent industrial, 17.2 percent parks and public lands, 42.8 percent agricultural/undeveloped, and 2.2 percent "other" (Clark 2004). A report drafted by the Wake County Growth Management Task Force in 2002 noted that the county had experienced "rapid, exponential" growth in the 1990s and had a population of 678,751 in July 2002 (Wake County 2002a). The report predicted that the county's population would increase by one-third over the ensuing 20 years, bringing the population "close" to one million. In 2006, however, the North Carolina State Demographer projected that the population of Wake County would exceed one million by 2015 and would be 1,133,110 by the year 2020 (NCOSBM 2006).

Initially, as rapid regional growth occurred, the county and its 12 municipalities continued a traditional approach of working independently to deliver services, to plan for futures, and to address growth-related impacts within their own borders. The county and municipalities each adopted their own land use plans, zoning and subdivision ordinances, and capital improvement programs (Wake County 2002b).

By the late 1990s, the county was encountering significant growth-related changes resulting from rapid growth, including traffic jams, overcrowded schools, and loss of open space and natural areas. County and municipal officials identified the need for a more comprehensive effort to address growth concerns in Wake County. As a result, the Wake County Board of Commissioners formed the Wake County Growth Management Task Force to develop a county-wide plan for growth management.

Wake County has developed a county-wide land use plan. In the Wake County Land Use Plan (Wake County 2003), the county has indicated that all land use planning should be based on the following broad goals:

- To guide quality growth throughout the County in conjunction with affected local governments.
- To encourage growth close to municipalities, to take advantage of existing and planned infrastructure, such as transportation, water and sewer facilities.
- To encourage the development of communities which provide adequate land for anticipated demands, in a pattern which allows a mixture of uses.
- To encourage maintenance of: open space, scenic aspects of rural areas, entrance ways to urban areas, and transition areas between urban areas.
- To encourage the conservation of environmentally significant areas and important natural and cultural resources.
- To allow owners of significant farmlands and forest lands the opportunity to maintain the productivity of their land.
- To ensure that the land use plan and transportation plan mutually support each other.
- To ensure that the County always protects the property rights of landowners.
- To maintain the quality and develop the capacity of surface water resources, using them for recreation sites, where appropriate.
- To prevent contamination of and maintain the capacity of groundwater resources.
- To ensure that local governments provide adequate, properly located land for recreational and leisure opportunities.

The Wake County Land Use Plan includes a special section devoted to the Harris Lake Watershed.

2.9 SOCIAL SERVICES AND PUBLIC FACILITIES

2.9.1 PUBLIC WATER SYSTEMS

Most HNP employees live in and around the communities of Raleigh, Cary, Apex, Holly Springs, Fuquay-Varina, and Sanford (Figure 2-2). The city of Raleigh's water treatment and distribution system serves more than 125,000 metered customers and 345,000 individuals (City of Raleigh 2004). The source of Raleigh's drinking water is Falls Lake, a 12,400-acre impoundment northwest of the city that can provide up to 100 million gallons of raw water a day to the city's E.M Johnson Water Plant (Raleigh Public Utilities 2006).

The towns of Cary and Apex use B. Everett Jordan Lake, located northwest of the town of Apex, as their source of drinking water (Town of Apex 2006; Town of Cary 2006). The towns of Cary and Apex co-own a water treatment facility that can treat up to 40 million gallons per day. A study prepared in 2000 for the Town of Cary predicted that water demand would increase from 8.6 million gallons per day (1998 value) to 26.7 million gallons per day in 2028 (Town of Cary 2000).

The town of Holly Springs purchases water from the city of Raleigh and from Harnett County (Town of Holly Springs 2006). The town is presently allocated 1.2 million gallons of water per day from the City of Raleigh and 2.0 million gallons per day from Harnett County. Harnett County uses the Cape Fear River as its source of drinking water (Harnett County 2006). Holly Springs' water supply system is currently producing around 1.5 million gallons per day and is capable of treating its entire allocation of 3.2 million gallons of water per day. The town has a planned future capacity of 12 million gallons per day using existing supply lines and a current storage capacity of 2.3 million gallons.

The town of Fuquay-Varina purchases its drinking water from the city of Raleigh and Harnett and Johnston Counties which use the Cape Fear River (Raleigh, Harnett County) and Neuse River (Johnston County), respectively, as their sources of drinking water (Fuquay-Varina 2006). Current treatment capacity for the town is 2.75 million gallons per day.

The city of Sanford uses the Cape Fear River system as its source for drinking water (City of Sanford 2005). The city's single water treatment plant is capable of producing 12 million gallons of clean drinking water per day, and typically provides around two billion gallons of drinking water (5.5 million gallons/day) to city residents annually.

HNP employees who live in areas with no public/municipal water systems use private wells to supply their drinking water.

HNP does not use water provided by any outside public water source. HNP treats water withdrawn directly from Harris Reservoir as its source of drinking and process water.

2.9.2 TRANSPORTATION

The entrance to HNP is located off of U.S. 1 approximately two miles south-southwest of the center of the town of New Hill and one mile southeast of the town of Bonsal near the Chatham County-Wake County line (Figure 2-3). The plant's address is in New Hill.

Most HNP employees live in three areas: Sanford southwest of the site, Holly Springs/Apex/Cary/Raleigh northeast of the site, and Fuquay-Varina southeast of the site (Shamblin 2004). Employees generally use state secondary and county roads to access U.S. 1 to travel to the site (Figure 2-3). Travel in the vicinity of the HNP is restricted primarily to county roads by the presence of Harris Reservoir and B. Everett Jordan Lake (located northwest of the site). U.S. 1 provides the major highway link through the area and the only readily accessible access to the plant.

Traffic count data for roads in the vicinity of HNP is shown in Table 2-5. None of the roads listed have level-of-service determinations. The State of North Carolina does not make level-of-service determinations in rural, non-metropolitan areas unless it is deemed necessary (Hensdale 2002).

2.10 METEOROLOGY AND AIR QUALITY

Meteorological information, as it relates to analysis of severe accidents, is included in Appendix E.

The U. S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for six common pollutants: nitrogen dioxide, sulfur dioxide, carbon monoxide, lead, ozone, and particulate matter with aerodynamic diameters of 10 microns or less (PM10). The EPA has designated all areas of the United States as having air quality better ("attainment") or worse ("non-attainment") than the NAAQS.

In July 1997, the U.S. Environmental Protection Agency (EPA) issued final rules establishing a new eight-hour ozone standard (62FR 38856) and a standard for particulate matter with a nominal size of less than 2.5 microns (PM-2.5; 62 FR 2). After several years of litigation, the PM-2.5 and 8-hour ozone standards have been upheld. EPA is taking steps to implement the new standards (e.g. collecting the data necessary to designate which areas are in non-attainment).

On April 15, 2004, the EPA Administrator implemented designations, classifications, and boundaries for areas of the country with respect to the 8-hour ground-level ozone NAAQS in accordance with the requirements of the Clean Air Act (69 FR 23857). Wake County, North Carolina was included in the non-attainment area of Raleigh-Durham-Chapel Hill (EPA 2005a). This non-attainment area was classified as "Subpart 1" and the maximum attainment dates extends through June 2009 (EPA 2005b).

HNP is located in Wake County, North Carolina, which is part of the Eastern Piedmont Intrastate Air Quality Control Region (AQCR). All counties in Raleigh-Durham-Chapel Hill Metropolitan Statistical Area are designated for 8-hour ozone non-attainment. Wake County is in attainment for all air quality standards with the exception of the new 8-hour ozone NAAQS (EPA 2005a).

2.11 HISTORIC AND ARCHAEOLOGICAL RESOURCES

Area History in Brief

Pre-History

The Paleoindians, the first people known to the Carolina region, were present during the late Pleistocene period, approximately 10,000 BC, when wetter, cooler weather prevailed in the southeast (Claggett 1996). Nomadic in nature, the Paleoindians hunted large mammals, many of which are now extinct (e.g., mastodons, mammoths, giant bison), gathered wild plant foods, and harvested fish and shellfish from rivers and estuaries. Archaic Indian cultures followed the Paleoindians.

Also relatively mobile, Archaic Indians occupied the region from 9,000 to 2,000 BC and adapted to post-glacial (Holocene) environments that were warmer than the Pleistocene. They made a variety of stone and wooden tools, pottery, and baskets, and made use of the many different species of plant and animal resources that surrounded them (Claggett 1996).

Woodland Indians followed the subsistence practices of their Archaic forebears, hunting and gathering plants for food, but also cultivated crops like squash, gourds, and maize, indicating a more sedentary settlement pattern (Claggett 1996). Woodland Indians invented the bow and arrow, which made it possible for a single hunter to harvest a large mammal like a white-tailed deer. Mississippian culture evolved out of Woodland culture, but was more complex socially and more militaristic. Most of the Indian groups discovered by early European explorers in the Carolinas were representatives of the Woodland culture; the Pee Dee and Cherokee Indians of that time were more Mississippian in character and may have been loosely allied with larger Mississippian groups from other parts of the southeast (Claggett 1996).

History

Between the 1620s and 1670s there was a marked increase in contact between Native American groups and Europeans. By that time traders from Virginia were making regular visits to the Piedmont. In 1701 John Lawson visited the area and by the 1730s there was an increasing flow of immigrants from Virginia, Maryland, Pennsylvania, and the North Carolina Coastal Plain. Wake County was established by an act of the North Carolina Legislature in 1771. By 1792 the capital city of Raleigh had been chosen and laid out, although growth was slow for several decades. There was no direct military action in the Wake County area during the Civil War because the war ended as Sherman approached Raleigh from Goldsboro (NSA 2006).

Due to the rural nature of the area, agriculture was the dominant activity through the 18th and 19th centuries, with all suitable alluvial and upland environments in cultivation. Until the 1820s subsistence farming prevailed, with a focus on corn, dairy, and hogs. With the establishment of transportation routes and infrastructure, however, the emphasis changed to market-oriented production. After the Civil War, with the emergence of the tenant farming system, production changed dramatically toward cash crops like cotton and tobacco. These practices in turn led to severe soil depletion and erosion. Toward the end of the 19th and beginning of the 20th centuries demographic patterns changed as people left farms and headed for urban areas (NSA 2006).

Initial Operation

In the Final Environmental Statement (FES) for the construction of HNP Units 1, 2, 3, and 4 (AEC 1973), Atomic Energy Commission (AEC) staff stated that the National Registry of Historic Places had no listed historic landmarks within five miles of HNP. In the same document, the AEC noted a Confederate iron works located 1½ miles south of HNP on the banks of the Cape Fear River, a site considered significant by the North Carolina Department of Archives and History (NCDAH), but not listed on the National Registry (AEC 1973). The Advisory Council on Historic Preservation was also consulted and, in its response, noted that the Draft Environmental Statement (DES) appeared to be adequate and no further comments were made (AEC 1973). Additionally, the United States Department of the Interior (USDOI), Office of the Secretary, was consulted for comment on the DES. In a letter dated February 22, 1973, the USDOI Deputy Assistant Secretary suggested that an archaeological survey be conducted to determine the presence of cultural resources in the site vicinity. The USDOI also determined that the proposed action would "…not directly affect any existing or proposed units of the National Park System, or any sites that are eligible or recommended for registration as National Historic, Natural, or Environmental Education Landmarks" (AEC 1973).

In the Revised Final Environmental Statement (RFES) for the construction of HNP Units 1, 2, 3, and 4 (AEC 1974) AEC staff made the following statement in reference to the USDOI recommendation for an archaeological survey: "In answer to a request from the applicant to perform an archaeological survey of the site, members of the Archaeological Department of the University of North Carolina advised that such a study would be of little value" (AEC 1974). Additionally, the USDOI was contacted for comment on the Revised DES. The USDOI made a second set of recommendations; to identify all proposed and alternative transmission line routes and to conduct cultural resource studies and surveys to determine potential impacts to resources in those areas (AEC 1974).

The Operating License Environmental Report for HNP (CP&L 1982) indicated that CP&L contracted with the Research Laboratories of Anthropology of the University of North Carolina at Chapel Hill (UNC) to perform an archaeological and historical survey of the reservoir sites, dam sites, and a potential makeup water pipeline route for HNP. The survey indicated that there were no sites within these areas which were either included in or met minimal criteria for nomination to the National Register of Historic Places (CP&L 1982). A series of summaries and reports relating to this survey may be obtained from the North Carolina State Archaeologist's office. Additionally, the North Carolina State Historic Preservation Officer was consulted and concurred that there were no sites within the reservoir areas that were eligible for inclusion in the National Register (CP&L 1982).

In the FES for the operation of HNP Units 1 and 2 (NRC 1983), NRC staff referenced the UNC cultural resources survey of the reservoir and associated components and concluded that the operation of HNP would have no significant impacts on historic or archaeological resources. Additionally, NRC stated that Deputy State Historic Preservation Officer (DSHPO) indicated that no adverse effects on cultural resources would result from the operation of HNP (NRC 1983). NRC staff responded to concerns expressed by the DSHPO regarding two houses (Burke and Ragan) of historic significance: the Burke house was sold and moved to Fuquay-Varina; the Ragan house remained intact, was inhabited, and was not on CP&L property; a third house, the Dupree house, was dismantled and moved to Durham County (NRC 1983).

Other Surveys in the HNP Vicinity

In June 2006, Progress Energy contract archaeologists visited the SHNP site to perform a cultural resources survey that would support this license renewal effort. The area of potential affect included approximately 180 acres of land in and around the existing nuclear facility and selected areas along the shoreline of the Harris Reservoir. Shortly after the impoundment of the reservoir in the 1970s, avocational archaeologists identified a number of cultural sites near its margins. Of particular concern, on this survey, were 13 of these sites, located between high and low water marks, which had not been evaluated by professional archaeologists for inclusion in the National Register of Historic Places (NRHP). Survey results indicate that, in addition to the 13 sites, two archaeological sites and three isolated finds were located and identified. Surveyors assessed all of the aforementioned sites and concluded that none met the criteria for listing in the NRHP and are recommended not eligible (NSA 2006).

In 1992 and 1993, the North Carolina Low-level Radioactive Waste Management Authority retained Chem-Nuclear Systems, Inc. (CNSI) to site, design, construct, operate, and close a proposed facility on land adjacent to HNP property. CNSI contracted with Law Environmental to perform cultural resources surveys of the land to meet Section 106 of the National Historic Preservation Act requirements. A copy of these surveys may also be obtained at the NCSOA office (Law Environmental 1992 and 1993).

A number of other cultural surveys of land within a ten-mile radius of the HNP have been conducted and may be viewed at the NCSOA office.

Current Status

As of November 2004, the National Register of Historic Places listed 164 locations in Wake County, 53 locations in Chatham County, 16 locations in Lee County, and 12 locations in Harnett County, North Carolina (U.S. Department of the Interior 2004). Of these 245 locations, 29 fall within a 6 mile radius of the HNP boundary. In addition to the listed sites, there are five locations that are Determined Eligible for inclusion on the

National Register list within a 6-mile radius. Tables 2.6-1 and 2.6-2 list the National Register of Historic Places sites within the 6-mile radius of HNP

Additionally, there are a number of cultural resources within or near the HNP boundaries that are not listed on the National Register of Historic Places. These include cemeteries, churches, building ruins, an old grist mill, and civil war rifle pits. Progress Energy employees dealing with real estate and ground disturbance activities are aware of these resources and their locations. Until 2004, efforts to preserve these resources were informal, yet effective.

In late 2004, Progress Energy issued formal guidelines for the protection of both previously-identified and heretofore-undiscovered archaeological and cultural resources that could be affected by land-disturbing activities (Progress Energy 2004b). These guidelines, which are part of Progress Energy's Environmental Compliance Manual, outline responsibilities of Progress Energy employees and contractors engaged in land-disturbing activities, such as the construction or expansion of power plants, substations, and transmission lines. The guidelines also designate an organization (Environmental Services Section) within Energy Supply and an organization (Environmental Health and Safety) within Energy Delivery that is responsible for consulting with the State Historic Preservation Office if a cultural site (e.g., a cemetery) is known to be near an area to be disturbed for construction or if cultural artifacts (e.g., spear points or pottery shards) are discovered once construction has begun.

2.12 KNOWN OR REASONABLY FORSEEABLY PROJECTS IN SITE VICINITY

EPA-Permitted Dischargers to Air, Water, and Soil

In its “Envirofacts Warehouse” online database, the U.S. Environmental Protection Agency identifies dischargers to air, water, and soil. A search on Wake County determined that 366 industries produce and release air pollutants; 60 facilities have reported toxic releases; 891 facilities have reported hazardous waste activities; 7 potential hazardous waste sites are part of the Superfund program; and 307 facilities are permitted to discharge to the waters of the United States (EPA 2006).

A search of Chatham County determined that 66 industries produce and release air pollutants; 20 facilities have reported toxic releases; 46 facilities have reported hazardous waste activities; 1 potential hazardous waste site is part of the Superfund program; and 105 facilities are permitted to discharge to the waters of the United States. Of the 105 facilities that discharge to the waters of the United States, many discharge to the Cape Fear River or to rivers that flow into the Cape Fear River (EPA 2006).

A search of Lee County determined that 69 industries produce and release air pollutants; 29 facilities have reported toxic releases; 99 facilities have reported hazardous waste activities; 1 potential hazardous waste site is part of the Superfund program; and 54 facilities are permitted to discharge to the waters of the United States. Of the 54 facilities that discharge to the waters of the United States, many discharge to the Cape Fear River or to rivers that flow into the Cape Fear River (EPA 2006).

A search of Harnett County determined that 53 industries produce and release air pollutants; 11 facilities have reported toxic releases; 45 facilities have reported hazardous waste activities; 2 potential hazardous waste sites are part of the Superfund program; and 56 facilities are permitted to discharge to the waters of the United States. Of the 56 facilities that discharge to the waters of the United States, many discharge to the Cape Fear River or to rivers that flow into the Cape Fear River (EPA 2006). Detailed information concerning these facilities in these counties may be accessed through the Envirofacts Warehouse.

Federal Facilities in the Vicinity of HNP

Federal lands within a 50-mile radius of the HNP include the B. Everett Jordan Project and the Falls Lake Project, both managed by the U.S. Army Corps of Engineers. B. Everett Jordan Lake is a 13,940-acre impoundment on the Haw River (tributary of the Cape Fear River) approximately 3 miles northwest of the HNP site (USACE 2006a). Falls Lake is a 12,410 acre impoundment on the Neuse River about 10 miles north of Raleigh and about 25 miles north-northeast of the HNP site (USACE 2006b). Both were built as flood control and water supply reservoirs, but were also intended to provide recreational opportunities and habitat for fish and wildlife. There are no significant military facilities within a 25-mile radius of the plant site. The nearest active military facility is Fort Bragg (35 miles south), a support base for Army training operations (FSAR, Section 2.2.1).

Industries in the Vicinity of HNP

Industrial activity in the area surrounding the HNP is not intensive. Sawmills, brick manufacturers, and quarries are the predominant industries within a 5-mile radius of the HNP. Durham, Wake, Guilford, Alamance, and Orange Counties contain the most concentrated industrial areas within a 50-mile radius of the HNP (FSAR, Section 2.2.1). There is some light industry at the 5600-acre Research Triangle Park, which is located approximately 20 miles north-northeast of the HNP (FSAR, Section 2.2.1).

Energy Utilities within the Vicinity of HNP

Cape Fear Steam Plant

The Cape Fear Steam Plant, also owned by Progress Energy, is located approximately 6 miles southwest of the HNP site on the east bank of the Cape Fear River in Chatham County. This site includes two coal-fired units capable of producing 316 MW, and two combined-cycle units capable of producing 84 MW (Progress Energy 2006b). The Cape Fear Plant has operated for more than 75 years, employs about 75 people, and is the largest taxpayer in Chatham County, paying approximately $640,000 annually to the county (Progress Energy 2006c).

Additional Units at Shearon Harris Nuclear Plant Site

Progress Energy is in the process of preparing a combined operating license (COL) application for two new nuclear units to be located on the HNP site. The current schedule calls for Progress to submit the COL application and associated Environmental Report to NRC in late 2007. No decision has been made to construct the new units at this time. The current Environmental Report addresses only the renewal of the operating license for Unit 1. The environmental impacts of the 2 additional reactors will be addressed in the Environmental Report submitted with the COL application, as will the cumulative impacts of issuing the new licenses and the renewal of the current operating license.

TABLE 2-1
ENDANGERED AND THREATENED SPECIES KNOWN TO OCCUR IN WAKE OR CHATHAM COUNTIES OR IN COUNTIES CROSSED BY HNP-ASSOCIATED TRANSMISSION LINES[a]

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Mammals			
Condylura cristata	Star-nosed mole (Coastal plain population)	-	SC
Myotis austroriparius	Southeastern myotis	-	SC
M. septentrionalis	Northern long-eared myotis	-	SC
Birds			
Aimophila aestivalis	Bachman's sparrow	-	SC
Egretta caerulea	Little blue heron		
Haliaeetus leucocephalus	Bald eagle	T[c]	T
Lanius ludovicianus ludovicianus	Loggerhead shrike	-	SC
Picoides borealis	Red-cockaded woodpecker	E	E
Reptiles and Amphibians			
Alligator mississippiensis	American alligator	T(S/A)	T
Ambystoma tigrinum	Eastern tiger salamander	-	T
Crotalus adamanteus	Eastern diamondback rattlesnake	-	E
C. horridus	Timber rattlesnake	-	SC
Heterodon simus	Southern hognose snake	-	SC
Hemidactylium scutatum	Four-toed salamander	-	SC
Micrurus fulvius	Eastern coral snake	-	E
Necturus lewisi	Neuse River waterdog	-	SC
Pituophis melanoleucus melanoleucus	Northern pine snake	-	SC
Rana heckscheri	River frog	-	SC
Sistrurus miliarius	Pigmy rattlesnake	-	SC
Fish			
Cyprinella sp.	Thinlip chub	-	SC
Etheostoma collis	Carolina darter (Eastern Piedmont population)	-	SC
Lampetra aepytera	Least brook lamprey	-	T
Notropis mekistocholas	Cape Fear shiner	E	E
Noturus sp.	Broadtail madtom	-	SC
N. furiosus	Carolina madtom	-	SC
Semotilus lumbee	Sandhills chub	-	SC

TABLE 2-1
ENDANGERED AND THREATENED SPECIES KNOWN TO OCCUR IN WAKE OR CHATHAM COUNTIES OR IN COUNTIES CROSSED BY HNP-ASSOCIATED TRANSMISSION LINES[a] (Continued)

Invertebrates			
Alasmidonta heterdon	Dwarf wedgemussel	E	E
A. undulata	Triangle floater	-	T
A. varicosa	Brook floater	-	E
Cambarus catagius	Greensboro burrowing crayfish	-	SC
Elliptio folliculata	Pod lance	-	SC
E. lanceolata	Yellow lance	-	E
E. marsupiobesa	Cape Fear spike	-	SC
E. roanokensis	Roanoke slabshell	-	T
Fusconia masoni	Atlantic pigtoe	-	E
Lampsilis caroisa	Yellow lampmussel	-	E
L. radiata radiata	Eastern lampmussel	-	T
L. radiata conspicua	Carolina fatmucket	-	T
Lasmigona subviridis	Green floater	-	E
Neonympha mitchellii francisci	Saint Francis' satyr	E	-
Orconectes carolinensis	North Carolina spiny crayfish	-	SC
Strophitus undulatus	Creeper	-	T
Toxolasma pullus	Savannah lilliput	-	E
Villosa constricta	Notched rainbow	-	SC
V. vaughaniana	Carolina creekshell	-	E
Plants			
Amorpha georgiana v. *georgiana*	Georgia indigo-bush	-	E
Astragalus michauxii	Sandhills milk-vetch	-	T
Carex barrattii	Barratt's sedge	-	E
C. exilis	Coastal sedge	-	T
Chrysoma pauciflosculosa	Woody goldenrod	-	E
Eupatorium resinosum	Pine barren boneset	-	T-SC
Helenium brevifolium	Littleleaf sneezeweed	-	E
Helianthus schweinitzii	Schweinitz's sunflower	E	E
Isoetes piedmontana	Piedmont quillwort	-	T
Lilium pyrophilum	Sandhills lily	-	E-SC
Lindera melissifolia	Pondberry (Southern spicebush)	E	E

TABLE 2-1
ENDANGERED AND THREATENED SPECIES KNOWN TO OCCUR IN WAKE OR CHATHAM COUNTIES OR IN COUNTIES CROSSED BY HNP-ASSOCIATED TRANSMISSION LINES[a] (Continued)

L. subcoriacea	Bog spicebush	-	T
Lobelia boykinii	Boykin’s lobelia	-	T
Lysimachia asperulaefolia	Rough-leaved loosestrife	E	E
Macbridea caroliniana	Carolina bogmint	-	T
Muhlenbergia torreyana	Pinebarren smokegrass	-	E
Myriophyllum laxum	Loose watermilfoil	-	T
Parnassia caroliniana	Carolina grass-of-parnassus	-	E
Portulaca smallii	Small’s portuluca	-	T
Pteroglossapsis ecristata	Spiked medusa	-	E
Ptilimnium nodosum	Harperella	E	E
Pyxidanthera barbulata v. brevifolia	Sandhills pixie-moss	-	E
Rhexia aristosa	Awned meadow-beauty	-	T
Rhus michauxii	Michaux’s sumac	E	E-SC
Rhynchospora macra	Southern white beaksedge	-	E
Rudbeckia heliopsidis	Sun-facing coneflower	-	E
Ruellia humilis	Low wild petunia	-	T
Schwalbea americana	American chaffseed	E	E
Solidago verna	Spring flowering goldenrod	-	T
Stylisma pickeringii v. *pickeringii*	Pickering’s dawnflower	-	E
Symphyotrichum georgianum	Georgia aster	C	T
Trillium pusillum v. *pusillum*	Carolina least trillium	-	E
Utricularia olivacea	Dwarf bladderwort	-	T

a. Species that are known to occur or historically have occurred in Chatham, Cumberland, Harnett, Lee, Randolph, and Wake Counties (USFWS 2006; NCDENR 2006b).

b. Source of federal status: USFWS 2006; source of state status: NCDENR 2006b.
Status codes: E = Endangered; T = Threatened; SC = Special Concern (state only); E-SC = State Endangered but may be propagated and sold under specific regulations; T-SC = State Threatened but may be propagated and sold under specific regulations; T(S/A) = Threatened due to similarity of appearance (the alligator has this designation because it is similar in appearance to other rare crocodilians); C = Candidate for listing; - = Not listed.

c. The U.S. Fish and Wildlife Service has proposed that the bald eagle be delisted, i.e., removed from the list of endangered and threatened species (71 FR 8238; February 16, 2006).

TABLE 2-2
ESTIMATED POPULATIONS AND ANNUAL GROWTH RATES

Population and Average Annual Growth Rate						
	Wake County		Lee County		North Carolina	
Year	Number	Percent	Number	Percent	Number	Percent
1980[a]	301,327	N/A	36,718	N/A	5,881,766	N/A
1990[a]	423,380	4.1	41,374	1.3	6,628,637	1.3
2000[b]	627,846	4.8	49,040	1.9	8,049,313	2.1
2010[c]	860,108	3.7	55,912	1.4	9,441,440	1.7
2020[c]	1,105,867	2.9	64,899	1.6	10,943,973	1.6
2030[c]	1,364,774	2.3	74,407	1.5	12,467,232	1.4
2040[d]	1,480,932	0.9	79,362	0.7	13,369,594	0.7
2050[d]	1,675,746	1.3	86,602	0.9	14,622,906	0.9

a. U.S. Census Bureau 1995.
b. U.S. Census Bureau 2004.
c. NCOSBM 2004.
d. Tetra Tech NUS 2004.

TABLE 2-3
MINORITY AND LOW-INCOME POPULATION CENSUS BLOCKS WITHIN 50-MILE RADIUS OF HNP

Counties at 20% criteria within 50 miles

COUNTY	STATE NAME	TOTAL BLOCK GROUPS WITHIN 50 MILES	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 BLOCK GROUPS WITHIN 50 MILES
Alamance	North Carolina	95	0	0	0	14	0	0	13	3	2
Caswell	North Carolina	4	0	0	0	0	0	0	0	0	0
Chatham	North Carolina	32	0	0	0	0	4	0	2	5	0
Cumberland	North Carolina	162	0	0	0	56	0	0	71	0	16
Durham	North Carolina	129	0	0	0	54	1	0	58	4	17
Franklin	North Carolina	21	0	0	0	6	0	0	6	0	0
Granville	North Carolina	20	0	0	0	7	0	0	7	0	1
Guilford	North Carolina	20	0	0	0	1	0	0	1	0	0
Harnett	North Carolina	43	0	0	0	7	0	0	5	0	2
Hoke	North Carolina	17	3	0	0	7	0	0	11	1	0
Johnston	North Carolina	68	0	0	0	5	0	0	4	1	1
Lee	North Carolina	39	0	0	0	4	2	0	8	5	5
Montgomery	North Carolina	9	0	0	0	1	1	0	2	2	0
Moore	North Carolina	55	0	0	0	6	1	0	6	2	1
Nash	North Carolina	10	0	0	0	2	0	0	2	0	0
Orange	North Carolina	56	0	0	0	4	0	0	4	0	6
Person	North Carolina	10	0	0	0	1	0	0	1	0	0
Randolph	North Carolina	50	0	0	0	1	0	0	2	4	1
Richmond	North Carolina	3	0	0	0	1	0	0	0	0	0
Robeson	North Carolina	4	1	0	0	0	0	0	2	0	0
Sampson	North Carolina	17	0	0	0	0	0	0	1	2	0
Scotland	North Carolina	1	0	0	0	1	0	0	1	0	0
Vance	North Carolina	4	0	0	0	1	0	0	0	0	0
Wake	North Carolina	263	0	0	0	40	3	0	46	8	11
Wayne	North Carolina	9	0	0	0	0	0	0	0	0	0
Wilson	North Carolina	5	0	0	0	0	0	0	0	0	0
	TOTAL	1146	4	0	0	219	12	0	253	37	63

(Shaded cells represent counties completely contained by 50 mile radius)

TABLE 2-3
MINORITY AND LOW-INCOME POPULATION CENSUS BLOCKS WITHIN 50-MILE RADIUS OF HNP. (CONT'D)

Counties at 50% criteria within 50 miles

COUNTY	STATE NAME	TOTAL BLOCK GROUPS WITHIN 50 MILES	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 BLOCK GROUPS WITHIN 50 MILES
Alamance	North Carolina	95	0	0	0	8	0	0	13	0	1
Caswell	North Carolina	4	0	0	0	0	0	0	0	0	0
Chatham	North Carolina	32	0	0	0	0	0	0	1	0	0
Cumberland	North Carolina	162	0	0	0	44	0	0	64	0	3
Durham	North Carolina	129	0	0	0	44	0	0	56	0	4
Franklin	North Carolina	21	0	0	0	4	0	0	6	0	0
Granville	North Carolina	20	0	0	0	3	0	0	7	0	0
Guilford	North Carolina	20	0	0	0	0	0	0	1	0	0
Harnett	North Carolina	43	0	0	0	3	0	0	5	0	0
Hoke	North Carolina	17	1	0	0	4	0	0	9	0	0
Johnston	North Carolina	68	0	0	0	3	0	0	4	0	1
Lee	North Carolina	39	0	0	0	4	0	0	8	0	0
Montgomery	North Carolina	9	0	0	0	0	0	0	1	0	0
Moore	North Carolina	55	0	0	0	2	0	0	5	0	0
Nash	North Carolina	10	0	0	0	0	0	0	1	0	0
Orange	North Carolina	56	0	0	0	2	0	0	4	0	3
Person	North Carolina	10	0	0	0	0	0	0	1	0	0
Randolph	North Carolina	50	0	0	0	0	0	0	1	0	0
Richmond	North Carolina	3	0	0	0	0	0	0	0	0	0
Robeson	North Carolina	4	0	0	0	0	0	0	1	0	0
Sampson	North Carolina	17	0	0	0	0	0	0	0	0	0
Scotland	North Carolina	1	0	0	0	0	0	0	1	0	0
Vance	North Carolina	4	0	0	0	0	0	0	0	0	0
Wake	North Carolina	263	0	0	0	35	0	0	45	0	3
Wayne	North Carolina	9	0	0	0	0	0	0	0	0	0
Wilson	North Carolina	5	0	0	0	0	0	0	0	0	0
	tOTAL	1146	1	0	0	156	0	0	234	0	15

(Shaded cells represent counties completely contained by 50 mile radius)

TABLE 2-4
SHEARON HARRIS NUCLEAR PLANT REAL AND PERSONAL PROPERTY TAX INFORMATION 2001-2005

Year	Wake County Property Tax Revenues[a]	Property Tax Paid by Progress Energy	Percent of Wake County Revenues	Property Tax Paid by NCEMPA[b]	Percent of Wake County Revenues
2001	$323,464,731	$7,117,927	2.2	$2,142,197	less than 1.0
2002	$316,962,980	$8,396,063	2.6	$2,078,175	less than 1.0
2003	$354,060,852	$7,424,030	2.1	$2,045,304	less than 1.0
2004	$368,446,098	$7,061,685	1.9	$1,954,395	less than 1.0
2005	$389,249,624	$8,384,754	2.2	$1,818,099	less than 1.0

a. Wake County 2006
b. NCEMPA 2006

TABLE 2-5
TRAFFIC COUNTS FOR ROADS IN THE VICINITY OF HNP

Route No.	Vicinity of	Est. AADT[a]	Location
U.S 1	Entrance to HNP South to Old U.S. 1	17,000	Figure 2-1
U.S 1	U.S. 1 near Apex	16,000	Figure 2-1
Old U.S 1	South of New Hill	1,800	Figure 2-1
Old U.S 1	Just North of Intersection with U.S.1	1,700	Figure 2-1
Old U.S 1	Just North of Merry Oaks	2,300	Figure 2-1

AADT = Annual Average Daily Traffic volume for 2003.
U.S. = United States highway.
a. NCDOT 2003.

TABLE 2.6-1
SITES LISTED IN THE NATIONAL REGISTER OF HISTORIC PLACES THAT FALL WITHIN A 6-MILE RADIUS OF HNP

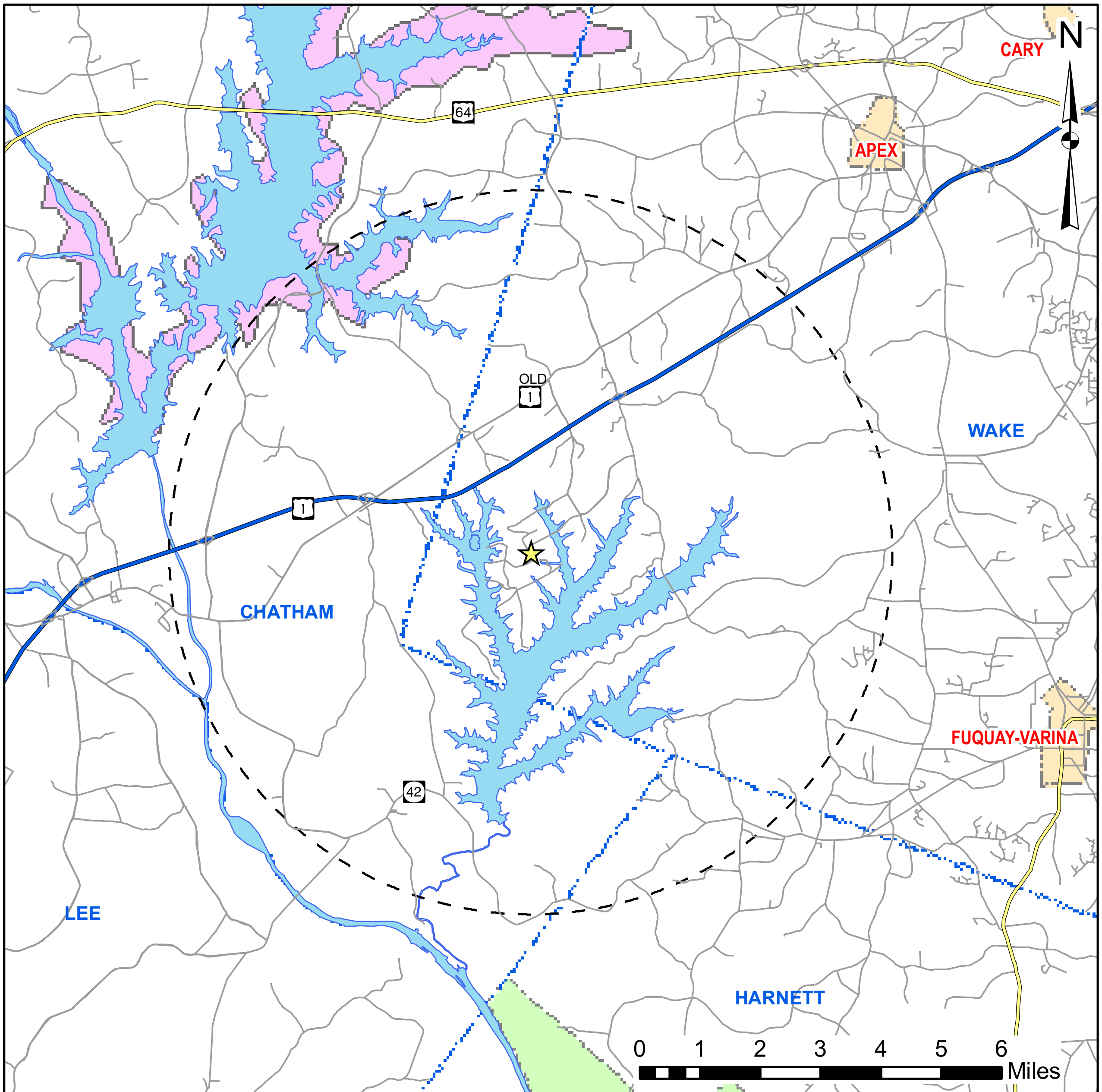
Site Name	Location
Ebenezer Methodist Church	SR 1008, Bells
Goodwin Farm Complex	SR 1900, Bells
Lockville Dam, Canal, and Powerhouse	West of Moncure at Deep River and US 1, Moncure
New Hope Rural Historical Archaeological District	Address Restricted, Wilsonville
Newkirk State (Site 31CH366)	Address Restricted, Moncure
James A. Thomas Farm	SR 1941, Pittsboro
Farish – Lambeth House	6308 Deep River Road, Sanford
Obediah Farrar House	9910 Barringer Road, Haywood
Apex City Hall	North Salem Street, Apex
Apex Historic District	Roughly bounded by North Elm, North Salem, Center, South Salem, and West Chatham Sts., Apex
Apex Historic District (Boundary Increase)	Roughly bounded by E. Chatham, South Hughes, South Mason and East Moore Sts., Apex
Apex Historic District (Boundary Increase)	Grove and Thompson Sts., and parts of Hunter St., Apex
Apex Union Depot	Southeast corner North Salem St. and Center St., Apex
Carpenter Historic District	Along Capenter-Morrisville Rd., East of CSX Railroad Tracks and West of Davis Dr., Cary
Cary Historic District	Roughly along Dry Ave., South Academy St., and Park St., Cary
Fuquay Mineral Spring	Northeast corner of Main and West Spring Sts., Fuquay-Varina
Fuquay Springs High School	112 North Ennis St., Fuquay-Varina
Fuquay Springs Historic District	Roughly, South Main St. and Fuquay Ave. from Spring St. to Sunset Dr. and Spring St. from Spring Ave. to Angier Rd., Fuquay-Varina
Green Level Historic District	Jct. Green Level Church, Green Level West Rd., and Beaver Dam Rd., Cary
J. Beale Johnson House	6321 Johnson Pond Rd., Fuquay-Varina
Nancy Jones House	NC 54, Cary
Jones--Johnson--Ballentine Historic District	SR 1301--522 Sunset Rd., Fuquay-Varina
Leslie--Alford--Mims House	100 Avent Ferry Rd., Holly Springs
Julius Lewis and Co. House	New Hill
New Hill Historic District	Roughly 0.5 south of jct. of Old US 1 and NC 1127, and 2 mi. west of jct. with Old US 1. New Hill
Utley Council House	Cary
Page—Walker Hotel	119 Ambassador Street, Cary.
Varina Commercial Historic District	Broad and Fayetteville Sts. between Stewart St. and Ransdell Rd., Fuquay-Varina
Ben—Wiley Hotel	331 South Main Street, Fuquay-Varina

Source: U.S. Department of the Interior 2004.
SR = State Route
NC = North Carolina
US = United States

**TABLE 2.6-2
SITES DETERMINED ELIGIBLE FOR THE
NATIONAL REGISTER OF HISTORIC PLACES
THAT FALL WITHIN A 6-MILE RADIUS OF HNP**

Site Name	Location
Beckwith Goodwin Farm	Adjacent to US 64 in Chatham County
J. B. Mills House	South of US 64 near Chatham/Wake County line.
Richard L. Adams Farm	Adjacent to SR 55, south of Holly Springs
Alsey J. Stephens House	Adjacent to SR 55, south of Holly Springs
Adams House	Adjacent to SR 55, south of Holly Springs

Source: North Carolina State Historic Preservation Office

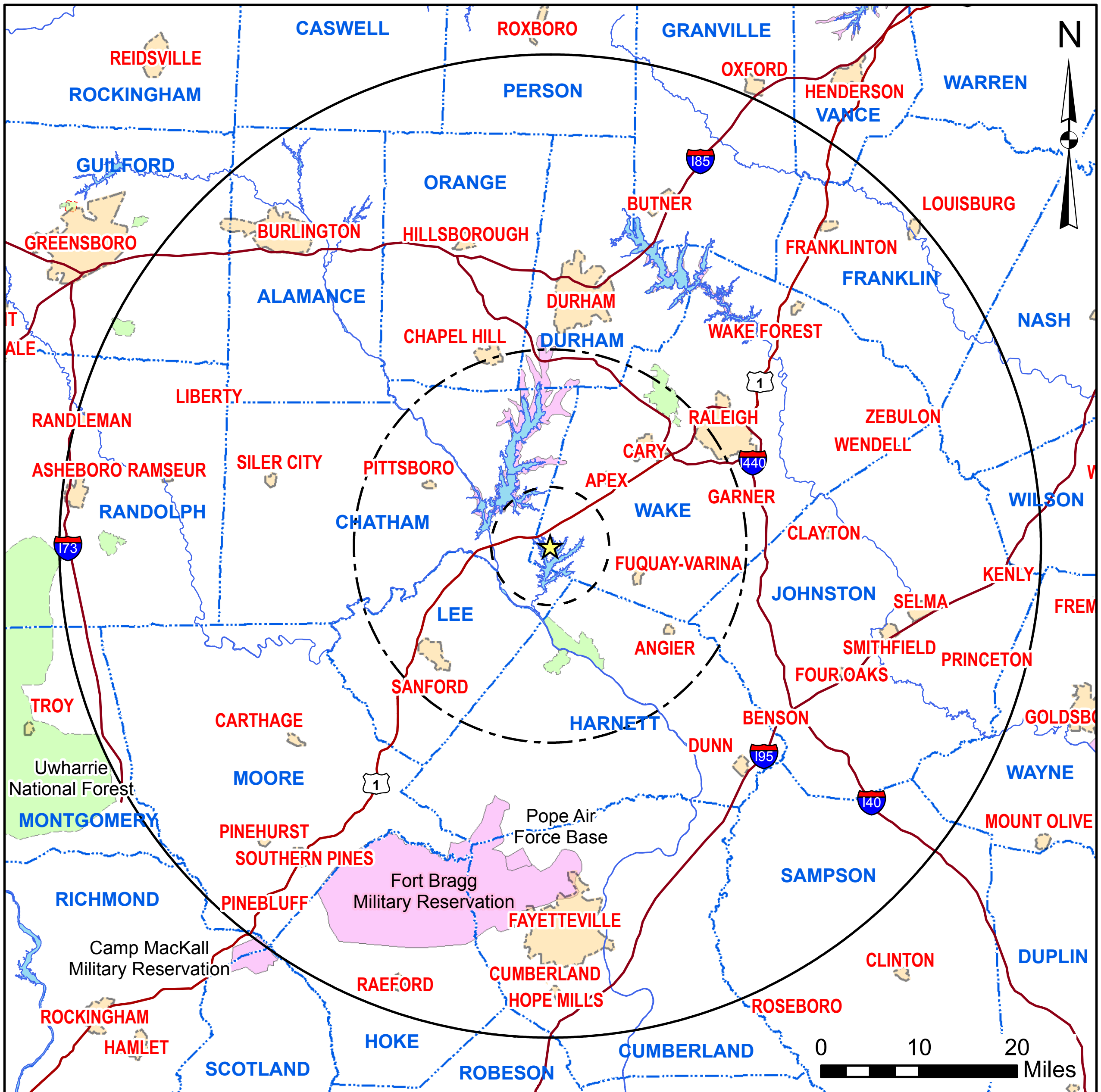


Legend

- SHEARON HARRIS NUCLEAR PLANT
- PRIMARY ROAD WITH LIMITED ACCESS
- PRIMARY ROAD
- SECONDARY ROAD
- 6-MILE RADIUS

SHEARON HARRIS NUCLEAR PLANT

Figure 2-1
6-MILE VICINITY MAP



Legend

☆ SHEARON HARRIS NUCLEAR PLANT

50-MILE RADIUS

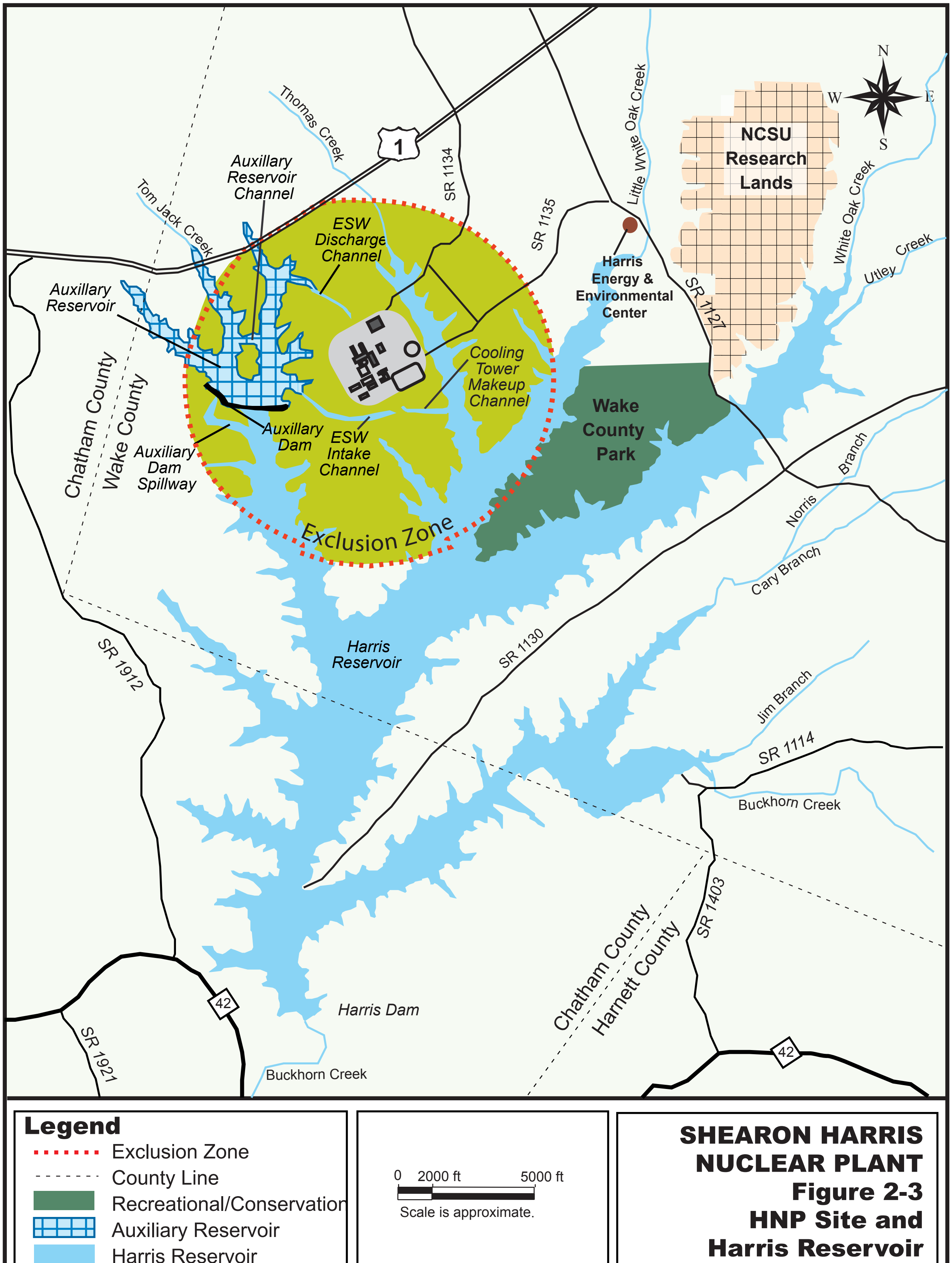
20-MILE RADIUS

6-MILE RADIUS

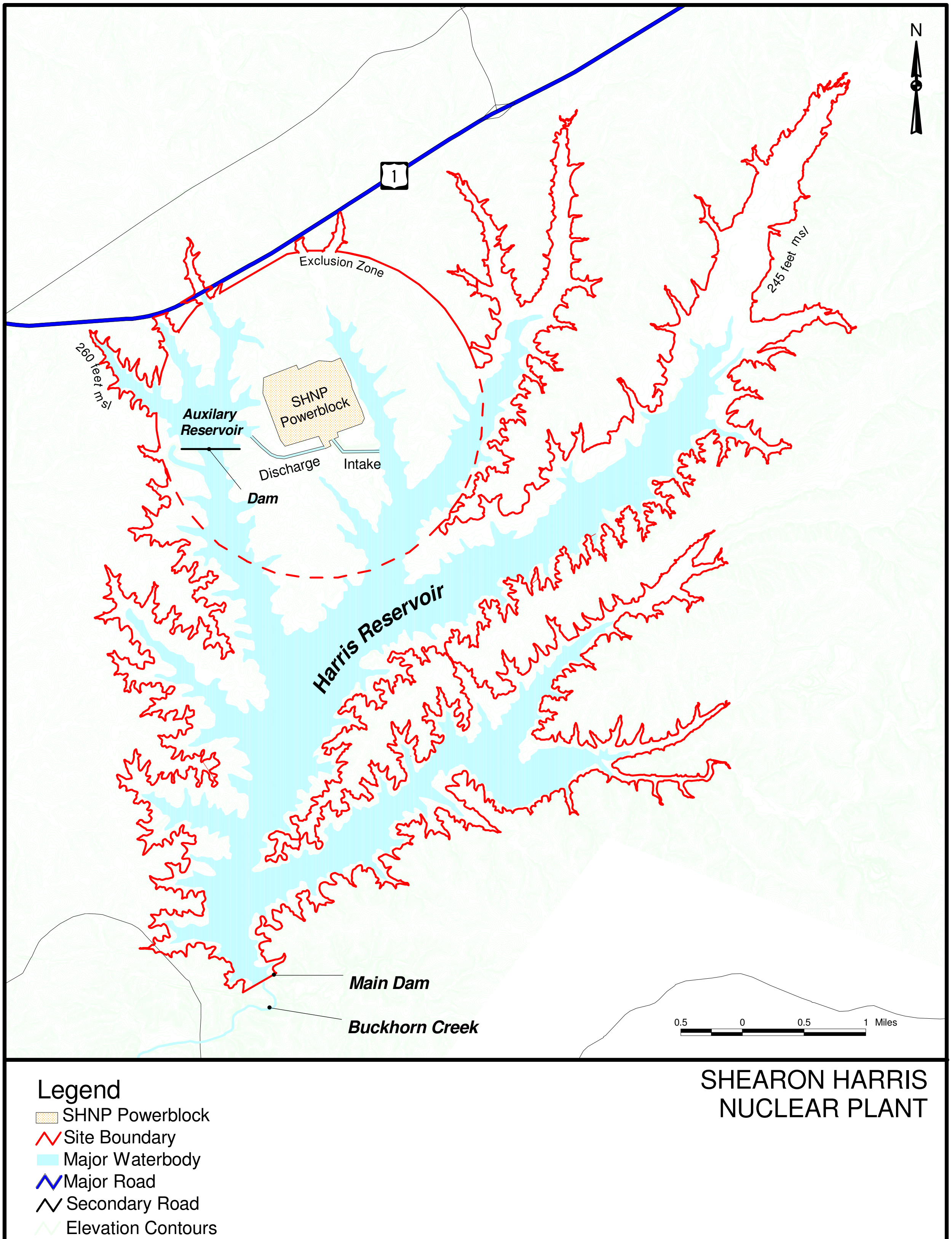
SHEARON HARRIS NUCLEAR PLANT

Figure 2-2

50-MILE VICINITY MAP

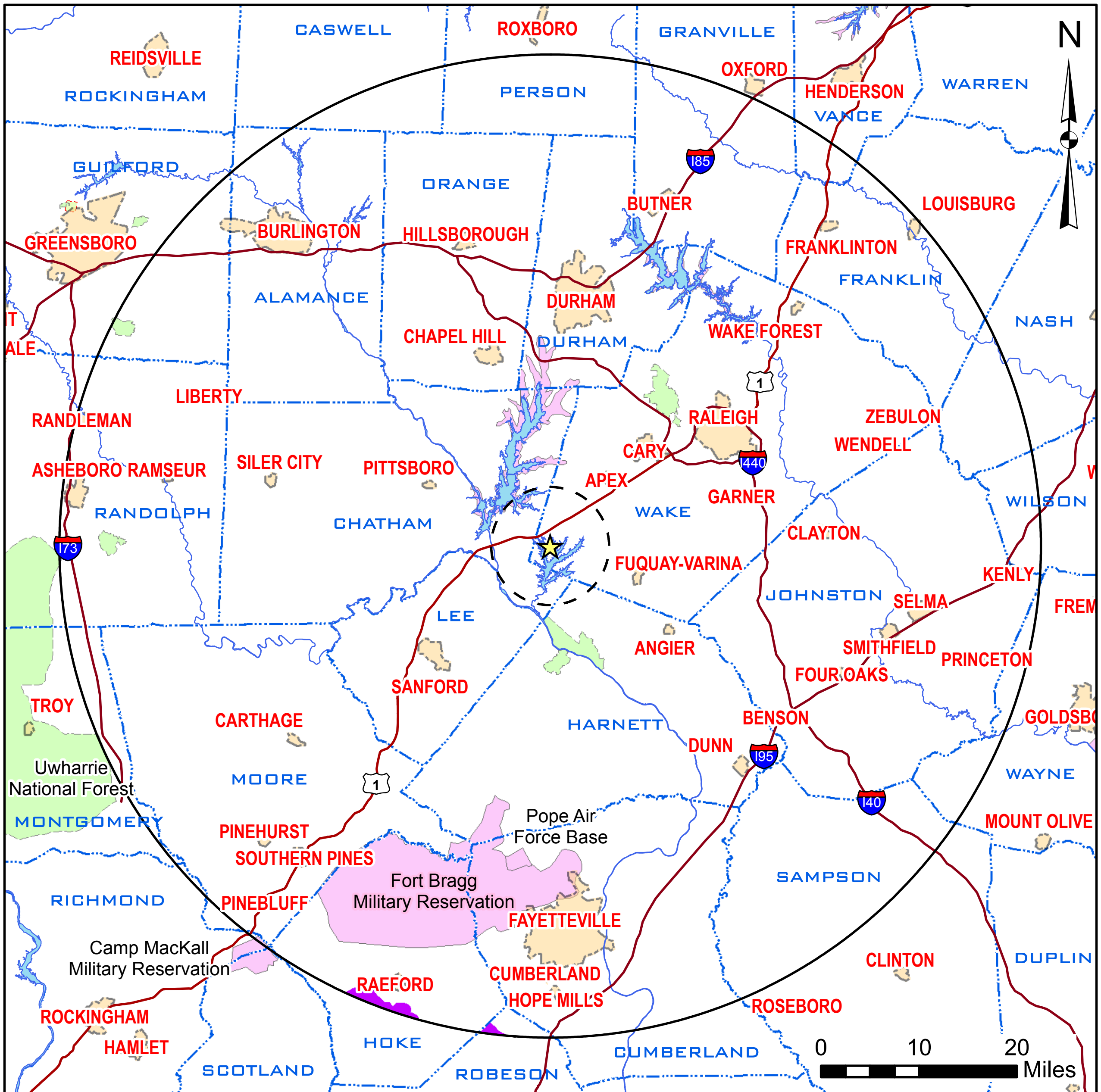


SHEARON HARRIS NUCLEAR PLANT
Figure 2-3
HNP Site and Harris Reservoir



SHEARON HARRIS
NUCLEAR PLANT

Figure 2-4
SHEARON HARRIS SITE BOUNDARY



Legend

☆ SHEARON HARRIS NUCLEAR PLANT

AMERICAN INDIAN OR ALASKAN NATIVE POPULATION

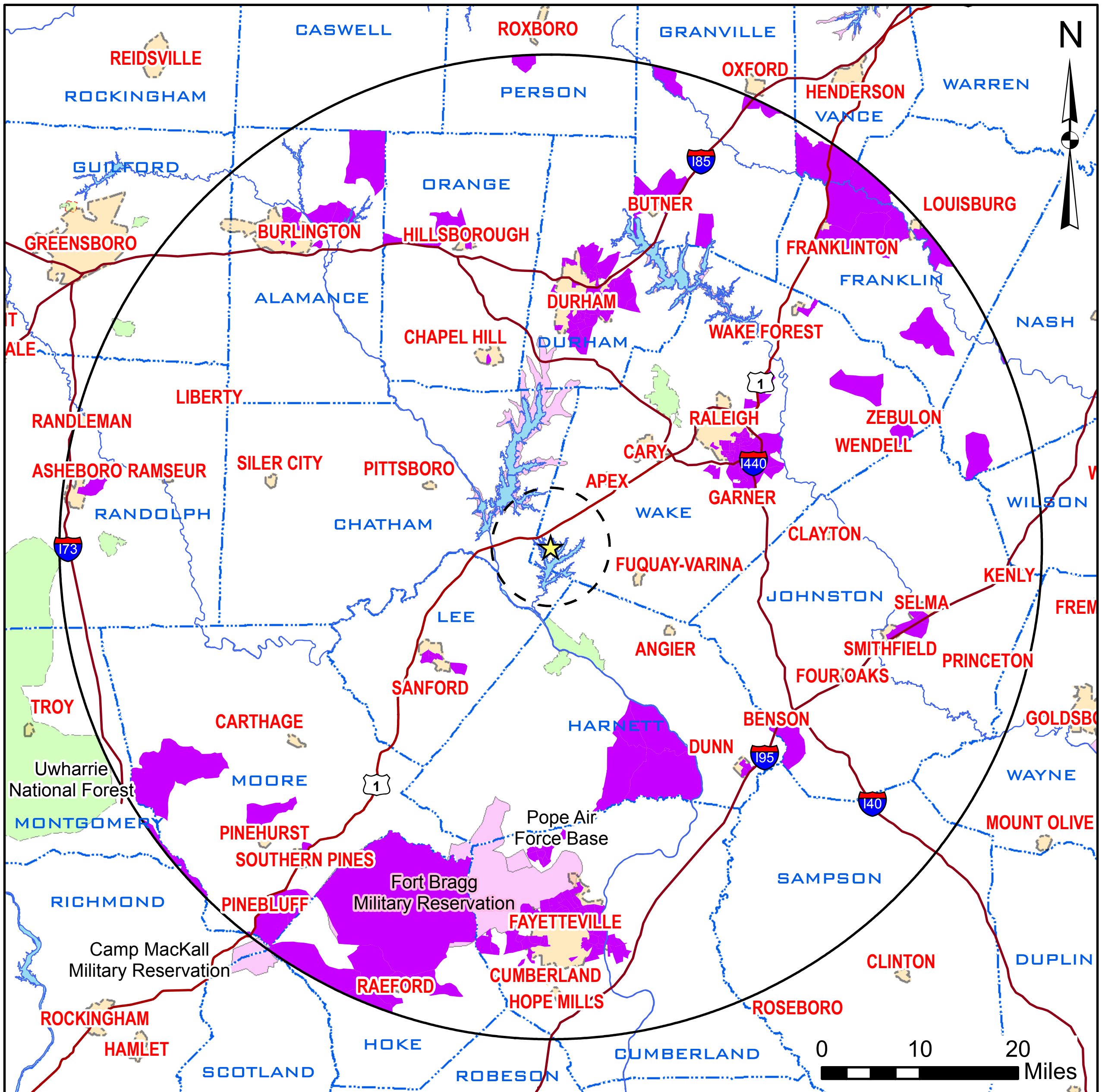
50-MILE RADIUS

– – – 6-MILE RADIUS

SHEARON HARRIS NUCLEAR PLANT

Figure 2-5

50-MILE AMERICAN INDIAN OR ALASKAN NATIVE POPULATION



Legend

☆ SHEARON HARRIS NUCLEAR PLANT

BLACK RACES POPULATION

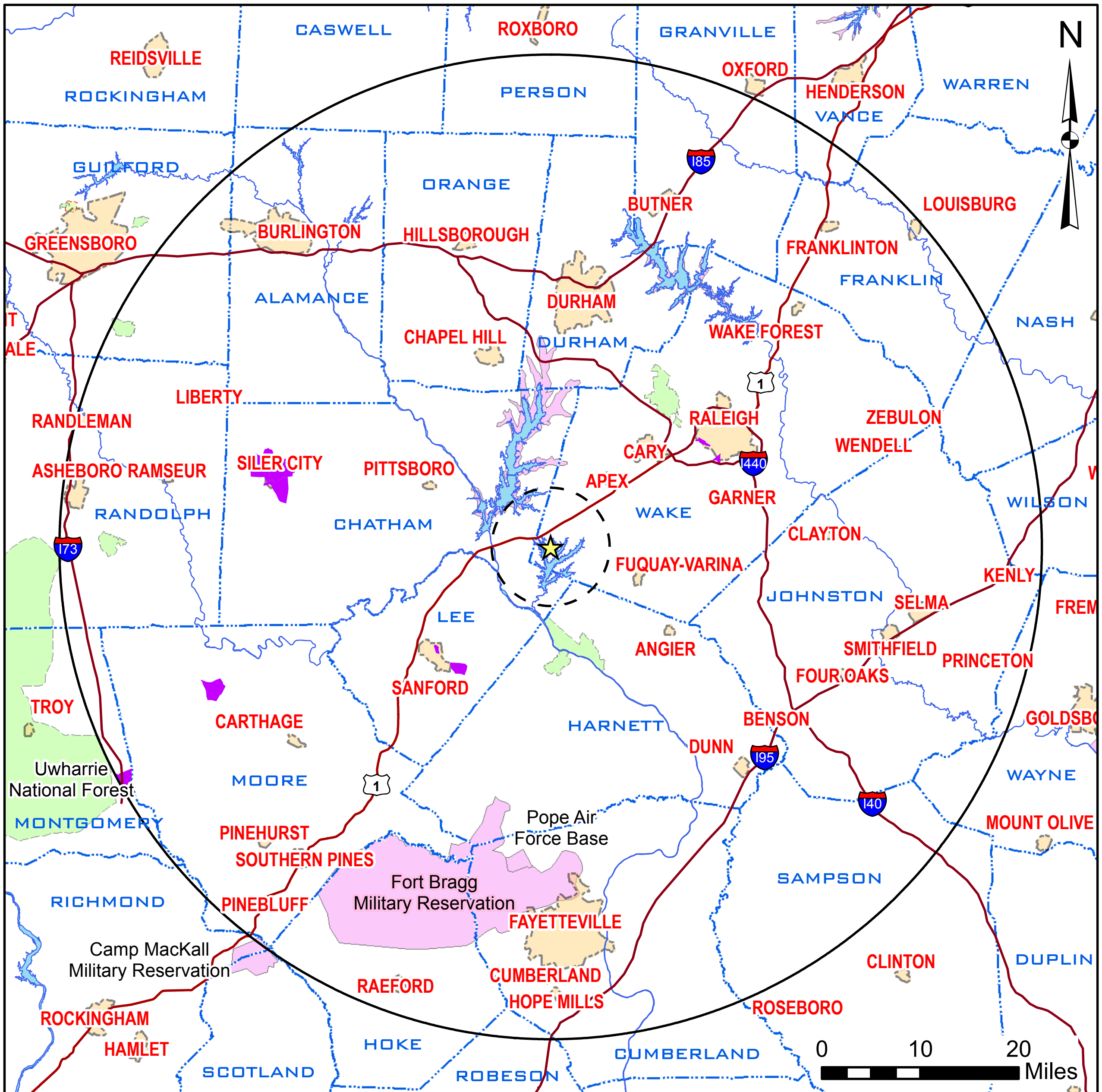
50-MILE RADIUS

– – – 6-MILE RADIUS

SHEARON HARRIS NUCLEAR PLANT

Figure 2-6

50-MILE BLACK RACES POPULATION



Legend

SHEARON HARRIS NUCLEAR PLANT

ALL OTHER SINGLE MINORITIES POPULATION

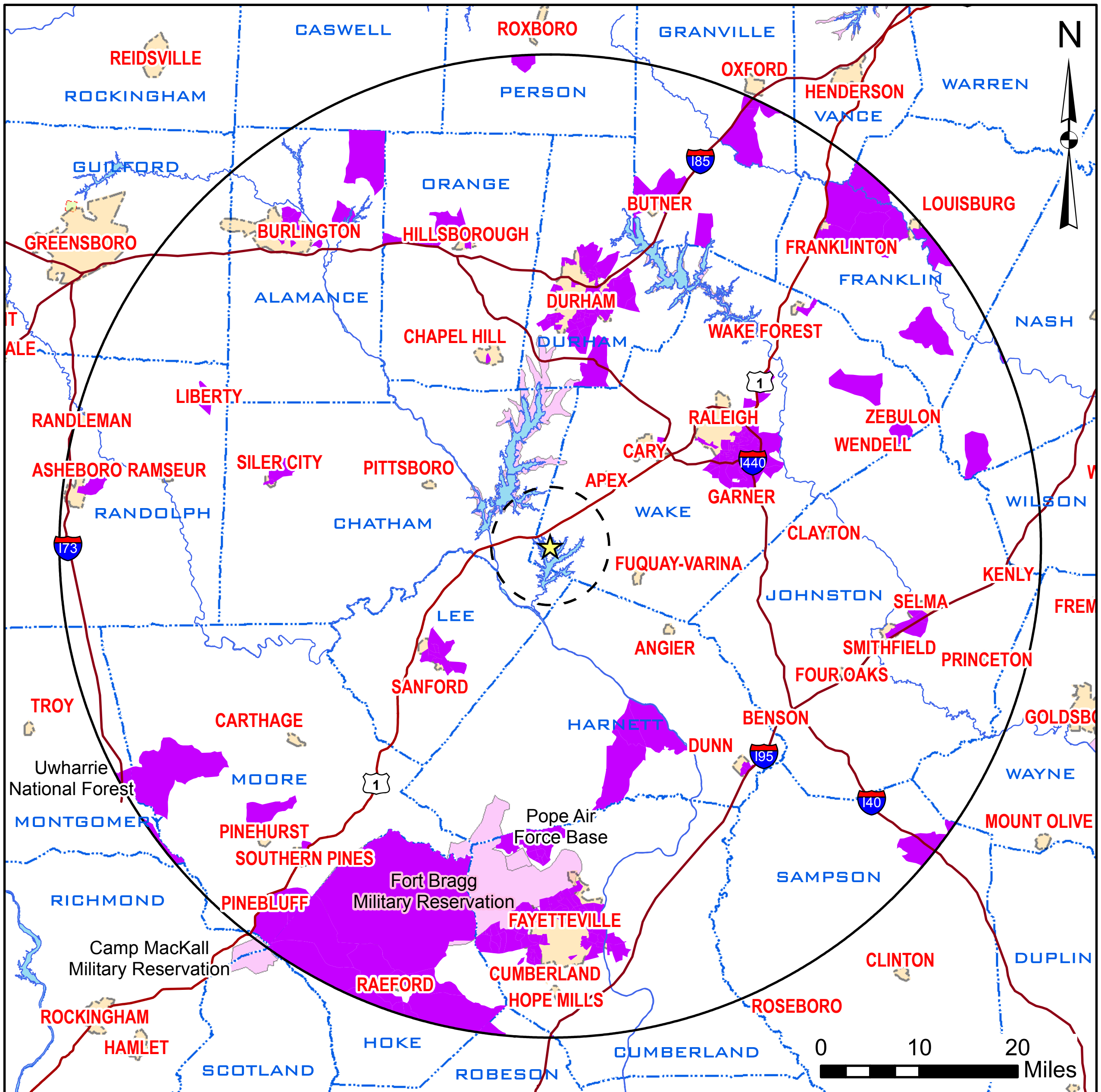
50-MILE RADIUS

6-MILE RADIUS

SHEARON HARRIS NUCLEAR PLANT

Figure 2-7

50-MILE ALL OTHER SINGLE MINORITIES POPULATION



Legend

☆ SHEARON HARRIS NUCLEAR PLANT

AGGREGATE OF MINORITY POPULATION

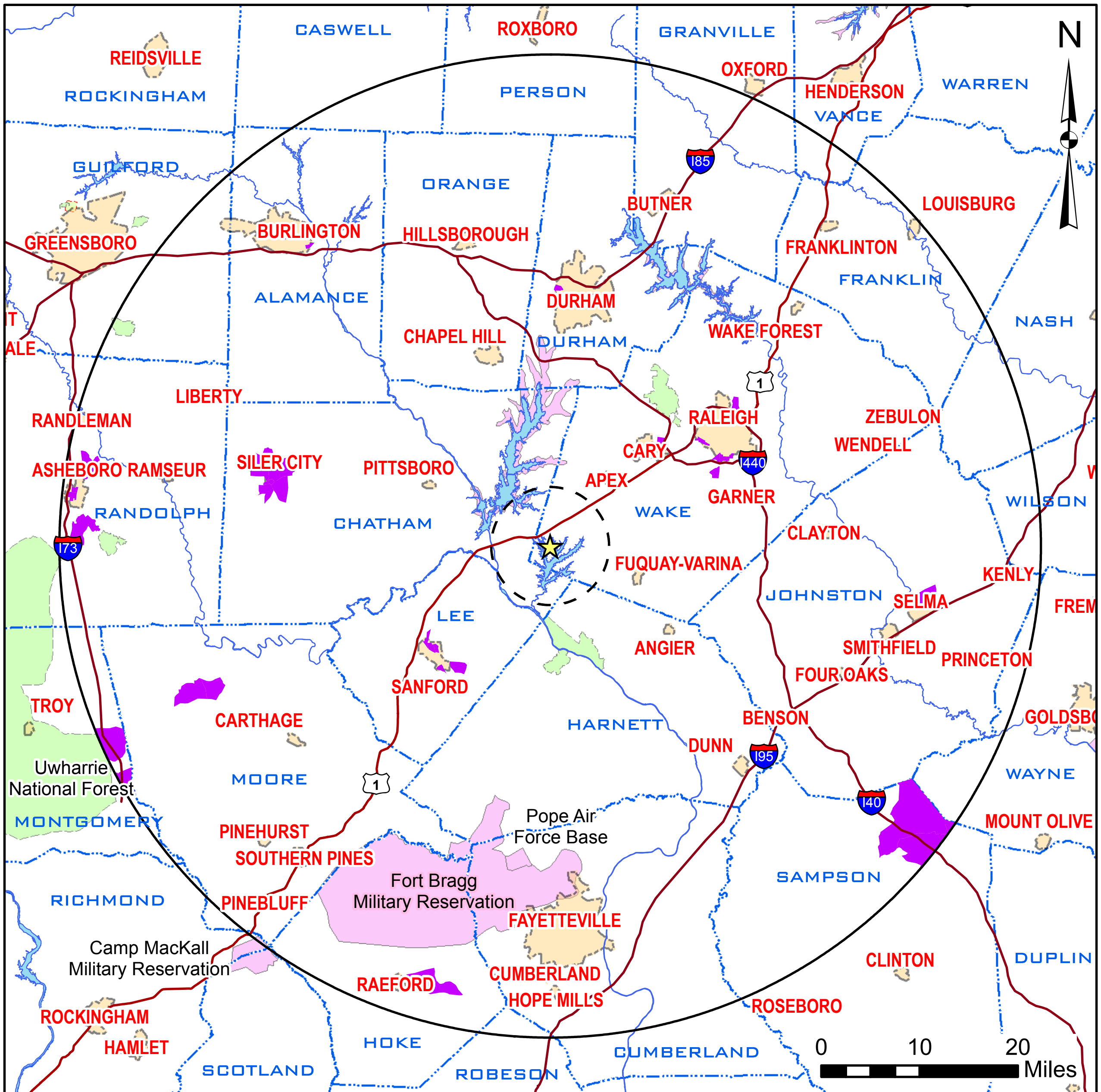
50-MILE RADIUS

– – – 6-MILE RADIUS

SHEARON HARRIS NUCLEAR PLANT

Figure 2-8

50-MILE AGGREGATE OF MINORITY POPULATION



Legend

☆ SHEARON HARRIS NUCLEAR PLANT

HISPANIC ETHNICITY POPULATION

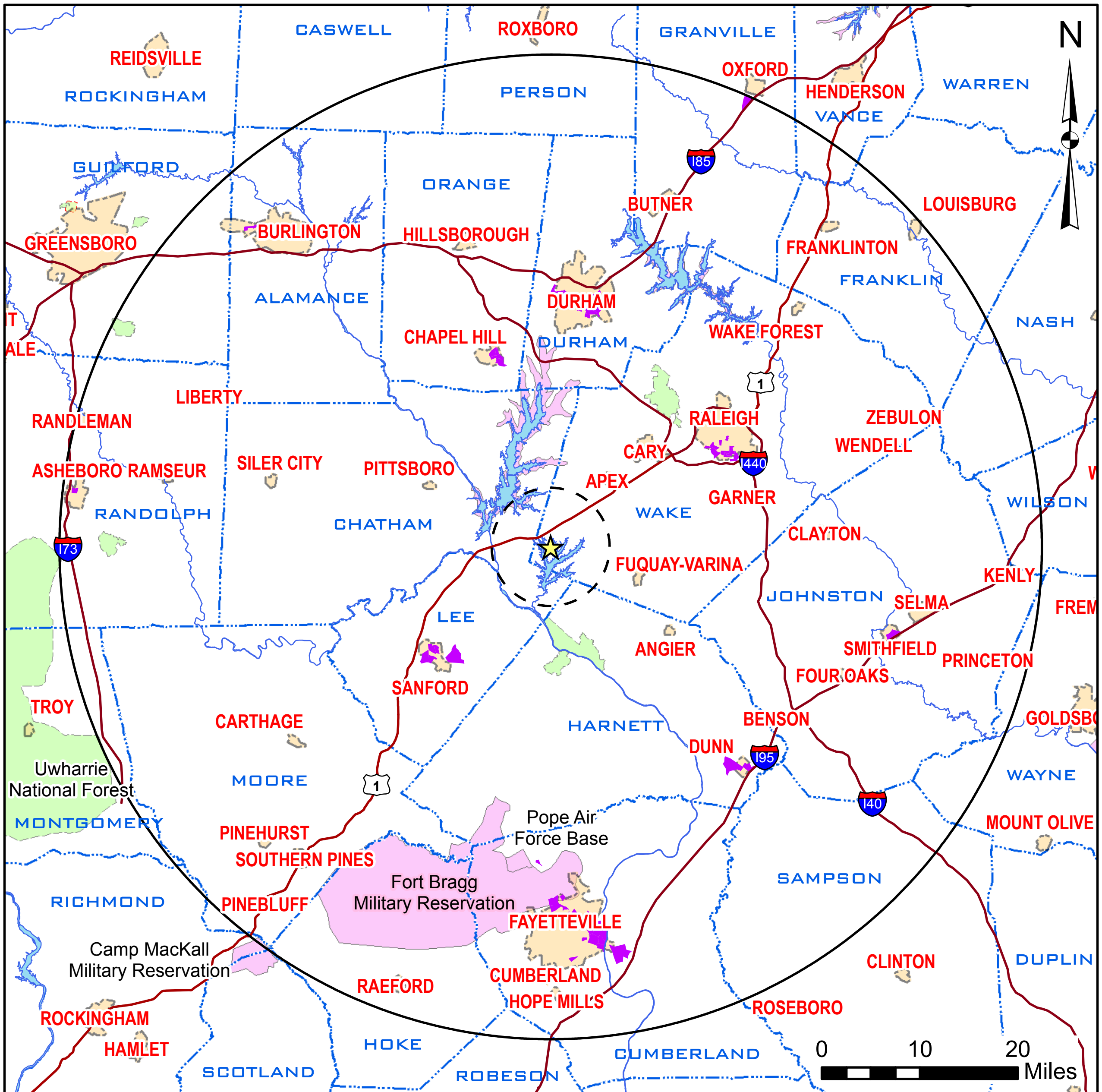
50-MILE RADIUS

– – – 6-MILE RADIUS

SHEARON HARRIS
NUCLEAR PLANT

Figure 2-9

50-MILE HISPANIC ETHNICITY POPULATION



Legend

SHEARON HARRIS NUCLEAR PLANT

- ☆ SHEARON HARRIS NUCLEAR PLANT
- LOW-INCOME POPULATION
- 50-MILE RADIUS
- 6-MILE RADIUS

Figure 2-10
50-MILE LOW-INCOME POPULATION

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3.0 PROPOSED ACTION

NRC

"…The report must contain a description of the proposed action, including the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

Progress Energy proposes that the U.S. Nuclear Regulatory Commission (NRC) renew the operating licenses for Shearon Harris Nuclear Plant Unit 1 (HNP) for an additional 20 years. Renewal would give Progress Energy and the state of North Carolina the option of relying on HNP to meet future electricity needs. Section 3.1 provides basic information on plant design and operation, including reactor and containment systems, cooling and auxiliary water systems, and transmission facilities. Sections 3.2 through 3.4 discuss whether facility modifications or administrative controls could occur as a result of license renewal.

3.1 GENERAL PLANT INFORMATION

General information about HNP is available in several documents. In 1973, the U.S. Atomic Energy Commission (AEC), the NRC's predecessor agency, prepared the Final Environmental Statement related to construction of Shearon Harris Nuclear Power Plant Units 1, 2, 3, and 4 (FES; AEC 1973). The FES analyzed impacts of constructing an 8,400-acre "cooling lake" (reservoir) to serve as a cooling water source and heat sink for the four nuclear units (AEC 1973, page 3-1). The AEC published a Revised Final Environmental Statement a year later (RFES; AEC 1974) that analyzed impacts of building and operating a four-unit facility with a cooling tower-based heat dissipation system when the EPA and the State of North Carolina indicated they were unwilling to approve a construction permit based on the cooling reservoir design (AEC 1974, page iii). The NRC staff noted, in introductory comments to the RFES, that "…natural-draft cooling towers, which are mandated by requirements of other agencies, are, on balance, an acceptable but more expensive cooling alternative" (AEC 1974, page iii). The AEC issued construction permits for Units 1, 2, 3, and 4 in January 1978 (NRC 1983, p. 1-1).

In December 1981, CP&L informed the NRC that units 3 and 4 had been cancelled, and in January 1982 requested that Units 1 and 2 be considered for operating licenses (NRC 1983, page 1-1). The FES related to the operation of Shearon Harris Nuclear Power Plant Units 1 and 2 (NRC 1983) analyzed impacts of operating a two-unit plant with a cooling tower-based heat dissipation system. The NRC Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996) describes certain HNP features and, in accordance with NRC requirements, Progress Energy maintains the Final Safety Analysis Report (FSAR) for HNP. Progress Energy referred to each of these documents while preparing this environmental report for license renewal.

3.1.1 REACTOR AND CONTAINMENT SYSTEMS

HNP is a single-unit plant with a conventional domed concrete containment building. The plant includes a pressurized light-water reactor nuclear steam supply system and turbine generator designed and manufactured by Westinghouse Electric Company (Scientech 2001). The plant achieved initial criticality on January 3, 1987 and began commercial operation on May 2, 1987.

The reactor containment structure is a steel-lined, reinforced-concrete structure in the shape of a (225-foot high X 130-foot diameter) cylinder, capped with a hemispheric dome (AEC 1973, page 3-1; HNP FSAR, page 1.3.1-11). The walls of the containment structure are 4.5 feet thick. The containment is designed to withstand internal pressure of 45 pounds per square inch above atmospheric pressure (45 psig). With its engineered safety features, the containment structure (reactor building) is designed to withstand severe weather (e.g., tornadoes and hurricanes) and provide radiation protection during normal operations and design-basis accidents.

Figure 3-1 shows the plant layout, including the location of the reactor building, the turbine building, and the control building.

As originally built and operated, HNP Unit 1 had a design rating of 2,775 megawatts-thermal (MWt) and an output of approximately 860 megawatts-electric (MWe) (Scientech 2001). On October 16, 2001, NRC approved an increase in the licensed maximum core thermal level of HNP Unit 1 from 2,775 MWt to 2,900 MWt, an increase of approximately 4.5 percent (NRC 2001). This corresponds to electrical ratings of 955 MWe (gross) and 900 MWe (net) (HNP FSAR, page 1.1-2). The NRC determined in an Environmental Assessment (EA) prepared at that time that the power uprate would not have a significant effect on human health and the environment and issued a Finding of No Significant Impact (Federal Register, Vol. 66, No. 197, pp. 51982-51985). The 4.5 percent power uprate for Unit 1 was carried out during an extended outage for refueling and steam generator replacement that began in late September 2001 and ended in early January 2002 (NCEMPA 2001, 2002; HNP FSAR, page 1.1-2).

As discussed earlier in this section, HNP was originally designed for four reactors, but only one was actually built. However, the plant's fuel handling building has four spent fuel pools, as originally designed. The NRC operating license for HNP issued in 1987 authorized CP&L to use two of the four pools for storage of spent fuel from the Harris Plant and the company's other nuclear units, Brunswick Units 1 and 2 and H. B. Robinson. In December 1998, CP&L asked the NRC for a license amendment that would allow the other two spent fuel pools to be placed in service. The spent fuel pool expansion was approved in December 2000 (NRC 2000).

Over the next several years, spent fuel from Brunswick and Robinson was shipped to HNP in Progress Energy-owned, NRC-licensed casks on dedicated railroad trains. The shipping routes were NRC-approved and Progress Energy provided notification to appropriate state officials, as required by the Code of Federal Regulations.

On April 30, 2003, Progress Energy announced it was considering building dry storage facilities for spent nuclear fuel at both BSEP and Robinson Nuclear Plant (Progress Energy 2003a). The company issued a Request for Proposal at that time "seeking solutions for on-site interim storage of spent nuclear fuel" in order to ensure that the company's spent fuel storage needs are met until the Yucca Mountain geologic repository opens. The Progress Energy press release noted that the Nuclear Waste Policy Act of 1982 and its amendments require the U.S. Department of Energy to locate, build, and operate a repository for high-level waste and to develop a transportation system that safely links U.S. nuclear power plants and the permanent repository. By law, the repository was to be in place by January 31, 1998, but the project is years behind schedule and continues to face court challenges.

Progress Energy shipped spent fuel from the Robinson Plant to HNP until 2004, when ground was broken for an Independent Spent Fuel Storage Installation (ISFSI). The ISFSI was completed in 2005, with initial loading of spent fuel in August of that year. Shipments of spent nuclear fuel from the Brunswick Plant to HNP are expected to end in 2008. The NRC license for the casks (rail containers) was extended from 2005 until 2008.

3.1.2 COOLING AND AUXILIARY WATER SYSTEMS

3.1.2.1 Surface Water

HNP is a single-unit plant, nominally rated at 900 megawatts-electrical (net), with a cooling tower-based heat dissipation system. A 4,150-acre main reservoir was constructed on Buckhorn Creek, a tributary of the Cape Fear River, to serve as the source of cooling tower makeup (see Figure 2-3). A smaller, 321-acre auxiliary reservoir was also built to serve as the primary source for the Emergency Cooling Water System, which is designed to remove heat from the reactor and critical components following a loss-of-coolant accident (LOCA) or a loss of off-site power.

HNP has two cooling water intake structures; one (Emergency Service Water and Cooling Tower Makeup Intake Structure) on the main reservoir (aka Harris Reservoir), from which cooling tower makeup water is obtained, and one (Emergency Service Water Intake Screening Structure) on the auxiliary reservoir, from which water is obtained for the plant's Emergency Service Water (ESW) System (see Figure 3-1). The former is equipped with two Cooling Tower Makeup (CTMU) pumps, each rated at 26,000 gallons per minute (gpm), and two ESW pumps, each rated at 20,000 gpm (Progress Energy 2003b, c). The ESW pumps may be used to draw water from either the auxiliary reservoir (preferred source) or the main reservoir (back-up source). During normal operation, one pump supplies all the necessary makeup water for the cooling tower. The CTMU pumps are also used to transfer water from the main reservoir to the auxiliary reservoir. The two ESW pumps are intended primarily for emergency use, but are tested periodically to ensure reliable operation. Typically, one or the other ESW pump draws water from the auxiliary reservoir about 4 days per quarter and draws water from the main reservoir about 10 days per year.

The CTMU pump bays are equipped with traveling screens that remove debris larger than 3/8 inch. The ESW pump bays are fitted with traveling screens that remove debris larger than 7/16 inch. The Revised FES for construction of HNP (AEC 1974) predicted that the approach velocity at the traveling screens for the CTMU pumps would be 0.5 fps or less. The FES for operation of HNP (NRC 1983) does not specify an approach or intake velocity for this system.

Under normal operating conditions, the cooling water flow of HNP is 533,000 gallons per minute (gpm). This total includes circulating water (483,000) and Normal Service Water (50,000) flows, apportioned as follows: three circulating water pumps @ 161,000 gpm each (Progress Energy 2003d) and two NSW pumps @ 25,000 gpm each (Progress Energy 2003c).

After passing through the main condenser, cooling water (combined flow of circulating water and service water) is routed to a 100 percent capacity, 523-foot-tall, hyperbolic natural-draft cooling tower where the bulk of the waste heated is removed (Progress Energy 2003b). The tower is designed to remove 6.663 X 10^9 BTU/hr at the design flow rate of 533,000 gpm and reduce water temperature 25 degrees F.

Cooling Tower Makeup Pumps (there are two, in the ESW and CTMU Intake Structure) supply makeup water from the main reservoir. Each Cooling Tower Makeup (CTMU) Pump has a 26,000 gpm capacity. Normally, one CTMU pump operates continuously, supplying makeup water to the cooling tower, while the other is kept in reserve. One pump supplies all the necessary makeup water to replace losses to drift, evaporation, and blowdown.

Under certain extraordinary circumstances, CTMU pumps are also used to transfer water from the main reservoir to the auxiliary reservoir. When drought limits the amount of water entering the auxiliary reservoir and water levels drop beyond those considered optimal for safe operations, water is pumped from the main reservoir to the 321-acre auxiliary reservoir. This typically requires 2 to 3 days of pumping in drought years.

Finally, HNP has a non-recirculating Emergency Service Water system that allows the pumping of water from the auxiliary reservoir or the main reservoir to the reactor and other critical components following a loss-of-coolant accident or loss of off-site power. This system, which is tested periodically to ensure reliability, is equipped with two 20,000 gpm pumps. Under typical circumstances, one of these pumps is operated while the other is kept in reserve.

3.1.2.2 Groundwater

Groundwater use in the vicinity of HNP is limited because of the low yield of the aquifer, the Sanford Formation of the Newark Group (Triassic) (HNP FSAR, pp. 2.4.13-1 and 2). Although a few small towns in the area used the aquifer at the time the site was permitted, these currently use surface water or purchase water from other utilities. The communities nearest the site, Sanford, Fuquay-Varina, and Holly Springs, use surface water or purchase water for their public water supplies. Sanford uses water from the Cape Fear River system (Sanford 2005). Fuquay-Varina purchases its water from the City of Raleigh, Harnett and Johnston Counties (Fuquay-Varina 2006). Holly Springs purchases its water from the City of Raleigh and Harnett County (Holly Springs 2006). Most wells in the area are for domestic use (HNP FSAR, page 2.4.13-2). As of the early 1980s, there were only two domestic users within two miles of HNP, both east and upgradient of the site (HNP FSAR, page 2.4.13-3).

Seven wells with a total capacity of 200 gallons per minute were completed at the HNP site in 1973 (HNP FSAR, page 2.4.13-3). Eight more wells with a total capacity of 250 gallons per minute were completed over the 1977-1979 period. Five more wells (no capacity provided in FSAR) were developed in 1980-1981, bringing the total number of production wells developed during the construction phase to 20. The construction-phase wells at HNP were installed in Triassic Basin sediments that overlie the Carolina Slate Belt by several thousand feet (HNP FSAR 2.4.13-4). None of the wells is currently being used as a source of potable or process water. Groundwater samples are sometimes obtained from these wells, however.

HNP is equipped with a closed-cycle cooling system that uses a natural draft cooling tower to dissipate heat from both its condenser cooling water and (normal) service water cooling systems. The plant's main reservoir, created by a dam on Buckhorn Creek, supplies all of the plant's water needs. Water is pumped from the main reservoir to the cooling tower to replace water lost to evaporation and blowdown. Water from the main reservoir is treated and used as potable water throughout the plant and is piped to the plant's Demineralized Water System, where it is de-aerated, treated, and demineralized for use in a variety of plant components, systems, and facilities. These include the reactor makeup storage tank, condensate storage tank, refueling water storage tank, and the fuel cask decontamination facility (NRC 1983, page 4-2; HNP FSAR, page 1.2.2-11). Demineralized water is also used to flush fixtures and clean tools and equipment under certain circumstances.

3.1.3 TRANSMISSION FACILITIES

The FES for operation of HNP (NRC 1983) notes that eight transmission lines were originally planned for HNP --- six 230 kV lines and two 500 kV lines --- but that the two 500 kV lines were never built. It refers the reader to the revised FES for construction of HNP (AEC 1974) for a description of the 230 kV lines. The revised FES for construction does not contained detailed descriptions of the lines: it simply states that the 230 kV lines will follow existing rights-of-way to substations near Asheboro, Fayetteville, West

Raleigh, and Erwin. The original FES for construction (AEC 1973) contains the same language.

The Shearon Harris OLER (CP&L 1982), which was available to NRC when the operations FES was prepared, identified the lines NRC later considered in the FES for operation and discusses modifications made in their design after the (1974) revised FES for construction was published.

The six lines evaluated in the 1983 FES for operation of HNP were:

- Harris-Asheboro 230 kV line
- Harris-Cape Fear 230 kV line
- Harris-Cary 230 kV line
- Harris-Fuquay-Erwin North 230 kV line
- Harris-Lillington-Erwin South 230 kV line
- Harris-Fayetteville 230 kV line

After publication in 1983 of the FES for operation of HNP, a number of changes were made to the transmission system, most significantly (1) the construction of a second Cape Fear 230 kV line, (2) the construction of a new 230 kV line from HNP to a substation several miles east of Raleigh, and (3) the termination of the Harris-Fayetteville line at the Woodruff Street substation on the Fort Bragg military installation. The Harris-Lillington-Erwin-South line was never built.

The current HNP Final Safety Analysis Report lists and describes the seven 230 kilovolt transmission lines that connect HNP to the transmission network: Cape Fear North, Cape Fear South, Fort Bragg (Woodruff Street), Erwin, Asheboro, Cary Regency Park, and Wake. The FSAR notes that these lines come from six different substations and approach the plant from different directions. It notes also that five circuits (Asheboro, Cape Fear North, Cape Fear South, Erwin, and Fort Bragg) share a common right-of-way as they enter the plant area.

Since the transmission system description in the FSAR was last updated, two additional changes were made in the system. In 2003, a new substation was put into service approximately 4 miles northeast of the plant, terminating the old Cary Regency Park line near Apex. In 2006, a new substation was built on the old Asheboro line, creating a new terminus for this circuit approximately 31 circuit miles from HNP near Siler City, North Carolina.

Figures 3-2 and 3-3 show the current configuration of the transmission system, with seven 230 kV transmission lines connecting HNP to the regional grid. These seven lines are described in more detail in the paragraphs that follow. These lines generally run through 100-foot-wide corridors. Some areas, such as the short segment of right-of-way immediately south of the switchyard that holds five lines, are as wide as 350 feet. But these wide segments are exceptions to the rule, making up a small proportion of the approximately 142 miles of transmission corridor associated with HNP.

Siler City - This line terminates at Siler City, 31 miles from HNP, but formerly extended to Asheboro, approximately 55 miles from the plant. The new Siler City substation was completed in 2006.

Cape Fear North – This is the original Cape Fear line considered in the operations FES. It connects HNP with the Cape Fear Steam Plant 7.4 circuit miles southwest of HNP (Figure 3-3).

Cape Fear South – This newer line was not considered in the FES for operation of HNP. It connects the plant with the Cape Fear Steam Plant following a more southerly 6.5-mile route than the north line (Figure 3-3).

Apex-U.S. 1 – This line terminates approximately four miles northeast of HNP, but formerly extended another 7 miles to the Cary Regency Park substation. In the OLER (Carolina Power & Light 1982), this line was referred to as the “Method Line.”

Erwin – This line was called the “Harris-Fuquay-Erwin North line” in the FES for operation. It is 30 miles long. The Harris-Lillington-Erwin South line described in the OLER (Carolina Power & Light 1982) was never constructed.

Fort Bragg – Woodruff Street – This line terminates at the Woodruff Street substation on the Fort Bragg post, approximately 36 miles from HNP. It formerly extended another 21 miles to Fayetteville, North Carolina.

Wake – This 230 kilovolt line was built, in part, along the same corridor that was created for the originally planned 500-kilovolt line to Wake County identified in the revised operating permit FES. This line is approximately 38 miles long.

In total, for the specific purpose of connecting HNP to the transmission system, Progress Energy has approximately 142 miles of transmission corridor (152 miles of transmission line) that occupy approximately 1,717 acres. Most corridors pass through land that is primarily agricultural and forest land. The areas are mostly remote, with low population densities. The longer lines cross numerous state and U.S. highways. Impact of these corridors on land usage is minimal; farmlands that have corridors passing through them generally continue to be used as farmland.

Progress Energy designed and constructed all HNP transmission lines in accordance with industry guidance that was current when the lines were built. Ongoing surveillance and maintenance of HNP-related transmission facilities ensure continued conformance to design standards. These maintenance practices are described in Sections 4.13. Section 4.13 also examines the conformance of the lines with the National Electrical Safety Code requirements on line clearance to limit shock from induced currents (IEEE 1997).

Progress Energy uses a variety of methods to control vegetation in transmission corridors. Because transmission corridors traverse areas with different kinds of terrain and soils, Progress Energy employs an Integrated Vegetation Management (IVM) approach that includes both mechanical and chemical control methods (Progress Energy 2006). Mechanical methods include pruning, felling, mowing, and hand trimming. Chemical controls include the use of tree growth regulators, which slow the growth of fast-growing trees under lines, and EPA-approved herbicides, which control undesirable woody vegetation that reseeds or re-sprouts after mowing. Over time, the use of herbicides results in the growth of low-growing, non-woody plants, such as grasses and herbaceous plants that provide wildlife with food and cover.

Progress Energy provides its residential customers in North Carolina with information on herbicide use in rights of ways, including dates (months) when herbicides will be used, method of application, and names of herbicides to be used (CP&L 1998). This information is normally provided in April, as an insert to power bills. A Progress Energy point of contact is also provided, should customers have additional questions or should they require additional information, such as Material Safety Data Sheets. The Progress Energy website also contains information on herbicide use in transmission line rights of way and provides a toll-free telephone number for customers with questions about the herbicide program (Progress Energy 2006).

Progress Energy plans to maintain these transmission lines, which are integral to the larger transmission system, indefinitely. These transmission lines will remain a permanent part of the transmission system even after HNP is decommissioned.

3.2 REFURBISHMENT ACTIVITIES

NRC

"… The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"… The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40 year license term will be from one of two broad categories: ... and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item…." NRC 1996

Progress Energy has addressed refurbishment activities in this environmental report in accordance with NRC regulations and complementary information in the NRC GEIS for license renewal (NRC 1996). NRC requirements for the renewal of operating licenses for nuclear power plants include the preparation of an integrated plant assessment (IPA) (10 CFR 54.21). The IPA must identify and list systems, structures, and components subject to an aging management review. Items that are subject to aging and might require refurbishment include, for example, piping, supports, and pump casings (see 10 CFR 54.21 for details), as well as those that are not subject to periodic replacement.

In turn, NRC regulations for implementing the National Environmental Policy Act require environmental reports to describe in detail and assess the environmental impacts of refurbishment activities such as planned modifications to systems, structures, and components or plant effluents [10 CFR 51.53(c)(2)]. Resource categories to be evaluated for impacts of refurbishment include terrestrial resources, threatened and endangered species, air quality, housing, public utilities and water supply, education, land use, transportation, and historic and archaeological resources.

The GEIS (NRC 1996) provides helpful information on the scope and preparation of refurbishment activities to be evaluated in this environmental report. It describes major refurbishment activities that utilities might perform for license renewal that would necessitate changing administrative control procedures and modifying the facility. The GEIS analysis assumes that an applicant would begin any major refurbishment work shortly after NRC grants a renewed license and would complete the activities during five outages, including one major outage at the end of the 40th year of operation. The GEIS refers to this as the refurbishment period.

GEIS Table B.2 (NRC 1996) lists license renewal refurbishment activities that NRC anticipated utilities might undertake. In identifying these activities, the GEIS intended to encompass actions that typically take place only once, if at all, in the life of a nuclear plant. The GEIS analysis assumed that a utility would undertake these activities solely for the purpose of extending plant operations beyond 40 years, and would undertake them during the refurbishment period. The GEIS indicates that many plants will have undertaken various refurbishment activities to support the current license period, but that some plants might undertake such tasks only to support extended plant operations.

The HNP IPA that Progress Energy conducted under 10 CFR 54 has not identified the need to undertake any major refurbishment or replacement actions to maintain the functionality of important systems, structures, and components during the HNP license renewal period or other facility modifications associated with license renewal that would directly affect the environment or plant effluents. Progress Energy has included the IPA as part of this application.

3.3 PROGRAMS AND ACTIVITIES FOR MANAGING THE EFFECTS OF AGING

NRC

"…The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40 year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals …." NRC 1996 (SMITTR is defined in NRC 1996 as surveillance, monitoring, inspections, testing, trending, and recordkeeping.)

The IPA required by 10 CFR 54.21 identifies the programs and inspections for managing aging effects at HNP. These programs are described in the Shearon Harris Nuclear Plant License Renewal Application, Appendix B, Aging Management Programs. Other than implementation of programs and inspections identified in the IPA, Progress Energy has no plans to modify administrative controls that are associated with license renewal.

3.4 EMPLOYMENT

Current Workforce

Progress Energy employs approximately 470 permanent employees and up to 250 long-term contract employees at HNP, a one-unit facility. Approximately 82 percent of the employees live in Wake and Lee Counties, North Carolina. The remaining employees are distributed across 14 counties in North Carolina, with numbers ranging from 1 to 21 employees per county. One individual lives outside of North Carolina.

HNP is on an 18-month refueling cycle. During refueling outages, site employment increases above the permanent workforce by as many as 800 workers for temporary duty.

License Renewal Increment

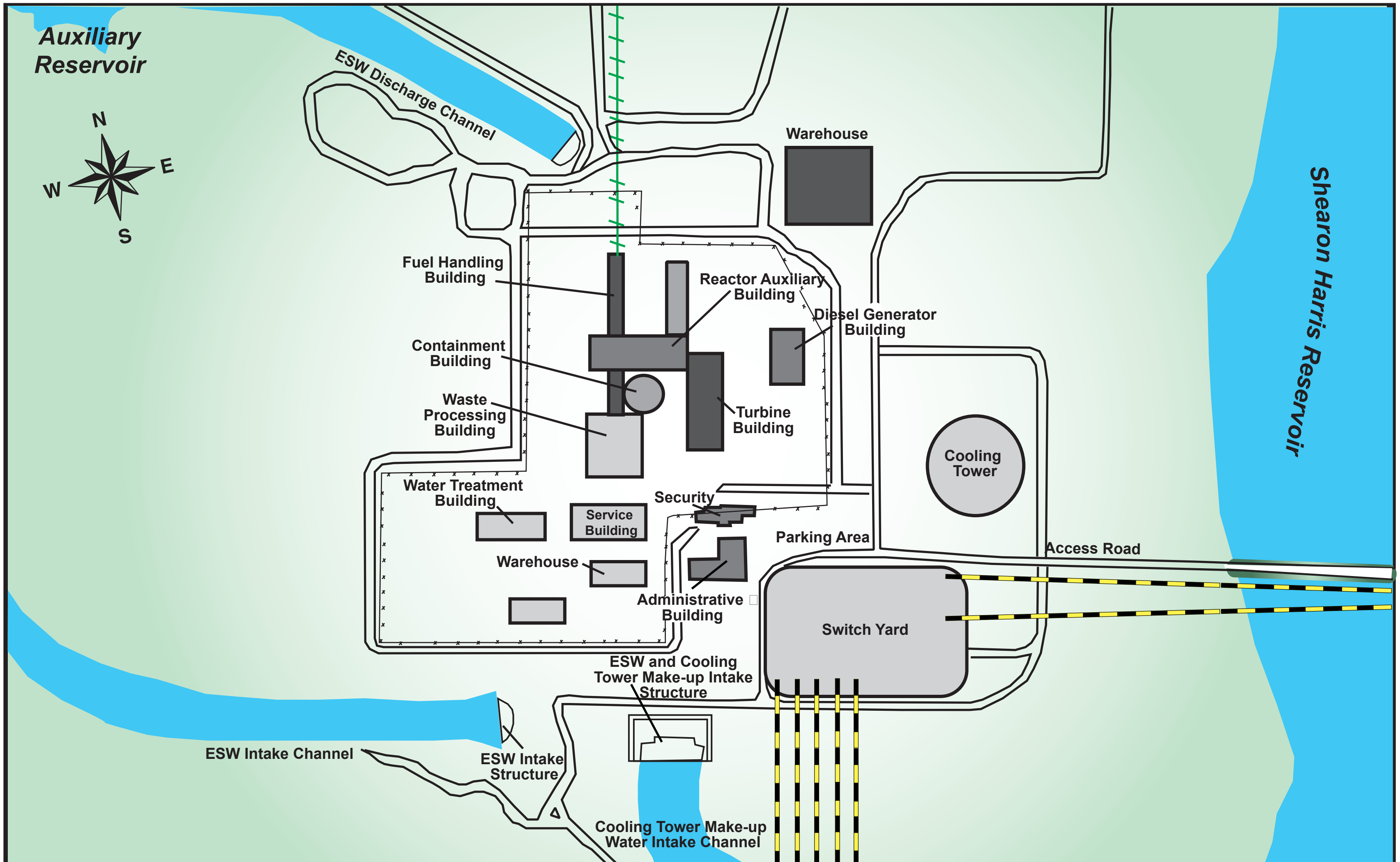
Performing the license renewal activities described in Sections 3.2 and 3.3 would necessitate increasing HNP staff workload by some increment. The size of this increment would be a function of the schedule within which Progress Energy must accomplish the work and the amount of work involved. Because Progress Energy has determined that no refurbishment is needed (Section 3.2), the analysis of license renewal employment increment focuses on programs and activities for managing the effects of aging (Section 3.3).

The GEIS (NRC 1996) assumes that NRC would renew a nuclear power plant license for a 20-year period, plus the duration remaining on the current license, and that NRC would issue the renewal approximately 10 years prior to license expiration. In other words, the renewed license would be in effect for approximately 30 years. The GEIS further assumes that the utility would initiate SMITTR activities at the time of issuance of the new license and would conduct license renewal SMITTR activities throughout the remaining 30-year life of the plant, sometimes during full-power operation (NRC 1996), but mostly during normal refueling and the 5- and 10-year in-service inspection and refueling outages (NRC 1996).

Progress Energy has determined that the GEIS scheduling assumptions are reasonably representative of HNP incremental license renewal workload scheduling. Many HNP license renewal SMITTR activities would have to be performed during outages. Although some HNP license renewal SMITTR activities would be one-time efforts, others would be recurring periodic activities that would continue for the life of the plant.

The GEIS estimates that the most additional personnel needed to perform license renewal SMITTR activities would typically be 60 persons during the 3-month duration of a 10-year in-service inspection and refueling outage. Having established this upper value for what would be a single event in 20 years, the GEIS uses this number as the expected number of additional permanent workers needed per unit attributable to license renewal. GEIS Section C.3.1.2 uses this approach in order to "...provide a realistic upper bound to potential population-driven impacts…."

Progress Energy has identified no need for significant new aging management programs or major modifications to existing programs. Progress Energy anticipates that existing "surge" capabilities for routine activities, such as outages, will enable Progress Energy to perform the increased SMITTR workload without increasing HNP staff. Therefore, Progress Energy has no plans to add non-outage employees to support HNP operations during the license renewal term. Progress Energy believes that increased SMITTR tasks can be performed within this schedule and employment level. Therefore, Progress Energy has no plans to add outage employees for license renewal term outages.



LEGEND

Property

Fence

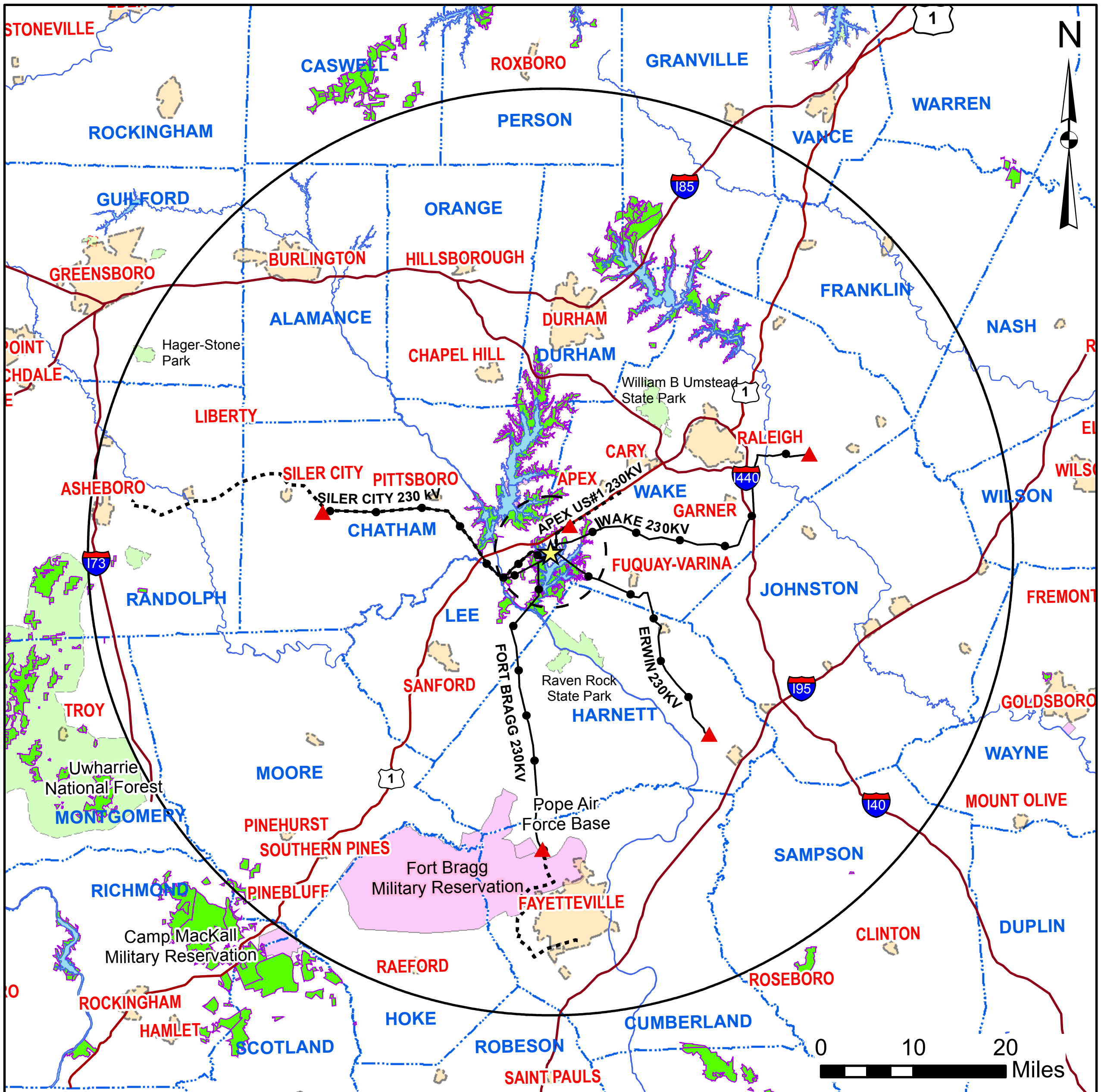
Railroad Tracks

Transmission Lines

0 500' 1,000'

Scale is approximate.

SHEARON HARRIS NUCLEAR PLANT
FIGURE 3-1
General Plant Layout



Legend

☆ SHEARON HARRIS

TRANSMISSION LINE (TO FIRST SUBSTATION)

TRANSMISSION LINE (FES)

SUBSTATION

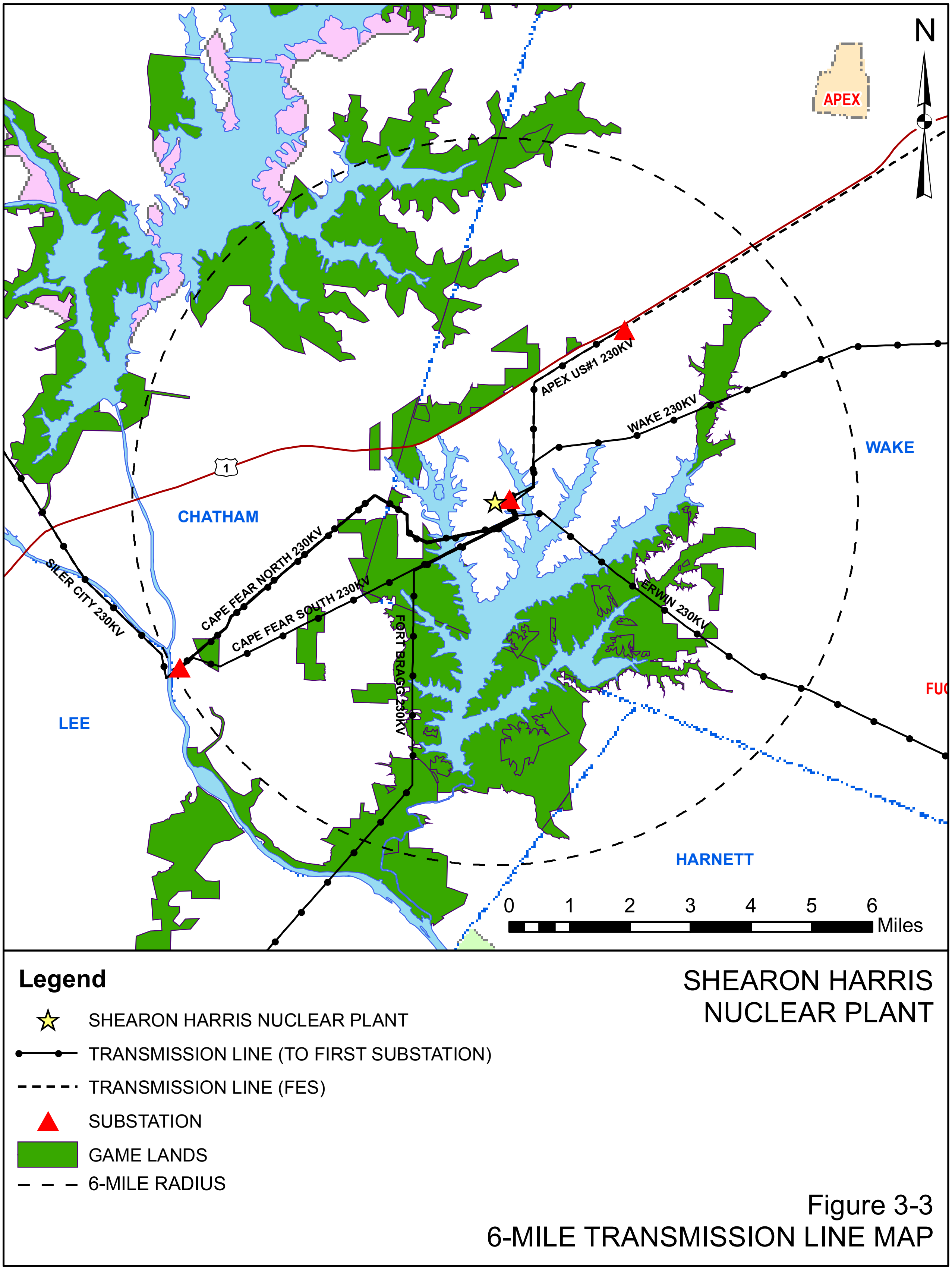
NORTH CAROLINA GAME LANDS

50-MILE RADIUS

6-MILE RADIUS

SHEARON HARRIS NUCLEAR PLANT

Figure 3-2
50-MILE TRANSMISSION LINE MAP



SHEARON HARRIS NUCLEAR PLANT

Figure 3-3
6-MILE TRANSMISSION LINE MAP

3.5 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 cited web pages are available in Progress Energy files. Some sites, for example 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 Progress Energy have been given for these pages, even though they may not be directly accessible.

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4.0 ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION AND MITIGATING ACTIONS

NRC

“The report must contain a consideration of alternatives for reducing impacts…for all Category 2 license renewal issues….” 10 CFR 51.53(c)(3)(iii)

“The environmental report shall include an analysis that considers…the environmental effects of the proposed action…and alternatives available for reducing or avoiding adverse environmental effects.” 10 CFR 51.45(c) as adopted by 10 CFR 51.53(c)(2)

The environmental report shall discuss the “…impact of the proposed action on the environment. Impacts shall be discussed in proportion to their significance….” 10 CFR 51.45(b)(1) as adopted by 10 CFR 51.53(c)(2)

“The information submitted…should not be confined to information supporting the proposed action but should also include adverse information.” 10 CFR 51.45(e) as adopted by 10 CFR 51.53(c)(2)

Chapter 4 presents an assessment of the environmental consequences associated with the renewal of the Shearon Harris Nuclear Plant (HNP) operating license. The U.S. Nuclear Regulatory Commission (NRC) has identified and analyzed 92 environmental issues that it considers to be associated with nuclear power plant license renewal and has designated the issues as Category 1, Category 2, or NA (not applicable). NRC designated an issue as Category 1 if, based on the result of its analysis, the following criteria were met:

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

If the NRC analysis concluded that one or more of the Category 1 criteria could not be met, NRC designated the issue as Category 2. NRC requires plant-specific analyses for Category 2 issues.

Finally, NRC designated two issues as NA, signifying that the categorization and impact definitions do not apply to these issues.

As discussed later in Chapter 5, Progress Energy is not aware of any new and significant information that would make NRC findings regarding Category 1 issues inapplicable to HNP. An applicant may reference the generic findings or GEIS analyses for Category 1 issues. Appendix A of this report lists the 92 issues and identifies the environmental report section that addresses each issue.

CATEGORY 1 AND NA LICENSE RENEWAL ISSUES

NRC

"The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to subpart A of this part." 10 CFR 51.53(c)(3)(i)

"…[A]bsent new and significant information, the analyses for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal…." (NRC 1996b, pg. 28483)

Progress Energy has determined that six of the 69 Category 1 issues do not apply to HNP because they are specific to design or operational features that are not found at the facility. Because Progress Energy is not planning any refurbishment activities, seven additional Category 1 issues related to refurbishment do not apply. Appendix A, Table A-1 lists the 69 Category 1 issues, indicates whether or not each issue is applicable to HNP, and if inapplicable provides the Progress Energy basis for this determination. Appendix A, Table A-1 also includes references to supporting analyses in the GEIS where appropriate.

Progress Energy has reviewed the NRC findings at 10 CFR 51 (Table B-1) and has not identified any new and significant information that would make the NRC findings, with respect to Category 1 issues, inapplicable to HNP. Therefore, Progress Energy adopts by reference the NRC findings for these Category 1 issues.

"NA" License Renewal Issues

NRC determined that its categorization and impact-finding definitions did not apply to Issues 60 and 92; however, Progress Energy included these issues in Table A-1. NRC noted that applicants currently do not need to submit information on Issue 60, chronic effects from electromagnetic fields (10 CFR 51). For Issue 92, environmental justice, NRC does not require information from applicants, but noted that it will be addressed in individual license renewal reviews (10 CFR 51). Progress Energy has included environmental justice demographic information in Section 2.6.2.

CATEGORY 2 LICENSE RENEWAL ISSUES

NRC

"The environmental report must contain analyses of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal and the impacts of operation during the renewal term, for those issues identified as Category 2 issues in Appendix B to subpart A of this part." 10 CFR 51.53(c)(3)(ii)

"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…." 10 CFR 51.53(c)(3)(iii)

NRC designated 21 issues as Category 2. Sections 4.1 through 4.20 (Section 4.17 addresses 2 issues) address each of the Category 2 issues, beginning with a statement of the issue. As is the case with Category 1 issues, nine Category 2 issues apply to operational features that HNP does not have. In addition, four Category 2 issues apply only to refurbishment activities. If the issue does not apply to HNP, the section explains the basis for inapplicability.

For the 8 Category 2 issues that Progress Energy has determined to be applicable to HNP, the appropriate sections contain the required analyses. These analyses include conclusions regarding the significance of the impacts relative to the renewal of the operating license for HNP and, if applicable, discuss potential mitigative alternatives to the extent required. Progress Energy has identified the significance of the impacts associated with each issue as either small, moderate, or large, consistent with the criteria that NRC established in 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

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

In accordance with National Environmental Policy Act (NEPA) practice, Progress Energy 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).

4.1 WATER USE CONFLICTS (PLANTS WITH COOLING PONDS OR COOLING TOWERS USING MAKEUP WATER FROM A SMALL RIVER WITH LOW FLOW)

NRC

"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." 10 CFR 51.53(c)(3)(ii)(A)

"…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…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 13

The NRC made surface water use conflicts a Category 2 issue because consultations with regulatory agencies indicate that water use conflicts are already a concern at two closed-cycle plants (Limerick and Palo Verde) and may be a problem in the future at other plants. In the GEIS, NRC notes two factors that may cause water use and availability issues to become important for some nuclear power plants that use cooling towers. First, some plants equipped with cooling towers are located on small rivers that are susceptible to droughts or competing water uses. Second, consumptive water loss associated with closed-cycle cooling systems may represent a substantial proportion of the flows in small rivers (NRC 1996, Section 4.3.2.1.).

This issue does not apply to HNP, because as indicated in Section 3.1.2, the plant does not use a cooling pond and does not withdraw makeup water from a small river. As described in Section 3.1.2, HNP employs a closed-cycle cooling system that uses a cooling tower-based heat dissipation system. Cooling tower makeup water is pumped from Harris Reservoir.

4.2 ENTRAINMENT OF FISH AND SHELLFISH IN EARLY LIFE STAGES

NRC

“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…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…entrainment.” 10 CFR 51.53(c)(3)(ii)(B)

“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.” 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 25

The NRC made entrainment of fish and shellfish a Category 2 issue because a number of agencies consulted for the GEIS (NRC 1996) expressed concerns about impacts of entrainment at several plants with once-through cooling systems. One agency also evidenced concern about the possible impact of entrainment losses on anadromous fish populations expanding as the result of restoration efforts.

The issue of entrainment of fish and shellfish in early life stages does not apply to HNP because the plant does not use once-through cooling or a cooling pond heat dissipation system. As discussed in Section 3.1.2, the plant uses a closed-cycle, cooling tower-based heat dissipation system. Harris Reservoir supplies the plant’s cooling tower makeup water.

4.3 IMPINGEMENT OF FISH AND SHELLFISH

NRC

"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…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…impingement…." 10 CFR 51.53(c)(3)(ii)(B)

"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." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 26

The NRC made impingement of fish and shellfish a Category 2 issue because consultations with resource agencies revealed that impingement was an on-going concern at power plants with once-through cooling systems, particularly where populations of anadromous fish are expanding due to restoration efforts (NRC 1996).

The issue of impingement of fish and shellfish in early life stages does not apply to HNP because the plant does not use once-through cooling or a cooling pond heat dissipation system. As discussed in Section 3.1.2, the plant uses a closed-cycle, cooling tower-based heat dissipation system. Harris Reservoir supplies the plant's cooling tower makeup water.

4.4 HEAT SHOCK

NRC

"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) variance in accordance with 40 CFR 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock …." 10 CFR 51.53(c)(3)(ii)(B)

"…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…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 27

The NRC made heat shock a Category 2 issue because ecological research and monitoring at operating nuclear plants suggested that thermal impacts could be moderate or even large at some plants with once-through cooling systems (NRC 1996). Also, the NRC noted that some plants might be forced to increase the temperature of their discharges in order to reduce entrainment and impingement impacts.

As described in Section 3.1.2, HNP employs a cooling tower-based heat dissipation system rather than a once-through or cooling pond-based system. As a consequence, the thermal discharge is limited to a relatively small volume of warm dilution water associated with cooling tower blowdown. Therefore the issue of Heat Shock does not apply.

4.5 GROUNDWATER USE CONFLICTS (PLANTS USING > 100 GPM OF GROUNDWATER)

NRC

"If the applicant's plant…pumps more than 100 gallons (total onsite) of ground water per minute, an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"…Plants that use more than 100 gpm may cause ground-water use conflicts with nearby ground-water users…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 33

NRC made this groundwater use conflict a Category 2 issue because overuse of an aquifer could exceed the natural recharge. Locally, a withdrawal rate of more than 100 gallons per minute (gpm) could create a cone of depression that could extend offsite. This could inhibit the withdrawal capacity of nearby offsite users.

As described in Section 2.3 (Groundwater Resources), the HNP does not use groundwater as domestic or process water. Therefore, the issue of groundwater use conflicts (plants using more than 100 gpm groundwater) does not apply.

4.6 GROUNDWATER USE CONFLICTS (PLANTS USING COOLING TOWERS WITHDRAWING MAKEUP WATER FROM A SMALL RIVER)

NRC

"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...[t]he applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(3)(ii)(A)

"…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…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 34

NRC made this groundwater use conflict a Category 2 issue because consumptive use of withdrawals from small rivers could adversely impact aquatic life, downstream users of the small river, and groundwater-aquifer recharge. This is a particular concern during low-flow conditions and could create a cumulative impact due to upstream consumptive use. Cooling towers and cooling ponds lose flow due to evaporation, which is necessary to cool the heated water before it is discharged to the environment.

The issues of groundwater conflicts stated above do not apply to HNP. Although HNP does use a closed loop system with cooling towers (Section 3.1.2), HNP withdraws makeup water from Harris Reservoir and not from a small river.

4.7 GROUNDWATER USE CONFLICTS (PLANTS USING RANNEY WELLS)

NRC

"If the applicant's plant uses Ranney wells…an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"…Ranney wells can result in potential ground-water depression beyond the site boundary. Impacts of large ground-water withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 35

NRC made this groundwater use conflict a Category 2 issue because large quantities of groundwater withdrawn from Ranney wells could degrade groundwater quality at river sites by induced infiltration of poor-quality river water into an aquifer.

The issue of groundwater use conflicts does not apply to HNP because the plant does not use Ranney wells. As Section 3.1.2 describes, HNP uses cooling towers with Harris Reservoir as the source of makeup water.

4.8 DEGRADATION OF GROUNDWATER QUALITY

NRC

"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." 10 CFR 51.53(c)(3)(ii)(D)

"…Sites with closed-cycle cooling ponds may degrade ground-water quality. For plants located inland, the quality of the ground water in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses…." 10 CFR 51, Subpart A, Appendix B, Table B 1, Issue 39

NRC made degradation of groundwater quality a Category 2 issue because evaporation from closed-cycle cooling ponds concentrates dissolved solids in the water and settles suspended solids. In turn, seepage into the water table aquifer could degrade groundwater quality.

The issue of groundwater degradation does not apply to HNP because the plant does not use cooling ponds. As Section 3.1.2 describes, HNP uses closed-cycle cooling towers for condenser cooling with Harris Reservoir as the source of makeup water.

4.9 IMPACTS OF REFURBISHMENT ON TERRESTRIAL RESOURCES

NRC

The environmental report must contain an assessment of "…the impacts of refurbishment and other license renewal-related construction activities on important plant and animal habitats…." 10 CFR 51.53(c)(3)(ii)(E)

"…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…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 40

"…If no important resources would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant…." NRC 1996

NRC made impacts to terrestrial resources from refurbishment a Category 2 issue, because the significance of ecological impacts cannot be determined without considering site- and project-specific details (NRC 1996). Aspects of the site and project to be ascertained are: (1) the identification of important ecological resources, (2) the nature of refurbishment activities, and (3) the extent of impacts to plant and animal habitats.

The issue of impacts of refurbishment on terrestrial resources is not applicable to HNP because, as discussed in Section 3.2, Progress Energy has no plans for refurbishment or other license-renewal-related construction activities at HNP.

4.10 THREATENED AND ENDANGERED SPECIES

NRC

"Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act." 10 CFR 51.53(c)(3)(ii)(E)

"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." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 49

NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed, and site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued plant operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate federal agency (NRC 1996, Sections 3.9 and 4.1).

Section 2.2 of this Environmental Report describes the aquatic communities in Harris Reservoir. Section 2.4 describes important terrestrial habitats at HNP and along the associated transmission corridors. Section 2.5 discusses threatened or endangered species that occur or may occur in the vicinity of HNP and along associated transmission corridors.

With the exception of the species identified in Section 2.5, Progress Energy is not aware of any threatened or endangered terrestrial species that could occur at HNP or along the associated transmission corridors. Current operations of HNP and Progress Energy vegetation management practices along transmission line rights-of-way do not adversely affect any listed terrestrial species or its habitat (see Section 2.5). Furthermore, plant 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.

Progress Energy wrote to the North Carolina Department of Environment and Natural Resources and the U.S. Fish and Wildlife Service requesting information on any listed species or critical habitats that might occur on the HNP site or along the associated transmission corridors, with particular emphasis on species that might be adversely affected by continued operation over the license renewal period. Agency responses are provided in Appendix C and indicate that license renewal is unlikely to affect any listed species as long as current vegetation management practices are followed.

As discussed in Section 3.2, Progress Energy has no plans to conduct refurbishment or construction activities at HNP 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. Furthermore, because Progress Energy has no plans to alter current operations and resource agencies contacted by Progress Energy evidenced no serious concerns about license renewal impacts, Progress Energy concludes that impacts to threatened or endangered species from license renewal would be SMALL and do not warrant mitigation. Renewal of the HNP license is not expected to result in the taking of any threatened or endangered species. Renewal of the HNP license is not likely to jeopardize the continued existence of any threatened or endangered species or result in the destruction or adverse modification of any critical habitat.

4.11 AIR QUALITY DURING REFURBISHMENT (NON-ATTAINMENT AREAS)

NRC

"…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…." 10 CFR 51.53(c)(3)(ii)(F)

"…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 numbers of workers expected to be employed during the outage…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 50

NRC made impacts to air quality during refurbishment a Category 2 issue because vehicle exhaust emissions could be cause for some concern, and a general conclusion about the significance of the potential impact could not be drawn without considering the compliance status of each site and the number of workers expected to be employed during an outage (NRC 1996). Information needed would include: (1) the attainment status of the plant-site area, and (2) the number of additional vehicles as a result of refurbishment activities.

Air quality during refurbishment is not applicable to HNP because, as discussed in Section 3.2, Progress Energy has no plans for refurbishment at HNP.

4.12 MICROBIOLOGICAL ORGANISMS

NRC

"If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow rate of less than 3.15×10^{12}ft^3/year (9×10^{10}m^3/year), an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided." 10 CFR 51.53(c)(3)(ii)(G)

"…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…." 10 CFR 51, Subpart A, Table B-1, Issue 57

The NRC made impacts on public health from thermophilic organisms a Category 2 issue because there was insufficient data on facilities using cooling ponds, lakes, or canals that discharge to small rivers.

This issue does not apply to HNP because, as indicated in Section 3.1.2, the plant does not use cooling ponds, lakes, or canals (as defined in the GEIS and used in the regulation) and does not discharge to a small river. HNP has a cooling tower-based heat dissipation system that discharges (blowdown) to Harris Reservoir.

4.13 ELECTRIC SHOCK FROM TRANSMISSION-LINE-INDUCED CURRENTS

NRC

The environmental report must contain an assessment of the impact of the proposed action on the potential shock hazard from transmission lines ". ...[i]f 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." 10 CFR 51.53(c)(3)(ii)(H)

"Electrical shock resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electric shock potential at the site." 10 CFR 51, Subpart A, Appendix B, Table B 1, Issue 59

NRC made impacts of electric shock from transmission lines a Category 2 issue because, without a review of each plant's transmission line conformance with the National Electrical Safety Code (NESC; IEEE 1997) criteria, NRC could not determine the significance of the electrical shock potential. In the case of HNP, there have been no previous NRC or NEPA analyses of transmission-line-induced current hazards. Therefore, this section provides an analysis of the plant's transmission lines' conformance with the NESC standard. The analysis is based on computer modeling of induced current under the lines.

Objects located 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 sudden discharge of the capacitive charge through the person's body to the ground. After the initial discharge, a steady-state current can develop of which the magnitude depends on several factors, including the following:

- 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
- the extent to which the object is grounded.

In 1977, the NESC adopted a provision that describes how to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98-kilovolt alternating current to ground[1]. The clearance must limit the induced current [2] due to electrostatic effects 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 3.1.3, there are seven 230-kilovolt lines that were specifically constructed to distribute power from HNP to the electric grid. Progress Energy's analysis of these transmission lines began by identifying the limiting case for each line. The limiting case is the configuration along each line where the potential for current-induced shock would be greatest. Once the limiting case was identified, Progress Energy calculated the electric field strength for each transmission line, then calculated the induced current.

Progress Energy calculated electric field strength and induced current using a computer code called ACDCLINE (Rev. 3.0), produced by the Electric Power Research Institute. The results of this computer program have been field-verified through actual electrostatic field measurements by several utilities. The input parameters included the design features of the limiting-case scenario, the NESC requirement that line sag be determined at 120ºF conductor temperature, and the maximum vehicle size under the lines as a tractor-trailer.

The analysis determined that none of the transmission lines has the capacity to induce as much as five milliamperes in a vehicle parked beneath the lines. Therefore, the transmission line designs conform to the NESC provisions for preventing electric shock from induced current. The results for each transmission line are provided in Table 4-1. Details of the analysis, including the input parameters for each line's limiting case, can be found in TtNUS (2004).

Progress Energy surveillance and maintenance procedures provide assurance that design ground clearances will not change. These procedures include routine aerial inspection approximately every six months, which 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 conducted once every two years include examination for clearance at questionable locations, integrity of structures, and surveillance for dead or diseased trees that might fall on the transmission lines. Problems noted during any inspection are brought to the attention of the appropriate organization(s) for corrective action.

Progress Energy's assessment under 10 CFR 51 concludes that electric shock is of SMALL significance for the HNP transmission lines. Due to the small significance of the

[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.

issue, mitigation measures, such as installing warning signs at road crossings or increasing clearances, are not warranted.

4.14 HOUSING IMPACTS

NRC

The environmental report must contain "...[a]n assessment of the impact of the proposed action on housing availability…" 10 CFR 51.53(c)(3)(ii)(I)

"…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 areas with growth control measures that limit housing development…." 10 CFR 51, Subpart A, Table B-1, Issue 63

"...[S]mall impacts result when no discernible change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and no housing construction or conversion occurs…." (NRC 1996)

NRC made housing impacts a Category 2 issue because impact magnitude depends on local conditions that NRC could not predict for all plants at the time of GEIS publication (NRC 1996). Local conditions that need to be ascertained are: (1) population categorization as small, medium, or high and (2) applicability of growth control measures.

Refurbishment activities and continued operations could potentially produce housing impacts due to increased staffing. As described in Section 3.2, HNP does not plan to perform refurbishment. Progress Energy concludes that there would be no refurbishment-related impacts to area housing and no analysis is therefore required. Accordingly, the following discussion focuses on impacts of continued HNP operations on local housing availability.

Sections 2.6 and 2.8 indicate that HNP is located in a high population area that is not subject to growth control measures that limit housing development. Using the NRC regulatory criteria at 10 CFR 51, Subpart A, Table B-1, Issue 63, HNP license renewal housing impacts would be expected to be small. Continued operations could result in housing impacts due to increased staffing. However, Progress Energy estimates that no additional workers would be needed to support HNP operations during the license renewal term (Section 3.4). Progress Energy concludes that since there would be no increase in staffing, no housing impacts would be experienced and, therefore, the appropriate characterization of HNP license renewal housing impacts is SMALL.

4.15 PUBLIC UTILITIES: PUBLIC WATER SUPPLY AVAILABILITY

NRC

The environmental report must contain "…an assessment of the impact of population increases attributable to the proposed project on the public water supply." 10 CFR 51.53(c)(3)(ii)(I)

"An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 65

"Impacts on public utility services are considered small if little or no change occurs in the 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 quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (NRC 1996)

NRC made public utility impacts a Category 2 issue because an increased problem with water availability, resulting from pre-existing water shortages, could occur in conjunction with plant demand and plant-related population growth (NRC 1996). Local information needed would include: (1) a description of water shortages experienced in the area, and (2) an assessment of the public water supply system's available capacity.

NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. HNP is registered with North Carolina as a user of water from Harris Reservoir for process, service, and domestic use. HNP provides onsite treatment for sanitary and process water and discharges effluent to Harris Reservoir under NPDES permit requirements. Progress Energy has identified no operational changes during the HNP license renewal term that would alter the plant water use source.

Because HNP has no groundwater production wells and obtains no drinking water from public water suppliers, it has no effect on local or regional public drinking water supply capacities. Similarly, the fact that HNP treats its own sanitary and process wastes means that it has no effect on the capacities or availability of local or regional sewage treatment facilities.

4.16 EDUCATION IMPACTS FROM REFURBISHMENT

NRC

The environmental report must contain "…[a]n assessment of the impact of the proposed action on…public schools (impacts from refurbishment activities only) within the vicinity of the plant…." 10 CFR 51.53(c)(3)(ii)(I)

"…Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors…." 10 CFR 51, Subpart A, Table B-1, Issue 66

"…[S]mall impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts are generally associated with 4 to 8 percent increases in enrollment. Impacts are considered moderate if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service….Large impacts are associated with project-related enrollment increases above 8 percent…." (NRC 1996)

NRC made refurbishment-related impacts to education a Category 2 issue because site- and project-specific factors determine the significance of impacts (NRC 1996). Local factors to be ascertained include: (1) project-related enrollment increases and (2) status of the student/teacher ratio.

The issue of education impacts from refurbishment is not applicable to HNP because, as discussed in Section 3.2, Progress Energy has no plans for refurbishment or other license-renewal-related construction activities at HNP.

4.17 OFFSITE LAND USE

4.17.1 OFFSITE LAND USE - REFURBISHMENT

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on... land-use... (impacts from refurbishment activities only) within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(I)

"…Impacts may be of moderate significance at plants in low population areas…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 68

"…[I]f plant-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile, and at least one urban area with a population of 100,000 or more within 50 miles…." (NRC 1996, Section 3.7.5)

This issue is not applicable to HNP because, as Section 3.2 discusses, Progress Energy has no plans for refurbishment at HNP.

4.17.2 OFFSITE LAND USE – LICENSE RENEWAL TERM

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on …land-use…within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(I)

"Significant changes in land use may be associated with population and tax revenue changes resulting from license renewal." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 69

"…[I]f plant-related population growth is less than five percent of the study area's total population, off-site land-use changes would be small…"

(NRC 1996, Section 3.7.5)

"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." (NRC 1996, Section 4.7.4.1)

NRC made impacts to offsite land use during the license renewal term a Category 2 issue because land-use changes may be perceived as beneficial by some community members and adverse by others. Therefore, NRC could not assess the potential significance of site-specific offsite land-use impacts (NRC 1996, Section 4.7.4.1). Site-specific factors to be considered in an assessment of new tax-driven land-use impacts include: (1) the size of plant-related population growth compared to the area's total population, (2) the size of the plant's tax payments relative to the community's total revenue, (3) the nature of the community's existing land-use pattern, and (4) the extent to which the community already has public services in place to support and guide development.

The GEIS presents an analysis of offsite land use for the renewal term that is characterized by two components: population-driven and tax-driven impacts (NRC 1996, Section 4.7.4.1).

Population-Related Impacts

Based on the GEIS case-study analysis, NRC concluded that all new population-driven land-use changes during the license renewal term at all nuclear plants would be small. Population growth caused by license renewal would represent a much smaller percentage of the local area's total population than the percentage presented by operations-related growth (NRC 1996, Section 4.7.4.2).

Tax-Revenue-Related Impacts

Tax Payment Significance

NRC has determined that the significance of tax payments as a source of local government revenue would be large if the payments are greater than 20 percent of revenue, moderate if the payments are between 10 and 20 percent of revenue, and small if the payments are less than 10 percent of revenue (NRC 1996, Section 3.7.3).

Land Use Significance

NRC defined the magnitude of land-use changes as follows (NRC 1996, 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.

NRC further determined that, if a plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land-use changes would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development.

Table 2-4 provides a comparison of total tax payments made by HNP to Wake County and Wake County's annual property tax revenues. For the four-year period from 2001 through 2004, HNP's tax payments to Wake County have represented 1.9 to 2.6 percent of the County's total annual property tax revenues. Using NRC's criteria, HNP's tax payments are of small significance to Wake County.

As stated in Chapter 2, North Carolina has experienced significant population and economic growth since the early 1990s. The state has been one of the fastest growing states in the nation, with most population growth through in-migration (Brookings Institution 2000). The main reason is a quality of life that as is supported by the state's economy, environment, cultural resources and activities, schools, colleges, universities, and recreational opportunities. North Carolina's metropolitan areas frequently show up at the top of lists of the nation's best places to live and work and, Raleigh-Durham in particular (Brookings Institution 2000). As a result, Wake County has experienced rapid population growth over the last several decades. From 1980 to 2000, Wake County's population growth more than doubled, growing from 301,327 to 627,846. The county's population is expected to exceed one million by the year 2020 and approach 1.5 million by 2040 (see Chapter 2, Table 2.4).

The size of the surrounding population and the level of commercial, industrial, and educational activity in this region supports the fact that HNP has a small impact on the local economy and tax base (see Sections 2.7 and 2.8). Any increase in license renewal-related population (assuming 100 percent in-migration) would be far less than one percent of the surrounding population. Similarly, any increase in tax revenues received by local taxing jurisdictions due to an increase in license renewal employment would be indiscernible when compared with current revenues. The local tax base is very large and tax payments made by HNP and its employees are comparatively small (see Section 2.7). Any changes to the infrastructure of Wake County and its municipalities would be attributable to the large population immigration already experienced by the County, and a large pool of residential, industrial, and commercial tax payers.

As described in Section 3.2, Progress Energy does not anticipate refurbishment or license renewal-related construction during the license renewal period. Therefore, Progress Energy does not anticipate any increase in the assessed value of HNP due to refurbishment-related improvements, nor any related tax-increase-driven changes to offsite land-use and development patterns.

Conclusion

Progress Energy concludes that land-use impacts would be SMALL and that mitigation for land-use impacts during the license renewal term would not be warranted.

4.18 TRANSPORTATION

NRC

The environmental report must "...assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license." 10 CFR 51.53(c)(3)(ii)(J)

"Transportation impacts…are generally expected to be of small significance. However, the increase in traffic associated with the additional workers and local road and traffic control conditions may lead to impacts of moderate or large significance at some sites." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 70

"Small impacts would be associated with a free flowing traffic stream where users are unaffected by the presence of other users (level of service A) or stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished (level of service B)." (NRC 1996)

NRC made impacts to transportation a Category 2 issue because impact significance is determined primarily by road conditions existing at the time of the project, which NRC could not forecast for all facilities (NRC 1996). Local road conditions to be ascertained are: (1) level of service conditions, and (2) incremental increases in traffic associated with refurbishment activities and license renewal staff.

As described in Section 3.2, no refurbishment is planned and no refurbishment impacts to local transportation are therefore anticipated. As described in Section 3.4, no additional license renewal employment increment is expected. Therefore, Progress Energy expects license-renewal impacts to transportation to be small.

4.19 HISTORIC AND ARCHAEOLOGICAL RESOURCES

NRC

The environmental report must contain an assessment of "…whether any historic or archaeological properties will be affected by the proposed project." 10 CFR 51.53(c)(3)(ii)(K)

"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." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71

"Sites are considered to have small impacts to historic and archaeological resources if (1) the State Historic Preservation Officer (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about altered historic character; and (3) if the conditions associated with moderate impacts do not occur." (NRC 1996, Section 3.7.7)

NRC made impacts to historic and archaeological resources a Category 2 issue, because determinations of impacts to historic and archaeological resources are site-specific in nature and the National Historic Preservation Act mandates that impacts must be determined through consultation with the State Historic Preservation Officer (NRC 1996, Section 4.7.7.3).

As a result of the cultural resources investigations for the construction and operation FESs for HNP, the AEC/NRC staff ultimately concluded that HNP would have no impacts on cultural resources (See Section 2.11).

As discussed in Section 3.2, Progress Energy has no refurbishment plans and no refurbishment-related impacts are anticipated. Progress Energy is not aware of any historic or archaeological resources that have been affected to date by HNP operations, including operation and maintenance of transmission lines. Progress Energy is aware, however, that the site vicinity and the surrounding environs have potential for containing cultural resources. Additionally, Progress Energy is aware of cultural resources that are within or near HNP boundaries. Because Progress Energy is aware of the potential for the discovery of cultural resources during land-disturbing activities at its facilities and along its transmission line corridors, it has developed a cultural resources guidelines document to protect those resources (Progress Energy 2004). Because Progress

Energy has no plans to construct new license renewal related facilities at HNP during the license renewal term, and because the policies and procedures established in the cultural resources guidelines document should protect any resources that are discovered, Progress Energy concludes that operation of generation and transmission facilities over the license renewal term would not impact cultural resources; hence, no mitigation would be warranted.

4.20 SEVERE ACCIDENT MITIGATION ALTERNATIVES

NRC

The environmental report must contain a consideration of alternatives to mitigate severe accidents "…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 environment assessment..." 10 CFR 51.53(c)(3)(ii)(L)

"…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…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76

Section 4.20 summarizes Progress Energy's analysis of alternative ways to mitigate the impacts of severe accidents. Appendix E provides a detailed description of the severe accident mitigation alternatives (SAMA) analysis.

The term "accident" refers to any unintentional event (i.e., outside the normal or expected plant operation envelope) that results in the release or a potential for release of radioactive material to the environment. NRC categorizes accidents as "design basis" or "severe." Design basis accidents are those for which the risk is great enough that NRC requires plant design and construction to prevent unacceptable accident consequences. Severe accidents are those that NRC considers too unlikely to warrant design controls.

NRC concluded in its license renewal rulemaking that the unmitigated environmental impacts from severe accidents met its Category 1 criteria. However, NRC made consideration of mitigation alternatives a Category 2 issue because not all plants had completed ongoing regulatory programs related to mitigation (e.g., individual plant examinations and accident management). Site-specific information to be presented in the license renewal environmental report includes: (1) potential SAMAs; (2) benefits, costs, and net value of implementing potential SAMAs; and (3) sensitivity of analysis to changes in key underlying assumptions.

Progress Energy maintains a probabilistic safety assessment model to use in evaluating the most significant risks of radiological release from HNP fuel into the reactor and from the reactor into the containment structure. For the SAMA analysis, Progress Energy used the model output as input to an NRC-approved model that calculates economic costs and dose to the public from hypothesized releases from the containment structure into the environment. Then, using NRC regulatory analysis techniques, Progress Energy calculated the monetary value of the unmitigated HNP severe accident risk. The result represents the monetary value of the base risk of dose to the public and worker, offsite and onsite economic costs, and replacement power. This value became a cost/benefit-screening tool for potential SAMAs; a SAMA whose cost of implementation exceeded the base risk value could be rejected as being not cost-beneficial.

Progress Energy used industry, NRC, and HNP-specific information to create a list of 22 SAMAs for consideration. Progress Energy analyzed this list and screened out SAMAs that would not apply to the HNP design, that Progress Energy had already implemented, or that would achieve results that Progress Energy had already achieved by other means. Progress Energy prepared cost estimates for the remaining SAMAs and used the base risk value to screen out SAMAs that would not be cost-beneficial.

Progress Energy calculated the risk reduction that would be attributable to each of the remaining SAMAs (assuming SAMA implementation) and re-quantified the risk value. The difference between the base risk value and the SAMA-reduced risk value became the averted risk, or the value of implementing the SAMA. Progress Energy then performed a cost/benefit comparison for these SAMAs using this averted risk value and the corresponding cost estimates.

Progress Energy performed additional analyses to evaluate how the SAMA analysis would change if certain key parameters were changed. The results of the uncertainty analysis are discussed in Appendix E.

Based on the results of this SAMA analysis, Progress Energy concludes that three potentially cost-beneficial options exist to reduce plant risk that could be examined further, but none are related to plant aging. Nevertheless, Progress Energy will be evaluating these SAMAs as part of the existing risk management program. Based on this action and the results of the SAMA analysis, Progress Energy concludes that further mitigation of severe accident risks would not be warranted.

TABLE 4-1
RESULTS OF INDUCED CURRENT ANALYSIS

Transmission Line	Limiting Case Induced Current* (milliamperes)
Asheboro[1]	<1.1
Cape Fear North	<1.6
Cape Fear South	<1.1
Cary Regency Park[2]	<1.3
Erwin	<1.4
Fayetteville[3]	<1.7
Wake	<3.1

*"Less-than" values are reported because the calculation was performed for a 212-degree Fahrenheit sag instead of the prescribed 120-degree sag.
[1]now terminates at Siler City
[2]now terminates at Apex
[3]now terminates at Ft. Bragg

4.21 REFERENCES

Brookings Institution. 2000. Adding It Up: Growth Trends and Policies in North Carolina. Center on Urban and Metropolitan Policy. Available online at http://www.brookings.edu/metro/ncreportexsum.htm. Accessed December 10, 2004.

IEEE (Institute of Electrical and Electronics Engineers). 1997. National Electrical Safety Code, 1997 Edition, New York, New York.

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

Progress Energy. 2004. Archaeological and Cultural Resources. Document Number: EVC-SUBS-00105. Revision 0. October.

TTNUS (Tetra Tech NUS). 2004. Calculation Package for Shearon Harris Transmission Lines Induced Current Analysis. Aiken, South Carolina. November 30.

5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

5.1 DISCUSSION

NRC

"…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 U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants and provides for license renewal, requiring a license renewal application that includes an environmental report (10 CFR 54.23). NRC regulations, 10 CFR 51, prescribe the environmental report content and identify the specific analyses the applicant must perform. In an effort to streamline the environmental review, NRC has resolved most of the environmental issues generically and only requires an applicant's analysis of the remaining issues.

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)]. The purpose of this requirement is to alert NRC staff to such information, so the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) conclusions (NRC 1996).

Progress Energy expects that new and significant information would include:

- Information that identifies a significant environmental issue not covered in the GEIS and codified in the regulation, or
- Information that was not covered in the GEIS analyses and that leads to an impact finding different from that codified in the regulation.

NRC does not specifically define the term "significant." For the purpose of its review, Progress Energy used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act authorizes CEQ to establish implementing regulations for federal agency use. NRC requires license renewal applicants to provide NRC with input, in the form of an environmental report, that NRC will use to meet National Environmental Policy Act 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). Progress Energy expects that moderate or large impacts, as defined by NRC, would be significant. Chapter 4 presents the NRC definitions of "moderate" and "large" impacts.

The new and significant assessment that Progress Energy conducted during preparation of this license renewal application included: (1) interviews with Progress Energy subject experts on the validity of the conclusions in the GEIS as they relate to Shearon Harris Nuclear Plant (HNP), (2) an extensive review of documents related to environmental issues at HNP, and (3) correspondence with state and federal agencies to determine if the agencies had concerns not addressed in the GEIS. Progress Energy notes that state and federal regulatory agencies routinely inspect HNP facilities and records as part of their oversight of the plant and its operation and to ensure that permit conditions are met. These inspections (and less frequent permit reviews) have identified no new and significant information.

Progress Energy is aware of no new and significant information regarding the environmental impacts of HNP license renewal.

5.2 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1996. Public Comments on the Proposed 10 CFR 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response. Volumes 1 and 2. NUREG-1529. Washington, DC. May.

6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

Progress Energy has reviewed the environmental impacts of renewing the Shearon Harris Nuclear Plant (HNP) operating license and has concluded that impacts would be small and would not require mitigation. This environmental report documents the basis for Progress Energy's conclusion. Chapter 4 incorporates by reference U.S. Nuclear Regulatory Commission (NRC) findings for the 57 Category 1 issues that apply to HNP, all of which have impacts that are small (Table A-1). The rest of Chapter 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 HNP license renewal would have on resources associated with Category 2 issues.

6.2 MITIGATION

NRC

“The report must contain a consideration of alternatives for reducing adverse impacts…for all Category 2 license renewal issues…” 10 CFR 51.53(c)(3)(iii)

“The environmental report shall include an analysis that considers and balances…alternatives available for reducing or avoiding adverse environmental effects…” 10 CFR 51.45(c) as incorporated by 10 CFR 51.53(c)(2) and 10 CFR 51.45(c)

Impacts of license renewal are small and would not require mitigation. Current operations include monitoring activities that would continue during the license renewal term. Progress Energy performs routine monitoring to ensure the safety of workers, the public, and the environment. These activities include the biological monitoring program, radiological environmental monitoring program, air monitoring, effluent chemistry monitoring, and effluent toxicity testing. These monitoring programs ensure that the plant’s permitted emissions and discharges are within regulatory limits and any unusual or off-normal emissions/discharges would be quickly detected, mitigating potential impacts.

6.3 UNAVOIDABLE ADVERSE IMPACTS

NRC

The environmental report shall discuss any "...adverse environmental effects which cannot be avoided should the proposal be implemented..." 10 CFR 51.45(b)(2) as adopted by 10 CFR 51.53(c)(2)

This environmental report adopts by reference NRC findings for applicable Category 1 issues, including discussions of any unavoidable adverse impacts (Table A-1). Progress Energy examined 21 Category 2 issues and identified the following unavoidable adverse impacts of license renewal:

- The 523-foot cooling tower and plume are visible from offsite. This visual impact will continue during the license renewal term.
- Procedures for the disposal of sanitary, solid, chemical, and radioactive wastes are intended to reduce adverse impacts from these sources to acceptably low levels. A small impact will be present as long as the plant is in operation. Solid radioactive wastes are a product of plant operations and long-term disposal of these materials must be considered.
- Operation of HNP results in a very small increase in radioactivity in the air and water. However, fluctuations in natural background radiation may be expected to exceed the small incremental increase in dose to the local population. Operation of HNP also establishes a very low probability risk of accidental radiation exposure to inhabitants of the area.
- Small numbers of adult and juvenile fish are impinged on the traveling screens at the emergency service water and cooling tower makeup intake structures.
- Some larval fish are entrained at the emergency service water and cooling tower makeup intake structures.

6.4 IRREVERSIBLE AND IRRETRIEVABLE RESOURCE COMMITMENTS

NRC

The environmental report shall discuss any "...irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented…" 10 CFR 51.45(b)(5) as adopted by 10 CFR 51.53(c)(2)

Continued operation of HNP for the license renewal term will result in irreversible and irretrievable resource commitments, including the following:

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

6.5 SHORT-TERM USE VERSUS LONG-TERM PRODUCTIVITY OF THE ENVIRONMENT

NRC

The environmental report shall discuss the "...relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity..." 10 CFR 51.45(b)(4) as adopted by 10 CFR 51.53(c)(2)

The current balance between short-term use and long-term productivity at the HNP site was established with the decision to construct the plant. The Revised Final Environmental Statement related to Construction (RFES; AEC 1974) evaluated the impacts of constructing and operating HNP in Wake and Chatham Counties, North Carolina. The greatest impact is the loss of terrestrial resources to Harris Reservoir, a 4,150 acre reservoir constructed to provide cooling tower makeup water to the reactor. The loss of productivity of forests and farmland covered by the reservoir could be long long-term if the reservoir remains after the plant ceases operations, however, this long-term loss likely would be offset by the recreational opportunities created by the lake.

After decommissioning, many environmental disturbances would cease and some restoration of the natural habitat would occur. Thus, the "trade-off" between the production of electricity and changes in the local environment is reversible to some extent.

Experience with other experimental, developmental, and commercial nuclear plants has demonstrated the feasibility of decommissioning and dismantling such plants sufficiently to restore a site to its former use. The degree of dismantlement, will take into account the intended new use of the site and a balance among health and safety considerations, salvage values, and environmental impact. However, decisions on the ultimate disposition of these lands have not yet been made. Continued operation for an additional 20 years would not increase the short-term productivity impacts described here.

TABLE 6-1
ENVIRONMENTAL IMPACTS RELATED TO
LICENSE RENEWAL AT HNP

No.	Issue	Environmental Impact
	Surface Water Quality, Hydrology, and Use (for all plants)	
13	Water use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	**None.** This issue does not apply. HNP does not use cooling ponds or cooling towers that withdraw makeup water from a small river with low flow.
	Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)	
25	Entrainment of fish and shellfish in early life stages	**Small.** HNP uses a closed-cycle cooling system with a cooling tower which constitutes compliance with CWA Section 316(b) requirements to provide best technology available to minimize impacts. Small numbers of larval fish are entrained with cooling tower makeup.
26	Impingement of fish and shellfish	**Small.** HNP uses a closed-cycle cooling system. Small numbers of fish are impinged with cooling tower makeup.
27	Heat shock	**None.** HNP uses a closed-cycle cooling system which constitutes compliance with CWA Section 316(a) to minimize heat shock.
	Groundwater Use and Quality	
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	**None.** HNP uses no groundwater.
34	Groundwater use conflicts (plants using cooling towers or cooling ponds withdrawing makeup water from a small river)	**None.** This issue does not apply because HNP does not use cooling ponds or cooling towers that withdraw makeup water from a small river.
35	Groundwater use conflicts (Ranney wells)	**None.** This issue does not apply because HNP does not use Ranney wells.
39	Groundwater quality degradation (cooling ponds at inland sites)	**None**. This issue does not apply because HNP does not use cooling ponds.
	Terrestrial Resources	
40	Refurbishment impacts	**None.** No impacts are expected because HNP will not undertake refurbishment.
	Threatened or Endangered Species	
49	Threatened or endangered species	**Small.** With the exception of bald eagles, which forage around Harris Reservoir and have built one nest on its shore, there are no known occurrences of federally threatened or endangered species at HNP. One state-endangered species, Carolina grass-of-parnassus, occurs on a transmission corridor. Progress Energy has no plans to change current natural resource management practices, and resource agencies contacted by Progress Energy expressed no concerns about threatened or endangered species.

TABLE 6-1
ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT HNP (Continued)

No.	Issue	Environmental Impact
		Air Quality
50	Air quality during refurbishment (non-attainment and maintenance areas)	**None.** No impacts are expected because HNP will not undertake refurbishment.
		Human Health
57	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	**None.** HNP does not have cooling canals, cooling towers, or cooling ponds that discharge to a small river.
59	Electromagnetic fields, acute effects (electric shock)	**Small.** The largest modeled induced current under the HNP lines is substantially less than the 5-milliampere limit. Therefore, the HNP transmission lines conform to the National Electrical Safety Code provisions for preventing electric shock from induced current.
		Socioeconomics
63	Housing impacts	**Small.** HNP anticipates no additional employment, thus negligible housing impacts.
65	Public services: public utilities	**Small.** HNP anticipates no additional plant water use or employment, thus little impact on public utilities.
66	Public services: education (refurbishment)	**None.** No impacts are expected because HNP will not undertake refurbishment.
68	Offsite land use (refurbishment)	**None.** No impacts are expected because HNP will not undertake refurbishment.
69	Offsite land use (license renewal term)	**Small.** No plant-induced changes to offsite land use are expected from license renewal. Impacts from continued operation would be positive.
70	Public services: transportation	**Small.** HNP anticipates no additional employment, thus no increase in traffic.
71	Historic and archeological resources	**Small.** Continued operation of HNP would not require construction at the site or new transmission lines. Therefore, license renewal would have little or no effect on historic or archeological resources.
		Postulated Accidents
76	Severe accidents	**Small.** Progress Energy identified potentially cost-beneficial SAMAs that offer a level of risk reduction. However, as these SAMAs do not relate to aging management during the license renewal term, they need not be implemented as part of license renewal.

6.6 REFERENCES

AEC (U.S. Atomic Energy Commission). 1974. Revised Final Environmental Statement related to the construction of Shearon Harris Nuclear Power Plant Units 1, 2, 3, and 4. Carolina Power and Light Company. Docket Nos. 50-400 50-401, 50-402, and 50-403. Directorate of Licensing. March. Washington, DC.

7.0 ALTERNATIVES TO THE PROPOSED ACTION

NRC

The environmental report shall discuss "Alternatives to the proposed action.…" 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2).

"...The report is not required to include discussion of need for power or economic costs and benefits of ... alternatives to the proposed action except insofar as such costs and benefits are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation...." 10 CFR 51.53(c)(2).

"While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable…" (NRC 1996a).

"…The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area...." (NRC 1996b).

Chapter 7 identifies actions that Progress Energy might take, and associated environmental impacts, if the U.S. Nuclear Regulatory Commission (NRC) chooses not to renew the plant's operating license. The chapter also addresses actions that Progress Energy has considered, but would not take, and identifies Progress Energy bases for determining that such actions would be unreasonable.

Progress Energy divided its alternatives discussion into two categories, "no-action" and "alternatives that meet system generating needs." In considering the level of detail and analysis that it should provide for each category, Progress Energy relied on the NRC decision-making standard for license renewal:

> "…the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decision makers would be unreasonable." [10 CFR 51.95(c)(4)].

Progress Energy has determined that the environmental report would support NRC decision making as long as the document provides sufficient information to clearly indicate whether an alternative would have a smaller, comparable, or greater environmental impact than the proposed action. Providing additional detail or analysis serves no function if it only brings to light additional adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which provide that the consideration of alternatives (including the proposed action) should enable reviewers to evaluate their comparative merits (40 CFR 1500-1508). Progress Energy believes that Chapter 7 provides sufficient detail about alternatives to establish the basis for necessary comparisons to the Chapter 4 discussion of impacts from the proposed action.

In characterizing environmental impacts from alternatives, Progress Energy has used the same definitions of “small,” “moderate,” and “large” that are presented in the introduction to Chapter 4.

7.1 NO-ACTION ALTERNATIVE

Progress Energy uses “no-action alternative” to refer to a scenario in which NRC does not renew the HNP operating license. Components of this alternative include replacing the generating capacity of HNP and decommissioning the facility, as described below.

Progress Energy supplies as much as 59.5 terawatt hours of electricity to its 1.4-million customer base in North and South Carolina (Progress Energy 2006a). A terawatt hour is one billion kilowatt hours. HNP provides approximately 7.9 terawatt hours annually or about 13 percent of the electricity Progress Energy provides to its customers in the Carolinas (EIA 2006a). Progress Energy believes that any alternative would be unreasonable that did not include replacing this capacity. Replacement could be accomplished by (1) building new generating capacity, (2) purchasing power from the wholesale market, or (3) reducing power requirements through demand reduction. Section 7.2.1 describes each of these possibilities in detail, and Section 7.2.2 describes environmental impacts from feasible alternatives.

The Generic Environmental Impact Statement (GEIS) (NRC 1996a) defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. NRC-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, Progress Energy would continue operating HNP until the current license expires, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of a larger reactor (the “reference” pressurized-water reactor is the 1,175-megawatts-electrical [MWe] Trojan Nuclear Plant). This description is comparable to decommissioning activities that Progress Energy would conduct at HNP.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include: occupational and public radiation dose; impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated in the Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities; Supplement 1 (NRC 2002a, Section 4.3.8) 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. Progress Energy adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

Progress Energy notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. Progress Energy will have to decommission HNP regardless of the NRC decision on license renewal; license renewal would only postpone decommissioning for another 20 years. NRC has established in the GEIS that the timing of decommissioning operations does not substantially influence the environmental impacts of decommissioning. Progress Energy adopts by reference the NRC findings (10 CFR 51, Appendix B, Table B-1, Decommissioning) to the effect that delaying decommissioning until after the renewal term would have small environmental impacts. The discriminators between the proposed action and the no-action alternative lie within the choice of generation replacement options to be part of the no-action alternative. Section 7.2.2 analyzes the impacts from these options.

Progress Energy concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those occurring following license renewal, as identified in the GEIS (NRC 1996a) and in the decommissioning generic environmental impact statement (NRC 2002a). These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

7.2 ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

Although HNP is in North Carolina, about 12.6 percent of Progress Energy's electrical energy is generated in South Carolina (EIA 2006b). Therefore, power generation in both states is of interest for this evaluation. The current mix of power generation options in the Carolinas is one indicator of what have been considered to be feasible alternatives within the Progress Energy service area.

North Carolina's electric utilities had a total generating capacity of 23,671 MWe in 2004. As Figure 7-1 indicates, this capacity includes units fueled by coal (52.8 percent); nuclear (20.9 percent); dual-fired (11.7 percent); hydroelectric (7.0 percent); gas (5.9 percent); and petroleum (1.7 percent). Approximately 3,439 MWe (12.7 percent of the State's generating capacity) was from non-utility sources in 2004 (EIA 2006c). North Carolina's non-utility generators also use a variety of energy sources.

In 2004, South Carolina's electric utilities had a total generating capacity of 20,406 MWe. As Figure 7-2 indicates, this capacity includes units fueled by nuclear (31.7 percent); coal (29.2 percent); hydroelectric (17.5 percent); dual-fired (13.4 percent); gas (4.8 percent); petroleum (3.4 percent) and renewable (0.01 percent). Approximately 1,789 MWe (8.1 percent of the State's generating capacity) was from non-utility sources (EIA 2006c). South Carolina's non-utility generators also use a variety of energy sources.

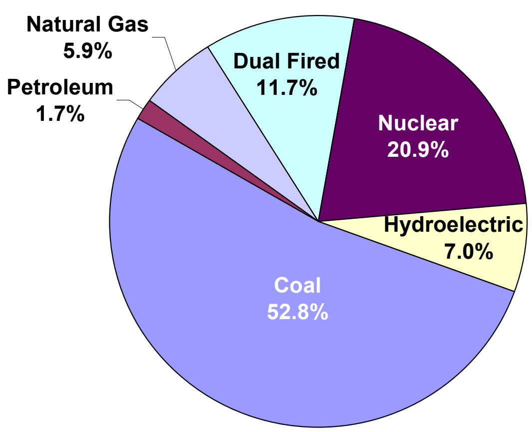

FIGURE 7-1. NORTH CAROLINA UTILITY GENERATING CAPACITY, 2004

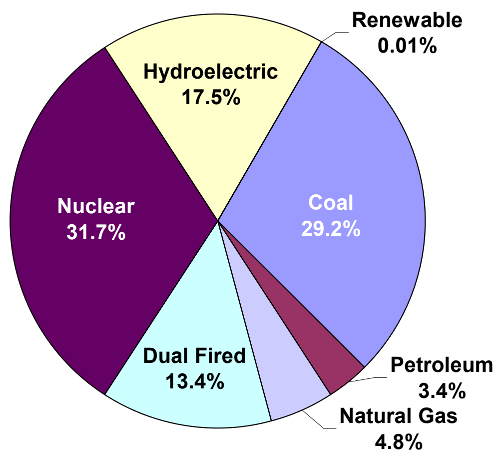

FIGURE 7-2. SOUTH CAROLINA UTILITY GENERATING CAPACITY, 2004

Based on 2004 generation data, North Carolina utility companies produced about 118 terawatt hours of electricity. As shown in Figure 7-3, utilities' generation by fuel type in North Carolina was dominated by coal (60.8 percent), followed by nuclear (33.9 percent), hydroelectric (3.4 percent), gas (1.7 percent), and petroleum (0.2 percent) (EIA 2006c).

Based on 2004 generation data, South Carolina's utility companies produced about 94 terawatt hours of electricity. As Figure 7-4 depicts, utilities' generation by fuel type in South Carolina was dominated by nuclear (54.2 percent), followed by coal (40.8 percent), gas (2.7 percent), hydroelectric (1.3 percent), petroleum (0.7 percent) and renewable (0.3 percent) (EIA 2006c).

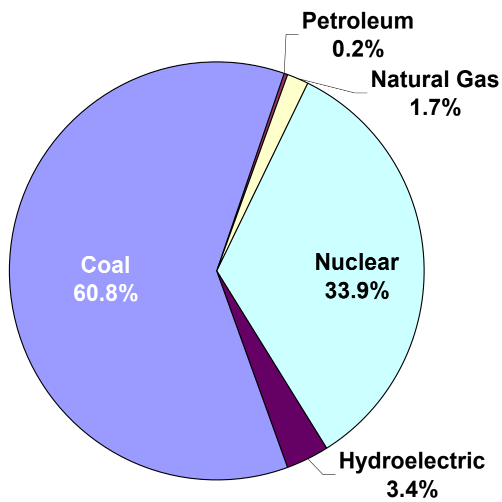

FIGURE 7-3. NORTH CAROLINA UTILITY GENERATION BY FUEL TYPE, 2004

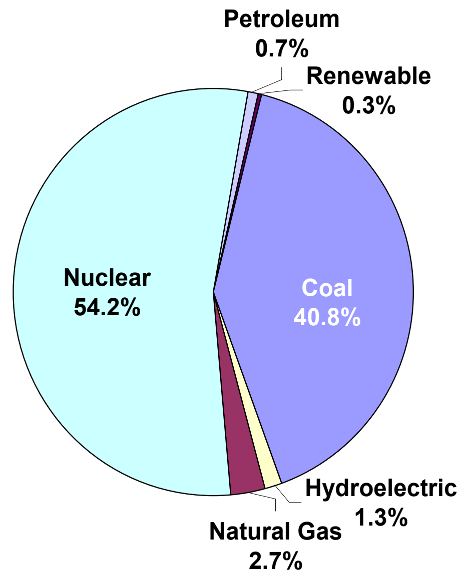

FIGURE 7-4. SOUTH CAROLINA UTILITY GENERATION BY FUEL TYPE, 2004

The difference between capacity and utilization is the result of optimal usage. For example, in North Carolina, nuclear energy represented 20.9 percent of utilities' installed capacity, but produced 33.9 percent of the electricity generated by utilities (EIA 2006c). This reflects North Carolina's reliance on nuclear energy as a base-load generating source. South Carolina also shows a preference for nuclear energy as a base-load generating source, with nuclear energy representing 31.7 percent of utilities' installed capacity and 54.2 percent of the electricity generated by utilities (EIA 2006c).

Progress Energy summer net generation capability (in North and South Carolina), including jointly owned capacity, was 12,519 MWe in 2005. As Figure 7-5 indicates 42.2 percent of Progress Energy's capacity was from coal, 27.8 percent from nuclear, 26.2 percent from dual-fired, and 1.7 percent from hydroelectric (Progress Energy 2006a). The Progress Energy share of energy supplied by these units in 2005 was 59.5 terawatt hours. Figure 7-6 illustrates the Progress Energy generation by fuel type in the Carolinas. Coal power generated 49.6 percent of the total electricity produced, nuclear 45.1 percent, natural gas generated 3.8 percent, hydroelectric generated 1.2 percent, and petroleum generated 0.3 percent (EIA 2006b).

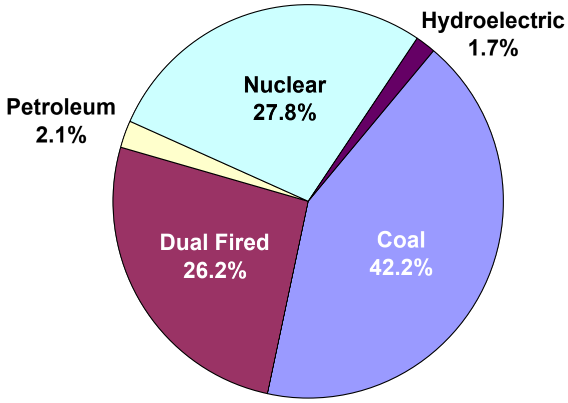

FIGURE 7-5. PROGRESS ENERGY GENERATING CAPACITY IN NORTH AND SOUTH CAROLINA, 2005

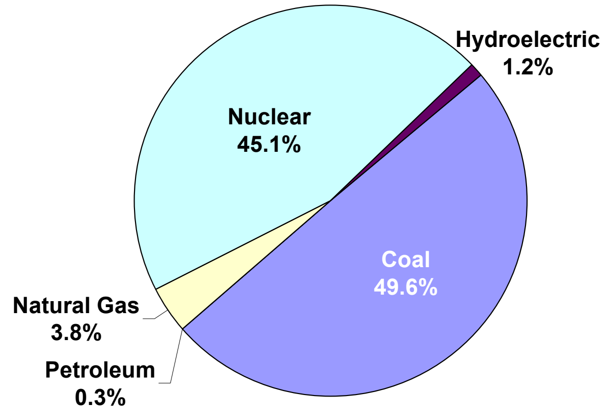

FIGURE 7-6. PROGRESS ENERGY GENERATION BY FUEL TYPE IN NORTH AND SOUTH CAROLINA, 2005

Figures 7-5 and 7-6 illustrate Progress Energy's reliance on nuclear capacity as a base-load generating source in North and South Carolina. Nuclear energy represented 26 percent of Progress Energy's 2005 installed capacity in the Carolinas, but produced 45.1 percent of the electricity generated (Progress Energy 2006a and EIA 2006b).

7.2.1 ALTERNATIVES CONSIDERED

Technology Choices

Progress Energy routinely conducts evaluations of alternative generating technologies. The most recent study evaluated 18 technologies: of these, 12 are commercially available and 9 are mature, proven technologies (Progress Energy 2005). Based on this review, Progress Energy identified candidate technologies that would be capable of replacing the maximum dependable base-load capacity (900 MWe-net) of the nuclear unit at HNP.

A cost-benefit analysis revealed that simple-cycle combustion turbines are the most economical commercially available technology for peaking service. For base-load service (like HNP), the most economical commercially available technologies are gas-fired combined-cycle, gasified coal combined-cycle, pulverized coal, and nuclear (Progress Energy 2005). Based on these evaluations, Progress Energy has concluded that feasible new plant systems that could replace the capacity of the HNP nuclear unit are limited to pulverized coal, integrated gasification combined-cycle (IGCC), gas-fired combined-cycle, and new nuclear units.

Mixture

NRC indicated in the GEIS that, while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, such expansive consideration would be too unwieldy, given the purposes of the alternatives analysis. Therefore, NRC determined that a reasonable set of alternatives should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically reasonable and commercially viable (NRC 1996a). Consistent with the NRC determination, Progress Energy has not evaluated mixes of generating sources. The impacts from nuclear, coal- and gas-fired generation presented in this chapter would bound the impacts from any generation mixture of the technologies.

Deregulation

Nationally, the electric power industry has been undergoing a transition from a regulated monopoly to a competitive market environment. Efforts to deregulate the electric utility industry began with passage of the National Energy Policy Act of 1992. Provisions of this act required electric utilities to allow open access to their transmission lines and encouraged development of a competitive wholesale market for electricity. The Act did not mandate competition in the retail market, leaving that decision to the states (NEI 2000).

Initially, deregulation of the electric utility industry received considerable attention in the Carolinas. The legislatures of both North and South Carolina studied the issue of electric power industry restructuring, or deregulation, but no further action has been taken to implement retail competition in the Carolinas (FEMP 2006).

If the electric power industry in the Carolinas is deregulated, retail competition would replace the electric utilities' mandate to serve the public, and electricity customers in the area would be able to choose among competing power suppliers, including those located outside the region. As such, electric generation would be based on the customers' needs and preferences, the lowest price, or the best combination of prices, services, and incentives.

This potential major source of competition from non-utility generators would affect the selection of alternatives for HNP license renewal. With the prospect of many suppliers being licensed to sell electricity in the Carolinas, Progress Energy could not control demand and would not remain competitive if it offered extensive conservation and load modification incentives. North and South Carolina would ensure that electricity generation by incumbent utilities would not inhibit the development of competition. Therefore, it is not clear whether Progress Energy or another supplier would construct new generating units to replace HNP, if its license were not renewed. Regardless of which entities would construct and operate the replacement power supply source, certain environmental impacts would be constant among these alternative power sources. Therefore, Chapter 7 discusses the impacts of reasonable alternatives to HNP without regard to whether they would be owned by Progress Energy.

Alternatives

The following sections present fossil-fuel-fired generation (Section 7.2.1.1) advanced light water reactor (Section 7.2.1.2), and purchased power (Section 7.2.1.3) as reasonable alternatives to license renewal. Section 7.2.1.4 discusses demand reduction and presents the basis for concluding that it is not a reasonable alternative to license renewal. Section 7.2.1.5 discusses other alternatives that Progress Energy has determined are not reasonable and Progress Energy bases for these determinations.

7.2.1.1 Construct and Operate Fossil-Fuel-Fired Generation

Progress Energy analyzed locating hypothetical new coal- and gas-fired units at the existing HNP site and at an undetermined greenfield site. Progress Energy concluded that HNP is the preferred site for new construction because this approach would minimize environmental impacts by building on previously disturbed land and by making the most use possible of existing facilities, such as transmission lines, roads and parking areas, office buildings, and components of the cooling system. Locating hypothetical units at the existing site has, therefore, been applied to the coal- and gas-fired units.

For comparability, Progress Energy selected gas- and coal-fired units of equal electric power capacity. One unit with a net capacity of 900 MWe could be assumed to replace the 900-MWe-net HNP maximum dependable capacity. However, Progress Energy's experience indicates that, although custom size units can be built, using standardized sizes is more economical. For example, a manufacturer's standard-sized units include a gas-fired combined-cycle plant of 293-MWe net capacity (Siemens 2006). Three 293-MWe plants would provide 879-MWe net capacity. For comparability, Progress Energy set the net power of the coal-fired unit equal to the gas-fired plants (879 MWe). Although this provides less capacity than the existing units, it ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other methods (see Mixture in Section 7.2.1).

It must be emphasized, however, that these are hypothetical scenarios. Progress Energy does not have plans for such construction at HNP.

<u>Pulverized Coal-Fired Generation</u>

NRC evaluated pulverized coal-fired generation alternatives for the McGuire Nuclear Station (NRC 2002b) and for the Catawba Nuclear Station (NRC 2002c). For McGuire, NRC analyzed 2,400 MWe of coal-fired generation capacity. Progress Energy has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed more generating capacity than the 879 MWe discussed in this analysis. In defining the HNP coal-fired alternative, Progress Energy has used site- and North Carolina-specific input and has scaled from the NRC analysis, where appropriate.

Table 7-1 presents the basic coal-fired alternative emission control characteristics. Progress Energy based its emission control technology and percent control assumptions on alternatives that the U.S. Environmental Protection Agency (EPA) has identified as being available for minimizing emissions (EPA 1998a). For the purposes of analysis, Progress Energy has assumed that coal and lime (calcium hydroxide) would be delivered via the existing rail line.

Integrated Coal Gasification Combined-Cycle Generation

NRC evaluated the integrated coal gasification combined-cycle (IGCC) process alternative for the Point Beach Nuclear Plant (NRC 2005). For Point Beach, NRC analyzed 1,200 MWe of IGCC generation capacity. Progress Energy has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed more generating capacity than the 879 MWe discussed in this analysis. In defining the HNP IGCC alternative, Progress Energy has used site- and North Carolina-specific input and has scaled from the NRC analysis, where appropriate.

Table 7.2 provides a summary of the characteristics of an IGCC plant that may be constructed to replace lost generation at HNP, should license renewal not occur. For the purposes of analysis, Progress Energy has assumed that the existing rail line would be used for delivery of coal to the plant, as well as shipment of sulfur and slag from the plant.

Gas-Fired Generation

Progress Energy has chosen to evaluate gas-fired generation using combined-cycle turbines because it has determined that the technology is mature, economical, and feasible. As indicated, a manufacturer's standard unit size (293 MWe net) is available and economical. Therefore, Progress Energy has analyzed 879 MWe of net power, consisting of three 293-MWe net capacity gas-fired combined cycle plants, to be located on HNP property. Table 7-3 presents the basic gas-fired alternative characteristics.

7.2.1.2 Construct and Operate New Nuclear Reactor

Since 1997, the NRC has certified four 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), the AP600 Design (10 CFR 52, Appendix C), and the AP1000 Design (71 FR 4464). All of these plants are light-water reactors. NRC evaluated new nuclear generation alternatives for the McGuire Nuclear Station (NRC 2002b) and for the Catawba Nuclear Station (NRC 2002c). For McGuire, NRC analyzed 2,258 MWe of new nuclear generation capacity. Progress Energy has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed more generating capacity than the 879 MWe discussed in this analysis. In defining the HNP new nuclear reactor alternative, Progress Energy has used site- and North Carolina-specific input and has scaled from the NRC analysis, where appropriate.

7.2.1.3 Purchase Power

Progress Energy has evaluated conventional and prospective power supply options that could be reasonably implemented before the current HNP license expires in 2026. Progress Energy has entered into long-term purchase contracts with several utilities to provide firm capacity and energy. Progress Energy presumes that this capacity might be available for purchase after the year 2026 to meet future demand. Because these contracts are part of Progress Energy's current and future capacity, however, Progress

Energy does not consider these power purchases a feasible option for the purchase power alternative.

In 2002, South Carolina exported 30.6 terawatt-hours of electricity (EIA 2006d). North Carolina, on the other hand, imported 43.6 terawatt-hours of electricity in 2002 (EIA 2006d). Therefore, approximately 13 terawatt-hours of electricity were imported to the Carolinas in 2002. Some of the interstate transactions may be the result of purchase contracts, which would prevent Progress Energy from using this power to replace HNP generation. However, Progress Energy cannot rule out the possibility that power would be available for purchase as an alternative to HNP license renewal. Therefore, Progress Energy has analyzed purchased power as a reasonable alternative.

Progress Energy assumes that the generating technology used to produce purchased power would be one of those that NRC analyzed in the GEIS. For this reason, Progress Energy is adopting by reference the GEIS description of the alternative generating technologies as representative of the purchase power alternative. Of these technologies, facilities fueled by coal and combined-cycle facilities fueled by natural gas are the most cost effective for providing base-load capacity. Given the amount of electricity generated by HNP, Progress Energy believes that it is reasonable to assume that new capacity would have to be built for the purchased-power alternative.

7.2.1.4 Reduce Demand

In the past, Progress Energy has offered demand-side management (DSM) programs that either conserve energy or allow the company to reduce customers' load requirements during periods of peak demand. Progress Energy's DSM programs fall into three categories (SCEO 2005):

Conservation Programs

- Educational programs that encourage the wise use of energy

Energy Efficiency Programs

- Discounted residential rates for homes that meet specific energy efficiency standards
- Incentive programs that encourage customers to replace old, inefficient appliances or equipment with new high-efficiency appliances or equipment

Load Management Programs

- Standby Generator Program – encourages customers to let Progress Energy switch loads to the customer's standby generators during periods of peak demand
- Interruptible Service Program – encourages customers to allow blocks of their load to be interrupted during periods of peak demand

- Time-of-Use Pricing – encourages customers to discontinue usage during specific times

Progress Energy annually projects both the summer and winter peak power (in MWe) and annual energy requirements (in gigawatt-hours) impacts of DSM. Future projections anticipate substantial decreases from the DSM initiatives that were in effect during past years. The market conditions which provided initial support for utility-sponsored conservation and load management efforts during the late 1970s and early 1980s can be broadly characterized by:

- increasing long-term marginal prices for capacity and energy production resources;

- forecasts projecting increasing demand for electricity across the nation;

- general agreement that conditions (1) and (2) would continue for the foreseeable future;

- limited competition in the generation of electricity;

- the use of average embedded cost as the basis for setting electricity prices within a regulated context.

These market and regulatory conditions would undergo dramatic changes in a deregulated market. Changes that have significantly impacted the cost effectiveness of utility-sponsored DSM 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 that has encouraged wholesale competition through open access to the transmission grid, as well as state legislation designed to facilitate retail competition.

The utility planning environment features shorter planning horizons, lower reserve margins, and increased reliance on market prices to direct utility resource planning. The changes occurring in the industry have greatly reduced the number of cost-effective DSM alternatives.

Other significant changes include:

- 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 utility-sponsored measures.

- In states that are currently transitioning into deregulation, third parties are increasingly providing energy services and products in competitive markets at prices that reflect their value to the customer. Market conditions can be expected to continue this shift among providers of cost-effective load management.

For these reasons, Progress Energy determined that the remaining DSM programs, which are primarily directed toward load management, are not an effective substitute for any of its large base-load units operating at high-capacity factors, including HNP.

7.2.1.5 Other Alternatives

This section identifies alternatives that Progress Energy has determined are not reasonable and the Progress Energy bases for these determinations. Progress Energy accounted for the fact that HNP is a base-load generator and that any feasible alternative to HNP would also need to be able to generate base-load power. In performing this evaluation, Progress Energy relied heavily upon NRC's GEIS (NRC 1996a).

Wind

Wind power, by itself, is not suitable for large base-load generation. As discussed in Section 8.3.1 of the GEIS, wind has a high degree of intermittence, and average annual capacity factors for wind plants are relatively low (less than 30 percent). Wind power, in conjunction with energy storage mechanisms, might serve as a means of providing base-load power. However, current energy storage technologies are too expensive for wind power to serve as a large base-load generator.

Wind power is not a technically feasible alternative in the Carolinas. According to the Wind Energy Resource Atlas of the United States (NREL 1986), areas suitable for wind energy applications must be wind power class 3 or higher. North Carolina and South Carolina do not have sufficient wind resources for wind energy applications (NREL 1986). Nearly 87 percent of the land area in North Carolina is less than wind power class 3. Areas in North Carolina that are wind power class 3 or higher are confined to exposed ridge crests and mountain summits in western North Carolina and the barrier islands along the Atlantic coast. While some exposed ridge crests and mountain summits in the extreme northwestern part of South Carolina are wind power class 3 or higher, more than 99 percent of the land area in the State has a wind power class of 1. The geography of these wind power class 3 areas makes them unsuitable for utility-scale wind energy applications (NREL 1986).

The GEIS estimates a land-use requirement of 150,000 acres per 1,000 MWe for wind power. Therefore, replacement of HNP generating capacity (900 MWe-net) with wind power, even assuming ideal wind conditions, would require dedication of about 211 square miles. Based on the lack of sufficient wind speeds and the amount of land needed to replace HNP, the wind alternative would require a large greenfield site, which would result in a large environmental impact. Additionally, wind plants have aesthetic impacts, generate noise, and harm birds.

Progress Energy has concluded that, due to the lack of area in the Carolinas having suitable wind speeds and the amount of land needed (approximately 211 square miles), wind power is not a reasonable alternative to HNP license renewal.

Solar

By its nature, solar power is intermittent. In conjunction with energy storage mechanisms, solar power might serve as a means of providing base-load power. However, current energy storage technologies are too expensive to permit solar power to serve as a large base-load generator. Even without storage capacity, solar power technologies (photovoltaic and thermal) cannot currently compete with conventional fossil-fueled technologies in grid-connected applications, due to high costs per kilowatt of capacity (NRC 1996a).

Solar power is not a technically feasible alternative for baseload capacity in the Carolinas. North and South Carolina receive about 3.3 kilowatt hours of solar radiation per square meter per day, compared with 5 to 7.2 kilowatt hours per square meter per day in areas of the West, such as California, which are most promising for solar technologies (NRC 1996a).

Finally, according to the GEIS, land requirements for solar plants are high, at 35,000 acres per 1,000 MWe for photovoltaic and 14,000 acres per 1,000 MWe for solar thermal systems. Therefore, replacement of HNP generating capacity with solar power would require dedication of about 49 square miles for photovoltaic and 20 square miles for solar thermal systems. Neither type of solar electric system would fit at the HNP site, and both would have large environmental impacts at a greenfield site.

Progress Energy has concluded that, due to the high cost, limited availability of sufficient incident solar radiation, and amount of land needed (approximately 20 to 49 square miles), solar power is not a reasonable alternative to HNP license renewal.

Hydropower

A portion (about 5,000 MWe) of utility generating capacity in the Carolinas is hydroelectric (EIA 2006c). As the GEIS points out in Section 8.3.4, hydropower's percentage of United States generating capacity 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 alteration of natural river courses. During the period 1990 to 2004, utilities reduced hydroelectric production from 8.0 percent to 3.1 percent in North Carolina and from 4.5 percent to 2.4 percent in South Carolina (EIA 2006c). According to the U.S. Hydropower Resource Assessment for North Carolina (INEEL 1998), there are no remaining sites in North Carolina that would be environmentally suitable for a large hydroelectric facility. Similarly, the U.S. Hydropower Resource Assessment for South Carolina (INEEL 1998), indicates that there are no environmentally suitable sites remaining in South Carolina for a large hydroelectric facility.

The GEIS estimates land use of 1,600 square miles per 1,000 MWe for hydroelectric power. Based on this estimate, replacement of HNP generating capacity would require flooding more than 1,440 square miles, resulting in a large impact on land use. Further, operation of a hydroelectric facility would alter aquatic habitats above and below the dam, which would impact existing aquatic communities.

Progress Energy has concluded that, due to the lack of suitable sites in the Carolinas and the amount of land needed (approximately 1,440 square miles), hydropower is not a reasonable alternative to HNP license renewal.

Geothermal

As illustrated by Figure 8.4 in the GEIS, geothermal plants might be located in the western continental United States, Alaska, and Hawaii, where hydrothermal reservoirs are prevalent. However, because there are no high-temperature geothermal sites in North or South Carolina, Progress Energy concludes that geothermal is not a reasonable alternative to HNP license renewal.

Wood Energy

As discussed in the GEIS (NRC 1996a), the use of wood waste to generate electricity is largely limited to those states with significant wood resources. According to the U.S. Department of Energy, North and South Carolina are considered to have excellent wood resource potential (Walsh et al. 2000). The pulp, paper, and paperboard industries in states with adequate wood resources generate electric power by consuming wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem. However, the largest wood waste power plants are 40 to 50 MWe in size.

Further, as discussed in Section 8.3.6 of the GEIS, construction of a wood-fired plant would have an environmental impact that would be similar to that for a coal-fired plant, although facilities using wood waste for fuel would be built on smaller scales. Like coal-fired plants, wood-waste plants require large areas for fuel storage, processing, and waste (i.e., ash) disposal. Additionally, operation of wood-fired plants has environmental impacts, including impacts on the aquatic environment and air. Wood has a low heat content that makes it unattractive for base-load applications. It is also difficult to handle and has high transportation costs.

While wood resources are available in the Carolinas, Progress Energy has concluded that, due to the lack of an environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy is not a reasonable alternative to HNP license renewal.

Municipal Solid Waste

As discussed in Section 8.3.7 of the GEIS, the initial capital costs for municipal solid waste plants are greater than for comparable steam turbine technology at wood-waste facilities. This is due to the need for specialized waste separation and handling equipment.

The decision to burn municipal solid waste to generate energy is usually driven by the need for an alternative to landfills, rather than by energy considerations. The use of landfills as a waste disposal option is likely to increase in the near term; however, it is unlikely that many landfills will begin converting waste to energy because of unfavorable economics.

Estimates in the GEIS suggest that the overall level of construction impacts from a waste-fired plant should be approximately the same as that for a coal-fired plant. Additionally, waste-fired plants have the same or greater operational impacts (including impacts on the aquatic environment, air, and waste disposal). Some of these impacts would be moderate, but still larger than the environmental effects of HNP license renewal.

Progress Energy has concluded that, due to the high costs and lack of environmental advantages, burning municipal solid waste to generate electricity is not a reasonable alternative to HNP license renewal.

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), and gasifying energy crops (including wood waste). As discussed in the GEIS, 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 HNP.

Further, estimates in the GEIS suggest that the overall level of construction impacts from a crop-fired plant should be approximately the same as that for a wood-fired plant. Additionally, crop-fired plants would have similar operational impacts (including impacts on the aquatic environment and air). These systems also have large impacts on land use, due to the acreage needed to grow the energy crops.

Progress Energy has concluded that, due to the high costs and lack of environmental advantage, burning other biomass-derived fuels is not a reasonable alternative to HNP license renewal.

Petroleum

Both North and South Carolina have several petroleum (oil)-fired power plants; however, they produce less than 1 percent of the total power generated in the Carolinas (EIA 2006c). Petroleum-fired operation is more expensive than nuclear or coal-fired operation. In addition, future increases in petroleum prices are expected to make petroleum-fired generation increasingly more expensive than coal-fired generation.

Also, construction and operation of a petroleum-fired plant would have environmental impacts. For example, Section 8.3.11 of the GEIS estimates that construction of a 1,000-MWe petroleum-fired plant would require about 120 acres. Additionally, operation of petroleum-fired plants would have environmental impacts (including impacts on the aquatic environment and air) that would be similar to those from a coal-fired plant.

Progress Energy has concluded that, due to the high costs and lack of obvious environmental advantage, petroleum-fired generation is not a reasonable alternative to HNP license renewal.

Fuel Cells

Fuel cell power plants are in the initial stages of commercialization. While more than two hundred turnkey plants have been installed, the global stationary fuel cell electricity generating capacity was just 75 MWe in 2001 (Hemberger 2001). Recent estimates suggest that a company would have to produce about 100 MWe of fuel cell stacks annually to achieve a price of $1,000 to $1,500 per kilowatt (Kenergy 2000). However, the production capability of the largest stationery fuel cell manufacturer is 50 MWe per year (CSFCC 2002). Progress Energy believes that this technology has not matured sufficiently to support production for a facility the size of HNP. Progress Energy has concluded that, due to cost and production limitations, fuel cell technology is not a reasonable alternative to HNP license renewal.

Delayed Retirement

Progress Energy currently has no plans for retiring any of its generating plants and expects to need additional new capacity in the near future (Progress Energy 2005). Therefore, there are no unit retirements that could be delayed as an alternative to HNP license renewal.

Although not currently feasible as an alternative to base load units like HNP, Progress Energy is exploring alternative fuel sources as a way of meeting increasing energy demand. The company is currently evaluating and investing in a range of renewable and alternative energy sources, including biomass, hydrogen fuel cells, solar photovoltaic systems, and hydrogen-based automobiles and fueling stations (Progress Energy 2006b).

7.2.2 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

This section evaluates the environmental impacts of alternatives that Progress Energy has determined to be reasonable alternatives to HNP license renewal: pulverized coal, IGCC, gas-fired combined-cycle, and new nuclear units, and purchased power.

7.2.2.1 Pulverized Coal-Fired Generation

NRC evaluated environmental impacts from pulverized coal-fired generation alternatives in the GEIS (NRC 1996a). NRC concluded that construction impacts could be substantial, due in part to the large land area required (which can result in natural habitat loss) and the large workforce needed. NRC pointed out that siting a new coal-fired plant where an existing nuclear plant is located would reduce many construction impacts. NRC identified major adverse impacts from operations as human health concerns associated with air emissions, waste generation, and losses of aquatic biota due to cooling water withdrawals and discharges.

The coal-fired alternative that Progress Energy has defined in Section 7.2.1.1 would be located at HNP.

Air Quality

A coal-fired plant would emit oxides of sulfur (SOx) and nitrogen (NOx), particulate matter, and carbon monoxide, all of which are regulated pollutants. As Section 7.2.1.1 indicates, Progress Energy has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. Progress Energy estimates the coal-fired alternative emissions to be as follows:

SO_x = 2,301 tons per year

NOx = 712 tons per year

Carbon monoxide = 712 tons per year

Particulates:

> Total suspended particulates = 148 tons per year
>
> PM10 (particulates having a diameter of less than 10 microns) = 34 tons per year

Table 7-4 shows how Progress Energy calculated these emissions.

In 2004, emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NOx) from North Carolina's generators ranked 7th and 13th nationally, respectively (EIA 2006c). In 1998, the EPA promulgated the NOx SIP (State Implementation Plan) Call regulation that required 22 states, including North Carolina, to reduce their NOx emissions by over 30 percent to address regional transport of ground-level ozone across state lines (EPA 1998b). The NOx SIP Call imposes a NOx "budget" to limit the NOx emissions from each state. Implementation of the NOx SIP Call rule was delayed while lawsuits against the EPA were being argued. On March 26, 2002 the U.S Court of Appeals for the D.C. Circuit issued a ruling largely upholding the NOx SIP Call (ATA 2001). To operate a fossil-fuel-fired plant at the HNP site, Progress Energy would need to obtain enough NOx credits to cover annual emissions either from the set-aside pool or by buying NOx credits from other sources.

NRC did not quantify coal-fired emissions, but implied that air impacts would be substantial. NRC noted that adverse human health effects from coal combustion have led to important federal legislation in recent years and that public health risks, such as cancer and emphysema, have been associated with coal combustion. NRC also mentioned global warming and acid rain as potential impacts. Progress Energy 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_2 emission allowances, NOx emission offsets, low NOx burners, overfire air, fabric filters or electrostatic precipitators, and scrubbers are regulatorily imposed mitigation measures. As such, Progress Energy concludes that the coal-fired alternative would have moderate impacts on air quality; the impacts would be noticeable, but would not destabilize air quality in the area.

Waste Management

Progress Energy concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste. The coal-fired plant would annually consume approximately 2,850,000 tons of coal having an ash content of 10.4 percent (Tables 7-4 and 7-1, respectively). After combustion, approximately 41 percent of this ash (121,600 tons per year), would be recycled. The remaining ash, approximately 174,900 tons per year, would be collected and disposed of onsite. In addition, approximately 125,500 tons of scrubber sludge would be disposed of onsite each year (based on annual lime usage of approximately 42,000 tons). Progress Energy estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 71 acres (a square area with sides of approximately 1,761 feet). Table 7-5 shows how Progress Energy calculated ash and scrubber waste volumes. The HNP site is approximately 10,800 acres. While only half this waste volume and acreage would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact.

Progress Energy believes that, with proper siting coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. There would be space within the HNP property for this disposal but it would be necessary to clear several hundred acres of woodlands. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, Progress Energy believes that waste disposal for the coal-fired alternative would have moderate impacts; the impacts of increased waste disposal would be noticeable, but would not destabilize any important resource, and further mitigation would be unwarranted.

Other Impacts

Progress Energy estimates that construction of the powerblock and coal storage area would affect 250 acres of land and associated terrestrial habitat. Because this construction would require some clearing of managed pine forest, impacts at the HNP site would be small to moderate, but would be somewhat less than the impacts of using a green field site. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite. Socioeconomic impacts from the construction workforce would be minimal, because worker relocation would not be expected, due to the site's proximity to Raleigh, North Carolina, 16 miles from the site. Progress Energy estimates an operational workforce of only 72 for the coal-fired alternative. The reduction in workforce would result in adverse socioeconomic impacts. Progress Energy believes these impacts would be small, due to HNP's proximity to Raleigh.

Impacts to aquatic resources and water quality would be similar to impacts of HNP, due to the plant's use of the existing natural draft cooling tower and cooling water system that withdraws from and discharges to Harris Reservoir, and would be offset by the concurrent shutdown of HNP. The additional stacks, boilers, and rail deliveries would increase the visual impact of the existing site. Impacts to cultural resources would be unlikely, due to the previously disturbed nature of the site.

Progress Energy believes that other construction and operation impacts would be small. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved. Due to the minor nature of these other impacts, mitigation would not be warranted beyond that previously mentioned.

7.2.2.2 Integrated Coal Gasification Combined-Cycle

NRC evaluated the integrated coal gasification combined-cycle (IGCC) process alternative for the Point Beach Nuclear Plant (NRC 2005). NRC concluded that construction impacts could be substantial, due to the large land area required (which can result in natural habitat loss). NRC pointed out that siting a new IGCC plant where an existing nuclear plant is located would reduce many construction impacts. A smaller workforce could have adverse socioeconomic impacts. Human health effects associated with air emissions would be of concern. Aquatic biota losses due to cooling water withdrawals would be offset by the concurrent shutdown of the nuclear generators.

The IGCC alternative that Progress Energy has defined in Section 7.2.1.1 would be located at HNP.

Air Quality

IGCC plants use a combination of chemical processes at elevated pressures and a variety of fuels to create a gas fuel (syngas) cleansed of sulfur and mercury. IGCC units also reduce the amount of carbon dioxide produced from the combustion process and produce energy with NOx emissions levels equivalent to controlled levels from pulverized coal plants. Progress Energy estimates the IGCC alternative emissions to be as follows:

SO_2 = 420 tons per year

NOx = 594 tons per year

Carbon monoxide = 742 tons per year

Particulates:

Total suspended particulates = 49 tons per year

PM10 (particulates having a diameter of less than 10 microns) = 49 tons per year

Table 7-6 shows how Progress Energy calculated these emissions.

Waste Management

The IGCC alternative generates substantially less solid waste than the pulverized coal-fired alternative. The largest solid waste stream produced by IGCC installations is slag, a black, glassy, sand- like material that is potentially a marketable byproduct. Slag production is a function of ash content. The other large-volume byproduct produced by IGCC plants is sulfur, which is extracted during the gasification process and can be marketed rather than placed in a landfill. IGCC units do not produce ash or scrubber wastes.

The IGCC plant would annually consume approximately 1,990,000 tons of coal having an ash content of 10.4 percent (Tables 7-6 and 7-2, respectively). After processing, approximately 90 percent of the slag produced from this ash (186,276 tons per year), would be recycled. The remaining slag, approximately 20,697 tons per year, would be collected and disposed of onsite. Progress Energy estimates that slag disposal over a 40-year plant life would require approximately 8 acres (a square area with sides of approximately 585 feet). While only half this waste volume and acreage would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact. In addition, the IGCC plant would produce approximately 16,600 tons of sulfur each year that would be marketed as a useable commodity. Table 7-6 shows how Progress Energy calculated waste slag volumes and sulfur production.

Progress Energy believes that, with proper siting coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. There would be space within the previously disturbed area of the HNP property for this disposal. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, Progress Energy believes that waste disposal for the IGCC alternative would have small impacts, and mitigation would be unwarranted.

Other Impacts

Progress Energy estimates that construction of the powerblock and coal storage area would affect 200 acres of land and associated terrestrial habitat. Because most of this construction would require some clearing of managed pine forest, impacts at the HNP site would be small to moderate, but would be somewhat less than the impacts of using a green field site. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be similar to the pulverized coal-fired alternative. Socioeconomic impacts of construction would be minimal. However, Progress Energy estimates a workforce of 150 for IGCC operations. The reduction in work force would result in adverse socioeconomic impacts. Progress Energy believes these impacts would be small and would be mitigated by the site's proximity to the metropolitan area of Raleigh.

7.2.2.3 Gas-Fired Generation

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. Section 7.2.1.1 presents Progress Energy's reasons for defining the gas-fired generation alternative as a combined-cycle plant on the HNP site. Land-use impacts from gas-fired units on HNP would be less than those from the IGCC and pulverized coal-fired alternatives. Reduced land requirements, due to a smaller facility footprint, would reduce impacts to ecological, aesthetic, and cultural resources. A smaller workforce could have adverse socioeconomic impacts. Human health effects associated with air emissions would be of concern. Aquatic biota losses due to cooling water withdrawals would be offset by the concurrent shutdown of the nuclear generators.

NRC has evaluated the environmental impacts of constructing and operating five 482-MWe combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal (NRC 2002c). Progress Energy has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed more generating capacity than the 879 MWe-net discussed in this analysis. Progress Energy has adopted the NRC analysis with necessary North Carolina- and Progress Energy-specific modifications noted.

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 NOx emissions. Progress Energy estimates the gas-fired alternative emissions to be as follows:

SO_2 = 69 tons per year

NOx = 222 tons per year

Carbon monoxide = 46 tons per year

Filterable Particulates = 39 tons per year (all particulates are PM10)

Table 7-7 shows how Progress Energy calculated these emissions.

The Section 7.2.2.1 discussion of regional air quality is applicable to the gas-fired generation alternative. NOx effects on ozone levels, SO_2 allowances, and NOx 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. Progress Energy concludes that emissions from the gas-fired alternative at HNP would noticeably alter local air quality, but would not destabilize regional resources (i.e., air quality). Air quality impacts would therefore be moderate, but substantially smaller than those of coal-fired generation.

Waste Management

Gas-fired generation would result in almost no waste generation, producing minor (if any) impacts. Progress Energy concludes that gas-fired generation waste management impacts would be small.

Other Impacts

Similar to the IGCC and pulverized coal-fired alternatives, the ability to construct the gas-fired alternative on the existing HNP site would reduce construction-related impacts. A new gas pipeline would be required for the three 293-MWe gas turbine generators in this alternative. To the extent practicable, Progress Energy would route the pipeline along existing, previously disturbed, right-of-way to minimize impacts. Approximately 2 miles of new pipeline construction would be required to connect HNP to the existing pipeline network. An 8-inch diameter pipeline would necessitate a 50-foot-wide corridor, resulting in the disturbance of as much as 12 acres. This new construction could also necessitate an upgrade of the State-wide pipeline network. Progress Energy estimates that 60 acres would be needed for a plant site; this much previously disturbed acreage is available at HNP, reducing loss of terrestrial habitat. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be similar to the pulverized coal-fired alternative, but smaller because of the reduced site size. Socioeconomic impacts of construction would be minimal. However, Progress Energy estimates a workforce of 32 for gas operations. The reduction in work force would result in adverse socioeconomic impacts. Progress

Energy believes these impacts would be moderate and would be mitigated by the site's proximity to the metropolitan area of Raleigh.

7.2.2.4 New Nuclear Reactor

As discussed in Section 7.2.1.2, under the new nuclear reactor alternative Progress Energy would construct and operate a single unit nuclear plant using one of the four NRC certified standard designs for nuclear power plants.

Air Quality

Air quality impacts would be minimal. Air emissions are primarily from non-facility equipment and diesel generators and are comparable to those associated with the continued operation of HNP. Overall, emissions and associated impacts would be considered small.

Waste Management

High level radioactive wastes would be similar to those associated with the continued operation of HNP. Low level radioactive waste impacts from a new nuclear plant would be slightly greater but similar to the continued operation of HNP. The overall impacts are characterized as small.

Other Impacts

Progress Energy estimates that construction of the reactor and auxiliary facilities would affect approximately 250 acres of land and associated terrestrial habitat. Because most of this construction would be on previously disturbed land, impacts at the HNP site would be small to moderate. For the purposes of analysis, Progress Energy has assumed that the existing rail line would be used for reactor vessel and other deliveries under this alternative. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite.

Progress Energy estimates a peak construction work force of 2,500. The surrounding communities would experience moderate to large demands on housing and public services. After construction, the communities would be impacted by the loss of jobs as construction workers moved on. Long-term job opportunities would be comparable to continued operation of HNP; therefore Progress Energy concludes that the socioeconomic impacts during operation would be small.

Impacts to aquatic resources and water quality would be similar to impacts of HNP, due to the plant's use of the existing cooling water system that withdraws from and discharges to Harris Reservoir, and would be offset by the concurrent shutdown of HNP.

Impacts to cultural resources would be unlikely, due to the previously disturbed nature of the site. Progress Energy is aware, however, that the site vicinity and the surrounding environs have potential for containing cultural resources. Additionally, Progress Energy is aware of cultural resources that are within or near HNP boundaries. If any archeological or historic artifacts were found during construction, work would cease in the vicinity of the find and Progress Energy's Environmental Services Section would be notified, consistent with corporate policies and procedures (Progress Energy 2004). Progress Energy would then coordinate with the North Carolina SHPO to protect any potentially significant cultural resources. Progress Energy concludes that the impact on cultural resources from construction and operation of new nuclear units at HNP would be small and no mitigation would be warranted.

Progress Energy thinks that other construction and operation impacts would be small. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved. Due to the minor nature of these other impacts, mitigation would not be warranted beyond that previously mentioned.

7.2.2.5 Purchased Power

As discussed in Section 7.2.1.2, Progress Energy assumes that the generating technology used under the purchased power alternative would be one of those that NRC analyzed in the GEIS. Progress Energy is also adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, therefore, environmental impacts would still occur, but they would likely originate from a power plant located elsewhere in the Carolinas. Progress Energy believes that imports from outside the Carolinas would not be required.

The purchased power alternative would include constructing an undetermined length of high-voltage (i.e., 230-kilovolt) transmission line (or lines) to get power from the elsewhere in the Carolinas to the Progress Energy network. Progress Energy believes most of the transmission lines could be routed along existing rights-of-way. However, Progress Energy assumes that the environmental impacts of such transmission line construction would be moderate. As indicated in the introduction to Section 7.2.1.1, the environmental impacts of construction and operation of new coal- or gas-fired generating capacity for purchased power at a previously undisturbed greenfield site would exceed those of a coal- or gas-fired alternative located on the HNP site.

TABLE 7-1
PULVERIZED COAL-FIRED ALTERNATIVE

Characteristic	Basis
Unit size = 439.5 MWe ISO rating net[a]	Calculated to be < HNP net capacity – 900 MWe
Unit size = 466 MWe ISO rating gross[a]	Calculated based on 6 percent onsite power
Number of units = 2	Assumed
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (EPA 1998a)
Fuel type = bituminous, pulverized coal	Typical for coal used in North Carolina
Fuel heating value = 12,415 Btu/lb	1999 value for coal used in North Carolina (EIA 2002)
Fuel ash content by weight = 10.4 percent	1999 value for coal used in North Carolina (EIA 2002)
Fuel sulfur content by weight = 0.85 percent	1999 value for coal used in North Carolina (EIA 2002)
Uncontrolled NOx emission = 10 lb/ton Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Heat rate = 10,200 Btu/Kwh	Typical for coal-fired, single-cycle steam turbines (EIA 2002)
Capacity factor = 0.85	Typical for large coal-fired units
NOx control = low NOx burners, overfire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NOx emissions (EPA 1998a)
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions (EPA 1998a)
SOx control = Wet scrubber – lime (95 percent removal efficiency)	Best available for minimizing SOx emissions (EPA 1998a)

a. The difference between “net” and “gross” is electricity consumed onsite.

Btu = British thermal unit
CO = carbon monoxide
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
Kwh = kilowatt hour
lb = pound
MWe = megawatt electric
NOx = nitrogen oxides
NSPS = New Source Performance Standard
SOx = oxides of sulfur
< = less than

TABLE 7-2
IGCC ALTERNATIVE

Characteristic	Basis
Unit size = 293 MWe ISO rating net[a]	Calculated to be < HNP net capacity – 900 MWe
Unit size = 322 MWe ISO rating gross[a]	Calculated based on 10 percent onsite power
Number of units = 3	Assumed
Fuel type = bituminous coal	Assumed – Typical for coal used in North Carolina
Fuel heating value = 12,415 Btu/lb	1999 value for coal used in North Carolina (EIA 2002)
Fuel ash content by weight = 10.4 percent	1999 value for coal used in North Carolina (EIA 2002)
Fuel sulfur content by weight = 0.85 percent	1999 value for coal used in North Carolina (EIA 2002)
Plant heat rate = 6,870 Btu/net-kWh	DOE 1999
Capacity factor = 0.85	Assumed
Controlled SOx emission = 0.017 lb/MMBtu	DOE 1999
Controlled NOx emission = 0.024 lb/MMBtu	DOE 1999
Uncontrolled CO emission = 0.030 lb/MMBtu	PSCW 2003
Controlled PM10 emission = 0.002 lb/MMBtu	DOE 1999

a. The difference between "net" and "gross" is electricity consumed onsite.

Btu = British thermal unit
CO = carbon monoxide
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
lb = pound
MM = million
MWe = megawatt electric
MWh = megawatt hour
NOx = nitrogen oxides
PM10 = particulate matter having a diameter of less than 10 microns
SOx = sulfur oxides
< = less than

TABLE 7-3
GAS-FIRED ALTERNATIVE

Characteristic	Basis
Unit size = 293 MWe ISO rating net:[a]	Manufacturer's standard size gas-fired combined-cycle plant that is < HNP net capacity of 900 MWe
Unit size = 305 MWe ISO rating gross:[a]	Calculated based on 4 percent onsite power
Number of units = 3	Assumed
Fuel type = natural gas	Assumed
Fuel heating value = 1,032 Btu/ft3	1999 value for gas used in North Carolina (EIA 2002)
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available (EPA 2000)
NOx control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NOx emissions (EPA 2000)
Fuel NOx content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas fired units with water injection (EPA 2000)
Fuel CO content = 0.00226 lb/MMBtu	Typical for large SCR-controlled gas fired units (EPA 2000)
Heat rate = 5,990 Btu/kWh	Progress Energy experience
Capacity factor = 0.85	Progress Energy experience

a. The difference between "net" and "gross" is electricity consumed onsite.

Btu = British thermal unit
CO = carbon monoxide
ft3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
MM = million
MWe = megawatt electric
NOx = nitrogen oxides
< = less than

TABLE 7-4
AIR EMISSIONS FROM PULVERIZED COAL-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual coal consumption	$1\,\text{Unit} \times \frac{932\,\text{MW}}{\text{Unit}} \times \frac{10{,}200\,\text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\,\text{kW}}{\text{MW}} \times \frac{\text{lb}}{12{,}415\,\text{Btu}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times \frac{8{,}760\,\text{hr}}{\text{yr}} \times 0.85$	2,849,976 tons of coal per year
SOx[a,c]	$\frac{38 \times 0.85\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100-95}{100} \times \frac{2{,}849{,}976\ \text{tons}}{\text{yr}}$	2,301 tons SOx per year
NOx[b,c]	$\frac{10\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100-95}{100} \times \frac{2{,}849{,}976\ \text{tons}}{\text{yr}}$	712 tons NOx per year
CO[c]	$\frac{0.5\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{2{,}849{,}976\ \text{tons}}{\text{yr}}$	712 tons CO per year
TSP[d]	$\frac{10 \times 10.4\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100-99.9}{100} \times \frac{2{,}849{,}976\ \text{tons}}{\text{yr}}$	148 tons TSP per year
PM10[d]	$\frac{2.3 \times 10.4\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100-99.9}{100} \times \frac{2{,}849{,}976\ \text{tons}}{\text{yr}}$	34 tons PM10 per year

a. EPA 1998a, Table 1.1-1.
b. EPA 1998a, Table 1.1-2.
c. EPA 1998a, Table 1.1-3.
d. EPA 1998a, Table 1.1-4.
CO = carbon monoxide
NOx = oxides of nitrogen
PM10 = particulates having diameter less than 10 microns
SOx = oxides of sulfur
TSP = total suspended particulates

TABLE 7-5
SOLID WASTE FROM PULVERIZED COAL-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual SOx generated[a]	$\frac{2{,}849{,}976 \text{ ton coal}}{\text{yr}} \times \frac{0.85 \text{ ton S}}{100 \text{ ton coal}} \times \frac{64.1 \text{ ton } SO_2}{32.1 \text{ ton S}}$	48,425 tons of SOx per year
Annual SOx removed	$\frac{48{,}425 \text{ ton } SO_2}{\text{yr}} \times \frac{95}{100}$	46,004 tons of SOx per year
Annual ash generated	$\frac{2{,}849{,}976 \text{ ton coal}}{\text{yr}} \times \frac{10.4 \text{ ton ash}}{100 \text{ ton coal}} \times \frac{99.9}{100}$	296,101 tons of ash per year
Annual lime consumption[b]	$\frac{48{,}425 \text{ ton } SO_2}{\text{yr}} \times \frac{56.1 \text{ ton CaO}}{64.1 \text{ ton } SO_2}$	42,382 tons of CaO per year
Calcium sulfate[c]	$\frac{46{,}004 \text{ ton } SO_2}{\text{yr}} \times \frac{172 \text{ ton } CaSO_4 \bullet 2H_2O}{64.1 \text{ ton } SO_2}$	123,443 tons of CaSO4·2H2O per year
Annual scrubber waste[d]	$\frac{42{,}382 \text{ ton CaO}}{\text{yr}} \times \frac{100-95}{100} + 123{,}443 \text{ ton } CaSO_4 \bullet 2H_2O$	125,562 tons of scrubber waste per year
Total volume of scrubber waste[e]	$\frac{125{,}562 \text{ ton}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{144.8 \text{ lb}}$	69,386,800 ft3 of scrubber waste
Total volume of ash[f]	$\frac{296{,}101 \text{ ton}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	236,880,897 ft3 of ash
Total volume of solid waste	69,386,800 ft3 + 236,880,897 ft3 $\times \frac{100-90}{100}$	93,074,8900 ft3 of solid waste
Waste pile area (acres)	$\frac{93{,}074{,}890 \text{ ft}^3}{30 \text{ ft}} \text{ x } \frac{\text{acre}}{43{,}560 \text{ ft}^2}$	71 acres of solid waste
Waste pile area (ft x ft square)	$\sqrt{(93{,}074{,}890 ft^3 / 30 ft)}$	1,761 feet by feet square of solid waste

Based on annual coal consumption of 5,917,186 tons per year (Table 7-3).

a. Calculations assume 100 percent combustion of coal.
b. Lime consumption is based on total SO2 generated.
c. Calcium sulfate generation is based on total SO2 removed.
d. Total scrubber waste includes scrubbing media carryover.
e. Density of CaSO4·2H2O is 144.8 lb/ft3.
f. Density of coal bottom ash is 100 lb/ft3 (FHA 2000).

S = sulfur
SOx = oxides of sulfur
CaO = calcium oxide (lime)
CaSO4·2H2O = calcium sulfate dihydrate

TABLE 7-6
AIR EMISSIONS AND BYPRODUCTS FROM GASIFIED COAL-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual coal consumption	$3\ \text{Units} \times \frac{322\ \text{MW}}{\text{Unit}} \times \frac{6{,}870\ \text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times \frac{\text{lb}}{12{,}415\ \text{Btu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times 0.85$	1,991,978 tons coal per year
Annual Btu input	$\frac{1{,}991{,}978\ \text{tons Coal}}{\text{yr}} \times \frac{2{,}000\ \text{lb}}{\text{ton}} \times \frac{12{,}415\ \text{Btu}}{\text{lb}} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}}$	49,460,822 mmBtu per year
SOx	$\frac{49{,}460{,}822\ \text{MMBtu}}{\text{yr}} \times \frac{0.017\ \text{lb}\ SO_X}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}}$	420 tons SOx per year
NOx	$\frac{49{,}460{,}822\ \text{MMBtu}}{\text{yr}} \times \frac{0.024\ \text{lb}\ NO_X}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}}$	594 tons NOx per year
CO	$\frac{49{,}460{,}822\ \text{MMBtu}}{\text{yr}} \times \frac{0.030\ \text{lb CO}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}}$	742 tons CO per year
PM10	$\frac{49{,}460{,}822\ \text{MMBtu}}{\text{yr}} \times \frac{0.002\ \text{lb PM10}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}}$	49 tons PM10 per year
Sulfur	$\frac{1{,}991{,}978\ \text{tons Coal}}{\text{yr}} \times \frac{0.0085\ \text{ton Sulfur}}{\text{ton Coal}} \times 0.98$	16,593 tons sulfur per year
Gasifier slag	$\frac{1{,}991{,}978\ \text{tons Coal}}{\text{yr}} \times \frac{10.4}{100}$	207,165 tons slag per year
Slag recycled	$\frac{207{,}166\ \text{tons Slag}}{\text{yr}} \times \frac{90}{100}$	186,449 tons slag per year
Waste slag	207,166 tons slag - 186,449 tons recycled	20,717 tons waste slag per year
Volume of waste slag	$\frac{1{,}991{,}978\ \text{tons slag}}{\text{yr}} \times \frac{2000\ \text{lb}}{\text{ton}} \times \frac{\text{ft}^3}{161.42\ \text{lb}} \times 40\ \text{years}$	10,267,166 ft^3 waste slag
Waste pile area (acres)	$\frac{10{,}267{,}166\ \text{ft}^3}{30\ \text{ft}} \times \frac{\text{acre}}{43{,}560\ \text{ft}^2}$	7.86 acres of solid waste
Waste pile area (ft x ft square)	$\sqrt{\frac{10{,}267{,}166\ \text{ft}^3}{30\ \text{ft}}}$	585 feet by feet square of solid waste

CO = carbon monoxide
NOx = oxides of nitrogen
PM10 = particulates having diameter less than 10 microns
SOx = oxides of sulfur
TSP = total suspended particulates

TABLE 7-7
AIR EMISSIONS FROM GAS-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual gas consumption	$3\ \text{units} \times \frac{305\ \text{MW}}{\text{unit}} \times \frac{5{,}990\ \text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times 0.85 \times \frac{\text{ft}^3}{1{,}032\ \text{Btu}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}}$	39,508,666,479 ft3 per year
Annual Btu input	$\frac{39{,}508{,}666{,}479\ \text{ft}^3}{\text{yr}} \times \frac{1{,}032\ \text{Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}}$	40,772,944 MMBtu per year
SOx[a]	$\frac{0.0034\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{40{,}772{,}944\ \text{MMBtu}}{\text{yr}}$	69 tons SOx per year
NOx[b]	$\frac{0.0109\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{40{,}772{,}944\ \text{MMBtu}}{\text{yr}}$	222 tons NOx per year
CO[b]	$\frac{0.00226\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{40{,}772{,}944\ \text{MMBtu}}{\text{yr}}$	46 tons CO per year
TSP[a]	$\frac{0.0019\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{40{,}772{,}944\ \text{MMBtu}}{\text{yr}}$	39 tons filterable TSP per year
PM10[a]	$\frac{39\ \text{tons TSP}}{\text{yr}}$	39 tons filterable PM10 per year

a. EPA 2000, Table 3.1-1.
b. EPA 2000, Table 3.1-2.
CO = carbon monoxide
NOx = oxides of nitrogen
PM10 = particulates having diameter less than 10 microns
SOx = oxides of sulfur
TSP = total suspended particulates

7.3 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 cited web pages are available in Progress Energy files. Some sites, for example the census data, cannot be accessed through their given URLs. The only way to access these pages is to follow queries on previous web pages. The complete URLs used by Progress Energy have been given for these pages, even though they may not be directly accessible.

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8.0 COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES

NRC

"To the extent practicable, the environmental impacts of the proposal and the alternatives should be presented in comparative form..." 10 CFR 51.45(b)(3) as adopted by 51.53(c)(2)

Chapter 4 analyzes environmental impacts of Shearon Harris Nuclear Plant (HNP) license renewal and Chapter 7 analyzes impacts from renewal alternatives. Table 8-1 summarizes environmental impacts of the proposed action (license renewal) and the alternatives, for comparison purposes. The environmental impacts compared in Table 8-1 are those that are either Category 2 issues for the proposed action, license renewal, or are issues that the Generic Environmental Impact Statement (GEIS) (NRC 1996) identified as major considerations in an alternatives analysis. For example, although the U. S. Nuclear Regulatory Commission (NRC) concluded that air quality impacts from the proposed action would be small (Category 1), the GEIS identified major human health concerns associated with air emissions from alternatives (Section 7.2.2). Therefore, Table 8-1 compares air impacts among the proposed action and the alternatives. Table 8-2 is a more detailed comparison of the alternatives.

TABLE 8-1
IMPACTS COMPARISON SUMMARY

Impact	Proposed Action (License Renewal)	No-Action Alternative					
		Base (Decommissioning)	With Coal-Fired Generation	With IGCC Generation	With Gas-Fired Generation	With New Nuclear Generation	With Purchased Power
Land Use	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE	SMALL to MODERATE	SMALL to MODERATE	MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Air Quality	SMALL	SMALL	MODERATE	MODERATE	MODERATE	SMALL	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	SMALL to MODERATE	SMALL	SMALL to MODERATE	SMALL to MODERATE	SMALL to MODERATE
Threatened or Endangered Species	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	MODERATE	MODERATE	SMALL	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Waste Management	SMALL	SMALL	MODERATE	SMALL	SMALL	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Cultural Resources	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

TABLE 8-2
IMPACTS COMPARISON DETAIL

		No-Action Alternative				
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With IGCC Generation**	**With Gas-Fired Generation**	**With New Nuclear Generation**	**With Purchased Power**
Alternative Descriptions						
HNP license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current HNP license. Adopting by reference, as bounding HNP decommissioning, GEIS description (NRC 1996, Section 7.1)	New construction at the HNP site.	New construction at the HNP site.	New construction at the HNP site.	New construction at the HNP site	Would involve construction of new generation capacity in North or South Carolina. Adopting by reference GEIS description of alternate technologies (Section 7.2.1.3)
		Use existing rail spur	Use existing rail spur	Construct up to 2 miles of gas pipeline in a 50-foot-wide corridor, disturbing as much as 12 acres. May require upgrades to existing pipelines.	Use existing rail spur for delivery of reactor vessel and other large equipment during construction.	
		Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Construct an unknown length of transmission lines
		Two 439.5-MW (net) tangentially-fired, dry bottom units; capacity factor 0.85	Three 293-MW of net power (Combined-cycle turbines to be used)	Three 293-MW of net power (Combined-cycle turbines to be used)		

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

		No-Action Alternative				
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With IGCC Generation**	**With Gas-Fired Generation**	**With New Nuclear Generation**	**With Purchased Power**
		Existing HNP intake/ discharge canal system	Existing HNP intake/ discharge canal system	Existing HNP intake/ discharge canal system	Existing HNP intake/ discharge canal system	
		Pulverized bituminous coal, 12,415 Btu/pound; 10,200 Btu/kWh; 10.4% ash; 0.85% sulfur; 10 lb/ton nitrogen oxides; 2,849,976 tons coal/yr	Syngas from pulverized bituminous coal, 12,415 Btu/pound; 6,870 Btu/net-kWh; 0.017 lb SO_x/MMBtu; 0.024 lb NO_x/MMBtu; 1,991,978 tons coal/yr	Natural gas, 1,032 Btu/ft^3; 5,990 Btu/kWh; 0.0034 lb sulfur/MMBtu; 0.0109 lb NO_x/MMBtu; 39,508,666,479 ft^3 gas/yr		
		Low NO_x burners, overfire air and selective catalytic reduction (95% NO_x reduction efficiency).	Gasification process removes sulfur and reduces NO_x emissions.	Selective catalytic reduction with steam/water injection		
		Wet scrubber – lime/limestone desulfurization system (95% SO_x removal efficiency); 42,382 tons limestone/yr				
		Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency)				

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With IGCC Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With New Nuclear Generation	No-Action Alternative: With Purchased Power
470 permanent and 250 long-term contract workers		72 workers (Section 7.2.2.1)	150 workers (Section 7.2.2.2)	32 workers (Section 7.2.2.3)		
Land Use Impacts						
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 52, 53)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL to MODERATE – 250 acres required for the powerblock and associated facilities. (Section 7.2.2.1)	SMALL to MODERATE – 200 acres required for the powerblock and associated facilities. (Section 7.2.2.2)	SMALL to MODERATE – 60 acres for facility at HNP location; 12 acres for pipeline (Section 7.2.2.3). New gas pipeline would be built to connect with existing gas pipeline corridor.	SMALL to MODERATE – 250 acres required for the powerblock and associated facilities. (Section 7.2.2.4)	MODERATE – most transmission facilities could be constructed along existing transmission corridors (Section 7.2.2.5) Adopting by reference GEIS description of land use impacts from alternate technologies (NRC 1996)

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

		No-Action Alternative				
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With IGCC Generation**	**With Gas-Fired Generation**	**With New Nuclear Generation**	**With Purchased Power**
			Water Quality Impacts			
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 5-11 and 32). Five Category 2 groundwater issues not applicable (Section 4.1, Issue 13; Section 4.5, Issue 33; Section 4.6, Issue 34; Section 4.7, Issue 35; and Section 4.8, Issue 39).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 89).	SMALL – Construction impacts minimized by use of best management practices. Operational impacts minimized by use of the existing cooling water system that withdraws from and discharges to Harris Reservoir. (Section 7.2.2.1)	SMALL – Construction impacts minimized by use of best management practices. Operational impacts minimized by use of the existing cooling water system that withdraws from and discharges to Harris Reservoir. (Section 7.2.2.2)	SMALL – Reduced cooling water demands, inherent in combined-cycle design (Section 7.2.2.3)	SMALL – Construction impacts minimized by use of best management practices. Operational impacts minimized by use of the existing cooling water system that withdraws from and discharges to Harris Reservoir. (Section 7.2.2.4)	SMALL to MODERATE – Adopting by reference GEIS description of water quality impacts from alternate technologies (NRC 1996)
			Air Quality Impacts			
SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 51). Category 2 issue not applicable (Section 4.11, Issue 50).	SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issue 88)	MODERATE – 2,301 tons SO_x/yr 712 tons NO_x/yr 712 tons CO/yr 148 tons TSP/yr 34 tons PM_{10}/yr (Section 7.2.2.1)	MODERATE – 420 tons SO_x/yr 594 tons NO_x/yr 742 tons CO/yr 49 tons PM_{10}/yr (Section 7.2.2.2)	MODERATE – 69 tons SO_x/yr 222 tons NO_x/yr 46 tons CO/yr 39 tons PM_{10}/yr[a] (Section 7.2.2.3)	SMALL – Air emissions would be comparable to those associated with the continued operation of HNP. (Section 7.2.2.4)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (NRC 1996)

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

		No-Action Alternative				
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With IGCC Generation**	**With Gas-Fired Generation**	**With New Nuclear Generation**	**With Purchased Power**
Ecological Resource Impacts						
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 15-24, 41-48). Four Category 2 issues not applicable (; Section 4.4, Issue 27, and Section 4.9, Issue 40).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 90)	SMALL to MODERATE – 35.5 acres of forested land could be required for ash/sludge disposal over 20-year license renewal term. (Section 7.2.2.1)	SMALL – 4 acres of forested land could be required for slag disposal over 20-year license renewal term. (Section 7.2.2.2)	SMALL to MODERATE – Construction of the pipeline could alter habitat. (Section 7.2.2.3)	SMALL – Impacts would be comparable to those associated with the continued operation of HNP. (Section 7.2.2.4)	SMALL to MODERATE – Adopting by reference GEIS description of ecological resource impacts from alternate technologies (NRC 1996)
Threatened or Endangered Species Impacts						
SMALL – No Federally threatened or endangered species are known along the transmission corridors. Bald eagles forage and nest around Harris Reservoir. An experimental population of endangered Michaux's sumac (*Rhus michauxii*), was transplanted in the Harris Research Tract near HNP in 2001, and is being monitored by biologists from North Carolina State University (Section 4.10, Issue 49)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative				
		With Coal-Fired Generation	**With IGCC Generation**	**With Gas-Fired Generation**	**With New Nuclear Generation**	**With Purchased Power**
			Human Health Impacts			
SMALL – Adopting by reference Category 1 issues (Table A-1, Issues 54-56, 58, 61, 62). The issue of microbiological organisms (Section 4.12, Issue 57) does not apply. Risk due to transmission-line induced currents minimal due to conformance with consensus code (Section 4.13, Issue 59)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 86)	MODERATE – Adopting by reference GEIS conclusion that risks such as cancer and emphysema from emissions are likely (NRC 1996)	MODERATE – Adopting by reference GEIS conclusion that risks such as cancer and emphysema from emissions are likely (NRC 1996)	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (NRC 1996)	SMALL – Impacts would be comparable to those associated with the continued operation of HNP. (Section 7.2.2.4)	SMALL to MODERATE – Adopting by reference GEIS description of human health impacts from alternate technologies (NRC 1996)

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

		No-Action Alternative				
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With IGCC Generation**	**With Gas-Fired Generation**	**With New Nuclear Generation**	**With Purchased Power**
Socioeconomic Impacts						
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 64, 67, 91). Two Category 2 issues are not applicable (Section 4.16, Issue 66 and Section 4.17.1, Issue 68). Location in high population area with limited growth controls minimizes potential for housing impacts. Section 4.14, Issue 63). Plant property tax payment represents less than 3 percent of Wake county's total tax revenues (Section 4.17.2, Issue 69). Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65 and Section 4.18, Issue 70)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 91)	SMALL – Reduction in permanent work force at HNP could adversely affect surrounding counties, but would be mitigated by HNP's proximity to Raleigh (Section 7.2.2.1).	SMALL – Reduction in permanent work force at HNP could adversely affect surrounding counties, but would be mitigated by HNP's proximity to Raleigh (Section 7.2.2.2).	MODERATE – Reduction in permanent work force at HNP could adversely affect surrounding counties, but would be mitigated by HNP's proximity to Raleigh (Section 7.2.2.3)	<u>Construction:</u> MODERATE to LARGE – Peak construction workforce of 2,500 could affect housing and public services in surrounding counties. <u>Operation</u>: SMALL – Impacts would be comparable to those associated with the continued operation of HNP. (Section 7.2.2.4)	SMALL to MODERATE – Adopting by reference GEIS description of socioeconomic impacts from alternate technologies (NRC 1996)

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

		No-Action Alternative				
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With IGCC Generation**	**With Gas-Fired Generation**	**With New Nuclear Generation**	**With Purchased Power**
Waste Management Impacts						
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 87)	MODERATE – 174,900 tons of coal ash and 125,500 tons of scrubber sludge would require 35.5 acres over 20-year license renewal term. Industrial waste generated annually (Section 7.2.2.1)	SMALL – 20,717 tons of slag per year would require 4 acres over 20-year license renewal term. Industrial waste generated annually (Section 7.2.2.2)	SMALL – Almost no waste generation (Section 7.2.2.3)	SMALL – Impacts would be comparable to those associated with the continued operation of HNP. (Section 7.2.2.4)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies (NRC 1996)
Aesthetic Impacts						
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 73, 74)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – The coal-fired power blocks and the exhaust stacks would be visible from a moderate offsite distance (Section 7.2.2.1)	SMALL – Steam turbines and stacks would create visual impacts comparable to those from existing HNP facilities (Section 7.2.2.2)	SMALL – Steam turbines and stacks would create visual impacts comparable to those from existing HNP facilities (Section 7.2.2.3)	SMALL – Impacts would be comparable to those associated with the continued operation of HNP. (Section 7.2.2.4)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (NRC 1996)

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

		No-Action Alternative				
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With IGCC Generation**	**With Gas-Fired Generation**	**With New Nuclear Generation**	**With Purchased Power**
Cultural Resource Impacts						
SMALL – SHPO consultation minimizes potential for impact (Section 4.19, Issue 71)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.1)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.2)	SMALL – Two miles of pipeline construction in east–central NC could affect some cultural resources (Section 7.2.2.3)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.4)	SMALL – Adopting by reference GEIS description of cultural resource impacts from alternate technologies (NRC 1996)

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

Btu = British thermal unit
ft^3 = cubic foot
gal = gallon
GEIS = Generic Environmental Impact Statement (NRC 1996)
kWh = kilowatt hour
lb = pound
MM = million
MW = megawatt
NO_x = nitrogen oxide
PM_{10} = particulates having diameter less than 10 microns
SHPO = State Historic Preservation Officer
SO_x = sulfur dioxide
TSP = total suspended particulates
yr = year

a. All TSP for gas-fired alternative is PM_{10}.

8.1 REFERENCES

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

9.0 STATUS OF COMPLIANCE

9.1 PROPOSED ACTION

NRC

"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." 10 CFR 51.45(d), as adopted by 10 CFR 51.53(c)(2)

9.1.1 GENERAL

Table 9-1 lists environmental authorizations that Progress Energy has obtained for current Shearon Harris Nuclear Plant (HNP) operations. In this context, Progress Energy uses "authorizations" to include any permits, licenses, approvals, or other entitlements. Progress Energy expects to continue renewing these authorizations during the current license period and through the U.S. Nuclear Regulatory Commission (NRC) license renewal period. Preparatory to applying for renewal of the HNP license to operate, Progress Energy conducted an assessment to identify any new and significant environmental information (Chapter 5). The assessment included interviews with Progress Energy subject experts, review of HNP environmental documentation, and communication with state and federal environmental protection agencies. Based on this assessment, Progress Energy concludes that HNP is in compliance with applicable environmental standards and requirements.

Table 9-2 lists additional environmental authorizations and consultations related to NRC renewal of the HNP license to operate. As indicated, Progress Energy anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.5 discuss some of these items in more detail.

9.1.2 THREATENED OR ENDANGERED SPECIES

Section 7 of the Endangered Species Act (16 USC 1531 et seq.) requires federal agencies to ensure that agency action is not likely to jeopardize any species that is listed, proposed for listing as endangered, or threatened. Depending on the action involved, the Act requires consultation with the U.S. Fish and Wildlife Service (FWS) regarding effects on non-marine species, the National Marine Fisheries Service (NMFS) for marine species, or both. FWS and NMFS have issued joint procedural regulations at

50 CFR 402, Subpart B, that address consultation, and FWS maintains the joint list of threatened and endangered species at 50 CFR 17.

Although not required of an applicant by federal law or NRC regulation, Progress Energy has chosen to invite comment from federal and state agencies regarding potential effects that HNP license renewal might have. Appendix C includes copies of Progress Energy correspondence with FWS and the North Carolina Department of Environment and Natural Resources (NCDENR). The (February 16, 2006) FWS response noted that the proposed action (license renewal) is not likely to adversely affect any species proposed for federal listing, any species currently listed as threatened or endangered, or any designated critical habitat. The (January 27, 2006) NCDENR response indicated that Progress Energy and the Natural Heritage Program of NCDENR had worked together in the past to preserve wildlife habitat and are currently working together to ensure the protection of several significant natural areas on the HNP site.

9.1.3 COASTAL ZONE MANAGEMENT PROGRAM COMPLIANCE

The federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on applicants for a federal license to conduct an activity that could affect a state's coastal zone (NRC 2004). HNP, located in Wake and Chatham counties, is not located within the North Carolina Coastal Management Area (NCDENR 2002). Therefore, certification from the North Carolina Coastal Resource Commission does not apply to this facility.

9.1.4 HISTORIC PRESERVATION

Section 106 of the National Historic Preservation Act (16 USC 470 et seq.) requires federal agencies having the authority to license any undertaking to, prior to issuing the license, take into account the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Council regulations provide for the State Historic Preservation Officer (SHPO) having a consultative role (36 CFR 800.2). Although not required of an applicant by federal law or NRC regulation, Progress Energy has chosen to invite comment by the North Carolina SHPO. Appendix D contains a copy of Progress Energy's letter to the North Carolina Department of Cultural Resources' State Historic Preservation Office (SHPO) and the SHPO response, dated January 26, 2006, which indicated that the Office was "…aware of no historic resources that would be affected by the project."

9.1.5 WATER QUALITY (401) CERTIFICATION

Federal Clean Water Act Section 401 requires applicants for a federal license to conduct an activity that might result in a discharge into navigable waters to provide the licensing agency a certification from the state that the discharge will comply with applicable Clean Water Act requirements (33 USC 1341). The Section 401 certification for HNP was issued to Carolina Power & Light Company by the North Carolina Department of Natural Resources & Community Development on September 14, 1977. The NPDES permit for HNP provides continuing assurance of compliance with the standards and requirements established under the Clean Water Act. Excerpts from this permit are provided in Appendix B.

9.2 ALTERNATIVES

NRC

"The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements." 10 CFR 51.45(d), as required by 10 CFR 51.53(c)(2)

The coal, gas, nuclear, and purchased power alternatives discussed in Section 7.2.1 probably could be constructed and operated to comply with applicable environmental quality standards and requirements. Progress Energy notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. Progress Energy also notes that the U.S. Environmental Protection Agency has revised requirements for design and operation of cooling water intake structures at new and existing facilities (40 CFR 125 Subparts I and J). These requirements could necessitate construction of cooling towers for fossil-fueled or nuclear alternatives if surface water were used for cooling.

TABLE 9-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT HNP UNIT 1 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	NPF-63	Issued 10/24/86; Expires 10/24/26	Operation of Unit 1
U.S. Fish and Wildlife Service	16 USC 703-712	Federal Fish and Wildlife Permit, Depredation	MB789112-0	Issued 04/21/06; Expires 03/31/07	Removal and relocation of migratory bird nests
U.S. Department of Transportation	49 USC 5108	Registration	0531065500130	Issued 6/01/06; Expires 6/30/07	Hazardous materials shipments
North Carolina Department of Environment and Natural Resources	Clean Water Act (33 USC 1251 et seq.), NC General Statute 143-215.1	National Pollutant Discharge Elimination System Permit	NC0039586	Issued 05/01/02; Expires 07/31/06	Wastewater discharges to Harris Reservoir (Part I), stormwater discharges to waters of the State (Part II). Emergency Service Water discharges to the auxiliary reservoir (Part II).

TABLE 9-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT HNP UNIT 1 OPERATIONS (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
North Carolina Department of Environment and Natural Resources	Clean Air Act Title V (42 USC 7661 et seq.); NC General Statutes Article 21B of Chapter 143	Air Permit	08455R03	Issued 04/10/02; Expires 03/31/07	Air emissions for boilers and emergency generators source operation
North Carolina Wildlife Resources Commission	NC Statutory Authority 113-274(c)(1)(a) NC Administrative Code Title 15A, Subchapter 10B.0106	Special Migratory Bird Permit	T-NC002-L06	Issued 02/15/06; Expires 12/31/06	Removal and relocation of migratory bird nests
South Carolina Department of Health and Environmental Control, Division of Waste Management	South Carolina Radioactive Waste Transportation and Disposal Act (Act No. 429)	South Carolina Radioactive Waste Transport Permit	0324-32-06-X	Issued 12/09/05; Expires 12/31/06	Transportation of radioactive waste into the State of South Carolina
State of Tennessee Department of Environment and Conservation, Division of Radiological Health	Tennessee Department of Environment and Conservation Rule 1200-2-10.32	Tennessee Radioactive Waste License-for-Delivery	T-NC002-L06	Issued 01/01/06; Expires 12/31/06	Transportation of radioactive waste into the State of Tennessee

TABLE 9-2
ENVIRONMENTAL AUTHORIZATIONS FOR
HNP UNIT 1 RENEWAL[a]

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	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with the U.S. Fish and Wildlife Service (Appendix C)
North Carolina Department of Environment and Natural Resources	Clean Water Act Section 401 (33 USC 1341)	Certification	State issuance of NPDES permit (Section 9.1.5) constitutes 401 certification (Appendix B)
North Carolina Department of Cultural Resources	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (SHPO). SHPO must concur that license renewal will not affect any sites listed or eligible for listing (Appendix D)

a. No renewal-related requirements identified for local or other agencies.

9.3 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 cited web pages are available in Progress Energy files. Some sites, for example 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 Progress Energy have been given for these pages, even though they may not be directly accessible.

NCDENR (North Carolina Department of Environment and Natural Resources). 2002. North Carolina Division of Coastal Management, CAMA Counties. Available at http://dcm2.enr.state.nc.us/cama_counties.htm. Accessed October 25, 2006.

NRC (U.S. Nuclear Regulatory Commission). 1996. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS). Volume 1, Section 4.2.1.1, page 4-4. NUREG-1437. Washington, DC. May.

NRC (U.S. Nuclear Regulatory Commission). 2004. Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues. NRR Office Instruction LIC-203, Revision 1. May 24.

APPENDIX A
NRC NEPA ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS

Progress Energy has prepared this environmental report in accordance with the requirements of U.S. Nuclear Regulatory Commission (NRC) regulation 10 CFR 51.53. NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants.

Table A-1 lists these 92 issues and identifies the section in which Progress Energy addressed each applicable issue in this environmental report. For organization and clarity, Progress Energy has assigned a number to each issue and uses the issue numbers throughout the environmental report.

TABLE A-1
HNP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUESA

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Surface Water Quality, Hydrology, and Use (for all plants)			
1. Impacts of refurbishment on surface water quality	1	NA	Issue applies to an activity, refurbishment, that HNP has no plans to undertake.
2. Impacts of refurbishment on surface water use	1	NA	Issue applies to an activity, refurbishment, that HNP has no plans to undertake.
3. Altered current patterns at intake and discharge structures	1	4.0	4.2.1.2.1/4-5
4. Altered salinity gradients	1	NA	Issue applies to an activity, discharge to saltwater, that HNP does not do.
5. Altered thermal stratification of lakes	1	4.0	4.2.2.1.4/4-17
6. Temperature effects on sediment transport capacity	1	4.0	4.2.1.2.3/4-8
7. Scouring caused by discharged cooling water	1	4.0	4.2.1.2.3/4-6
8. Eutrophication	1	4.0	4.2.1.2.3/4-9
9. Discharge of chlorine or other biocides	1	4.0	4.2.1.2.4/4-10
10. Discharge of sanitary wastes and minor chemical spills	1	4.0	4.2.1.2.4/4-10
11. Discharge of other metals in waste water	1	4.0	4.2.1.2.4/4-10
12. Water use conflicts (plants with once-through cooling systems)	1	NA	Issue applies to a plant feature, once-through cooling, that HNP does not have.
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	NA, and discussed in Section 4.1	Issue applies to a feature, make-up water from a small river that HNP does not have.
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	NA	Issue applies to an activity, refurbishment, that HNP has no plans to undertake.
15. Accumulation of contaminants in sediments or biota	1	4.0	4.2.1.2.4/4-10
16. Entrainment of phytoplankton and zooplankton	1	4.0	4.2.2.1.1/4-15
17. Cold shock	1	4.0	4.2.2.1.5/4-18
18. Thermal plume barrier to migrating fish	1	4.0	4.2.2.1.6/4-19

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
19.	Distribution of aquatic organisms	1	4.0	4.2.2.1.6/4-19
20.	Premature emergence of aquatic insects	1	4.0	4.2.2.1.7/4-20
21.	Gas supersaturation (gas bubble disease)	1	4.0	4.2.2.1.8/4-21
22.	Low dissolved oxygen in the discharge	1	4.0	4.2.2.1.9/4-23
23.	Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.0	4.2.2.1.10/4-24
24.	Stimulation of nuisance organisms (e.g., shipworms)	1	4.0	4.2.2.1.11/4-25
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)				
25.	Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.2	Issue applies to a heat dissipation system, once-through cooling, that HNP does not have.
26.	Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.3	Issue applies to a heat dissipation system, once-through cooling, that HNP does not have.
27.	Heat shock for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.4	Issue applies to a heat dissipation system, once-through cooling, that HNP does not have.
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)				
28.	Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	4.0	4.3.3/4-33
29.	Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	4.0	4.3.3/4-33
30.	Heat shock for plants with cooling-tower-based heat dissipation systems	1	4.0	4.3.3/4-33
Groundwater Use and Quality				
31.	Impacts of refurbishment on groundwater use and quality	1	NA	Issue applies to an activity, refurbishment, that HNP has no plans to undertake.
32.	Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	4.0	4.8.1.1/4-116 and 4.8.2.1/4-119
33.	Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	NA, and discussed in Section 4.5	Issue applies to an activity, using 100 gpm or more of groundwater, that HNP does not do.

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
34.	Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	NA, and discussed in Section 4.6	Issue applies to an activity, withdrawing make-up water from a small river, that HNP does not do.
35.	Groundwater use conflicts (Ranney wells)	2	NA, and discussed in Section 4.7	Issue applies to a plant feature, Ranney wells, that HNP does not have.
36.	Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney wells, that HNP does not have.
37.	Groundwater quality degradation (saltwater intrusion)	1	NA	Issue applies to a feature, location at an ocean or estuary site, that HNP does not have.
38.	Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Issue applies to a feature, location in a salt march, that HNP does not have.
39.	Groundwater quality degradation (cooling ponds at inland sites)	2	NA, and discussed in Section 4.8	Issue applies to a feature, cooling ponds, that HNP does not have.
Terrestrial Resources				
40.	Refurbishment impacts to terrestrial resources	2	NA, and discussed in Section 4.9	Issue applies to an activity, refurbishment, that HNP has no plans to undertake.
41.	Cooling tower impacts on crops and ornamental vegetation	1	4.0	4.3.4/4-34
42.	Cooling tower impacts on native plants	1	4.0	4.3.4/4-34
43.	Bird collisions with cooling towers	1	4.0	4.3.5.2/4-45
44.	Cooling pond impacts on terrestrial resources	1	NA	Issue applies to a feature, cooling ponds, that HNP does not have.
45.	Power line right-of-way management (cutting and herbicide application)	1	4.0	4.5.6.1/4-71
46.	Bird collisions with power lines	1	4.0	4.5.6.2/4-74
47.	Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.0	4.5.6.34-77
48.	Floodplains and wetlands on power line right-of-way	1	4.0	4.5.7.7/4-81
Threatened or Endangered Species (for all plants)				
49.	Threatened or endangered species	2	4.10	4.1/4-1

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
		Air Quality		
50.	Air quality during refurbishment (non-attainment and maintenance areas)	2	NA, and discussed in Section 4.11	Issue applies to an activity, refurbishment, that HNP does not plan to undertake.
51.	Air quality effects of transmission lines	1	4.0	4.5.2/4-62
		Land Use		
52.	Onsite land use	1	4.0	3.2/3-1
53.	Power line right-of-way land use impacts	1	4.0	4.5.3/4-62
		Human Health		
54.	Radiation exposures to the public during refurbishment	1	NA	Issue applies to an activity, refurbishment, that HNP has no plans to undertake.
55.	Occupational radiation exposures during refurbishment	1	NA	Issue applies to an activity, refurbishment, that HNP has no plans to undertake.
56.	Microbiological organisms (occupational health)	1	4.0	4.3.6/4-48
57.	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	NA, and discussed in Section 4.12	Issues applies to plant features, cooling towers or cooling ponds that discharge to a small river, that HNP does not have.
58.	Noise	1	4.0	4.3.7/4-49
59.	Electromagnetic fields, acute effects	2	4.13	4.5.4.1/4-66
60.	Electromagnetic fields, chronic effects	NA	4.0	
61.	Radiation exposures to public (license renewal term)	1	4.0	4.6.2/4-87
62.	Occupational radiation exposures (license renewal term)	1	4.0	4.6.3/4-95
		Socioeconomics		
63.	Housing impacts	2	4.14	3.7.2/3-10 (refurbishment - not applicable to HNP) 4.7.1/4-101 (renewable term)

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
64.	Public services: public safety, social services, and tourism and recreation	1	4.0	Refurbishment (not applicable to HNP) 3.7.4/3-14 (public service) 3.7.4.3/3-18 (safety) 3.7.4.4/3-19 (social) 3.7.4.6/3-20 (tour, rec) Renewal Term 4.7.3/4-104 (public safety) 4.7.3.3/4-106 (safety) 4.7.3.44-107 (social) 4.7.3.6/4-107 (tour, rec)
65.	Public services: public utilities	2	4.15	3.7.4.5/3-19 (refurbishment - not applicable to HNP) 4.7.3.5/4-107 (renewable term)
66.	Public services: education (refurbishment)	2	NA, and discussed in Section 4.16	Issue applies to an activity, refurbishment, that HNP does not plan to undertake.
67.	Public services: education (license renewal term)	1	4.0	4.7.3.1/4-106
68.	Offsite land use (refurbishment)	2	NA, and discussed in Section 4.17.1	Issue applies to an activity, refurbishment, that HNP does not plan to undertake.
69.	Offsite land use (license renewal term)	2	4.17.2	4.7.4/4-107
70.	Public services: transportation	2	4.18	3.7.4.2/3-17 (refurbishment - not applicable to HNP) 4.7.3.2/4-106 (renewal term)
71.	Historic and archaeological resources	2	4.19	3.7.7/3-23 (refurbishment - not applicable to HNP) 4.7.7/4-114 (renewal term)
72.	Aesthetic impacts (refurbishment)	1	NA	Issue applies to an activity, refurbishment, that HNP has no plans to undertake.
73.	Aesthetic impacts (license renewal term)	1	4.0	4.7.6/4-111
74.	Aesthetic impacts of transmission lines (license renewal term)	1	4.0	4.5.8/4-83
	Postulated Accidents			
75.	Design basis accidents	1	4.0	5.3.2/5-11 (design basis) 5.5.1/5-114 (summary)

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
76.	Severe accidents	2	4.20	5.3.3/5-12 (probabilistic analysis) 5.3.3.2/5-19 (air dose) 5.3.3.3/5-49 (water) 5.3.3.4/5-65 (groundwater) 5.3.3.5/5-95 (economic) 5.4/5-106 (mitigation) 5.5.2/5-114 (summary)
Uranium Fuel Cycle and Waste Management				
77.	Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4.0	6.2/6-8
78.	Offsite radiological impacts (collective effects)	1	4.0	Not in GEIS.
79.	Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4.0	Not in GEIS.
80.	Nonradiological impacts of the uranium fuel cycle	1	4.0	6.2.2.6/6-20 (land use) 6.2.2.7/6-20 (water use) 6.2.2.8/6-21 (fossil fuel) 6.2.2.9/6-21 (chemical)
81.	Low-level waste storage and disposal	1	4.0	6.4.2/6-36 (low-level def) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)
82.	Mixed waste storage and disposal	1	4.0	6.4.5/6-63
83.	Onsite spent fuel	1	4.0	6.4.6/6-70
84.	Nonradiological waste	1	4.0	6.5/6-86
85.	Transportation	1	4.0	6.3/6-31, as revised by Addendum 1, August 1999.
Decommissioning				
86.	Radiation doses (decommissioning)	1	4.0	7.3.1/7-15
87.	Waste management (decommissioning)	1	4.0	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88.	Air quality (decommissioning)	1	4.0	7.3.3/7-21 (air) 7.4/7-25 (conclusions)
89.	Water quality (decommissioning)	1	4.0	7.3.4/7-21 (water) 7.4/7-25 (conclusions)
90.	Ecological resources (decommissioning)	1	4.0	7.3.5/7-21 (ecological) 7.4/7-25 (conclusions)
91.	Socioeconomic impacts (decommissioning)	1	4.0	7.3.7/7-19 (socioeconomic) 7.4/7-24 (conclusions)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Environmental Justice			
92. Environmental justice	NA	2.6.2	

a. Source: 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)

b. Source: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437).

APPENDIX B
NPDES PERMIT

This Appendix contains selected pages of Shearon Harris Nuclear Plant's National Pollutant Discharge Elimination System permit, including the cover page, which authorizes the Plant to discharge wastewater to the Harris Reservoir in the Cape Fear River Basin.

Permit No. NC0039586

STATE OF NORTH CAROLINA
DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES
DIVISION OF WATER QUALITY

PERMIT

TO DISCHARGE WASTEWATER UNDER THE

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provision of North Carolina General Statute 143-215.1, other lawful standards and regulations promulgated and adopted by the North Carolina Environmental Management Commission, and the Federal Water Pollution Control Act, as amended,

Carolina Power and Light Co.

is hereby authorized to discharge wastewater from a facility located at

Harris Nuclear Plant and Harris Energy and Environmental Center
5413 Shearon Harris Road
New Hill
Wake County

to receiving waters designated as Harris Reservoir in the Cape Fear River Basin in accordance with effluent limitations, monitoring requirements, and other conditions set forth in Parts I, II, III, IV, V and VI hereof.

The permit shall become effective May 1, 2002.

This permit and the authorization to discharge shall expire at midnight on July 31, 2006.

Signed this day April 12, 2002.

David A. Goodrich

for Gregory J. Thorpe, Director
Division of Water Quality
By Authority of the Environmental Management Commission

Permit No. NC0039586

SUPPLEMENT TO PERMIT COVER SHEET

Carolina Power and Light Co.

is hereby authorized to:

1. Continue to discharge cooling tower blowdown through outfall 001; and

2. Continue to operate a 0.05 MGD extended aeration wastewater treatment plant consisting of dual package plants with the following components:
   - equalization tanks
   - aeration tanks
   - sludge holding tanks
   - clarifiers
   - chlorine contact tanks

   discharging through outfall 002; and

3. Continue to operate a metal cleaning waste treatment system consisting of dual neutralization basins discharging through outfall 003; and

4. Continue to operate a low volume waste treatment system consisting of:
   - Waste neutralization basin (also used for metal cleaning waste treatment, outfall 003)
   - Settling basin

   discharging through outfall 004; and

5. Continue to operate a radwaste treatment system consisting of a Modular Fluidized Transfer Demineralization System discharging through outfall 005; and

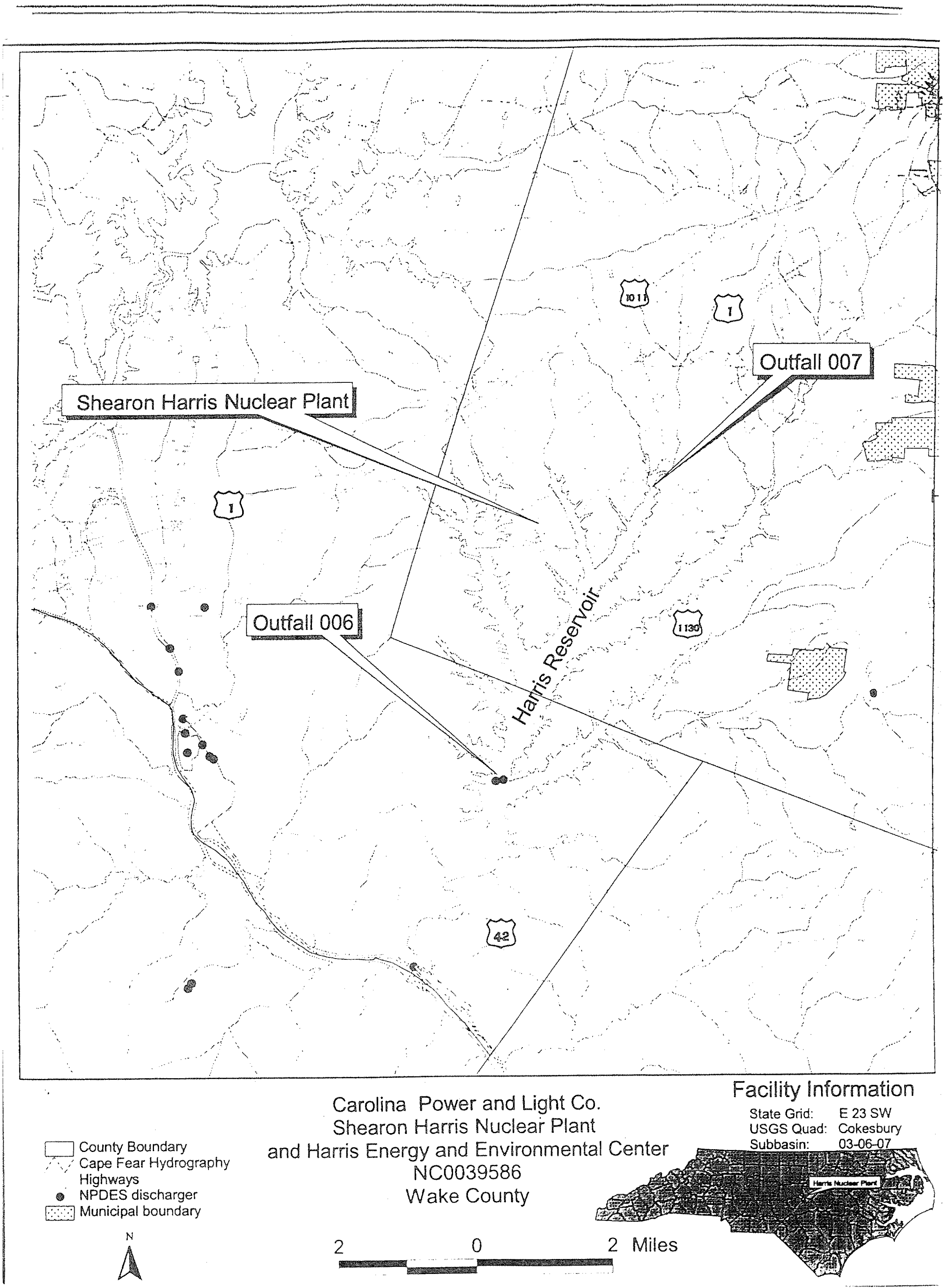
6. Discharge wastewater from outfalls 001 through outfall 005 through the combined outfall 006 located at the Harris Nuclear Power Plant, 5413 Shearon Harris Road, New Hill, Wake County; and

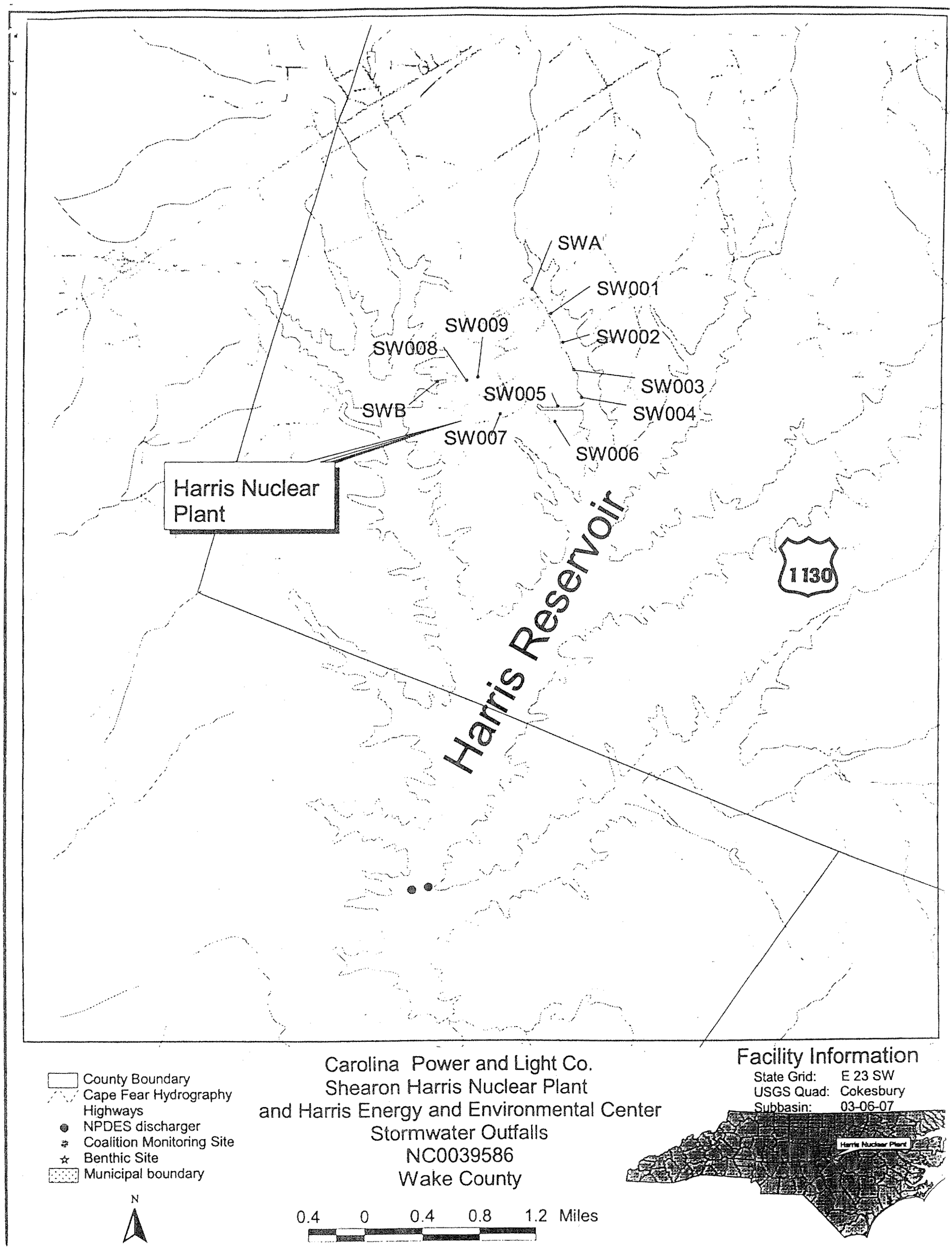
7. Continue to operate a 0.02 MGD wastewater treatment facility consisting of:
   - holding tanks
   - comminutor
   - bar screen
   - influent pump station
   - aerated pond
   - stabilization pond
   - polishing pond
   - sand filter,
   - chlorination and dechlorination

   discharging through outfall 007 located at the Harris Energy and Environmental Center, 3932 New Hill/Holleman Road, New Hill, Wake County; and

8. Continue to discharge stormwater, normal service water, emergency service water, circulating water, potable water, demineralized water, hydrostatic flushing of system piping and wash water from outfalls SW-001, SW-002, SW-003, SW-004, SW-005, SW-006, SW-007, SW-008, SW-009, SW-A and SW-B.

9. Discharge from said treatment works and stormwater outfalls into Harris Reservoir, a Class WS-V water in the Cape Fear River Basin, at the locations specified on the attached maps.


Shearon Harris Nuclear Plant
Outfall 007
Outfall 006
Harris Reservoir
1011
1
1130
42
Carolina Power and Light Co.
Shearon Harris Nuclear Plant
and Harris Energy and Environmental Center
NC0039586
Wake County
Facility Information
State Grid: E 23 SW
USGS Quad: Cokesbury
Subbasin: 03-06-07
Harris Nuclear Plant
County Boundary
Cape Fear Hydrography
Highways
NPDES discharger
Municipal boundary
N
2
0
2 Miles


SWA
SW001
SW002
SW003
SW004
SW005
SW006
SW007
SW008
SW009
SWB
Harris Nuclear Plant
Harris Reservoir
1130
County Boundary
Cape Fear Hydrography
Highways
NPDES discharger
Coalition Monitoring Site
Benthic Site
Municipal boundary
N
Carolina Power and Light Co.
Shearon Harris Nuclear Plant
and Harris Energy and Environmental Center
Stormwater Outfalls
NC0039586
Wake County
0.4 0 0.4 0.8 1.2 Miles
Facility Information
State Grid: E 23 SW
USGS Quad: Cokesbury
Subbasin: 03-06-07
Harris Nuclear Plant

Permit No. NC0039586

PART I
MONITORING CONTROLS AND LIMITATIONS FOR PERMITTED DISCHARGES

SECTION A(1). EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

Beginning on the effective date of this permit and lasting until expiration, the Permittee is authorized to discharge cooling tower blowdown from outfall 001. Such discharges shall be limited and monitored by the Permittee as specified below:

Effluent Characteristics	Effluent Limitations		Monitoring Requirements		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location[1]
Flow[2]			Continuous	Recorder	Effluent
Free Available Chlorine[3]	0.2 mg/L	0.5 mg/L	Weekly	See Note 4	See Note 4
Total Residual Chlorine			Weekly	See Note 4	See Note 4
Time of TRC[3] (min/day/unit)		120.0 min	Weekly	Calculations	Effluent
Total Chromium[5]	0.2 mg/L	0.2 mg/L	Weekly	Grab	Effluent
Total Zinc[5]	1.0 mg/L	1.0 mg/L	Weekly	Grab	Effluent
The 126 Priority Pollutants[5]			Annually	Grab	Effluent

Notes:

1. Effluent prior to mixing with any other waste stream.
2. Discharge of blowdown from the cooling system shall be limited to the minimum discharge of recirculating water necessary for the purpose of discharging materials contained in the water, the further built-up of which would cause concentrations in amounts exceeding limitations established by best engineering practices. The permitee may discharge cooling water to the auxiliary reservoir in compliance with Part II.2 of this permit.
3. Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Director that the units in question cannot operate at or below this level of chlorination. The permittee shall record and report times of release as part of the monthly monitor report.
4. Free available chlorine shall be a daily average and daily maximum. Samples shall be multiple grabs at the tower which shall consists of grab samples collected at the approximate beginning of the total residual chlorine discharge and once every 15 minutes thereafter until the end of the total residual chlorine discharge. For the purpose of this permit, daily average (as it relates to the chlorination period) shall mean the average over any total residual chlorine discharge period.
5. These limitations and monitoring requirements apply only if these materials are added for cooling tower maintenance by the permittee. There shall be no discharge of detectable amounts of the 126 priority pollutants (40 CFR 423 Appendix A) contained in chemicals added for cooling tower maintenance except for Total Chromium and Total Zinc. Compliance with the limitations for the 126 pollutants may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the discharge by the analytical methods in 40 CFR 136.

APPENDIX C
SPECIAL-STATUS SPECIES CORRESPONDENCE

Letter **Page**

Progress Energy

SERIAL: HNP-05-112

NOV 1 6 2005

Mr. Garland Pardue
Ecological Services Supervisor
Raleigh Field Office
U.S. Fish & Wildlife Service
P.O. Box 33726
Raleigh, NC 27636-3726

SHEARON HARRIS NUCLEAR POWER PLANT
DOCKET NO. 50-400/LICENSE NO. NPF-63
LICENSE RENEWAL - REQUEST FOR INFORMATION
LISTED SPECIES AND IMPORTANT HABITATS

Dear Mr. Pardue:

Carolina Power & Light Company, doing business as Progress Energy Carolinas, Inc. (PEC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Harris Nuclear Plant (HNP), which expires in 2026. PEC intends to submit this application for license renewal in the fourth quarter of 2006. 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. 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 area. By contacting you in advance, we hope to identify any issues that need to be addressed or information required to expedite the NRC's consultation.

PEC has operated HNP and associated transmission lines since 1987, when the plant began commercial operation. HNP is located in the extreme southwest corner of Wake County, North Carolina. Portions of the HNP site also lie in southeastern Chatham County. The City of Raleigh, North Carolina is approximately 16 miles northeast of the plant, and the City of Sanford, North Carolina is approximately 15 miles southwest of the plant. The Cape Fear River flows in a northwest-to southeast direction approximately 7.0 miles south of the plant. CP&L constructed a dam in 1980 on Buckhorn Creek about 2.5 miles north of its confluence with the Cape Fear River to create 4,100-acre Harris Reservoir for cooling tower makeup. Filling of the reservoir began in the fall of 1980, and was completed in early 1983. The HNP power block area (i.e., reactor building, generating facilities, and switchyard) is located on the northwest shore of the reservoir, about 4.5 miles north of the main dam. The plant is located on a peninsula that extends into Harris Reservoir from the northwest (Figure 1). The Tom

Progress Energy Carolinas, Inc.
Harris Nuclear Plant
P. O. Box [illegible]
New Hill NC 27562

Mr. Garland Pardue
HNP-05-112 / Page 2

Jack Creek arm of the reservoir lies to the west; the Thomas Creek arm of the reservoir lies to the east. The reactor building and generating facilities lie within a nuclear exclusion area, access to which is controlled. The exclusion area is roughly circular, with a radius of approximately 7,000 feet, but is not a perfect circle; its axis ranges from 6,640 feet to 7,200 feet. The distance from the center of the exclusion area to the boundary ranges from 6,640 feet (to the northwest, because US Hwy 1 truncates the circle) to 7,000 feet (east) to 7,200 feet (south). The exclusion area, comprised of both high ground and portions of Harris Reservoir, encompasses approximately 3,535 acres.

Seven 230 kilovolt transmission lines connect HNP to the regional electric system. The transmission system is described in the following paragraphs and is depicted in its original configuration in Figure 2. With a few exceptions, the corridors are 100 feet wide.

Apex, US 1 Substation – This substation was added since the publication of the Environmental Report for the initial Operating License. It is located 3.4 circuit miles northeast of HNP and is now the terminus of the Cary Regency Park transmission line.

Asheboro – This 57-mile long line originally connected HNP with a switching station in the Asheboro, North Carolina area, west of HNP. More recently, the Siler City switching station was constructed, creating a new terminus for this line 31 circuit miles from HNP.

Cape Fear North – This line connects HNP with the Cape Fear Steam Plant 7.4 circuit miles southwest of the plant.

Cape Fear South – This newer line also connects HNP with the Cape Fear Steam Plant, but follows a more southerly 6.5-mile route than the north line.

Cary Regency Park – Originally named the Method line, the Cary Regency Park switching station, at 10 miles from HNP, is approximately 5 circuit miles shorter than the original run to Method. More recently, the Apex U.S. 1 switching station was built 3.4 circuit miles northeast of HNP and is now the terminus of this transmission line.

Erwin – This line, which is approximately 30 miles long, terminates just north of the town of Erwin, southeast of HNP.

Fayetteville – This line has its terminus at the Ft. Bragg Woodruff Street switching station, approximately 40 circuit miles south of the HNP site. It originally ran another 16 miles to Fayetteville.

Mr. Garland Pardue
HNP-05-112 / Page 3

Wake – This line, which is 38 miles long, connects HNP with the Wake switching station northeast of the site.

The corridors pass through land that is primarily agricultural and forestland. The areas are mostly remote, with low population densities. The longer lines cross numerous state and U.S. highways. Impact of these corridors on land usage is minimal; farmlands that have corridors passing through them generally continue to be used as farmland.

PEC believes that operation of the plant, including maintenance of the transmission lines, over the license renewal period (i.e., an additional 20 years) would not adversely affect any threatened or endangered species.

PEC would appreciate a response to this letter by February 1, 2006, providing any information you may have concerning listed species or ecologically-significant habitats that may occur on the HNP site, or along associated transmission corridors. This will enable PEC to meet the current application preparation schedule. PEC will include a copy of this letter and your response in the license renewal application to the NRC.

Please refer any questions regarding this submittal to Mr. Jan Kozyra, Lead Engineer - License Renewal, at (843) 857-1872.

Sincerely,

Dave Corlett

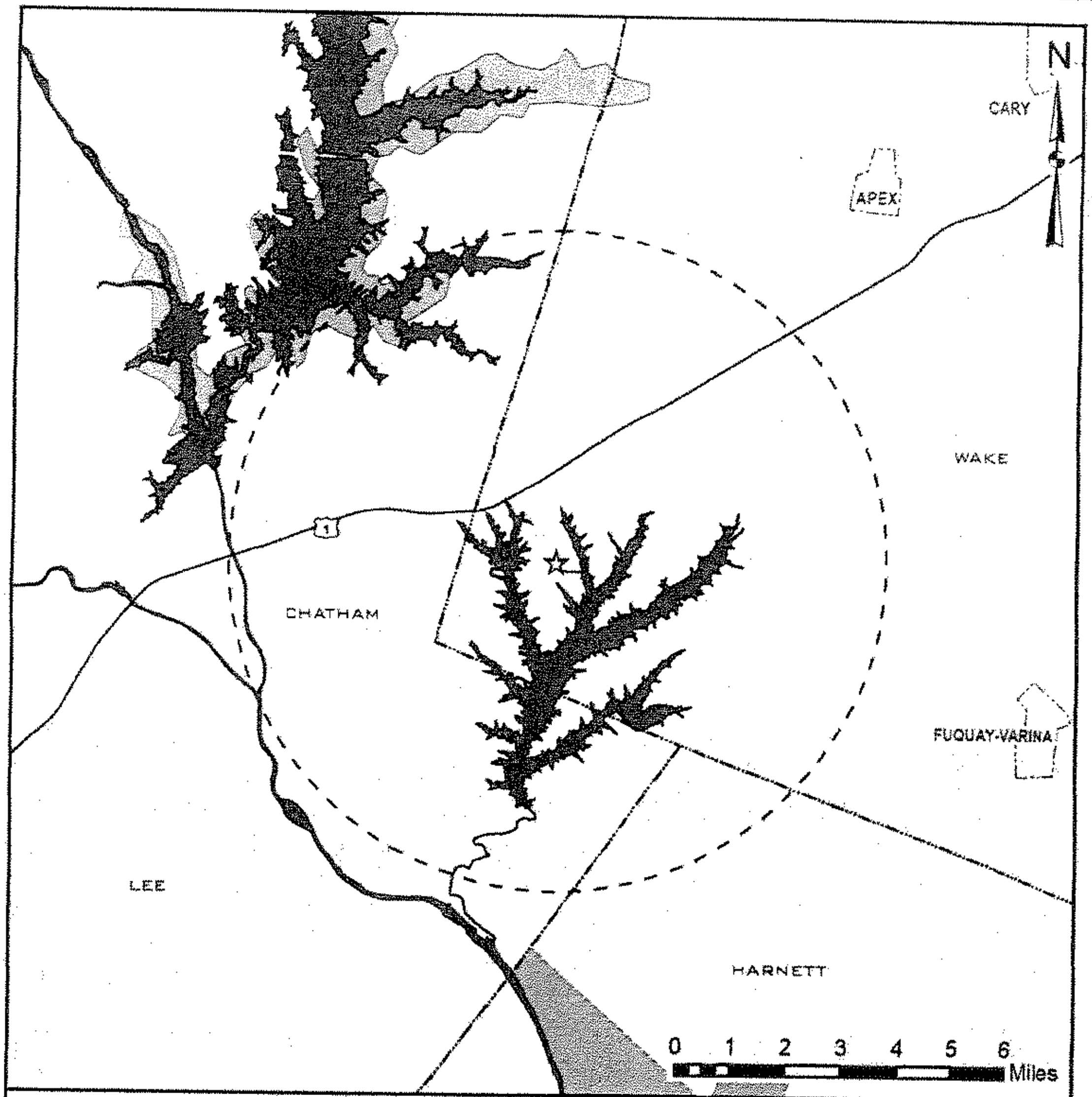
Dave Corlett
Supervisor-
Licensing and Regulatory Affairs
Harris Nuclear Plant

JSK/jsk

Enclosures:
Figure 1 – Harris Nuclear Plant 6-Mile Vicinity Map
Figure 2 – Harris Nuclear Plant Transmission Line Map

Mr. Garland Pardue
HNP-05-112 / Page 4

bcc: Ms. D. B. Alexander
Mr. P. Snead
Mr. R. T. Wilson
HNP Licensing File: H-X-230
Nuclear Records



Legend

☆ SHEARON HARRIS NUCLEAR PLANT

--- 6 MILE RADIUS

SHEARON HARRIS NUCLEAR PLANT

Figure 1

6 MILE VICINITY MAP

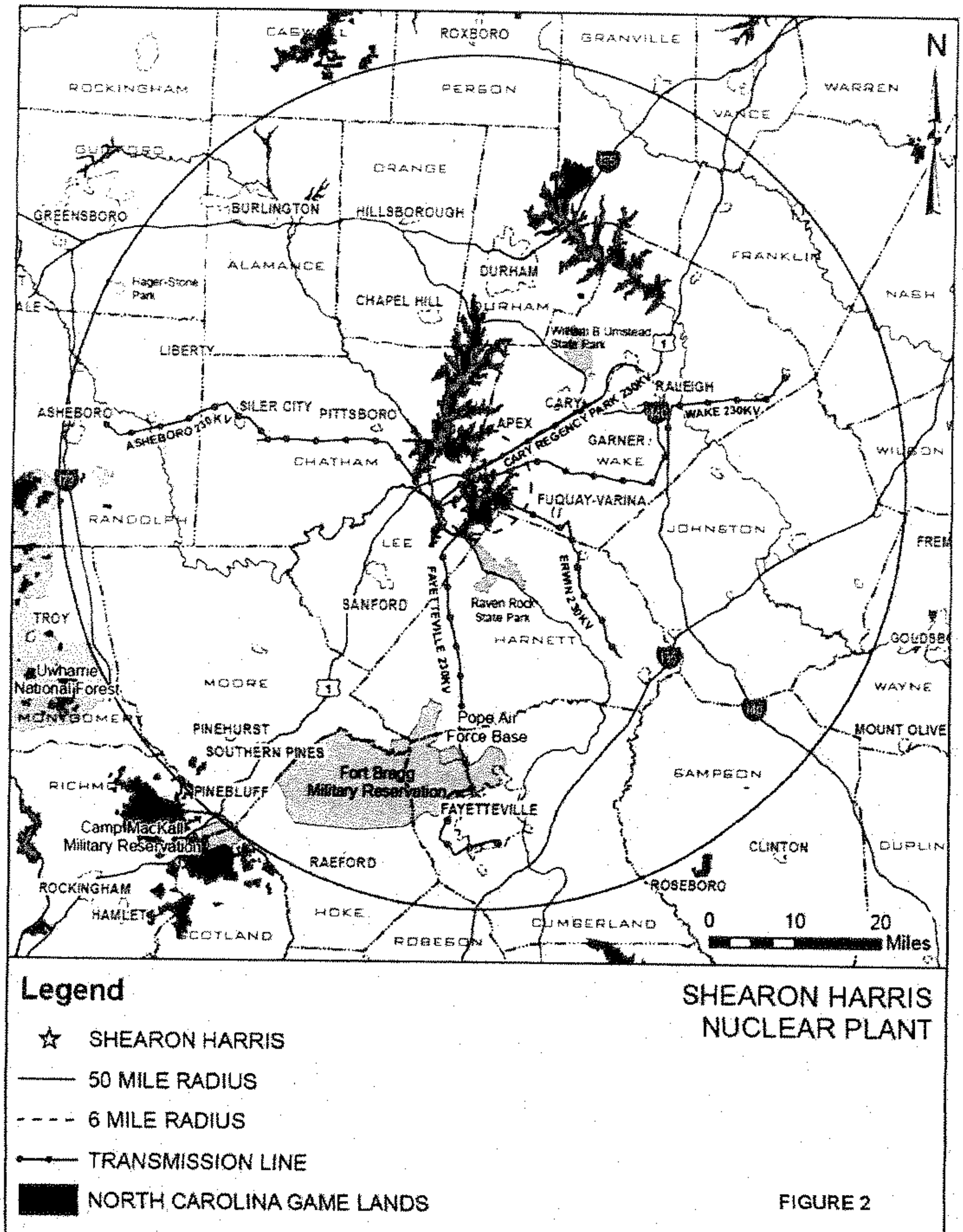


FIGURE 2

50 MILE TRANSMISSION LINE MAP

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Raleigh Field Office
Post Office Box 33726
Raleigh, North Carolina 27636-3726

February 16, 2006

Dave Corlett
Progress Energy Carolinas, Inc.
Harris Nuclear Plant
P.O. Box 165
New Hill, NC 27562

Re: Shearon Harris Nuclear Power Plant, Wake and Chatham County, NC

Dear Dave Corlett:

Thank you for your letter, dated November 16, 2005, requesting comments from the U.S. Fish and Wildlife Service on the subject project. Our comments are submitted pursuant to, and in accordance with, provisions of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 et seq.) (Act).

Based on the information provided and other information available, it appears that the proposed project is not likely to adversely affect any federally-listed endangered or threatened species, their formally designated critical habitat, or species currently proposed for listing under the Act. We believe that the requirements of section 7(a)(2) of the Act have been satisfied. Please remember that obligations under section 7 consultation must be reconsidered if: (1) new information reveals impacts of this identified action that may affect listed species or critical habitat in a manner not previously considered; (2) this action is subsequently modified in a manner that was not considered in this review; or, (3) a new species is listed or critical habitat determined that may be affected by the identified action.

Thank you for your cooperation with our agency in protecting federally-listed species. If you have any questions or comments, please contact Mr. David Rabon at (919) 856-4520, extension 16, or via email at david_rabon@fws.gov.

Sincerely,

Pete Benjamin
Ecological Services Supervisor

Progress Energy

SERIAL: HNP-05-110

NOV 1 6 2005

Mr. Harry LeGrand
North Carolina Natural Heritage Program
Office of Conservation and Community Affairs
North Carolina Department of Environment and Natural Resources
1615 MSC
Raleigh, NC 27699-1615

SHEARON HARRIS NUCLEAR POWER PLANT
DOCKET NO. 50-400/LICENSE NO. NPF-63
LICENSE RENEWAL - REQUEST FOR INFORMATION
LISTED SPECIES AND IMPORTANT HABITATS

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Progress Energy Carolinas, Inc.
Harris Nuclear Plant
P. O. Box 165
New Hill NC 27562

Mr. Harry LeGrand
HNP-05-110 / Page 2

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Mr. Harry LeGrand
HNP-05-110 / Page 3

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PEC would appreciate a response to this letter, by February 1, 2006, providing any information you may have concerning listed species or ecologically-significant habitats that may occur on the HNP site, or along associated transmission corridors. This will enable PEC to meet the current application preparation schedule. PEC will include a copy of this letter and your response in the license renewal application to the NRC.

Please refer any questions regarding this submittal to Mr. Jan Kozyra, Lead Engineer - License Renewal, at (843) 857-1872.

Sincerely,

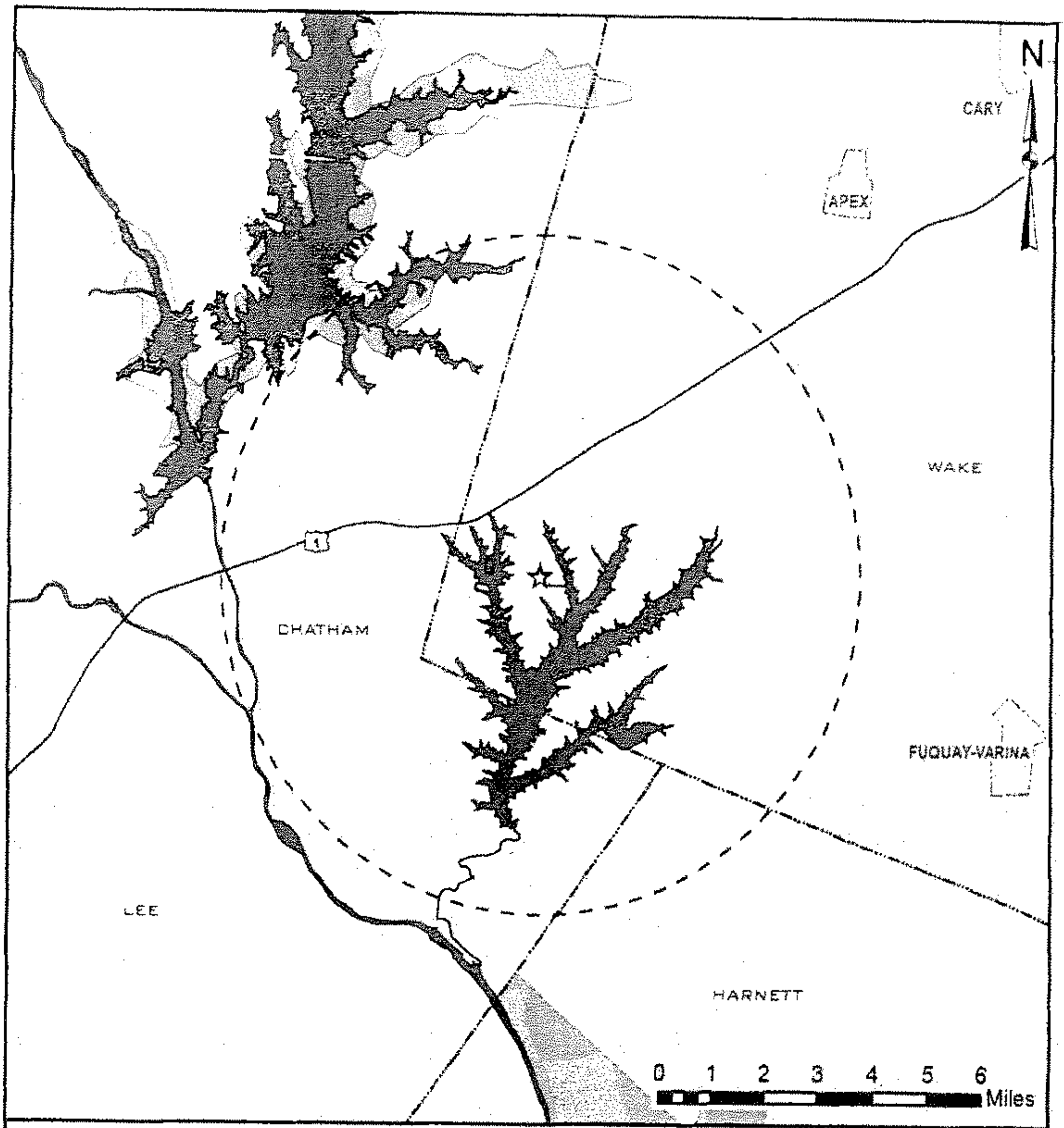
Dave Corlett
Supervisor-
Licensing and Regulatory Affairs
Harris Nuclear Plant

JSK/jsk

Enclosures:
Figure 1 – Harris Nuclear Plant 6-Mile Vicinity Map
Figure 2 – Harris Nuclear Plant Transmission Line Map

Mr. Harry LeGrand
HNP-05-110 / Page 4

bcc: Ms. D. B. Alexander
Mr. P. Snead
Mr. R. T. Wilson
HNP Licensing File: H-X-230
Nuclear Records



Legend

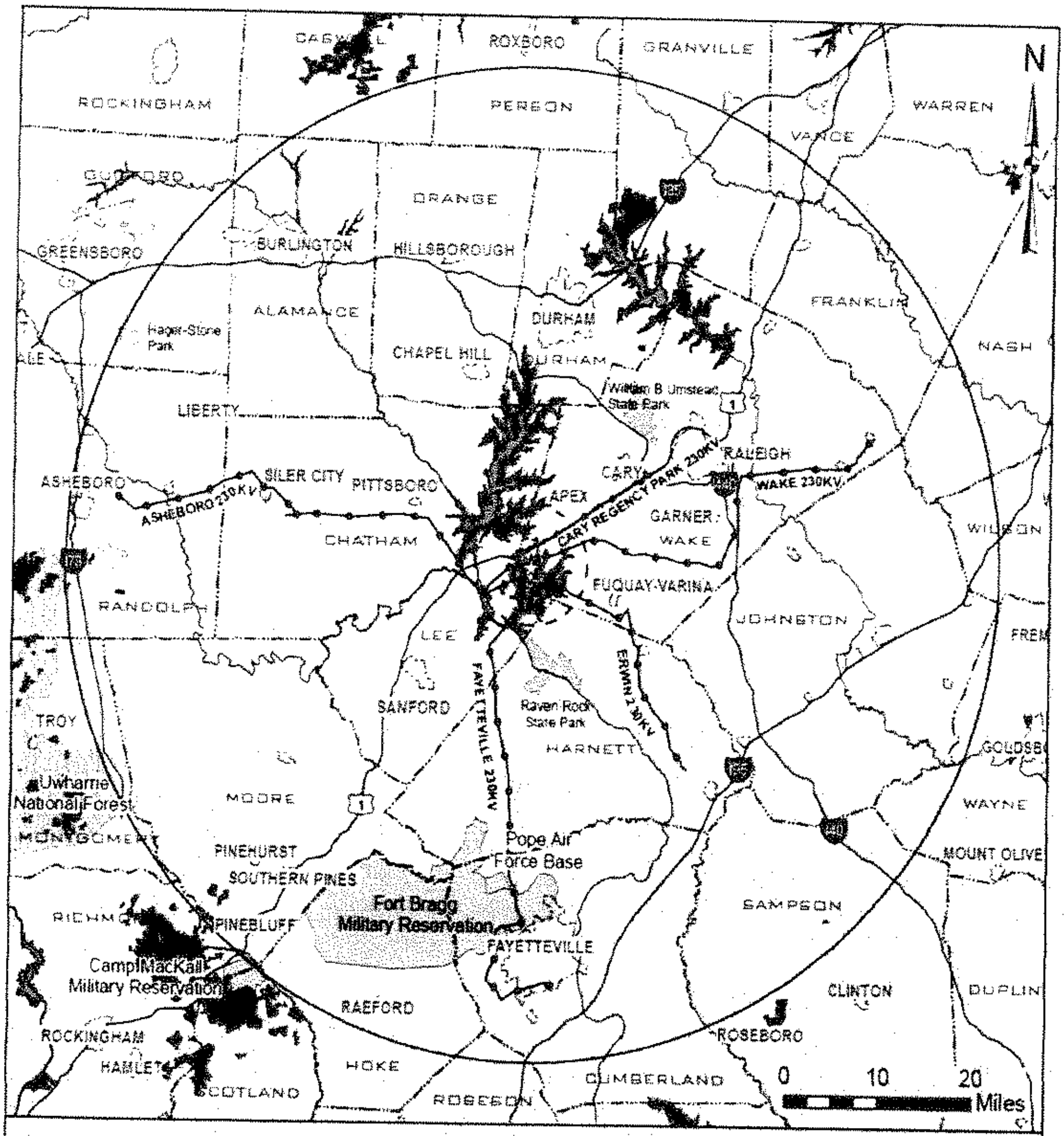
☆ SHEARON HARRIS NUCLEAR PLANT

--- 6 MILE RADIUS

SHEARON HARRIS
NUCLEAR PLANT

Figure 1

6 MILE VICINITY MAP



Legend

- ☆ SHEARON HARRIS
- —— 50 MILE RADIUS
- - - - 6 MILE RADIUS
- —•— TRANSMISSION LINE
- ■ NORTH CAROLINA GAME LANDS

SHEARON HARRIS NUCLEAR PLANT

FIGURE 2

50 MILE TRANSMISSION LINE MAP

NCDENR

North Carolina Department of Environment and Natural Resources

Michael F. Easley, Governor

William G. Ross Jr., Secretary

January 27, 2006

Mr. Dave Corlett
Progress Energy Carolinas, Inc.
Harris Nuclear Plant
P.O. Box 165
New Hill, NC 27562

Subject: License Renewal for the Harris Nuclear Plant (HNP); Wake and Chatham counties

Dear Mr. Corlett:

The Natural Heritage Program has numerous records of rare species, significant natural communities, and priority natural areas at the HNP site. Significant natural areas on the property are:

- Utley Creek Slopes, Regionally significant
- Shearon Harris Longleaf Pine Forest, Regionally significant
- Cape Fear River/Buckhorn Levees, Regionally significant
- Hollemans Crossroads Slopes, County significant
- Hollemans Crossroads Salamander Pools, County significant
- Jim Branch/Buckhorn Creek Forests, County significant

Our Program is currently working with Progress Energy to ensure protection for several of these sites through the Registry of Natural Heritage Areas. Progress Energy formerly registered a site with our Program to protect a red-cockaded woodpecker (*Picoides borealis*) colony, but the registry was terminated after all birds had vacated the site.

The HNP also fronts a portion of the Cape Fear River, whose aquatic habitat in this area is considered to be Nationally significant.

Rare species on the HNP are:

- red-cockaded woodpecker (*Picoides borealis*), Federal and State Endangered; several historic locations only
- bald eagle (*Haliaeetus leucocephalus*), Federal and State Threatened; active nest, plus foraging habitat at Harris Lake
- four-toed salamander (*Hemidactylium scutatum*), State Special Concern; might be located just off HNP

1601 Mail Service Center, Raleigh, North Carolina 27699-1601
Phone: 919-733-4984 • FAX: 919-715-3060 • Internet: www.enr.state.nc.us

One NorthCarolina *Naturally*

Lemmer's pinion [moth] (*Lithophane lemmeri*), State Significantly Rare
Colonial Wading Bird Colony – great blue heron nesting colony
Michaux's sumac (*Rhus michauxii*), Federal and State Endangered; transplanted population from off-site
Virginia spiderwort (*Tradescantia virginiana*), State Significantly Rare
Lewis's heartleaf (*Hexastylis lewisii*), State Significantly Rare
buttercup phacelia (*Phacelia covillei*), State Significantly Rare and Federal Species of Concern

Site reports for the natural areas are enclosed. A map showing the general HNP and the associated rare species and natural areas is also enclosed.

The request for data along the many and lengthy transmission lines covers numerous counties and/or quad maps and is too time-consuming for our staff to review and comment. We prefer that you obtain a data layer of Natural Heritage features (sites, element occurrences, etc.) from the N.C. Center for Geographic Information and Analysis, at <http://cgia.cgia.state.nc.us/cgia/>. You may still wish to contact our Program upon determination that a project might impact such a Natural Heritage feature.

You may wish to check the Natural Heritage Program database website at <www.ncsparks.net/nhp/search.html> for a listing of rare plants and animals and significant natural communities in the county and on the topographic quad map. Please do not hesitate to contact me at 919-715-8697 if you have questions or need further information.

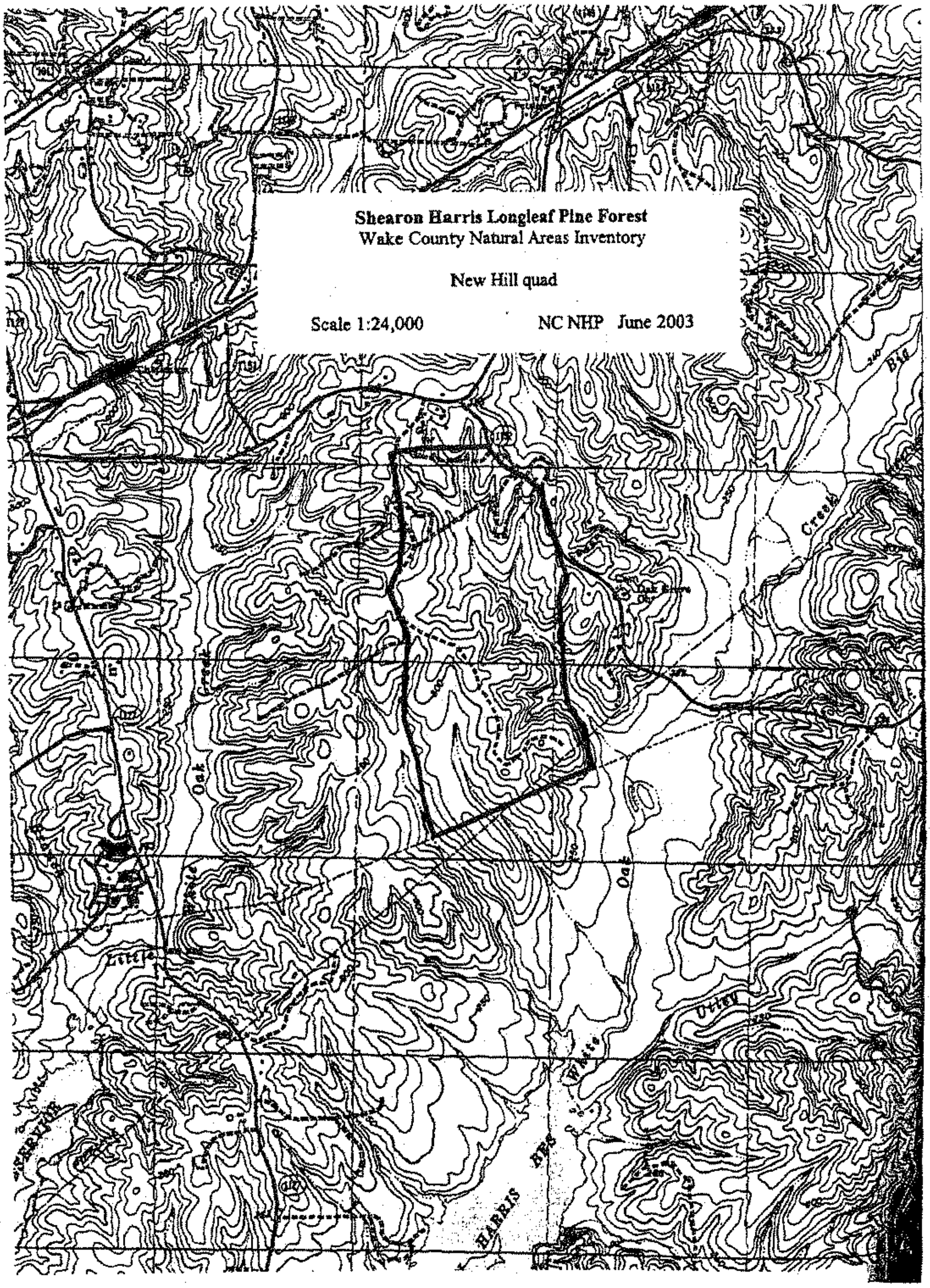
Sincerely,

Harry E. LeGrand Jr.

Harry E. LeGrand, Jr., Zoologist
Natural Heritage Program

Enclosures

HEL/hel


Shearon Harris Longleaf Pine Forest
Wake County Natural Areas Inventory
New Hill quad
Scale 1:24,000
NC NHP June 2003

Wake County Natural Areas Inventory

SHEARON HARRIS LONGLEAF PINE FOREST

Site Number: 40 **Size:** about 360 acres
Site Significance: Regional **Quadrangle:** New Hill
Ownership: Progress Energy (Carolina Power & Light Company)

SIGNIFICANT FEATURES: There are a few hundred longleaf pines (*Pinus palustris*) scattered over this part of the Shearon Harris property, one of the better concentrations of this species in the county. The area features a rare Piedmont Longleaf Pine Forest natural community.

LANDSCAPE RELATIONSHIPS: The site lies about a mile northwest of the Utley Creek Slopes natural area. The Hollemans Crossroads Slopes is also about 1-1.5 miles away, across Harris Lake to the south. The natural area is included within the Harris Lake Wildlife Habitat site.

SITE DESCRIPTION: This natural area is located in the southwestern portion of Wake County, just northeast of Harris Lake. It lies just southwest of Holly Springs - New Hill Road (SR 1152). The natural area consists of gently rolling slopes in the Triassic Basin. The area is a remnant Piedmont Longleaf Pine Forest that has long been fire-suppressed but is now being managed by North Carolina State University to restore the longleaf pine (*Pinus palustris*) stand. The central half of the site was harvested within the past few years with a seed-tree cut, leaving only widely scattered longleaf pines. Surrounding this is a more typical mixed forest, dominated by loblolly pines (*P. taeda*) but with widely scattered longleaf pines.

Two "forms" of Piedmont Longleaf Pine Forest are present in the natural area: 1) natural, fire-suppressed; and 2) artificially opened. The natural, fire-suppressed stands that surround the cut area appear to have been selectively thinned over time, with canopies generally touching but not dense. The thinnings have kept the forests mostly with a pine canopy rather than a more even hardwood-pine mix. In general, the stands average 65-75' tall, and in some places are probably around 80' tall. Loblolly pine is the dominant tree. Shortleaf pine (*P. echinata*) is widely scattered, and here and there are longleaf pines. There are just enough longleaf pines to identify the community as this type. Widespread hardwoods, mostly in the subcanopy but a few reaching the canopy, are sweetgum (*Liquidambar styraciflua*), red maple (*Acer rubrum*), white oak (*Quercus alba*), and southern red oak (*Q. falcata*). The understory is often fairly dense with these hardwoods. The shrub layer is typically dense with ericaceous species; the most numerous are dangleberry (*Gaylussacia frondosa*), deerberry (*Vaccinium stamineum*), lowbush blueberry (*V. tenellum*), and staggerbush (*Lyonia mariana*). Herbs are spotty, and are found mainly along road margins and other openings. Common are goat's-rue (*Tephrosia virginiana*) and rosinweed (*Silphium compositum*).

The artificially opened area is a large clearcut in the center of the area, harvested of all trees

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except longleaf pines perhaps 2-3 years ago. After the harvest, a burn was conducted, and smoke from the burn was still evident on the site visit, even though the cleared area was mostly vegetated in herbaceous species. Widely scattered longleaf pines 40-60' tall are present, though none appear old enough to produce cones. A few of the pines have been killed by the fire. The ground contains somewhat weedy native species – seedlings of red maple and sweetgum; winged sumac (*Rhus copallina*), blackberry (*Rubus argutus*), dog-fennel (*Eupatorium capillifolium*), toadflax (*Linaria canadensis*), pokeweed (*Phytolacca americana*), horseweed (*Conyza canadensis*), broomsedge (*Andropogon* sp.), and others.

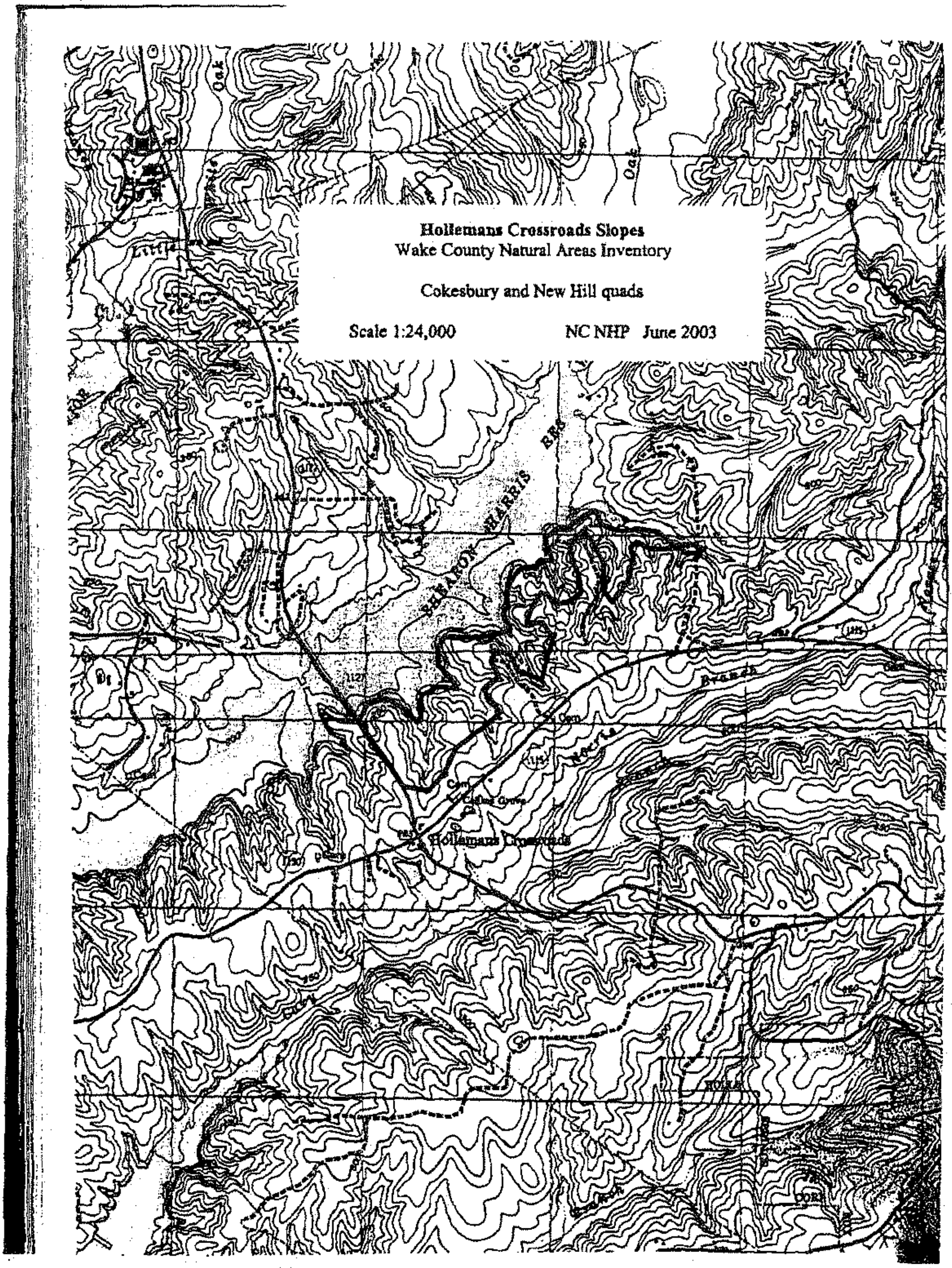
PROTECTION AND MANAGEMENT: This natural area is owned by Progress Energy (Carolina Power & Light Company). It has been leased to North Carolina State University to manage for re-establishment of longleaf pine and the Piedmont Longleaf Pine Forest community. When the management of the site is farther along, with seedling longleaf pines established, there may be a need to discuss protection in terms of a Registry of Natural Heritage Areas agreement. However, the site is still undergoing active management, so it appears best not to be concerned with Registry in the interim.

Both N.C. State University and Progress Energy are actively involved with the management of the site. A 135-acre site was burned in the fall of 1998, and the natural regeneration harvest to release longleaf pine was done in 1999. There will be periodic burning of the study tract, and monitoring/sampling plots have been established by the N.C. Vegetation Survey program (Gary Blank, pers. comm.).

The cleared area should be burned frequently (every 2-3 years at the longest) in order to keep sweetgums, loblolly pines, and other trees from invading the site. It is recommended that no further clearcutting be done in the natural area surrounding the cleared study area. However, this surrounding area could be burned in the winter. Or, there could be thinning of some trees surrounding the longleaf pines, yet keeping the area still in a forested condition. Re-introduction of other plants characteristic of this natural community might be considered; wiregrass (*Aristida stricta*) is found at a few such Piedmont sites elsewhere, though it might be difficult and labor-intensive for establishment of this grass.

NATURAL COMMUNITIES: Piedmont Longleaf Pine Forest

REFERENCES:
LeGrand, H.E., Jr. 2002. Site survey report: Harris Lake – Longleaf Pine Forest. N.C. Natural Heritage Program, DPR, DENR, Raleigh.


Hollemans Crossroads Slopes
Wake County Natural Areas Inventory
Cokesbury and New Hill quads
Scale 1:24,000
NC NHP June 2003
Hollemans Crossroads

Wake County Natural Areas Inventory

HOLLEMANS CROSSROADS SLOPES

Site Number: 41 **Size:** about 135 acres
Site Significance: County **Quadrangles:** Cokesbury, New Hill
Ownership: Progress Energy (Carolina Power & Light Company), other private

SIGNIFICANT FEATURES: The natural area contains unusual ridges of sedimentary rocks with a mafic influence, though likely over felsic rock. There is an abundance of chalk maple (*Acer leucoderme*), which is very rare in the eastern Piedmont. The site contains a good diversity of shrubs and small trees of "mafic" character on some slopes and ridges. American lotus (*Nelumbo lutea*), a Watch List species, occurs as several stands in coves at the lake.

LANDSCAPE RELATIONSIPS: This site lies very close – a few hundred yards -- to Utley Creek Slopes and could be combined into a single large site of Regional significance. The Hollemans Crossroads Salamander Pools site lies adjacent to the southeast, along Old Avent Ferry Road (SR 1115). Across the lake to the north lies the Shearon Harris Longleaf Pine Forest. The natural area is a part of the much larger Harris Lake Wildlife Habitat site.

SITE DESCRIPTION: The Hollemans Crossroads Slopes is a narrow southwest-northeast corridor along the edge of Harris Lake. It consists of many rather narrow ridges and ravines, including some steep slopes overlooking the lake. Most of these slopes contain mature hardwood forests, over slightly acidic to nearly circumneutral soils in the Triassic Basin.

The site contains three main communities, with the most significant being Basic Oak-Hickory Forest. This type lies on dry ridges, especially near their ends overlooking the lake. The canopy is dominated by white oak (*Quercus alba*), but a variety of other oaks and hickories is present. The understory contains much white ash (*Fraxinus americana*), but chalk maple (*Acer leucoderme*) is quite common and is the indicator species for this community, which lies over "shaly" soil that has a mafic character. This maple is seemingly unknown elsewhere in Wake County. The shrub layer is dominated by dense stands of downy arrowwood (*Viburnum rafinesquianum*). Mafic conditions are indicated by the presence of species such as bigleaf snowbell (*Styrax grandifolia*) and the near lack of ericads. There are very few herbs.

Slopes more to the southwest, toward New Hill - Holleman Road (SR 1127), are covered in Dry Oak-Hickory Forest. White oak again is the dominant tree. Scarlet oak (*Q. coccinea*) is present, along with other oaks and hickories. Sourwood (*Oxydendrum arboreum*) is common in the subcanopy. The shrub layer is dense, with downy arrowwood being abundant but ericads being widespread, such as deerberry (*Vaccinium stamineum*) and dangleberry (*Gaylussacia frondosa*). Some light gaps contains various grasses.

Slopes facing the lake contain a dry subtype or variant of Mesic Mixed Hardwood Forest, which has some elements of a Heath Bluff. Though American beech (*Fagus grandifolia*) is dominant,

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indicating this community, openings contain herbs that are typical of drier soils, such as white goldenrod (*Solidago bicolor*) and wavy-leaved aster (*Aster undulatus*). The understory contains hop-hornbeam (*Ostrya virginiana*), chalk maple, American hornbeam (*Carpinus caroliniana*), and some redbud (*Cercis canadensis*). Downy arrowwood is common, and witch-hazel (*Hamamelis virginiana*) is also numerous.

PROTECTION AND MANAGEMENT: Nearly all of the natural area is owned by Progress Energy (Carolina Power & Light Company); a small area at the southern end is in other private ownership. The Progress Energy lands are leased to the N.C. Wildlife Resources Commission as the Shearon Harris Game Land. The natural area is worthy of protection, especially the portions with chalk maple, as a Registered Natural Heritage Area, as currently there is no protection for the site. Because this site is somewhat different – a "mafic" character over sedimentary rock – from others in the county, stronger protection such as a conservation easement might be pursued.

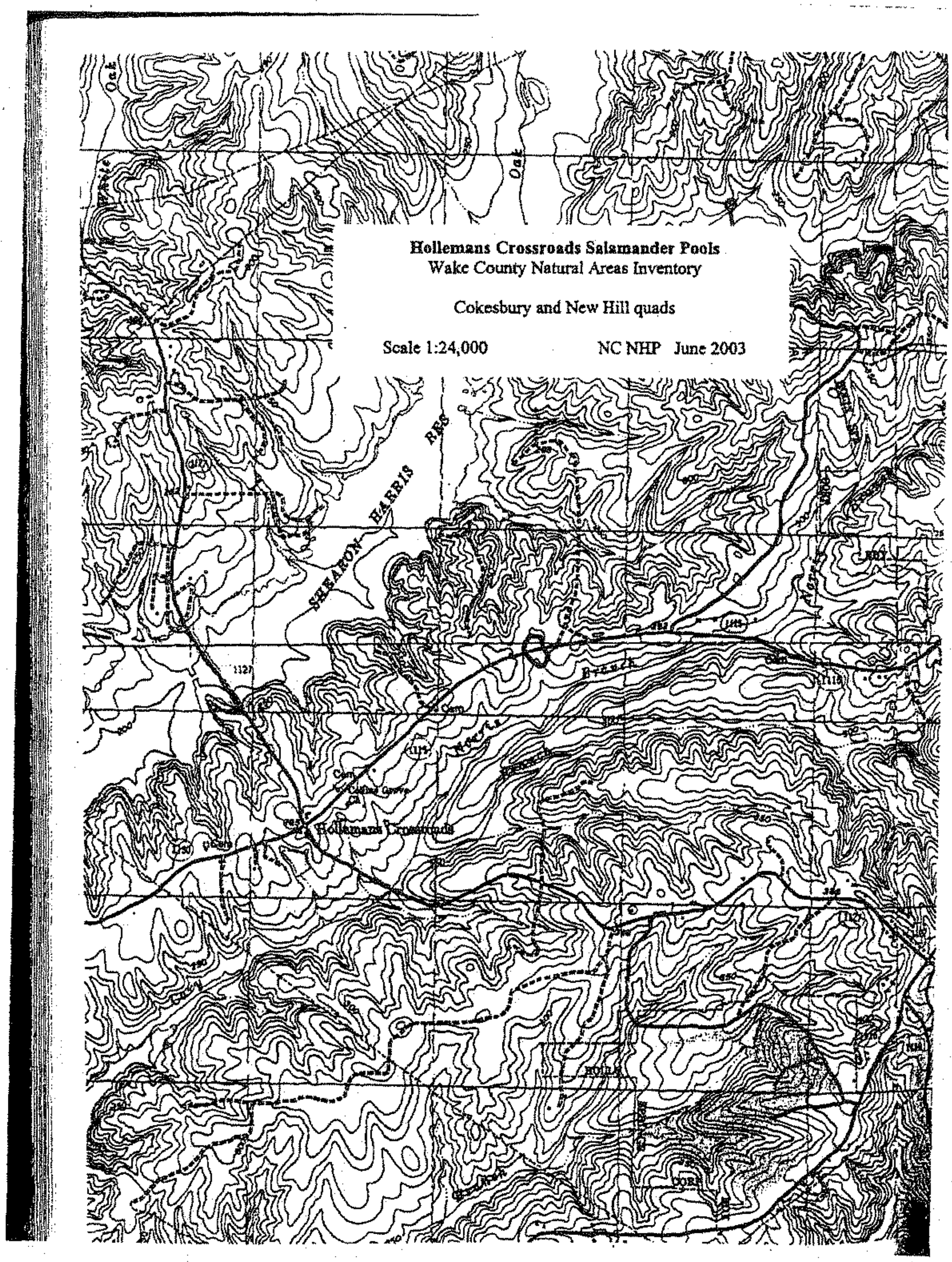
No management is needed. No timber, at least hardwoods, should be removed from the site. Currently, the only trails on Shearon Harris property are the White Oak Nature Trail and trails located at the Wake County park. The natural area would be suitable for hosting a hiking trail near the lakeshore. Such a trail might conflict with hunting interests, but there is a considerable land base along the lakeshore that would be very suitable for a lengthy hiking trail.

NATURAL COMMUNITIES: Basic Oak-Hickory Forest, Dry Oak-Hickory Forest, Mesic Mixed Hardwood Forest (Slope variant)

RARE PLANTS: Watch List – American lotus (*Nelumbo lutea*)

REFERENCES:

LeGrand, H.E., Jr. 2002. Site survey report: Harris Lake – Hollemans Crossroads Slopes. N.C. Natural Heritage Program, DPR, DENR, Raleigh.


Hollemans Crossroads Salamander Pools
Wake County Natural Areas Inventory
Cokesbury and New Hill quads
Scale 1:24,000
NC NHP June 2003
SHEARON HARRIS RES
Hollemans Crossroads

Wake County Natural Areas Inventory

HOLLEMANS CROSSROADS SALAMANDER POOLS

Site Number: 42
Site Significance: County
Ownership: private
Size: about 3 acres
Quadrangles: Cokesbury, New Hill

SIGNIFICANT FEATURES: This site is one of the few places in Wake County used for breeding by four-toed salamanders (*Hemidactylium scutatum*), a species of Special Concern in North Carolina. The seasonal pools also provide breeding habitat for several other species of amphibians.

LANDSCAPE RELATIONSHIPS: This site lies adjacent to two other sites – immediately southeast of Hollemans Crossroads Slopes and just southwest of Utley Creek Slopes. The area is part of the much larger Harris Lake Wildlife Habitat site.

SITE DESCRIPTION: There are two very small pools located off Old Avent Ferry Road (SR 1115), 1 mile northeast of the intersection with New Hill - Holleman Road (SR 1127), known as Hollemans Crossroads. One pool is just north of the road (by about about 10 yards), and the other is about 30 yards south of the road.

These vernal pools serve as breeding habitat for several species of amphibians. It is one of only a few places in the county where the Special Concern four-toed salamanders (*Hemidactylium scutatum*) are known to still breed. The pool just north of the road is completely lined in sphagnum moss, with portions of moss emerging above the water. It is under these protruding mats that the female salamanders deposit and attend to their their eggs. The pool on the south side of the road has a much smaller amount of sphagnum and a substrate of silty soil and leaf litter. Spotted salamanders (*Ambystoma maculatum*), upland chorus frogs (*Pseudacris triseriata*), and southern leopard frogs (*Rana utricularia*) are among the other amphibian species that use this habitat.

The north pool has several standing snags and live trees rooted in the water. The canopy here consists mainly of sweetgum (*Liquidambar styraciflua*) and loblolly pine (*Pinus taeda*). The south side of the road has a greater diversity of tree species, including tuliptree (*Liriodendron tulipifera*), hickories (*Carya* spp.), and river birch (*Betula nigra*). Both pools contain emergent vegetation, primarily sedges (*Carex* sp.). Greenbrier (*Smilax rotundifolia*) is abundant along the edges of both pools. The natural community represented by these pools is unclear. The sites are formed by blocked drainage of the upper end of a south-flowing stream, with the northern pool blocked by the road and the southern pool possibly blocked by treefall or other woody debris.

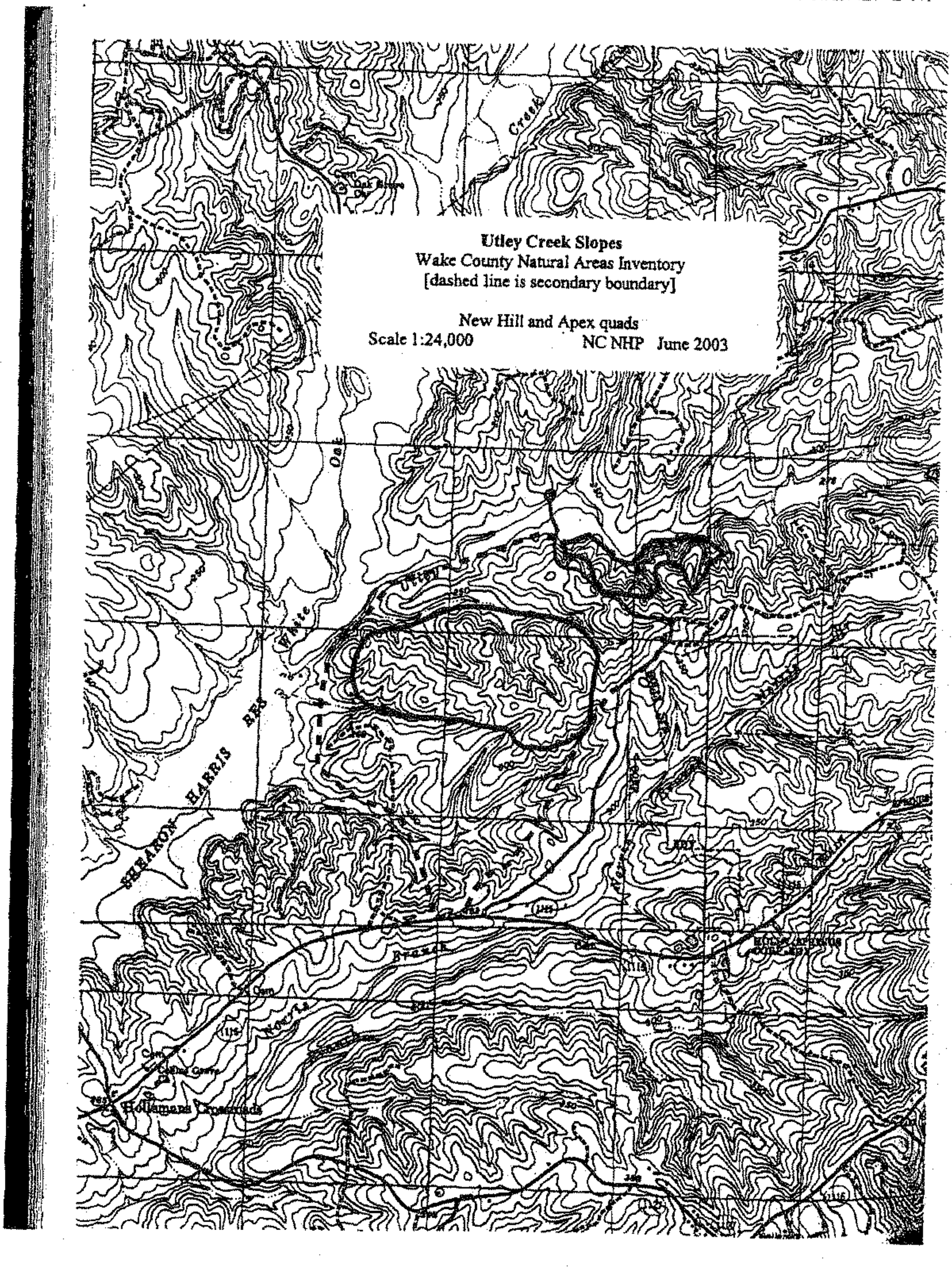
PROTECTION AND MANAGEMENT: The site is owned by a private landowner – not Progress Energy -- and is unprotected. The landowner should be informed of the significance of these pools and the options available for their protection, such as a conservation easement or registry as a Natural Heritage Area. Due to its relatively small size, this property may be a good candidate for acquisition and preservation.

The town of Holly Springs, about 3 miles northeast of the site, is rapidly expanding due to residential development. Some of the adjacent land has already been purchased from Progress Energy by developers. If growth continues at the present rate, this site may no longer exist in the near future.

RARE ANIMALS: four-toed salamander (*Hemidactylium scutatum*)

REFERENCES:

Wiecek, C. 2002. Site survey report: Holly Springs Four-toed Salamander Site. N.C. Natural Heritage Program, DPR, DENR, Raleigh.


Utley Creek Slopes
Wake County Natural Areas Inventory
[dashed line is secondary boundary]
New Hill and Apex quads
Scale 1:24,000
NC NHP June 2003
Creek
Utley
White
Oak
SHEARON HARRIS RES
Branch
Hollemans Crossroads

Wake County Natural Areas Inventory

UTLEY CREEK SLOPES

Site Number: 43 **Size:** about 590 acres (220 in primary area)
Site Significance: Regional **Quadrangles:** New Hill, Apex
Ownership: Progress Energy (Carolina Power & Light Company)

SIGNIFICANT FEATURES: The natural area has a very large extent of Dry Oak-Hickory Forest, and much exists in good to excellent condition. The site has a very large outcropping of sedimentary rocks for the Triangle area, as the site lies in the Triassic Basin. The rocks harbor "caves", as well as waterfalls during good water flow conditions. Several slopes contain Virginia spiderwort (*Tradescantia virginiana*), Significantly Rare and a first Wake County record.

LANDSCAPE RELATIONSHIPS: Immediately to the west is the Hollemans Crossroads Slopes, and the Hollemans Crossroads Salamander Pools is just to the southwest. The Shearon Harris Longleaf Pine Forest lies to the northwest by about a mile. The natural area is a part of the much larger Harris Lake Wildlife Habitat site.

SITE DESCRIPTION: The natural area, on Shearon Harris lands in the southwestern part of the county, contains two primary areas and consists of moderate slopes north of Old Avent Ferry Road (SR 1115) to steep north-facing slopes adjacent to Utley Creek. Much of the area consists of mature hardwood forests, including a considerable acreage of Dry Oak-Hickory Forest, not usually found in sizable stands in the county.

There are numerous exposed sedimentary rocks along steep slopes such as side ravines and along Utley Creek. These rocks are not exposed on their tops, but mainly on their sides (vertical erosion). Under some there are small "caves" extending back about 10 feet and up to 4-5 feet tall; the caves are mostly wedges in the rocks. Other rocks are exposed along creeks, such that when one is walking upstream, a creek appears to end at a rock, or the stream falls 5-8 feet over the rock as a small waterfall.

Three main natural communities appear to be present, though only the first two are of high quality. Dry Oak-Hickory Forest is prevalent along an east-west ridge in the center of the natural area. This is one of the best, or the most extensive, examples in the Triangle area. The mature canopy is dominated by white oak (*Quercus alba*), with considerable post oak (*Q. stellata*), southern red oak (*Q. falcata*), pignut hickory (*Carya glabra*), and a few other oak species. Virginia red-cedar (*Juniperus virginiana*) is scattered in the understory. Other understory trees include sourwood (*Oxydendrum arboreum*) and black gum (*Nyssa sylvatica*). The shrub layer is quite dense. Downy arrowwood (*Viburnum rafinesquianum*) is scattered, though much less common than in the next community. Blueberries are abundant, including deerberry (*Vaccinium stamineum*) and lowbush blueberry (*V. pallidum*). There are some "glady" openings with various grasses and forbs, such as rattlesnake-weed (*Hieracium venosum*) and

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summer bluet (*Houstonia purpurea*).

Dry-Mesic Oak-Hickory Forest is the most common community in the natural area. Some of the ridges, and most of the mid- and lower slopes, contain this community, the most common natural community in Wake County. White oak is the dominant tree. A few other oaks are present in the canopy along with pignut hickory, tuliptree (*Liriodendron tulipifera*), and an occasional sweetgum (*Liquidambar styraciflua*). The well-developed understory has flowering dogwood (*Cornus florida*), red maple (*Acer rubrum*), black gum, and sourwood as common components. The shrub layer contains an abundance of downy arrowwood. A scattering of ericads such as deerberry are present. The sparse herb layer contains vines such as muscadine (*Vitis rotundifolia*) and Virginia creeper (*Parthenocissus quinquefolius*).

On the steeper slopes, especially the north-facing ones such as along Utley Creek, are acidic examples of Mesic Mixed Hardwood Forest. These are shrub- and herb-poor types compared to others on rich soils. As with other types, American beech (*Fagus grandifolia*) is a canopy dominant. Hop-hornbeam (*Ostrya virginiana*) dominates the understory, but Florida maple (*Acer barbatum*) is locally common. The shrub layer is poor, such that it is easy to observe long distances through the community. Typical herbs are Christmas fern (*Polystichum acrostichoides*), dwarf heartleaf (*Hexastylis minor*), dittany (*Cunila origanoides*), and crested dwarf iris (*Iris cristata*). The Significantly Rare Virginia spiderwort (*Tradescantia virginiana*), not previously known from Wake County, is found on several gentle slopes. This herb occurs in just a handful of lower Piedmont counties in the state and is normally found on high pH soils.

The Special Concern black vulture (*Coragyps atratus*) was noted during the site visit and is likely nesting at the site or nearby. This extensive hardwood forest is likely important nesting habitat for many Neotropical migrant songbirds.

PROTECTION AND MANAGEMENT: The natural area is wholly owned by Progress Energy (Carolina Power & Light Company) and is part of the Shearon Harris Game Land managed by the N.C. Wildlife Resources Commission. The natural area has no current protection but definitely should be pursued for protection as a Registered Natural Heritage Area. Because it is considered of Regional significance, a stronger measure of protection such as a conservation easement might be warranted.

Some effort is needed to clearly delineate the natural area. Presently, this description covers two separate areas, bisected by a dirt road and pine stands. Thus, an additional site visit or two might be necessary to more clearly define the area worthy of protection.

Most of the area should be set aside with no management. Any timber harvest should be limited to pines. A green-tree reservoir just north of the rocky slopes and bluffs is an eye-sore, especially being nearly dry, and it has impacted the floodplain of the creek. Instead of a shady, forested floodplain, it is a sunny, baked area with many dead trees and some exposed mud. It might be best to allow the area to return to a forested condition, if that can be done.

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NATURAL COMMUNITIES: Dry Oak-Hickory Forest, Dry-Mesic Oak-Hickory Forest, Mesic Mixed Hardwood Forest (Slope variant)

RARE PLANTS: Virginia spiderwort (*Tradescantia virginiana*)

RARE ANIMALS: Black vulture (*Coragyps atratus*)

REFERENCES:

LeGrand, H.E., Jr. 2002. Site survey report: Harris Lake – Utley Creek Slopes. N.C. Natural Heritage Program, DPR, DENR, Raleigh.

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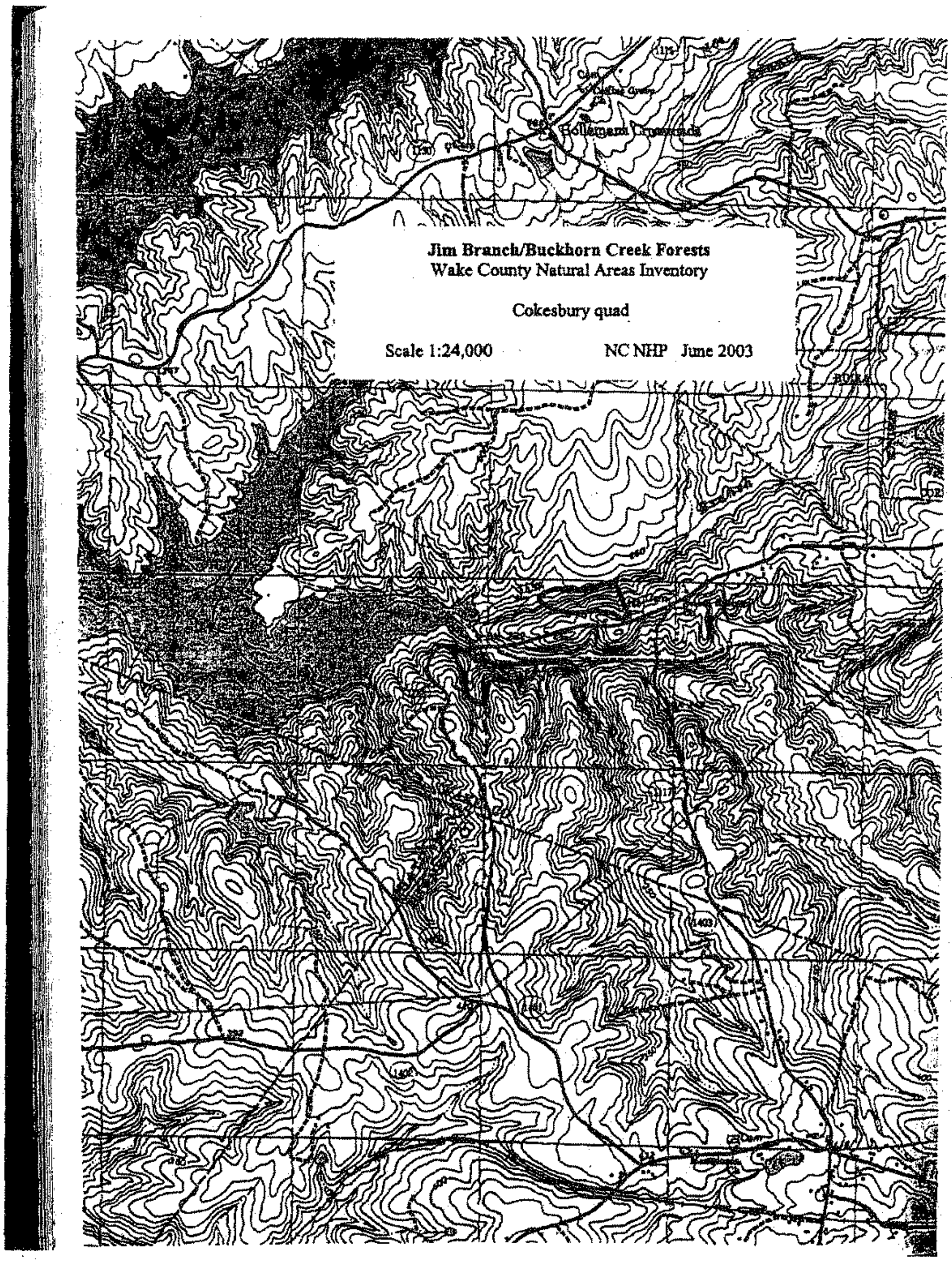
Jim Branch/Buckhorn Creek Forests
Wake County Natural Areas Inventory
Cokesbury quad
Scale 1:24,000
NC NHP June 2003
Holleman's Crossroads

Wake County Natural Areas Inventory

JIM BRANCH/BUCKHORN CREEK FORESTS

Site Number: 44
Size: about 25 acres
Site Significance: County
Quadrangle: Cokesbury
Ownership: Progress Energy (Carolina Power & Light Company), other private

SIGNIFICANT FEATURES: There are fairly rich hardwood slopes at the site, and the presence of both showy orchis (*Orchis spectabilis*) and lily-leaved twayblade (*Liparis lilifolia*) indicates rich soils. The natural area contains a nesting colony of great blue herons (*Ardea herodias*) along Jim Branch.

LANDSCAPE RELATIONSHIPS: The site is roughly 2 miles south of the Hollemans Crossroads Slopes. It is part of the Harris Lake Wildlife Habitat site that encompasses much of the southwestern corner of Wake County and extends into neighboring Chatham and Harnett counties.

SITE DESCRIPTION: The natural area consists of two separate portions – slopes along Buckhorn Creek, south of Cass Holt Road (SR 1188); and slopes and creek along Jim Branch (north of the road). Both areas have fairly rich hardwood slopes, mostly with Mesic Mixed Hardwood Forest and some Dry-Mesic Oak-Hickory Forest. Along Jim Branch is a moderate-sized colony of nesting great blue herons (*Ardea herodias*). On the site visit, about 32 nests were counted in six to seven trees, mostly in mature loblolly pines (*Pinus taeda*); this is apparently the largest known colony in the county and one of the larger ones for the eastern Piedmont.

The primary natural community at the site is Mesic Mixed Hardwood Forest. The portion along Buckhorn Creek, especially along an unnamed tributary, is of good quality. The slope facing Buckhorn Creek is somewhat of a dry example of this type. The canopy contains much American beech (*Fagus grandifolia*), along with white oak (*Quercus alba*) and white ash (*Fraxinus americana*). Hop-hornbeam (*Ostrya virginiana*) dominates the understory, but Florida maple (*Acer barbatum*) is numerous. The shrub layer is moderate, featuring dry-mesic species such as fringetree (*Chionanthus virginicus*), maple-leaved viburnum (*Viburnum acerifolium*), downy arrowwood (*V. rafinesquianum*), and pink azalea (*Rhododendron periclymenoides*). The herb layer is sparse, dominated by Christmas fern (*Polystichum acrostichoides*).

On the tributary streams, especially the one to the west, the soil is richer and herb diversity increases. Tuliptree (*Liriodendron tulipifera*) and northern red oak (*Q. rubra*) are major canopy components. Hop-hornbeam is common in the understory. The herb layer contains much Christmas fern, and broad beech fern (*Thelypteris hexagonoptera*) is locally abundant, as is hog-peanut (*Amphicarpa bracteata*). Black cohosh (*Cimicifuga racemosa*) is widespread and conspicuous, and a few showy orchis (*Orchis spectabilis*) plants are present.

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The Mesic Mixed Hardwood Forest on the north-facing slope above Jim Branch is quite a bit different. Here, the canopy is much taller, dominated by 100-110' tall tuliptrees. Northern red oak is numerous. Redbud (*Cercis canadensis*) and hop-hornbeam are common in the understory. The shrub layer is mostly seedlings of redbud, with thousands of young trees dominating the slope. Christmas fern and broad beech fern are also abundant on these slopes. At the foot of the slopes, bigleaf snowbell (*Styrax grandifolia*) is common. There are few wildflowers on this slope, though a scattering of lily-leaved twayblade (*Liparis lilifolia*) is present.

The Dry-Mesic Oak-Hickory Forest occurs in the Buckhorn Creek portion but is not widespread. White oak dominates the canopy, but some scarlet oak (*Q. coccinea*) is present. Understory trees such as flowering dogwood (*Cornus florida*), sourwood (*Oxydendrum arboreum*), and American holly (*Ilex opaca*) mix with the hop-hornbeam. Ericads such as deerberry (*Vaccinium stamineum*) are present in the shrub layer; and the herb layer is sparse, with woodland tick-trefoil (*Desmodium nudiflorum*) the most common species.

PROTECTION AND MANAGEMENT: Most of the natural area is owned by Progress Energy (Carolina Power & Light Company) and managed by the N.C. Wildlife Resources Commission as the Shearon Harris Game Land. The site is unprotected. There is probably little need for Registry as a Natural Heritage Area at the present time. Additional field work is recommended, as is additional monitoring of the heronry.

No timber harvest should be done in the area. The heronry site especially needs to be set aside from the timber base. The herons require tall trees, preferably in water, for nesting. Interestingly, most of the nest trees are on dry land. Unfortunately, silverberry (*Elaeagnus umbellata*) has escaped on the slopes and may be too far advanced in the natural area for control. Nonetheless, some control of this invasive shrub might be worth initiating.

NATURAL COMMUNITIES: Mesic Mixed Hardwood Forest (Slope variant), Dry-Mesic Oak-Hickory Forest

REFERENCES:

LeGrand, H.E., Jr. 2002. Site survey report: Harris Lake – Jim Branch/Buckhorn Creek Forests. N.C. Natural Heritage Program, DPR, DENR, Raleigh.

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Wake County Natural Areas Inventory

HARRIS LAKE WILDLIFE HABITAT

Site Number: 48

Size: about 35,000 acres (about 18,300 acres in Wake County)

Site Significance: not rated

Quadrangles: Wake County – Cokesbury, Merry Hill, Apex

Ownership: Progress Energy (Carolina Power & Light Company), other private

SIGNIFICANT FEATURES: This is the largest expanse of undeveloped, privately-owned lands in Wake County, mostly in Progress Energy (Carolina Power & Light Company) ownership. The wildlands site includes Harris Lake and various forested and timbered lands surrounding the lake, and the site extends into neighboring Chatham and Harnett counties, to the Cape Fear River. The area contains the best examples of Piedmont Longleaf Pine Forests in the county, and the Federally Endangered red-cockaded woodpecker (*Picoides borealis*) formerly inhabited the area. A number of rare plants and animals inhabit the site, and the area is important for breeding Neotropical migrant songbirds, game animals, herons, and other species.

LANDSCAPE RELATIONSHIPS: Five standard sites (County or higher significance) are present within this wildlife habitat in Wake County. These are the Jim Branch/Buckhorn Creek Forests, Shearon Harris Longleaf Pine Forest, Hollemans Crossroads Slopes, Hollemans Crossroads Salamander Pools, and Utley Creek Slopes. This wildlife habitat lies as close as a mile at one point from the southern end of the Jordan Lake Wildlife Habitat, near Old US 1 (New Hill area). This site also can be considered continuous with other extensive forested lands along the Cape Fear River, both upstream and downstream (to Raven Rock State Park); however, this wildlife habitat is arbitrarily delineated just east and west of where Buckhorn Creek enters the Cape Fear River.

SITE DESCRIPTION: This site incorporates most of the landholding of Progress Energy, including Harris Lake, but excludes the man-made facilities, such as the Shearon Harris Nuclear Power Plant and the Harris Energy & Environmental Center. Various timber company lands to the west and/or south are included also, as well as lands owned by private individuals in the Hollemans Crossroads area.

The great majority of the wildlife habitat lies in the Chatham Group (also called "Deep River") Triassic Basin. This relatively flat area of sedimentary rock provides very wide floodplains for quite small creeks, and reservoirs in such basins (e.g., Harris Lake, Jordan Lake, Falls Lake) are quite extensive with broad arms. Longleaf pine (*Pinus palustris*) is scattered over the wildlife habitat, and a few areas, such as the Shearon Harris Longleaf Pine Forest and a portion of the Harris Lake County Park, have been actively managed to promote the Piedmont Longleaf Pine Forest natural community. Though much of the wildlife habitat is now timbered, and thus in early successional stages or in pine stands, portions are in hardwoods, especially along moderate to steep slopes. Areas near Utley Creek contain extensive rock outcrops and rich slopes, and

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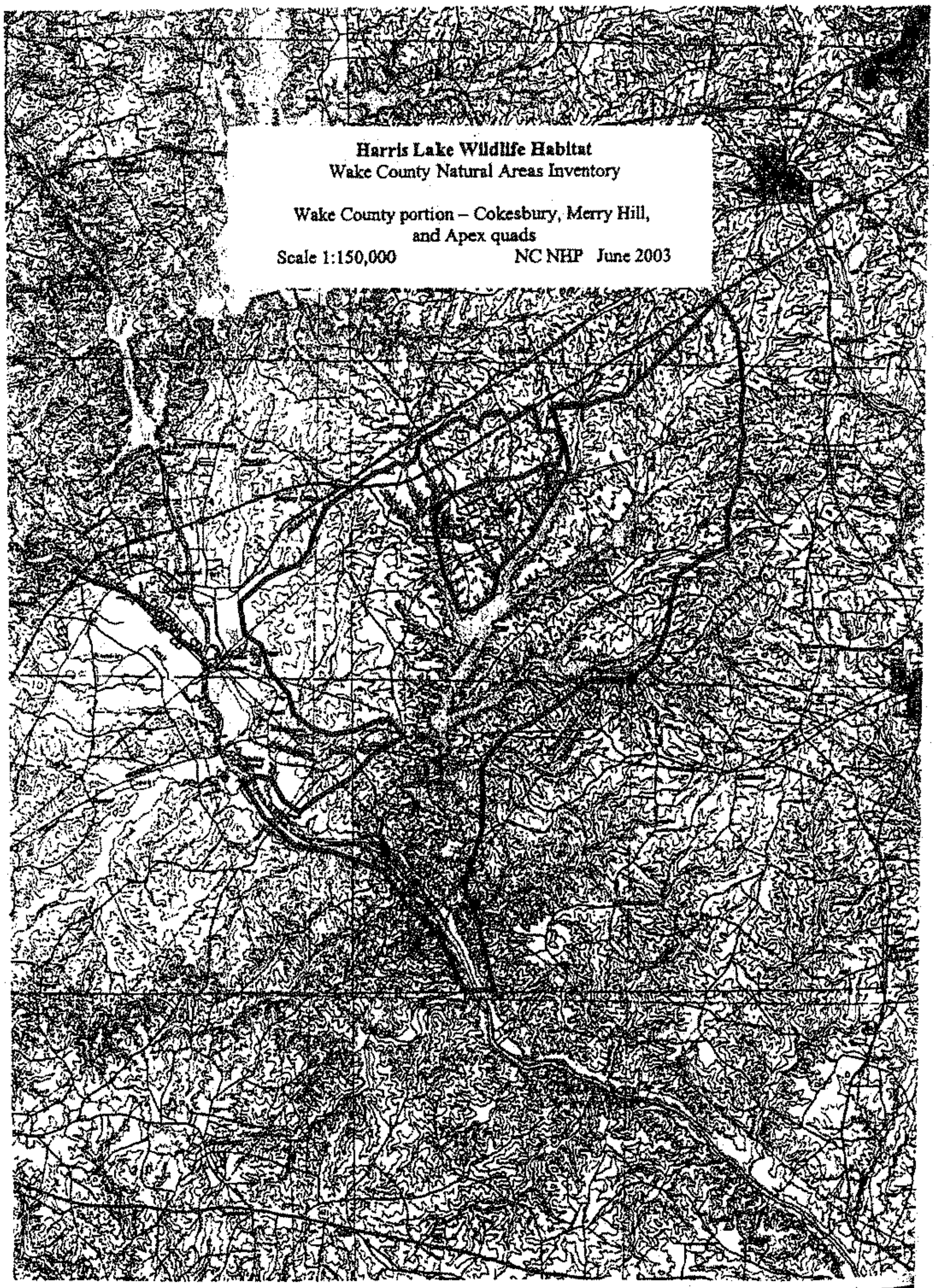
Harris Lake Wildlife Habitat
Wake County Natural Areas Inventory
Wake County portion – Cokesbury, Merry Hill,
and Apex quads
Scale 1:150,000
NC NHP June 2003

some dry ridges near Harris Lake north of Hollemans Crossroads contain chalk maple (*Acer leucoderme*), very rare near the Fall Line.

The site is important for uncommon species of animals. Unfortunately, the several clusters of the Federally Endangered red-cockaded woodpecker (*Picoides borealis*) were abandoned by about 1990, owing to fire suppression and lack of recruitment of other birds from nearby areas (for gene flow). Because there are now no active clusters of the species within perhaps 30 miles (in the Sandhills region), there is no need to consider re-introduction of the species into Wake County. The Significantly Rare eastern fox squirrel (*Sciurus niger*), generally a Coastal Plain inhabitant, has recently been seen in the area. A few pools provide habitat for salamanders, including the Special Concern four-toed salamander (*Hemidactylium scutatum*). Great blue herons (*Ardea herodias*) have a nesting colony near Harris Lake, and the Federally Threatened bald eagle (*Haliaeetus leucocephalus*) is seen occasionally at the lake and may well nest in upcoming years in the nearby forests.

Extensive undeveloped lands are important for wildlife such as white-tailed deer (*Odocoileus virginianus*), wild turkey (*Meleagris gallopavo*), red-shouldered hawk (*Buteo lineatus*), and other large vertebrates. Most of the breeding bird species found in Wake County occur in this wildlife habitat. Because of the numerous recent clearcuts, this area of the county contains the largest populations of species requiring shrub/scrub habitats, such as yellow-breasted chat (*Icteria virens*) and prairie warbler (*Dendroica discolor*), and species utilizing dead snags, such as red-headed woodpecker (*Melanerpes erythrocephalus*), are numerous as well.

PROTECTION AND MANAGEMENT: Progress Energy owns the great majority of this wildlife habitat, including Harris Lake and surrounding buffer lands. The company utilizes a number of agencies to help manage their extensive lands. Most of the landholdings (excluding developed areas) are leased to the N.C. Wildlife Resources Commission as the Shearon Harris Game Land (almost 15,000 acres). N.C. State University manages some lands east of the Management Center for longleaf pine restoration. A peninsula south of the Management Center is leased to Wake County for the Harris Lake County Park. A boy scout troop has developed a nature trail next to the Center. Thus, quite a few recreational opportunities exist on these lands, from boating and fishing on the lake, to hiking and picnicking at the park, to hunting on the forested lands.

There is a need to have some type of protection for the natural areas identified in this report, such as conservation easements, or at a minimum the placement on the Registry of Natural Heritage Areas. In fact, Carolina Power & Light Company (now acquired by Progress Energy) did register a site that contained the only remaining active red-cockaded woodpecker cluster on the property in the late 1980's; this site, located along the north side of US 1, has since been de-registered because the birds abandoned the site a few years later. Thus, this company has worked with the NC NHP previously to protect important places there, and the company's willingness to work with other agencies to manage their lands is also favorable for maintaining and improving habitat for rare plants and animals and natural communities. However, Registry agreements are not long-term or permanent, and several sites within the wildlife habitat deserve

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stronger or more long-term protection.

Several concerns are apparent with this wildlife habitat. There is much timber management, and thus areas now identified as natural areas, mostly hardwood stands, might be timbered in the future. If not timbered, there is the potential of sale for development. Some of the former Progress Energy lands at the eastern end of the area have recently been sold to the Town of Holly
Springs for an industrial park and/or other development. Thus, a precedent has been set such that other lands somewhat far removed from the power plant could be sold in the near future.

This wildlife habitat can be connected southward along Buckhorn Creek to the Cape Fear River, which has a fairly wide floodplain extending far upstream into Chatham, Lee, and Moore counties and downstream to Raven Rock State Park (in Harnett County) and farther into the Coastal Plain. There is thus a connection to the Jordan Lake Game Land northward from the Cape Fear. Old US 1, a 2-lane road, lies between this wildlife habitat and the Jordan Lake Wildlife Habitat, barely a mile away. This road is not a barrier to large animals, and there is relatively little traffic and development along this road now that US 1 has been constructed. It is possible that a connector between Corps lands at Jordan and Progress Energy lands at Harris can be made. However, the 4-lane US 1, with its wide median, forms a bit of an animal movement barrier south of Old US 1. At least, there are fingers of Harris Lake that extend northward past US 1 that could make a connection to Jordan lands, if conservation organizations feel that this connection is a high priority.

NATURAL COMMUNITIES (Wake County): Mesic Mixed Hardwood Forest (Slope variant), Dry-Mesic Oak-Hickory Forest, Dry Oak-Hickory Forest, Piedmont Longleaf Pine Forest, Basic Oak-Hickory Forest, Floodplain Pool, Piedmont/Low Mountain Alluvial Forest

RARE PLANTS (Wake County): Virginia spiderwort (*Tradescantia virginiana*), Lewis's heartleaf (*Hexastylis lewisii*); Watch List – nestronia (*Nestronia umbellula*), American lotus (*Nelumbo lutea*)

RARE ANIMALS (Wake County): four-toed salamander (*Hemidactylium scutatum*), red-cockaded woodpecker (*Picoides borealis*), eastern fox squirrel (*Sciurus niger*), black vulture (*Coragyps atratus*), Lemmer's pinion [moth] (*Lithophane lemmeri*)

REFERENCES:

LeGrand, H.E., Jr. 1987. Inventory of the natural areas of Wake County, North Carolina. Report to Triangle Land Conservancy, N.C. Natural Heritage Program, and Wake County Parks and Recreation Commission.

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LeGrand, H.E., Jr. 2002. Harris Lake – NCSU Research Lands (South) – notes from August 8, 2002 visit. N.C. Natural Heritage Program, DPR, DENR, Raleigh.

LeGrand, H.E., Jr. 2002. Harris Lake – upper Utley Creek drainage; notes from August 22, 2002 site visit. N.C. Natural Heritage Program, DPR, DENR, Raleigh.

Wiecek, C. 2002. Site survey report: Holly Springs Four-toed Salamander Site. N.C. Natural Heritage Program, DPR, DENR, Raleigh.

SITE NAME: Buckhorn Bluffs and Levees

SIGNIFICANCE: County
INTEGRITY: Fair
THREATS: Medium -- clearcutting of adjoining areas
PROTECTION STATUS: Managed as gamelands by the NC Wildlife Commission through short-term lease with the landowner

JURISDICTION: Cape Fear Township
OWNERSHIP:

SUMMARY OF SIGNIFICANT FEATURES:

1. Buttercup phacelia (Phacelia ranunculacea), a candidate for state listing, grows abundantly on the rich levees present at this site.
2. This site has the most mature and most extensive levee forest in the county.

GENERAL SITE DESCRIPTION:

Just a few miles to the west of this site, the Haw and Deep Rivers join together to form the Cape Fear in the broad bottomlands of the Triassic Basin. Almost immediately, The Cape Fear enters the slate-belt and flows through some extremely rugged terrain before reaching the Fall Line a few miles downstream in Harnett County at Raven Rock State Park. Although hemmed in by steep bluffs on both sides, this initial reach of the Cape Fear is relatively wide even below the low impoundment created by the Buckhorn Dam. Several large areas of alluvial bottomlands are present along the northeast shore, and in some areas levee deposits have created extensive islands, the most distinctive feature of this site.

Levee forests are usually restricted to narrow bands along the larger rivers, and most broad areas of bottomland have been thoroughly exploited with little original forest left. The levee forest at this site is thus noteworthy both for the large area it covers and for the fact that it has been little disturbed, particularly on the larger islands where flooding is frequent and accessibility is limited. On the islands, American elm (Ulmus americana), sweet gum (Liquidambar styraciflua), southern sugar maple (Acer floridanum), bitternut hickory (Carya cordiformis) and swamp chestnut oak (Quercus michauxii) dominate a canopy composed of mature trees up to 72 cm diameter. Shrubs and vines are plentiful, including pawpaw (Asimina triloba), spicebush (Lindera benzoin), possumhaw (Ilex decidua), storax (Styrax grandifolia), greenbriers (Smilax spp.), poison ivy (Toxicodendron radicans) and crossvine (Anisostichus capreolata). In this mature forest the herbs are sparse but fairly diverse, especially on higher spots where such species as Jack-in-the-pulpit (Arisaema triphyllum), broad beech fern (Thelypteris hexagonoptera) and bloodroot (Sanguinaria canadensis) occur.

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and hackberry (Celtis laevigata). Shrubs are few but the herb layer is dense. It is in this area that a broad carpet of the rare buttercup phacelia can be found in the spring, along with such common bottomland herbs as chickweed (Stellaria media), spring beauty (Claytonia virginica), and sweet cicely (Osmorhiza longistylis).

A typical mesic mixed-hardwood forest occupies the steep slopes bordering the bottomlands at this site. While some patches of this forest are fairly intact, most of the area shows the effects of considerable disturbance and exploitation.

The faunal list for this site is relatively incomplete, reflecting visits made outside the main nesting season for birds. No prothonotary warblers or redstarts were observed, for instance, despite the presence of suitable habitat; the only riparian forest birds we recorded during our April visit were the yellow-throated warbler (Dendroica dominica) and the northern parula warbler (Parula americana), both of which are early migrants. One species of riparian bird that should be especially looked for at this site is the cerulean warbler (Dendroica cerulea), an animal that is virtually restricted in North Carolina to old-growth levee forests along major rivers.

The most noteworthy animals actually observed were the Carolina anole (Anolis carolinensis), which penetrates the piedmont up from the coastal plain primarily along river floodplains, and two typically montane species, the sumo mite (Allothrombium sp.) and a landsnail (Mesomphix sp.), both of which may have been rafted across the river from the steep north-facing slopes on the Lee County side of the river. The presence of river otter (Lutra canadensis), gray fox (Urocyon cinereoargenteus), and pileated woodpecker (Dryocopus pileatus) is indicative of the large amount of undeveloped forest in this part of the county.

CONSERVATION RECOMMENDATIONS:

The bottomlands and levees leased by the NC Wildlife Resources Commission should be spared from further timbering; too little of this type of forest -- critical to wildlife -- exists in a mature state in North Carolina. Further protection for the overall natural area must also involve the preservation of buffer strips of forest left along the slopes and ridge crests above the bottomlands; this might be best approached through the acquisition of conservation easements or a change in forestry management practices to favor selective harvest over clearcutting.

APPENDIX D
STATE HISTORIC PRESERVATION OFFICER CORRESPONDENCE

Letter **Page**

Progress Energy

SERIAL: HNP-05-111

NOV 1 6 2005

Dr. Jeffrey Crow
Deputy Secretary of Archives and History
State Historic Preservation Officer
North Carolina Department of Cultural Resources
4610 Mail Service Center
Raleigh NC 27699-4610

SHEARON HARRIS NUCLEAR POWER PLANT
DOCKET NO. 50-400/LICENSE NO. NPF-63
LICENSE RENEWAL - REQUEST FOR INFORMATION
HISTORIC AND ARCHAEOLOGICAL RESOURCES

Dear Dr. Crow:

Carolina Power & Light Company, doing business as Progress Energy Carolinas, Inc. (PEC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Harris Nuclear Plant (HNP), which expires in 2026. PEC intends to submit this application for license renewal in the fourth quarter of 2006. 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 will consult with your office, at a later date, under Section 106 of the National Historic Preservation Act of 1966, as amended (i.e., 16 USC 470), and Federal Advisory Council on Historic Preservation regulations (i.e., 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.

PEC has operated HNP and associated transmission lines since 1987, when the plant began commercial operation. HNP is located in the extreme southwest corner of Wake County, North Carolina. Portions of the HNP site also lie in southeastern Chatham County. The City of Raleigh, North Carolina is approximately 16 miles northeast of the plant, and the City of Sanford, North Carolina is approximately 15 miles southwest of the plant. The Cape Fear River flows in a northwest-to southeast direction approximately 7.0 miles south of the plant. CP&L constructed a dam in 1980 on Buckhorn Creek about 2.5 miles north of its confluence with the Cape Fear River to create 4,100-acre Harris Reservoir for cooling tower makeup. Filling of the reservoir began in the fall of 1980, and was completed in early 1983. The HNP power block area (i.e., reactor building, generating facilities, and switchyard) is located on the northwest shore of the reservoir, about 4.5 miles north of the main dam. The plant is located on a peninsula that extends into Harris Reservoir from the northwest (Figure 1). The Tom Jack Creek arm of the reservoir lies to the west; the Thomas Creek arm of the reservoir lies to the east. The reactor building and generating facilities lie within a nuclear exclusion area, access to which is controlled. The exclusion area is roughly circular,

Progress Energy Carolinas, Inc.
Harris Nuclear Plant
P O Box 165
New Hill, NC 27562

Dr. Jeffrey Crow
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with a radius of approximately 7,000 feet, but is not a perfect circle; its axis ranges from 6,640 feet to 7,200 feet. The distance from the center of the exclusion area to the boundary ranges from 6,640 feet (to the northwest, because US Hwy 1 truncates the circle) to 7,000 feet (east) to 7,200 feet (south). The exclusion area, comprised of both high ground and portions of Harris Reservoir, encompasses approximately 3,535 acres.

Seven 230 kilovolt transmission lines connect HNP to the regional electric system. The transmission system is described in the following paragraphs and is depicted in its original configuration in Figure 2. With a few exceptions, the corridors are 100 feet wide.

Apex, US 1 Substation – This substation was added since the publication of the Environmental Report for the initial Operating License. It is located 3.4 circuit miles northeast of HNP and is now the terminus of the Cary Regency Park transmission line.

Asheboro – This 57-mile long line originally connected HNP with a switching station in the Asheboro, North Carolina area, west of HNP. More recently, the Siler City switching station was constructed, creating a new terminus for this line 31 circuit miles from HNP.

Cape Fear North – This line connects HNP with the Cape Fear Steam Plant 7.4 circuit miles southwest of the plant.

Cape Fear South – This newer line also connects HNP with the Cape Fear Steam Plant, but follows a more southerly 6.5-mile route than the north line.

Cary Regency Park – Originally named the Method line, the Cary Regency Park switching station, at 10 miles from HNP, is approximately 5 circuit miles shorter than the original run to Method. More recently, the Apex U.S. 1 switching station was built 3.4 circuit miles northeast of HNP.

Erwin – This line, which is approximately 30 miles long, terminates just north of the town of Erwin, southeast of HNP.

Fayetteville – This line has its terminus at the Ft. Bragg Woodruff Street switching station, approximately 40 circuit miles south of the HNP site. It originally ran another 16 miles to Fayetteville.

Wake – This line, which is 38 miles long, connects HNP with the Wake switching station northeast of the site.

The corridors pass through land that is primarily agricultural and forestland. The areas are mostly remote, with low population densities. The longer lines cross numerous state

Dr. Jeffrey Crow
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and U.S. highways. Impact of these corridors on land usage is minimal; farmlands that have corridors passing through them generally continue to be used as farmland.

As a result of investigations, PEC compiled a list of sites on the National Register of Historic Places within a six-mile radius of the HNP property. As of November 2004, the Register listed 164 locations in Wake County, 53 locations in Chatham County, 16 locations in Lee County, and 12 locations in Harnett County, North Carolina. Of these 245 locations, 29 fall within a six-mile radius of HNP. In addition, there are five locations that are Determined Eligible for inclusion on the National Register list within the 6-mile radius. This information will be provided to the NRC to aid in the evaluation of the license renewal application.

PEC would appreciate a response to this letter, by February 1, 2006, detailing any concerns regarding historic or archaeological properties in the area of HNP, or confirming PEC's conclusion that operation of HNP, over the license renewal term, would have no effect on any historic or archaeological properties in North Carolina. This will enable PEC to meet the current application preparation schedule. PEC will include a copy of this letter and your response in the license renewal application to the NRC.

Please refer any questions regarding this submittal to Mr. Jan Kozyra, Lead Engineer - License Renewal, at (843) 857-1872.

Sincerely,

Dave Corlett

Dave Corlett
Supervisor-
Licensing and Regulatory Affairs
Harris Nuclear Plant

JSK/jsk

Enclosures:
Figure 1 – Harris Nuclear Plant 6-Mile Vicinity Map
Figure 2 – Harris Nuclear Plant Transmission Line Map

Dr. Jeffrey Crow
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bcc: Ms. D. B. Alexander
Mr. R. T. Wilson
Mr. P. Snead
HNP Licensing File: H-X-230
Nuclear Records

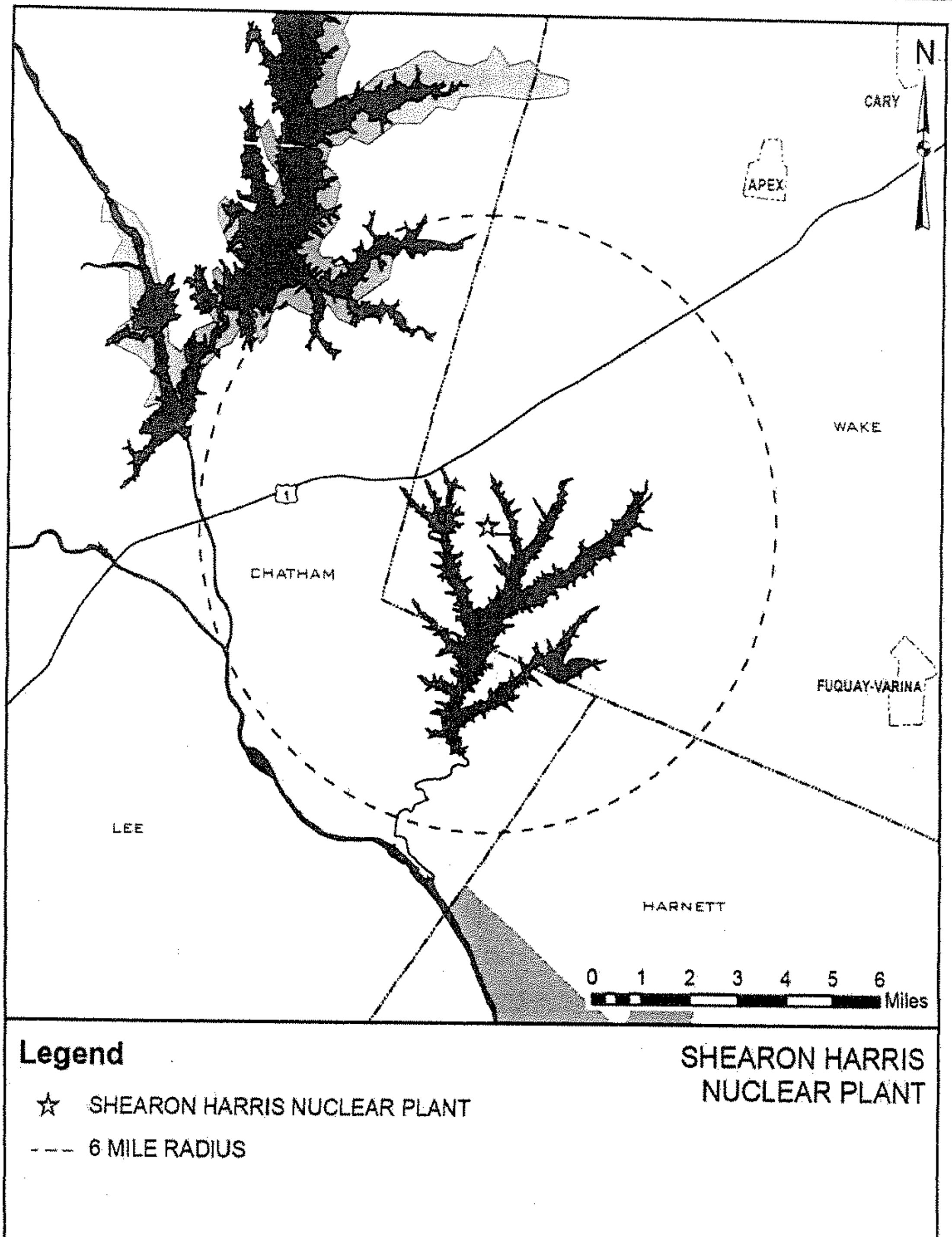
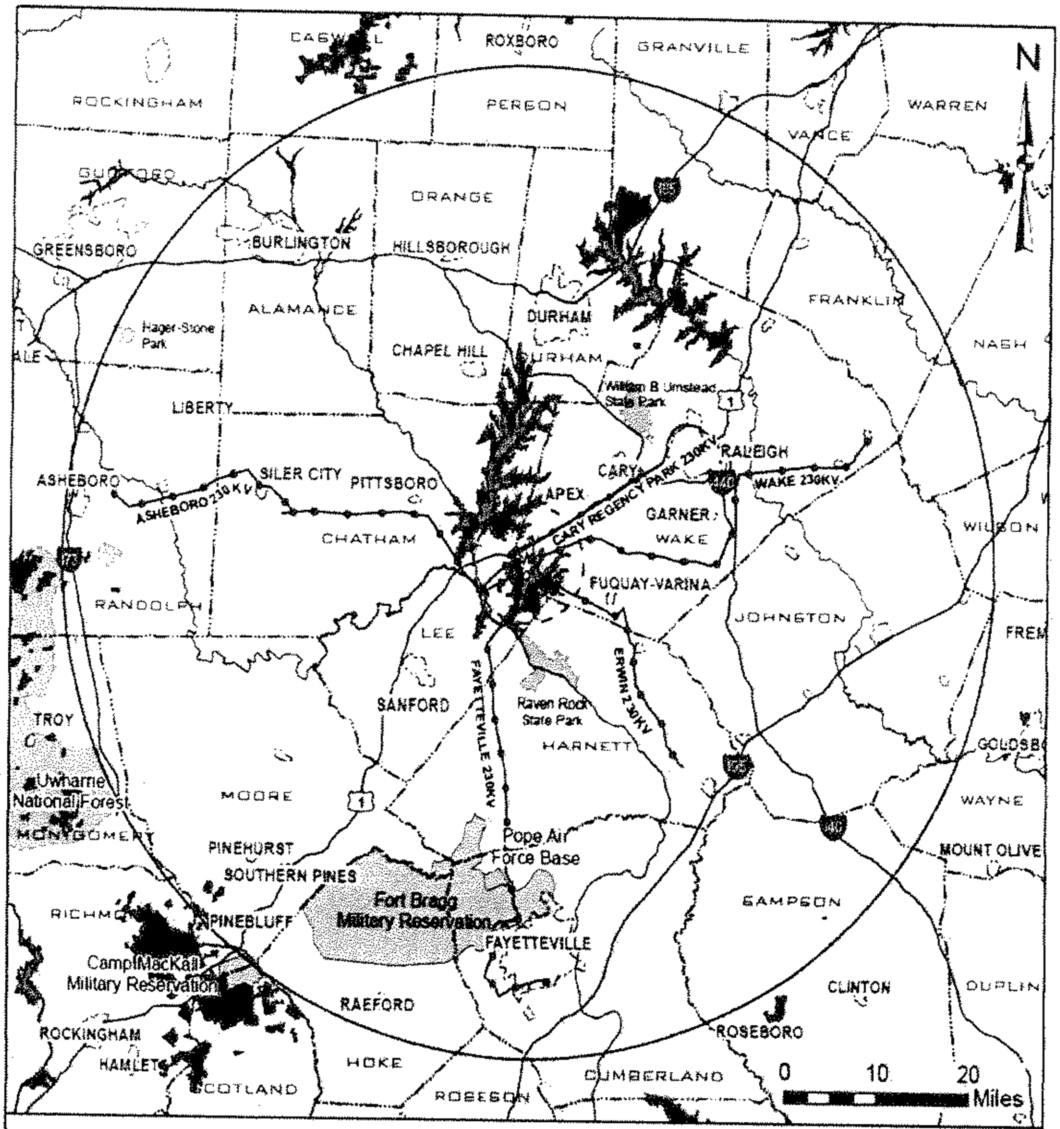


Figure 1

6 MILE VICINITY MAP



Legend

☆ SHEARON HARRIS

—— 50 MILE RADIUS

- - - - 6 MILE RADIUS

•—•— TRANSMISSION LINE

■ NORTH CAROLINA GAME LANDS

SHEARON HARRIS
NUCLEAR PLANT

FIGURE 2

50 MILE TRANSMISSION LINE MAP

North Carolina Department of Cultural Resources
State Historic Preservation Office
Peter B. Sandbeck, Administrator

Michael F. Easley, Governor
Lisbeth C. Evans, Secretary
Jeffrey J. Crow, Deputy Secretary

Office of Archives and History
Division of Historical Resources
David Brook, Director

January 26, 2006

Dave Corlett
Licensing and Regulatory Affairs
Progress Energy
Harris Nuclear Power Plant
PO Box 165
New Hill, NC 27562

Re: License Renewal, Shearon Harris Nuclear Power Plant, Wake County, ER 05-2747

Dear Mr. Corlett:

Thank you for your letter of November 16, 2005, concerning the above project.

We have conducted a review of the project and are aware of no historic resources that would be affected by the project. Therefore, we have no comment on the project as proposed.

The above comments are made pursuant to Section 106 of the National Historic Preservation Act and the Advisory Council on Historic Preservation's Regulations for Compliance with Section 106 codified at 36 CFR Part 800.

Thank you for your cooperation and consideration. If you have questions concerning the above comment, please contact Renee Gledhill-Earley, environmental review coordinator, at 919/733-4763. In all future communication concerning this project, please cite the above-referenced tracking number.

Sincerely,

Renee Gledhill-Earley
for Peter Sandbeck

	Location	Mailing Address	Telephone/Fax
ADMINISTRATION	507 N. Blount Street, Raleigh NC	4617 Mail Service Center, Raleigh NC 27699-4617	(919)733-4763/733-8653
RESTORATION	515 N. Blount Street, Raleigh NC	4617 Mail Service Center, Raleigh NC 27699-4617	(919)733-6547/715-4801
SURVEY & PLANNING	515 N. Blount Street, Raleigh, NC	4617 Mail Service Center, Raleigh NC 27699-4617	(919)733-6545/715-4801

APPENDIX E
SEVERE ACCIDENT MITIGATION ALTERNATIVES

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Acronyms Used in Appendix E

ACP	auxiliary control panel
AFW	auxiliary feedwater
AMSAC	ATWS mitigation system actuation circuit
ATWS	anticipated transient without scram
BWR	boiling water reactor
CCF	common cause failure
CCW	component cooling water
CDF	core damage frequency
CR	control room
CRD	control rod drive
CS	containment spray
CSIP	charging/safety injection pump
CST	condensate storage tank
DBE	design basis event
DG	diesel generator
DHR	decay heat removal
DWS	demineralized water system
ECCS	emergency core cooling system
EDG	emergency diesel generator
EPRI	electric power research institute
EPZ	emergency planning zone
ESF	engineered safeguard feature
ESRI	Environmental Systems Research Institute
ESW	emergency service water
FP	fire protection
FPS	fire protection system
FW	Feedwater
GE	General Electric
HCLPF	high confidence low probability of failure
HEP	human error probability
HHSI	high head safety injection
HNP	Harris Nuclear Plant
HPCI	high pressure coolant injection
HPI	high pressure injection

Acronyms Used in Appendix E

HPSI	high pressure safety injection
HVAC	heating ventilation and air-conditioning
IE	initiating event
INEEL	Idaho National Engineering and Environmental Laboratory
IPE	individual plant examination
IPEEE	individual plant examination – external events
ISLOCA	interfacing system LOCA
LOCA	loss-of-coolant accident
LOOP	loss of off-site power
LPSI	low pressure safety injection
MAAP	Modular Accident Analysis Program
MACCS2	Melcor Accident Consequences Code System, version 2
MACR	maximum averted cost-risk
MCC	motor control center
MCR	main control room
MET	meteorological
MMACR	modified maximum averted cost-risk
MOV	motor operated valve
MSIV	main steam isolation valve
NPSH	net positive suction head
NRC	U.S. Nuclear Regulatory Commission
NSW	normal service water
OECR	off-site economic cost-risk
OSP	off-site power
PE	Progress Energy
pga	peak ground acceleration
PMP	probable maximum precipitation
PORV	power operated relief valve
PRA	probabilistic risk analysis
PSA	probabilistic safety assessment
PTS	pressurized thermal shock
PWR	pressurized water reactor
RAB	reactor auxiliary building
RAS	recirculation acutation signal

Acronyms Used in Appendix E

RCIC	reactor core isolation cooling
RDR	real discount rate
RHR	residual heat removal
RHRSW	residual heat removal service water
RLE	review level earthquake
RPS	reactor protection system
RPV	reactor pressure vessel
RRW	risk reduction worth
RWST	refueling water storage tank
SAMA	severe accident mitigation alternative
SBO	station blackout
SG	steam generator
SGTR	steam generator tube rupture
SRP	standard review plan
SRV	safety relief valve
SSE	safe shutdown equipment
SSES	Susquehanna Steam Electric Station
SW	service water
TD AFW	turbine driven auxiliary feedwater
USAR	updated safety analysis report
WOG	Westinghouse Owners Group

Appendix E
Severe Accident Mitigation Alternatives

The severe accident mitigation alternatives (SAMA) analysis discussed in Section 4.20 of the Environmental Report is presented below.

E.1 METHODOLOGY

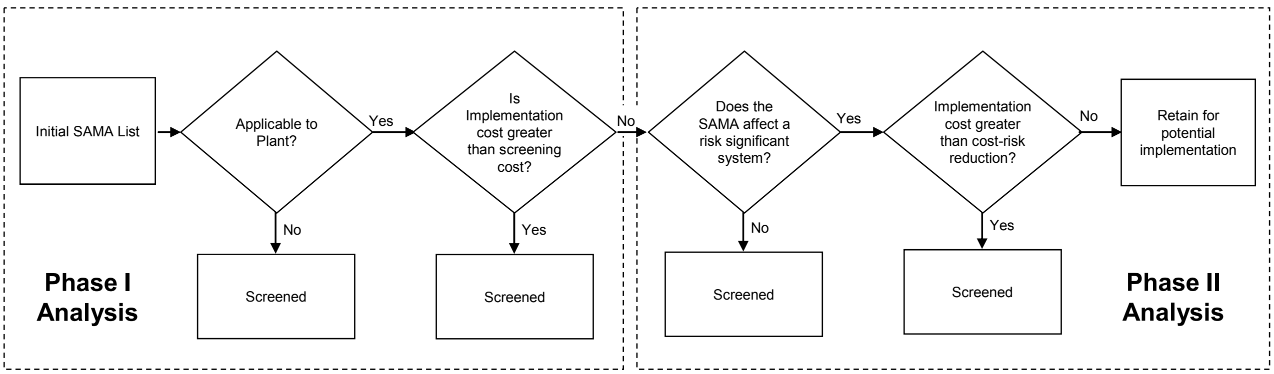
The methodology selected for this analysis involves identifying SAMA candidates that have the highest potential for reducing plant risk and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. The metrics chosen to represent plant risk include the core damage frequency (CDF), the dose-risk, and the off-site economic cost-risk. These values provide a measure of both the likelihood and consequences of a core damage event. The SAMA process consists of the following steps:

- HNP Probabilistic Safety Assessment (PSA) Model – Use the HNP Internal Events PSA model as the basis for the analysis (Section E.2). Incorporate external events contributions as described in Section E.5.1.7.
- Level 3 PSA Analysis – Use HNP Level 1 and 2 Internal Events PSA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 PSA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section E.3).
- Baseline Risk Monetization – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of the unmitigated HNP severe accident risk. This becomes the maximum averted cost-risk (MACR) that is possible (Section E.4).
- Phase I SAMA Analysis – Identify potential SAMA candidates based on the HNP PSA, Individual Plant Examination – External Events (IPEEE), and documentation from the industry and NRC. Screen out Phase I SAMA candidates that are not applicable to the HNP design or are of low benefit in pressurized water reactors (PWRs) such as HNP, candidates that have already been implemented at HNP or whose benefits have been achieved at HNP using other means, and candidates whose estimated cost exceeds the possible MACR (Section E.5).
- Phase II SAMA Analysis – Calculate the risk reduction attributable to each remaining SAMA candidate and compare to a more detailed cost analysis to identify the net

cost-benefit. PSA insights are also used to screen SAMA candidates in this phase (Section E.6).

- Uncertainty Analysis – Evaluate how changes in the SAMA analysis assumptions might affect the cost-benefit evaluation (Section E.7).
- Conclusions – Summarize results and identify conclusions (Section E.8).

The steps outlined above are described in more detail in the subsections of this appendix. The graphic below summarizes the high-level steps of the SAMA process.



E.2 HNP PSA MODEL

The SAMA analysis is based on the 2005 update of the HNP PSA model for internal events (i.e., the MOR2005 model). The original IPE model submitted in 1993 has been subsequently updated in 1995, 1998, 2000, 2001, 2003 and 2005 to maintain design fidelity with the operating plant and reflect the latest PSA technology. The 2001 update reflected modifications from the implementation of the HNP power up-rate (PUR) of approximately 4.5% and replacement of Steam Generators.

The HNP PRA model peer review was conducted in June 2002. The final report was prepared by Westinghouse, which was the lead in performing the PWR Utility peer assessment. The peer assessment identified two Level A Facts & Observations (F&Os) and 27 Level B F&Os. All A and B Level F&Os have been addressed and closed. In addition, all C Level and D Level F&Os have been closed.

The following subsections provide more detailed information related to the evolution of the HNP internal events PSA model and the current results. These topics include:

- PSA changes since the IPE
- Level 1 model overview
- Level 2 model overview
- PSA model review summary

Section E.5.1.6 provides a description of the process used to integrate external events contributions into the HNP SAMA process; therefore, no additional discussion of the external events models is included here.

E.2.1 PSA MODEL CHANGES SINCE IPE SUBMITTAL

The original 1993 IPE Level I model was updated (Section E.2.1.1) in 1995 to incorporate plant specific configurations and data as of October 1995 as well as updated the Level II analysis. The 1998 model update (Section E.2.1.2) was also based on plant configuration as of Refueling Outage 6. The 2000 model update (Section E.2.1.3) incorporated plant configuration through Refueling Outage 9, highlighted by instrument air compressor replacements. In 2001, the PSA model was updated (Section E.2.1.4) to include plant configuration as of May 12, 2000, plant-specific data through December 1999, and incorporation of RFO10 plant modifications and plant procedure changes due to Steam Generator (SG) replacement and Power Uprate (PUR) of approximately 4.5%. Also in 2001, the Level 2 PSA model LERF fractions were updated based on updated containment analysis performed for the SG replacement and PUR. Further, improvements to plant specific unavailability data for the CSIP and CCW pumps were incorporated based on insights from the maintenance rule program. The 2003 model update (Section E.2.1.5) included various update items and the first cut resolution of Peer Certification F&O comments. The 2005 model update (Section E.2.1.6) included general model updates as well as several model changes that resulted from responses to Peer Certification F&O comments and development of an updated model to support implementation of the Mitigating Systems Performance Index.

The historical nominal CDF and LERF results for HNP are as follows:

HNP Model	CDF (per yr)	LERF (per yr)	Truncation (per yr)
IPE 1993	7.0E-05	NA	1.0E-08
MOR1995	6.16E-05	2.46E-06	1.0E-08
MOR1998	5.02E-05	3.43E-06	5.0E-09
MOR2000	5.03E-05	3.53E-06	5.0E-09
MOR2001	4.87E-05	2.34E-06	4.0E-09
MOR2003	2.47E-05	4.09E-06	1.0E-10
MOR2005	9.24E-06	1.02E-06	1.0E-10

Summary descriptions of the model changes that were made as part of above updates are provided is subsections E.2.1.1 through E.2.1.6 for reference purposes. Detailed descriptions of the 1998-2005 changes are maintained as plant model documentation.

E.2.1.1 1995 PSA UPDATE

The HNP PSA IPE was submitted in August, 1993. A PSA model update standard was later established that requires elements of Progress Energy PSA models to be evaluated for update after every refueling outage. The model update described below reflects HNP plant configuration after the sixth refueling outage.

The 1995 model update (MOR1995) upgraded the PSA model with the intent of incorporating findings from the IPE, improving communication of PSA information, improving model quantification capability and updating plant specific data. The following discussion provides more detail.

E.2.1.1.1 Plant Changes

The PSA model was updated to reflect plant changes from the IPE freeze date of January 1, 1992 through RFO6 (September 1995). The PSA fault tree models were updated to include the following plant modifications:

- Addition of CSIP pump alternate minimum flow lines
- Installation of rotary instrument air compressor
- Installation of isolation valves in the RHR pump recirculation lines to the RWST to reduce likelihood of latent human error induced LHSI flow diversion.

E.2.1.1.2 Event Tree Changes:

The success criteria for small LOCAs, seal LOCAs and unisolated SG tube rupture sequences, which included a loss of all secondary side heat removal, required that a vent path be present for the bleed function of feed and bleed cooling. MAAP analysis indicated that these small breaks would drop the reactor pressure below the SRV setpoint but would provide insufficient decay heat removal to preclude core damage. Therefore, for those sequences, operation of one-of-three pressurizer PORVs was included as a requirement for successful heat removal.

E.2.1.1.3 Fault Tree Model

A major initiative was to improve model quantification speed. As a result, the fault tree model structure was converted for quantification using a one-top approach.

Recovery actions that had been applied to the cut sets manually for the IPE results were added to the model. Some specific recoveries added to the fault tree are:

- Local recovery of failed automatic bus transfer of Buses A, B, D and E from the UATs to the SUTs were added to the fault tree. The operator action was modeled to recover loss of actuation signal failure or loss of non-safety DC bus events occurring at time zero. The model change also captured component failure modes related to the recovery path.

- RHR pump failed automatic actuation recovery was added. This action was not credited for large LOCA.

The system fault tree model changes also included improvements to common cause failure groups to standardize the approach for consistency between system models.

E.2.1.1.4 New System Models

For the IPE, the fault tree model included a number of undeveloped events to mark system failures such as the availability of MFW after a trip or the availability of the Boric Acid Transfer system. For long term makeup to the RWST, an operator action was used to model the availability of the Demineralized Water System. The following system models and their support system ties were developed for the model update:

- Main Feedwater and Condensate Systems
- Boric Acid Transfer System
- Reactor Make-up Water System
- Demineralized Water System

E.2.1.1.5 Initiating Event Fault Tree Models

For the IPE, all initiating events were modeled as individual events in the fault tree model. For system related initiating events, the values were based on hand calculations of the possible failure modes. By converting the individual initiating events to fault tree models, a more complete assessment of system importances is possible. For the 1995 PSA update, the following system related initiating events were converted to fault trees.

- Loss of Normal Service Water
- Loss of Normal Service Water Return Valves from ESW headers
- Loss of CCW

- Loss of CVCS/CSIPs
- Loss of DC Bus
- Loss of AC Bus

E.2.1.1.6 Initiating Event Data Update

The LOCA initiating event frequencies were updated using the EPRI pipe break analysis methodology. The LOSP analysis was updated to capture the latest industry experience. Both LOSP initiating event frequencies and recovery probabilities were updated.

The transient initiating event categories without plant-specific initiating event system models were updated based on a review of the HNP experience from startup through RFO6.

E.2.1.1.7 Component Reliability Data Update

The plant specific reliability and availability data was updated. The control operator log books were reviewed for the time period between the IPE freeze date, January 1, 1992, and September 15, 1995.

E.2.1.1.8 Human Reliability Analysis

Revisions to plant operating procedures made between the IPE freeze date and RFO6 were reviewed for potential impact on the PSA.

In the IPE fault tree model, a common operator action was used for recovery of a number of failed actuation signals. A more realistic approach was adopted that removed the complete dependence between systems. The HRA analysis was updated to system specific recoveries of actuation signal failures for CCW pumps, SI injection MOVs, ESW booster pumps, and ECWS Chillers.

A number of operator actions from the HRA analysis were re-assessed to provide more realistic HEPs, improve consistency of the analysis and to remove conservatisms found in the IPE analysis.

As part of the attempt to improve model quantification speed, operator action dependencies were added to the fault tree model.

E.2.1.1.9 Level II Analysis

Following the IPE submittal, changes were made to the core damage model that resulted in a change in the composition and frequency of the accident sequences. In order to gain insights into how these changes have altered the containment results and conclusions, the containment model was revised to use an automated process.

E.2.1.2 1998 PSA UPDATE

The HNP PSA model of record (MOR1998) was performed to account for plant configurations from RFO6, September 1995, through RFO7, ending June 1997. The model update is described below.

E.2.1.2.1 Plant Modifications

Plant modifications were reviewed for the cycle 7 time period and there were no significant changes affecting the PSA.

E.2.1.2.2 Event Tree Changes

An analysis was performed showing that based on the uncertainty in the break size of S1 LOCAs and transient induced LOCAs, that the break flow could exceed the makeup capability for refilling the RWST following a failure of recirculation sequences. Credit for RWST makeup was removed from S1 and transient induced (TQ) LOCA event trees.

The TQ LOCA and S1LOCA event tree logic was modified to take credit for rapid cooldown and depressurization based on procedural guidance in the EOPs.

An analysis was performed showing that CCW cooling to the RHR system was not required during HHSI or LLHSI recirculation mode for S1LOCA and TQ LOCA events with secondary side cooling available. The S1 LOCA and TQ LOCA event trees and sequence logic were updated with a new gate for RHR operation without the CCW requirement.

The station blackout branches in the transient tree were removed to implement rule based recovery of offsite power.

E.2.1.2.3 Fault Tree Model

The turbine trip initiating event %T3, was added as input to the loss of condenser cooling because the turbine trip data includes MSIV isolation

E.2.1.2.4 Initiating Event Data Update

The transient initiating event categories without plant-specific initiating event system models were updated based on a review of the HNP experience through cycle 7.

The Loss of Offsite Power (LOSP) analysis was updated to capture the latest industry experience. Both LOSP initiating event frequencies and recovery probabilities were updated. Rule base recovery was employed for LOSP recovery.

E.2.1.3 2000 PSA UPDATE

The HNP PSA model of record (MOR2000) update was performed to incorporate plant changes related to the time period between the start of Cycle 8, June 1997, through RFO9, May 2000. Changes to operating procedures were also reviewed for procedure revisions impact to the PSA model through January 1999. The PSA model revision occurred in two phases with the first phase addressing modification and procedure reviews through RFO8. The interim model published in 1999 exhibited little variation from the 1998 results. The second phase of the 2000 PSA model update focused on an instrument air system modification that was completed after the beginning of Cycle 10. The PSA model update is described below.

E.2.1.3.1 Plant Modifications

Of the plant modifications reviewed for the period of June 1997 through May 2000, the only significant plant change was the replacement of the four reciprocating instrument air compressors with two rotary air compressors. The primary reason for this plant modification was to increase the availability of the instrument air compressors. The instrument air fault tree model and support systems were revised for this modification.

E.2.1.3.2 Initiating Event Fault Tree Models

In addition to revising the instrument air system fault tree model associated with post trip response, a new Loss of Instrument Air initiating event fault tree was developed to replace the single point estimate basic event that was comprised of generic data updated to plant experience. The loss of instrument air fault tree was developed to appropriately model the impact of configuration specific risk and improve reporting of system and component type importance measures.

E.2.1.3.3 System Models

The demineralized water system model was revised to capture procedural changes to OP-102 requiring the normal position of the RWMST supply valve to be normally closed. An operator action was added to the model to realign the flow path when required.

Other changes were made to the AFW and Containment Fan Coolers (CFC) models to capture procedural requirements in OP-137 that the associated train of CFCs must be made inoperable when a train of ESW is lined up to AFW.

E.2.1.3.4 Human Reliability Analysis

As part of the procedure reviews the operator actions in the PSA model were revisited to improve overall consistency and documentation quality.

E.2.1.4 2001 PSA UPDATE

The HNP PSA model of record (MOR2001) update was performed to account for plant configurations between the start of Cycle 10, May 2000, through RFO10, that ended in December 2001. The PSA update incorporated RFO10 plant modifications and procedure changes due to SG replacement and Power Uprate (PUR). The model update is described below.

E.2.1.4.1 Plant Modifications

The SG replacement and PUR were the major plant change for the 2001 PSA update.

As part of the SG replacement, the AFW discharge to the MFW pre-heater bypass line was removed in order to connect AFW to the new dedicated SG nozzles for AFW. The change allows MFW to continue using the normal at power flow path immediately following a plant trip, thus improving the availability of main feedwater for accident mitigation. The AFW and MFW models were updated to incorporate these changes.

As part of the PUR, the normal operating state of HHSI flow path isolation valves 1SI-1 and 1SI-2 through the BIT to the cold legs were locked open with power removed. The fault tree model was updated accordingly including regrouping the common cause failure inputs for injection pathway MOVs.

Another modification included in the PSA model was the removal of the screen wash pump discharge check valve internals.

E.2.1.4.2 Event Tree Changes

In the 1998 model update, credit for refilling the RWST was limited to SGTR sequences because the potential break flow of S1 LOCAs and transient induced LOCAs could exceed the make-up capability to the RWST. For the 2001 update, it was recognized that SGTR sequences that included a loss of secondary side heat removal would result in feed and bleed cooling attempts. Credit for RWST makeup was removed from this sequence because the bleed path of one pressurizer PORV could result in make-up requirements exceeding RWST makeup capability.

The success criterion for recirculation following a S2 LOCA was changed from low head recirculation to high head recirculation based on updated thermal hydraulic analysis.

E.2.1.4.3 Initiating Event Modeling

The plant specific ISLOCA initiating event tree was revised to include operator intervention for smaller break sizes.

The common-cause failure analysis was expanded in the CCW initiating event tree to include the swing pump credit in prevention of a loss of CCW initiating event

E.2.1.4.4 System Modeling

Containment pressure signal logic fault trees were developed for the model update. The logic replaced undeveloped events used in the IPE.

E.2.1.4.5 Initiating Event Data Update

The transient initiating events and SGTR frequencies were updated based on plant experience through December 1999. The LOSP analysis was updated to capture the latest industry experience. Both LOSP initiating event frequencies and recovery probabilities were updated.

E.2.1.4.6 Component Reliability Data Update

The plant specific reliability and availability data was updated. The control operator log books were reviewed for the time period from September 1995 (RFO6) through December 1999. The generic and plant specific common cause failure data was updated to capture industry experience and plant specific experience.

As part of the ISLOCA model update, the specific valve failure modes were changed from using shared type code failure rates to specific hand calculated failure probabilities specific to each valve's potential failure modes.

An interim update was performed to correct CSIP and CCW pump unavailability data and was included, for documentation purposes, as part of the MOR2001 update.

E.2.1.4.7 Level II Analysis

Following the SG replacement and PUR, resulting changes in the composition and frequency of the accident sequences required analysis of the impact of these changes on the containment results and conclusions. Therefore, the containment assessment was revised to update changes in core damage bin distribution and frequency. The level II analysis was updated to revise the plant damage split fractions used to calculate the LERF contribution fractions of each plant damage state.

E.2.1.5 2003 PSA UPDATE

The HNP PSA model of record (MOR2003) update was performed to account for plant configuration from beginning of Cycle 11, December 2001 through RFO11, ending, May 2003. For the PSA update, RFO11 plant modifications and procedure changes were reviewed for potential impact on the PSA model. No PSA model changes resulted from the plant configuration or procedures following RFO11. A general update of the PSA model was conducted to revise model data and incorporate peer certification comment resolution. The model updates are described below.

E.2.1.5.1 Peer Certification F&O Comment Resolution

The Rhodes seal LOCA model was implemented to replace the NUREG/CR-4550 model. The loss of offsite power recovery values were updated as part of change. The steam line break initiator frequency was recalculated using generic data from NUREG-5750.

The most recent Westinghouse guidance on modeling SGTR sequences, WCAP-15955, was incorporated in the event trees and sequence logic.

The most recent Westinghouse guidance on modeling ATWS sequences, WCAP-15831, was incorporated in the event trees and sequence logic. This model includes more stringent success criteria for secondary cooling, new human error probabilities for ATWS related actions, more accurate accounting of the impact of moderator temperature coefficient with core life, and more detailed modeling of RPS logic.

The potential for containment sump clogging was added based on data from NUREG/CR-3394 and plant specific sump design considerations.

The frequencies of RCS LOCAs was revised to use the values in NUREG-5750 without any Bayesian update based on plant-specific piping configurations. The plant-specific piping configurations are used to determine an appropriate split of the medium LOCA frequency based on piping sizes, since the NUREG has three LOCA sizes while HNP uses four different sizes.

Based on review comments, the common cause analysis was updated.

The ISLOCA fault trees were removed and replaced with single point estimates in order to improve the check valve internal rupture probability and account for correlation between similar failure modes of isolation valves.

E.2.1.5.2 System Model

Local operation of TDAFW pump when B Train DC power is unavailable was added to the fault tree model, based on plant procedures, using a screening value.

E.2.1.5.3 Initiating Event Data Update

The transient initiating events frequencies were updated based on plant experience through December 2002. The LOSP analysis was updated through 2002 using latest EPRI industry data. Both LOSP initiating event frequencies and recovery probabilities were updated.

E.2.1.5.4 Component Reliability Data Update

The plant specific reliability and availability data was updated. The control operator log books were reviewed for the time period from January 2000 through December 2002.

E.2.1.6 2005 PSA UPDATE

The HNP PSA model of record (MOR2005) update was performed in support of issuing a Mitigating System Performance Index (MSPI) Basis Document for implementation of the MSPI program. The model update is called MOR2005 and various changes are described below.

E.2.1.6.1 Peer Certification F&O Comment Resolution

An update to the modeled operator actions (HRA analysis) was performed and the results placed in a rule-base recovery file. A revised HRA dependency analysis was performed with the previous dependency events removed from the fault tree and the revised/updated dependencies placed in a rule-based recovery file.

The LOSP recovery analysis was updated to reflect the change from the Rhodes Seal LOCA model to the WOG2000 Seal LOCA model.

An update to the Internal Flooding Analysis was performed to reflect more current analysis methodology.

E.2.1.6.2 System Modeling

The EDG ventilation events were renamed from HVAC system designator to EDG system designator to properly account for system importance.

An Operator Action was added to the model to credit an alternate means of cooling the CSIP rooms when the chiller is not available per procedurized actions of opening the pump room door and installing a fan to cool the room.

E.2.1.6.3 Event Tree Changes:

The S1 LOCA and transient induced LOCA event trees were conservatively revised to remove credit for cool-down/depressurization with Secondary Side Heat Removal and going on shutdown cooling with no LPI and no HHSI available.

E.2.1.6.4 Component Reliability Data Update

Common-cause failure events were updated in accordance with NUREG/CR-5497. In addition, data updates for several valves were made to reflect demand failure rates verses standby failure rates.

E.2.1.6.5 Human Reliability Analysis

A complete update to the HRA analysis, including dependency analysis, was performed to respond to Peer Certification comments.

E.2.2 HNP PLANT LEVEL 1 PSA MODEL (MOR2005)

The SAMA analysis is based on the HNP Model of Record developed in 2005 (MOR2005). This model includes changes and analysis that were required to support the HNP power uprate of approximately 4.5% and Steam Generator Replacement that occurred in 2001. In addition, all HNP PSA model Westinghouse Peer Certification comments (F&Os) have been dispositioned and those requiring model and/or documentation changes have been addressed with the issuance of this model (MOR2005).

The contribution to core damage frequency (9.24E-06) due to initiating events shows that four initiators contribute 10% or more: Loss of Offsite Power (30%), Internal Flood (17%), LOCA (14%), and Loss of AC Bus (10%).

Loss of offsite AC power is significant due to the reliance upon the two emergency diesel generators (EDGs) and their support systems. Typically, core damage sequences following this initiating event are a result of an eventual station blackout condition, subsequent reactor coolant pump seal failures and resulting RCS leakage without makeup. In some cutsets, power may be lost on one train, and equipment fails on the energized train, causing a loss of a critical function. Credit is taken for recovery of offsite power based on industry experience with the duration of loss of offsite power events.

Loss of an AC bus is significant due to the impact on an entire safety train of equipment. Failures in the opposite safety train then cause unavailability of the safety functions. Non-safety systems credited for accident mitigation, such as main feedwater, rely on AC power for operation. Train B has been more significant than train A in prior models, due to reliance of the AFW turbine-driven pump on safety train B DC power. However, local manual operation of the TDAFW pump after a B Train DC power failure is now credited, based on procedural changes made, which has reduced this asymmetry.

SGTR is a not as significant a contributor to overall core damage frequency. While a SGTR is significant due to the potential for uncontrolled release of reactor coolant to the environment, core cooling can easily be maintained by injecting and bleeding through the break and the primary SRVs.

Figure E.2-1 provides a more complete depiction of the HNP CDF contributions grouped by initiating event category. In addition, Figures E.2-2 and E.2-3 provide the contribution to CDF by system and the system based Risk Achievement Worth rankings, respectively.

E.2.3 HNP LEVEL 2 PSA MODEL (MOR2005)

The SAMA analysis is based on the HNP Model of Record developed in 2005 (MOR2005). This model incorporates changes and analysis that were required to support the HNP power uprate of approximately 4.5% and Steam Generator Replacement. In addition, all HNP PSA model Westinghouse Peer Certification comments (F&Os) have been dispositioned and those requiring model and/or documentation changes have been addressed with the issuance of this model.

The containment response analysis (Level 2) evaluates the best estimate performance of the containment during a severe accident. The status of the containment safeguards systems is modeled to account for the effects of containment cooling and isolation. This model accounts for core damage sequences that cause a direct bypass of containment, such as a SGTR or inter-system LOCA. The design pressure of the HNP containment is 45 psig, but based on a probabilistic evaluation of the containment structure, the mean expected failure pressure is 153 psig at which point the basemat will shear at the point it meets the containment wall. Thus the containment is relatively robust against failure due to overpressure.

The dynamic response to core debris expulsion as it is transported through the vessel cavity and through other containment compartments is analyzed to estimate the effects of direct containment heating and subsequent containment pressurization. Other severe accident effects, such as hydrogen generation and ignition are evaluated as to their likelihood in each sequence. The level 2 analysis is used to predict the ability of the containment to mitigate severe accident challenges and, in the case of failure, to predict the timing of containment failure and subsequent radionuclide release for each release category.

As is typical of most large dry containments, the HNP containment is robust against severe accident challenges, such as hydrogen burns and the effects of high pressure melt ejection. These failure mechanisms are calculated to produce pressure increases within the capability of the HNP containment structure, and so are not likely to cause containment failure.

It is important to define a special group of release categories where the radionuclide release from the containment would occur prior to the initiation of evacuation planning and is of such a magnitude that the potential for some measurable health effects cannot be precluded. This variety of release is typically measured by the large early release frequency (LERF). A large early release from the containment can occur from containment breach due to containment failure at the time of reactor vessel break or a bypass of containment due to such events as a steam generator tube rupture (SGTR), interfacing systems LOCA, or isolation failure. Typically it involves the rapid, unscrubbed release of airborne aerosol fission products to the environment with core damage occurring or a containment failure pathway of sufficient size to release the contents of the containment within one hour, which occurs before or within 4 hours of vessel breach.

The large early release frequency (LERF) is calculated to be 1.02E-6 per year. This numeric measure, like CDF, is used in applying the PRA results by evaluating relative changes, and together with CDF are the two major "figures of merit" applied to PRA. Figure E.2-4 presents the initiating event contributions to LERF. For HNP, the dominant LERF contributor is a SGTR with cycling or stuck open secondary SRVs providing the containment failure pathway.

The LERF must be understood in context of the overall level 2 results. The conditional containment failure probability (CCFP) is 0.28. This equates to a containment success probability of 0.72. Figure E.2-5 summarizes the contribution of the containment failure modes, which make up the CCFP. The CCFP is comprised of several different classes of failure. Of these different failure classes representing the CCFP, bypass failures, occurring near the time of core damage and reactor vessel failure, and resulting in large fission product releases, represent about one third of the CCFP. The remaining containment failure sequences are late failures that involve a significant time delay between core damage and containment failure of up to several days. This means that for the most likely severe accident sequences (about 91% of core damage sequences), significant time is available to implement emergency measures to protect the public. This is significant when evaluating plant conditions using level 2 results. For cases involving a failure of containment, the dominant cause of containment breach involves core damage sequences that end with the RWST being depleted and no long-term decay heat removal mechanism available. For these sequences, the containment fails due to gradual overpressure of the containment due to steam and non-condensable gas generation. Another significant cause of containment failure is basemat failure resulting from long-term (greater than 3 days) concrete ablation by molten core material.

E.2.3.1 HNP LEVEL 2 RELEASE CATEGORIES

The solution of the numerous event trees results in the generation of a large number of accident sequences. Once developed, these accident sequences must be propagated through the containment safeguards assessment and the containment event tree to develop release categories. To reduce the burden on the analyst, the accident sequences can be grouped, commonly referred to as binning, into accident sequence categories.

The method of binning the accident sequences is much like that used to categorize the transient initiating events. A set of parameters is identified which can be used to define unique accident sequence classes. These parameters are typically defined based on the needs of the containment analysis. For example, one parameter commonly used in the binning process is the timing of reactor pressure vessel (RPV) failure. The timing of RPV failure is important to the containment analysis and determines the timing of containment pressure challenges, in-vessel hydrogen generation, and radionuclide retention within the reactor coolant system (RCS). This parameter, therefore, is typically chosen for binning accident sequences. Once the important parameters are identified the next step is to determine the physically possible combinations of the parameters. Each combination of the parameters defines a core damage bin (CDB).

Once the CDBs are finalized, the different (Level 1) event tree accident sequences are assigned to the CDBs by comparing the CDB parameters and the cut sets that comprise the specific accident sequence.

To develop a complete accident sequence definition for transfer to the containment assessment, the CDB information must be combined with the status of the containment safeguards systems. This combination results in a Plant Damage State (PDS).

The Containment Safeguards Event Tree (CSET) provides a means for interfacing the core damage (Level 1) model with the containment safeguards functions. The event tree addresses the status of the containment systems to complete the system-level information needed by the level II PSA analyst. Additionally, the use of a CSET that incorporates fault tree and event tree models allows the core damage sequence cut sets to be linked directly to the CSET. The direct linking of the system model results in containment and core safety system dependencies being identified and explicitly addressed.

The end states of the CSET represent the possible states of the systems associated with the containment that are of interest in the PSA. The status of the containment systems is important in determining containment pressure challenges, source term composition, and other physical parameters associated with the level II PSA. An alphabetic code is used to distinguish each CSET end state. When the CSET end state code is combined with the CDB the PDS definition is identified. For example, PDS 1P represents a sequence from CDB 1 and CSET end state P.

A containment event tree (CET) is developed that provides a convenient method to identify the various possible outcomes resulting from different combinations of phenomenological effects. The PDS is used to transfer information from the front-end analysis (level 1) to the back end analysis (level 2). The PDS event is important for two reasons. It provides the initiating event frequency for the CET and also transmits physical conditions and plant status from the front-end analysis to the back-end analysis. The CET is solved for each PDS identified to determine the conditional probabilities for each CET outcome. These split fractions are then combined with the

PDS frequency to determine the contribution by PDS. Summing the frequency for a release category class determines the contribution for that attribute.

The CET end states correspond to the outcome of possible severe accident sequences. Each end point defines a different containment state with an associated radionuclide release. Simplifications can be attained by grouping sequences with similar release characteristics into release categories. A set of release categories is defined such that all accidents assigned to the same category are assumed to have the same set of release fractions.

The main characteristics used to define the release categories are release energy, containment isolation failure size, timing of the release, and isotopic consumption.

Specific MAAP sequences were developed to mimic CET end states and the estimated releases determined. Like CET end states were grouped to minimize the number of MAAP sequences required. The MAAP code outputs fission product data in the tabular output file (*.tab). This information is used to group similar sequences according to time of release and radionuclide release into the 14 release categories. An intact containment state is also presented to address situations where the containment function is maintained. Since intact containment sequences are covered by design-based leakage, they are not further assessed. The following paragraphs define each release category and related assumptions.

E.2.3.1.1 Containment Intact (IC–1)

This release category represents an accident sequence in which the containment is intact. The source term for this type of sequence is very small and limited to the containment design leakage rate. The baseline frequency for this release category is 7.30E-06/yr.

E.2.3.1.2 Release Category 1 (RC–1)

This release category is a late containment failure caused by gradual overpressurization. The core debris is assumed to be coolable. This type of gradual pressure increase is assumed to result in a relatively benign containment failure and the duration of the release could be over a long period of time. The release from the containment is scrubbed by either the containment sprays or a pool of water over the core debris. The baseline frequency for this release category is 3.22E-09/yr.

E.2.3.1.3 Release Category 1A (RC–1A)

This release category is similar to RC–1 except that revaporization occurs. Revaporization is caused by the self-heating of radionuclides plated out on the surfaces of the RCS. This revaporization is postulated to occur late in the accident sequence after the containment has failed. This allows the radionuclides to be released from the containment after only a limited holdup time. The impact of revaporization on the source term is to increase the contribution of volatile radionuclides. The baseline frequency for this release category is 1.07E-10/yr.

E.2.3.1.4 Release Category 1B (RC–1B)

This release category is similar to RC–1 except that no scrubbing by containment sprays and/or water pools is available. If containment sprays function, or the RWST inventory is otherwise dumped into containment, then both debris cooling and scrubbing will be attained (unless debris uncoolability is assumed). This can be assumed because for the HNP containment when the RWST is discharged the water level reaches several feet over the debris, completely covering the debris bed for the duration of all applicable sequences studied. Thus, this category applies to sequences in which the RWST is not injected and the debris bed eventually dries up resulting in considerable core-concrete interaction (CCI). The baseline frequency for this release category is 3.97E-07/yr.

E.2.3.1.5 Release Category 1BA (RC–1BA)

This release category is similar to RC–1 except that both revaporization and no containment scrubbing are assumed to occur. The baseline frequency for this release category is 2.17E-08/yr.

E.2.3.1.6 Release Category 2 (RC–2)

This release category represents a large early containment failure. The core debris is assumed to be coolable. The failure is assumed to be significantly large to reduce radionuclide holdup time in the containment. High-pressure melt ejection sequences leading to containment failure and liner failure releases are assigned to this category. The release from the containment is scrubbed by containment spray operation at the time following fission product releases from the primary side. In this case the releases will be driven by the prompt release of fission products at containment failure and the effect of revaporization, if any, should be small. Thus, release categories with revaporization will not be postulated for the large early containment failures. The baseline frequency for this release category is 8.13E-09/yr.

E.2.3.1.7 Release Category 2B (RC–2B)

This release category is similar to RC–2 except that no scrubbing by containment sprays and/or water pools is assumed to occur. The baseline frequency for this release category is 3.54E-08/yr.

E.2.3.1.8 Release Category 3 (RC–3)

This release category represents an early containment isolation failure with a small leakage rate (<4" diameter). The core debris is assumed to be coolable. The release from the containment is scrubbed by either the containment sprays or a pool of water over the core debris. For the larger of the small leakage failures (i.e. close to 4" in diameter) the releases, if any, should be small, and will be driven by the prompt release of fission products at containment failure and the effect of revaporization. Smaller diameter isolation failures will result in reduced source terms due to the longer time available for natural removal mechanisms, such as gravitational settling, to take place. Release categories with revaporization is not postulated for the small early containment failures. The baseline frequency for this release category is 4.37E-08/yr.

E.2.3.1.9 Release Category 3B (RC–3B)

This release category is similar to RC–3 except that no scrubbing by containment sprays and/or water pools is assumed to occur. The baseline frequency for this release category is 4.60E-08/yr.

E.2.3.1.10 Release Category 4 (RC–4)

This release category represents a containment bypass accident sequence with a small leakage rate. The leakage rate that would correspond to a SGTR sequence with cycling Safety Relief Valves, or an Inter-system LOCA (ISLOCA) in which operators react in time to mitigate effects of the ISLOCA. The core debris is assumed to be coolable and releases from the containment are scrubbed. Scrubbing by water in the ruptured steam generator above the break is assumed to occur, since the procedures would direct the operators to maintain a minimum level in the ruptured steam generator. The baseline frequency for this release category is 1.62E-07/yr.

E.2.3.1.11 Release Category 4C (RC–4C)

This release category is similar to RC–4 except that no scrubbing by water in the ruptured steam generator above the break occurs. The core debris is assumed to be coolable and releases from the containment scrubbed.

Note that a release category for no scrubbing by containment sprays and/or water pools is not postulated in this case. This is so because for the bypass sequences most of the release would be directly from the primary to the environment or the auxiliary building. The non-volatile contribution to the source term should be negligible since CCI is unlikely in all the dominant SGTR sequences for HNP. This is so, because core damage is averted in sequences for which the high pressure injection pumps are available, assuming the refueling water storage tank (RWST) is refilled. Since the run for the release category could only be ran to 17 hours due to the limitations of MAAP, the RWST water level is not known past that 17 hour end time. However, the refilling of the RWST is considered likely due to the extrapolation of the MAAP outputs for the RWST water level, which indicates that at least 20 hours would pass before the RWST would empty. When high pressure injection is not available the RWST inventory would be discharged to the containment via containment spray operation and cool down the debris, or at least scrub the releases. At any rate, even if CCI occurs, the containment would be at low pressure (depressurizes through the stuck open relief valve for the cases involving loss of RWST inventory outside containment) and thus, there would be little driving force for further releases. The baseline frequency for this release category is 6.36E-09/yr.

E.2.3.1.12 Release Category 5 (RC–5)

This sequence represents a containment bypass accident with a large leakage rate. Such rate is representative of a SGTR accident with a stuck open SRV on the ruptured steam generator, or an unmitigated ISLOCA accident. The core debris is assumed to be coolable and releases from the containment scrubbed. The release from the ruptured steam generator is assumed to be scrubbed by water above the break line. Since the SRV is stuck open, the potential for maintaining coverage is low. Therefore, the unscrubbed source term (RC–5C) will be conservatively assigned to these low probability branches. The baseline frequency for this release category is 1.75E-07/yr.

E.2.3.1.13 Release Category 5C (RC–5C)

This release category is similar to RC–5 except that scrubbing by water in the ruptured steam generator does not occur. The baseline frequency for this release category is 6.40E-07/yr.

E.2.3.1.14 Release Category 6 (RC–6)

This category represents cases for which the containment failure mode would be a very late failure due to basemat melt through. The baseline frequency for this release category is 3.93E-07/yr.

E.2.3.1.15 Release Category 7 (RC–7)

This category represents cases for which containment fails "very late" due to over pressurization. That is, in this case the pressure rise in containment is mainly caused by the build up of noncondensible gases from CCI.

CET end states were examined to perform qualitative groups of like or similar outcomes based on the success and failure identified in the CET and engineering judgment. Based on this consolidation MAAP sequences were generated that reflect the range of

CET outcomes. These sequences were then assigned as representatives of different postulated release categories and used to develop the RC source terms.

The estimate of the source term for each release category used results from deterministic analysis of representative PDS sequences. The analysis used the MAAP code, which calculates source terms for severe accident progressions. The releases predicted by a particular representative sequence were used to define release fractions for a release category, whenever the characteristics of the sequence closely matched a containment end state. Otherwise, information implied from the complete set of PDS runs, or new sequences designed for a specific release category, were used to complement the results of representative sequence in assigning release fractions. Using the results of MAAP runs for the representative sequences, the release fractions were obtained. The baseline frequency for this release category is 9.55E-07/yr.

E.3 LEVEL 3 PSA ANALYSIS

Progress Energy used the MACCS2 computer code (Chanin and Young 1997) to determine two types of consequences of severe accidents: human health in terms of dose and economic in terms of cost. For human health impacts, Progress Energy calculated collective dose to the 50-mile population. Economic costs include the costs associated with short-term relocation of people, decontamination of property and equipment, interdiction of food supplies, land, and equipment use, and condemnation of property.

The MACCS2 code was specifically developed for NRC to evaluate severe accidents at nuclear power plants. It primarily addresses the air pathway, but it does calculate dose from runoff and deposition on surface water. The exposure pathways modeled include external exposure to the passing plume, external exposure to material deposited on the ground and skin, inhalation of material in the passing plume and resuspended from the ground after deposition, and ingestion of contaminated food and surface water.

The input parameters given with the MACCS2 “Sample Problem A” formed the basis for the present analysis. These generic values were supplemented with parameters specific to HNP and the surrounding area. Site-specific data included population, economic, and agricultural parameters as well as radionuclide release and meteorological data. The modeled behavior of the population during a release was based on site-specific set points (i.e., declaration of a General Emergency) and the emergency planning zone evacuation times. These data were used to simulate the probability distribution of impact risks (exposure and economic) to the surrounding population (within 50 miles from the representative accident sequences at HNP).

E.3.1 POPULATION

The resident population within a 50-mile radius of HNP was estimated based on the most recent United States Census Bureau decennial census data as provided by the program SECPOP2000 (NRC 2003). The population distribution was estimated in 10 concentric bands at 0 to 1 mile, 1 to 2 miles, 2 to 3 miles, 3 to 4 miles, 4 to 5 miles, 5 to 10 miles, 10 to 20 miles, 20 to 30 miles, 30 to 40 miles, and 40 to 50 miles from HNP and 16 directional sectors, each direction consisting of 22.5 degrees. The transient population was then combined with the resident population.

Once the 2000 population was determined for each of the 160 sectors, projections were made for the year 2040. Growth rates were calculated for each county based on 2000 census populations and State projections for the year 2030 (State of North Carolina 2005). Once county growth rates were determined, ArcView 3.1 was used to determine the percentage of each sector occupied by a particular county. ArcView 3.1 is geographic information system (GIS) software developed by Environmental Systems Research Institute (ESRI). The sectors were divided into fractions by county, and projections for each fraction were calculated based on the county growth rate. The population projections for the year 2040 were then totaled by sector, and rounded to the nearest whole number to obtain the final result. The sector population projections by emergency planning zone sector are depicted in Table E.3-1.

E.3.2 ECONOMY AND AGRICULTURE

Progress Energy used SECPOP2000 to determine the spatial distribution of certain economic data in the same manner as the population. In addition, generic economic data that is applied to the region as a whole was revised from the MACCS2 sample problem input when better information was available. Several parameters were escalated from 1986 to 2004 by the ratio of the consumer price index of 1.68 derived http://data.bls.gov/cgi-bin/cpicalc.pl. These revised parameters include value of farm and non-farm wealth and fraction of farm wealth from improvements (e.g., buildings, equipment). The average value per hectare of farm land and buildings within 50 miles and the average value per hectare of non-farm land and buildings within 50 miles were calculated with a spreadsheet using county data from the U.S. Department of Agriculture and the Bureau of Economic Analysis. A geographical information system analysis assisted in determining the weighted contribution of each county in the 50-mile radius.

E.3.3 RADIONUCLIDE RELEASE

The core inventory used for the analysis was derived from the plant's Final Safety Analysis Report, Table 15.0.9-1. The release data (Table E.3-2) were for 14 release sequences, which were determined by Modular Accident Analysis Program (MAAP) runs. A ground level release was used as the base case for the HNP SAMA analysis as the largest contributors to the release consequences are SGTR and ISLOCA events, which do not release through the plant stack. Some ambiguity exists for the treatment of the SGTR scenarios as the steam generator PORV release points are on the Reactor Auxiliary Building roof rather than at the foot of the building, but the ground level release is considered to be more representative of the HNP conditions than a stack release. For additional information related to the impact of the assumed release height, refer to Section E.7.3.2.

E.3.4 EVACUATION

Scram for each sequence was taken as time zero relative to the core containment response times. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. General Emergency declarations ranged from 0.2 hours for the RC-2B sequence to 9.9 hours for the RC-4 sequence.

The MACCS2 Users Guide input parameters of 95 percent of the population within 10 miles of the plant (Emergency Planning Zone) evacuating and 5 percent not evacuating were employed. These values have been used in similar license renewal SAMA analyses and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the emergency planning zone.

Evacuation speed (EZESPEED) of 1.2 meters per second was selected based on data in the HNP evacuation time study (IEM 2002) that indicated 243 minutes to evacuate the EPZ. This value includes a 15-minute delay.

E.3.5 METEOROLOGY

Data from the HNP meteorological monitoring program were used to build the meteorological data file. A meteorological consulting firm was used to develop complete MACCS2 input files. The input files contain hourly data for an entire year for direction, speed, stability class, and precipitation. Data were available for 2001 to 2005. Each year's data was used to calculate impacts to determine the year with the greatest impacts. The year 2003 was selected for the base case analysis. Sensitivity to selection of the meteorological data is presented in Section E.7.3.1.

E.3.6 MACCS2 RESULTS

The resulting annual risks from the fourteen HNP release sequences are provided in Table E.3-3. The largest dose risks are from sequences RC-5 and RC-5C, which contribute to 88 percent of the dose risk. These sequences are also marked by higher frequencies. These two sequences contribute over 77 percent of the cost risk.

E.4 BASELINE RISK MONETIZATION

This section explains how PE calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). PE also used this analysis to establish the maximum benefit that could be achieved if all risk for reactor operation were eliminated.

E.4.1 OFF-SITE EXPOSURE COST

The baseline annual off-site exposure risk was converted to dollars using NRC's conversion factor of $2,000 per person-rem, and discounted to present value using NRC standard formula (NRC 1997):

$$W_{pha} = C \times Z_{pha}$$

Where:

W_{pha}	=	monetary value of public health risk after discounting
C	=	$[1-\exp(-rt_f)]/r$
t_f	=	years remaining until end of facility life = 20 years
r	=	real discount rate (RDR) (as fraction) = 0.03 per year
Z_{pha}	=	monetary value of public health (accident) risk per year before discounting ($ per year)

The Level 3 analysis showed an annual off-site population dose risk of 28.97 person-rem, as documented in Table E.3-3. The calculated value for C using 20 years and a 3 percent discount rate is approximately 15.04. Therefore, calculating the discounted monetary equivalent of accident dose-risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (15.04). The calculated off-site exposure cost is estimated to be $871,395.

E.4.2 OFF-SITE ECONOMIC COST RISK

The Level 3 analysis showed an annual off-site economic risk of $43,030, as documented in Table 3-3. Calculated values for off-site economic costs caused by severe accidents must be discounted to present value as well. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $647,155.

E.4.3 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using NRC methodology that involves separately evaluating immediate and long-term doses (NRC 1997).

For immediate dose, NRC recommends using the following equation:

Equation 1:

$$W_{IO} = R\{(FD_{IO})_S - (FD_{IO})_A\}\{[1 - \exp(-rt_f)]/r\}$$

Where:

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

R = monetary equivalent of unit dose ($2,000 per person-rem)

F = accident frequency (9.24E-06 events per year)

D_{IO} = immediate occupational dose [3,300 person-rem per accident (NRC estimate)]

$_S$ = subscript denoting status quo (current conditions)

$_A$ = subscript denoting after implementation of proposed action

r = RDR (0.03 per year)

t_f = years remaining until end of facility life (20 years).

Assuming F_A is zero, the best estimate of the immediate dose cost is:

$$W_{IO} = R\,(FD_{IO})_S\{[1 - \exp(-rt_f)]/r\}$$

$$= 2{,}000 * 9.24\text{E-}06 * 3{,}300 * \{[1 - \exp(-0.03 * 20)]/0.03\}$$

$$= \$917$$

For long-term dose, NRC recommends using the following equation:

Equation 2:

$$W_{LTO} = R\{(FD_{LTO})_S - (FD_{LTO})_A\}\{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/rm\}$$

Where:

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

D_{LTO} = long-term dose [20,000 person-rem per accident (NRC estimate)]

m = years over which long-term doses accrue (as long as 10 years)

Using values defined for immediate dose and assuming F_A is zero, the best estimate of the long-term dose is:

$$W_{LTO} = R\,(FD_{LTO})_S\,\{[1 - \exp(-rt_f)]/r\}\,\{[1 - \exp(-rm)]/rm\}$$

$$= 2{,}000*9.24E\text{-}06*20{,}000*\{[1 - \exp(-0.03*20)]/0.03\}\,\{[1 - \exp(-0.03*10)]/0.03*10\}$$

$$= \$4{,}802$$

The total occupational exposure is then calculated by combining Equations 1 and 2 above. The total accident related on-site (occupational) exposure risk (W_O) is:

$$W_O = W_{IO} + W_{LTO} = (\$917 + \$4{,}802) = \$5{,}719$$

E.4.4 ON-SITE CLEANUP AND DECONTAMINATION COST

The total undiscounted cost of a single event in constant year dollars (C_{CD}) that NRC provides for cleanup and decontamination is $1.5 billion (NRC 1997). The net present value of a single event is calculated as follows. NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$PV_{CD} = [C_{CD}/mr][1-\exp(-rm)]$$

Where:

PV_{CD} = net present value of a single event

C_{CD} = total undiscounted cost for a single accident in constant dollar years

r = RDR (0.03)

m = years required to return site to a pre-accident state

The resulting net present value of a single event is $1.3E+09. The NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$U_{CD} = [PV_{CD}/r][1\text{-}\exp(-rt_f)]$$

Where:

PV_{CD} = net present value of a single event ($1.3E+09)

r = RDR (0.03)

t_f = 20 years (license renewal period)

The resulting net present value of cleanup integrated over the license renewal term, $1.95E+10, must be multiplied by the total CDF (9.24E-06) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is $180,087.

E.4.5 REPLACEMENT POWER COST

Long-term replacement power costs were determined following NRC methodology in NUREG/BR-0184 (NRC 1997). The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

$$PV_{RP} = [\$1.2\times10^8/r] * [1 - \exp(-rt_f)]^2$$

Where:

PV_{RP} = net present value of replacement power for a single event, ($)

r = RDR (0.03)

t_f = 20 years (license renewal period)

To attain a summation of the single-event costs over the entire license renewal period, the following equation is used:

$$U_{RP} = [PV_{RP} / r] * [1 - \exp(-rt_f)]^2$$

Where:

U_{RP} = net present value of replacement power over life of facility ($-year)

After applying a correction factor to account for HNP size relative to the generic reactor described in NUREG/BR-0184 (i.e., 900 megawatt electric/910 megawatt electric) the replacement power costs are determined to be 5.46E+09 ($-year). Multiplying this value by the CDF (9.24E-06) results in a replacement power cost of $50,494.

E.4.6 TOTAL COST RISK

The sum of the baseline costs is as follows:

Off-site exposure cost	=	$871,395
Off-site economic cost	=	$647,155
On-site exposure cost	=	$5,719
On-site cleanup cost	=	$180,087
Replacement Power cost	=	$50,494
Total cost	=	$1,754,850

The total cost-risk represents the maximum averted cost-risk if all on-line, internal events risk were eliminated. The MACR is rounded to next highest thousand ($1,755,000) for SAMA calculations.

As described in Section E.5.1.7, the internal events MACR is doubled to account for external events contributions. The resulting modified MACR (MMACR) is $3,510,000 and was used in the Phase I screening process.

E.5 PHASE I SAMA ANALYSIS

The Phase I SAMA analysis, as discussed in Section E.1, includes the development of the initial SAMA list and a coarse screening process. This screening process eliminated those candidates that are not applicable to the plant's design or are too expensive to be cost beneficial even if the risk of on-line operations were completely eliminated. The following subsections provide additional details of the Phase I process.

E.5.1 SAMA IDENTIFICATION

The initial list of SAMA candidates for HNP was developed from a combination of resources including:

- HNP PSA results
- Industry Phase II SAMAs
- HNP IPE (CPL 1993)
- HNP IPEEE (CPL 1995)

These resources are judged to provide a list of potential plant changes that are most likely to reduce risk in a cost-effective manner for HNP.

In addition to the "Industry Phase II SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the HNP plant specific SAMA list. While the industry SAMA review cited above was used to identify SAMAs that might have been overlooked in the development of the HNP SAMA list due to PSA modeling issues, a generic SAMA list was used as an idea source to identify the types of changes that could be used to address the areas of concern identified through the HNP importance list review. For example, if long term DC power availability was determined to be an important issue for HNP, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address HNP's needs. If an appropriate SAMA was found to exist, it would be used in the HNP list to address the DC power issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of several industry SAMA analyses and has been provided in Addendum 1 for reference purposes.

E.5.1.1 LEVEL 1 HNP IMPORTANCE LIST REVIEW

The HNP PSA was used to generate a list of events sorted according to their risk reduction worth (RRW) values. The top events in this list are those events that would provide the greatest reduction in the HNP CDF if the failure probability were set to zero. The events were reviewed down to the 1.014 level, which corresponds to about a 1.4 percent change in the CDF given 100 percent reliability of the event. If the dose-risk and off-site economic cost-risk were also assumed to be reduced by a factor of 1.014, the corresponding averted cost-risk would be approximately $24,228 if these inputs are reprocessed using the methodology outlined in Section E.4. Applying a factor of 2 to estimate the potential impact of external events (refer to Section E.5.1.7); the result is about $48,500. This cost is the estimated maximum averted cost-risk for any single event not included in importance list review. The cost of $48,500 is approximately equal to what is considered to be the lower end of implementation costs for potential plant changes. This low end implementation cost is based on the cost of a procedural change, which has been estimated to be about $50,000. (CPL 2004) No further review of the importance listing was performed below the 1.014 level. Table E.5-1 documents the disposition of each event in the Level 1 HNP RRW list with RRW values of 1.014 or greater.

E.5.1.2 LEVEL 2 HNP IMPORTANCE LIST REVIEW

A similar review was performed on the importance listings from the Level 2 results. In this case, a composite file based on the top 87 percent of all dose-risk was used to identify potential SAMAs. The composite file was composed of the results from the RC-5 and RC-5C release categories. This method was chosen to prevent high frequency-low consequence events from dominating the importance listing.

Release category 7 was considered for inclusion in the composite file (an additional 6.6 percent of dose-risk), but no means were readily available to extract the cutsets that only contribute to RC-7 for review. RC-7 is defined as long term containment failures, which are typically caused by loss of DHR cases in SBO. These accident sequences are well represented in the Level 1 results and the important contributors are considered to have been addressed as part of the Level 1 review.

The Level 2 RRW values were also reviewed down to the 1.014 level. As described for the Level 1 RRW list, events below the 1.014 threshold value are estimated to yield an averted cost-risk less than $48,500 and are not considered to be likely candidates for identifying cost effective SAMAs. As such, the events with RRW values below 1.014 were not reviewed. Table E.5-2 documents the disposition of each event in the Level 2 HNP RRW list with RRW values greater than 1.014 (note: there are no events in the HNP importance list between 1.013 and 1.015).

E.5.1.3 INDUSTRY SAMA ANALYSIS REVIEW

The SAMA identification process for HNP is primarily based on the PSA importance listings, the IPE, and the IPEEE. In addition to these plant-specific sources, selected industry SAMA submittals were reviewed to identify any Phase II SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the HNP SAMA list if they were considered to address potential risks not identified by the HNP importance list review.

While many of the industry SAMAs reviewed are ultimately shown not to be cost beneficial, some are close contenders and a small number have been estimated to be cost beneficial at other plants. Use of the HNP importance ranking should identify the types of changes that would most likely be cost beneficial for HNP, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for HNP due to PSA modeling differences or SAMAs that represent alternate methods of addressing risk. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the HNP SAMA identification process.

Phase II SAMAs from the following U.S. nuclear power sites have been reviewed:

- Turkey Point (FPL 2000)
- H.B. Robinson (CPL 2002)

- Point Beach (NMC 2004)
- V.C. Summer (SCE&GC 2002)
- Peach Bottom (Exelon 2001)
- Quad Cities (Exelon 2003)

Four PWR and two boiling water reactor (BWR) sites were chosen from available documentation to serve as the Phase II SAMA sources. Few of the Phase II SAMAs from these sources were included in the initial HNP SAMA list. Many of the industry Phase II SAMAs were already represented by other SAMAs in the HNP list, were known not to impact important plant systems, or were judged not to have the potential to be close contenders for HNP. These SAMAs were not considered further. The following provides a summary of some of the issues considered during the review of the industry SAMAs.

E.5.1.3.1 Turkey Point

Turkey Point used a generic SAMA list as its starting point and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. Some of the SAMAs included in the Phase 2 list were, however, related to important issues at HNP:

- Turkey Point SAMA 111 – This SAMA suggests using Firewater as an alternate means of providing makeup to the steam generators. The prominent cases involving loss of SG makeup flow at HNP include failure to restart main feedwater after AFW failure during a transient and TD AFW failure in an SBO. For the former case, operator action is primary failure for re-establishing main feedwater so any SAMAs that require an operator to perform the same type of function using a different system would have minimal benefit due to dependence. For the latter case, failure to start terms are the leading cause of failure for TD AFW and Firewater would not be adequate to provide makeup to the SGs early in accidents. SAMA 7 is considered to better address SG makeup failure issues at HNP and the use of Firewater for SG makeup has not been included on the HNP SAMA list.

- Turkey Point SAMA 131 – This SAMA proposes the installation of logic to perform automatic swap over to recirculation mode after RWST depletion. HNP does not currently have logic to do this, but the importance list review has shown that this action is not a major contributor to plant risk. This SAMA has not been included on the HNP list.

E.5.1.3.2 H.B. Robinson

While a generic SAMA list similar to the one used for Turkey Point was used in the H.B. Robinson SAMA submittal, two SAMAs on the Phase 2 list related to important HNP functions were found to be cost beneficial:

- Phase 2 SAMA 3 suggests improving the cross-tie capability for the EDG level AC emergency buses. For HNP, cross-tie hardware does not exist at the 6.9kV AC emergency bus level and this SAMA would require major hardware changes to the plant. Because the importance list review showed that a vast majority of cutsets with single EDG failures also included failures of the opposite division of power (e.g., about 90 percent of EDG start failures), the benefit of a cross-tie is low compared with lower cost or comparable cost alternatives that could be used to mitigate SBO conditions. Installation of a 6.9kV AC cross-tie has not been included on the HNP SAMA list.

- Phase 2 SAMA 4 suggested an increased testing frequency for valves in ISLOCA pathways. This SAMA is not included in the HNP SAMA list because the Maintenance Rule is considered to address maintenance issues for all valves in ISLOCA pathways. In addition, it is recognized that increased testing does not necessarily correspond to a reduced ISLOCA frequency. In some cases, increased testing results in an increased ISLOCA frequency due to maintenance errors.

E.5.1.3.3 Point Beach

As with Turkey Point, this analysis relied on a generic SAMA list and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. The SAMAs identified in the Point Beach submittal as potentially cost effective appeared to be procedural updates to include check off provisions within the procedures. Some HRA methodologies credit placekeeping aids in procedures as a means of reducing the potential to skip a step in the cognitive portion of the HEP. While inclusion of such provisions may be reflected quantitatively in the PRA, it would be difficult to justify changes to a large number of procedures based on a detail in a specific HRA methodology. In addition, HNP procedures already include placekeeping aids. No SAMAs related to procedure updates to include placekeeping aids were included in the HNP SAMA list.

E.5.1.3.4 V.C. Summer

V.C. Summer's Phase 2 SAMA list is based on an industry SAMA list similar to those used by Turkey Point, Point Beach, and H.B. Robinson. While no SAMAs were found to be cost effective in the baseline analysis for V.C. Summer, the following two SAMAs were close:

- Phase 2 SAMA 3: Use existing hydrostatic test pump for seal injection
- Phase 2 SAMA 10: Improve 4kV AC bus cross-tie capability

Summer's Phase 2 SAMA 3 is similar to HNP SAMA 1, but the HNP SAMA includes additional changes to allow it to operate during SBO conditions. Summer's Phase 2 SAMA 10 would not be highly beneficial for HNP, as discussed in Section E.5.1.3.3. Neither of these SAMAs has been included on the HNP SAMA list.

E.5.1.3.5 Peach Bottom

The Peach Bottom Phase 2 SAMA list, while based on an industry SAMA list similar to those for the PWRs examined as part of this task, included some additional plant changes that could be applicable to HNP.

- Phase 2 SAMA number 1 suggests improving procedural guidance for use of cross-tied CCW pumps. The HNP CCW system is normally cross-tied, and capable of supplying either division with any one of three pumps. The RHR Heat exchangers are normally isolated during normal operation, but any of the CCW pumps is capable of supplying either RHR Heat Exchanger through the cross-ties. However, for normal

RHR operation, the CCW system cross-ties are removed, to prevent the possibility of running out a CCW pump should the other divisions pump trip. No SAMAs are considered to be required for HNP

- Phase 2 SAMAs 6 and 7 (Containment Spray Enhancement SAMAs): The Level 3 results for HNP are dominated by SGTR and ISLOCA. Changes made to improve containment spray could improve that capability, but they would not have a meaningful impact on public risk. Inclusion of this SAMA is not suggested.

- Phase 2 SAMA 2 suggests improving the ability to provide cooling to the RHR heat exchangers. Loss of RHR cooling is an important issue for HNP, but providing alternate flow to the heat exchangers is not an effective risk reducing strategy for HNP. Many contributors to loss of RHR cooling are due to RHR side failures that would not be mitigated with alternate flow to the heat exchangers. In addition, the largest contributors to loss of ESW side flow are loss of power cases that would also impact the RHR pumps such that alternate flow to the heat exchangers would again be ineffective. Inclusion of this SAMA is not suggested.

- Phase 2 SAMA 21 is a BWR change involving a small, low pressure, motor driven pump that provides boiloff makeup from the suppression pool to the RPV. For HNP, failure of low pressure injection/recirculation alone is of limited importance. Cases requiring alternate low pressure injection typically imply failure of secondary side heat removal and RHR heat removal. Use of low pressure injection without a means of heat removal is not a success path for HNP. Inclusion of an alternate low pressure injection SAMA is not suggested.

E.5.1.3.6 Quad Cities

Of the Phase 2 SAMAs considered for Quad Cities, only a limited number were found to be potentially applicable to HNP. One such SAMA was Phase 2 SAMA 5, which suggests installing an alternate cooling system for the EDGs. The importance listings for HNP did not identify EDG cooling as an issue that could yield cost beneficial SAMAs; however, as emergency AC power availability is an important issue for HNP in general, it was considered worth investigating. A review of the HNP configuration shows that EDG cooling is provided by ESW. This means that if the cooling is lost to the EDGs, multiple other systems required for accident mitigation are also unavailable and any alternate cooling alignments that only impact the EDGs will have a limited impact. The scope of the SAMA would have to be changed from its original low cost vision to a large scale change that would involve multiple systems in order for it to benefit HNP. Based on these considerations, this SAMA is not considered to be a potentially cost beneficial change for HNP and it has not been included on the SAMA list.

E.5.1.3.7 Industry SAMA Identification Summary

The important issues for HNP are considered to be addressed by the SAMAs developed through the PRA importance list review. Further, the plant changes suggested as part of that review were developed to meet the specific needs of the plant such that those SAMAs are more likely to provide effective means of risk reduction than SAMAs taken from other sites. However, effort was made to review other industry SAMA analyses to determine if other sites identified plant changes that could be cost beneficial for HNP. While it was found that other plants had developed SAMAs that addressed areas of concern for HNP, the SAMAs developed based on the plant specific PRA results were considered to represent the most appropriate risk reducing strategies for HNP and no additional industry SAMAs were added to the list based on this review.

E.5.1.4 HNP IPE

The HNP IPE generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPE process are implemented and closed out; however, there are some items that are not completed within the industry due to high projected costs or other criteria. Because the criteria for implementation of a SAMA may be different than what was used in the post-IPE decision-making process, these recommended improvements are re-examined in this analysis.

As a result of the IPE, three potential plant improvements were identified and considered for implementation at the plant. The following table summarizes the status of these plant improvements.

Description of Potential Enhancement	Status of Implementation	Disposition
1) Revise operating procedures to provide explicit instructions for locally aligning offsite AC power if the breakers fail to automatically actuate and cannot be controlled form the main control room.	Implemented.	No further review required.
2) Install instrumentation for improved battery monitoring capability, especially for detection of open circuit faults while the bus is carried by the battery charger.	Not Implemented.	As this type of monitoring system was not required by code and because procedures were put in place to mitigate the non-vital 125V DC battery failures, this enhancement was not pursued. Loss of non-vital 125V DC can cause a plant trip and, more importantly, failure of the switchyard breakers to swap emergency power to the offsite source. While monitoring equipment for the non-vital 125V DC system is a potential means of reducing the frequency of a trip and subsequent LOOP, an alternate solution has been included on the SAMA list. SAMA 2 suggests changing the normal emergency bus power supply from the UATs to the SUTs. This would eliminate the dependence on non-vital DC to swap power supplies after a trip.
3) Ensure that the testing and maintenance procedures for the non-vital 125 VDC battery are equivalent to the practices for the safety related batteries.	Verified to have already been the plant practice. No changes were required.	No further review required.

Change number 2 was not implemented at the site, but it has not explicitly been included on the HNP SAMA list as an alternate plant enhancement has been suggested to address the issue (SAMA 2).

E.5.1.5 HNP IPEEE

Similar to the IPE, any proposed plant changes that were previously rejected based on non-SAMA criteria should be re-examined as part of this analysis. In addition, any issues that are in the process of being resolved should be examined as their resolutions could be important to the disposition of some SAMAs. The IPEEE was used to identify these items.

The following table summarizes the status of the potential plant enhancements resulting from the IPEEE processes and their treatment in the SAMA analysis. As can be seen, no outstanding changes have been identified:

Description of Potential Enhancement	Status of Implementation	Disposition
For fire induced MCR evacuation scenarios, incorporate procedure changes that require the operators to check the PORV status and to close the associated block valve if a PORV is stuck open.	Implemented.	No further review required.

An effort was also made to use the IPEEE to develop new SAMAs based on a review of the original results. However, the HNP IPEEE was not maintained as a “living” analysis. This limits the capability of the models that make up the IPEEE as they do not include the latest PSA practices nor do they necessarily represent the current plant configuration or operating characteristics. The fact that the models are not currently in a quantifiable state presents further difficulty because the results are limited to what has been retained from the original analysis. These factors limit the qualitative insights and quantitative estimates that can be made with regard to external events contributors. Therefore, the external events models are considered to be useful tools for identifying important accident sequences and mitigating equipment, but the quantitative results should not be directly combined with those from the internal events models due to the differences in the modeling characteristics. In this analysis, external events contributions are estimated for the reasons described above.

In addition, it was necessary to review the changes to the site and surrounding area that were implemented after the completion of the IPEEE to determine if the changes could impact the conclusions of IPEEE. HNP staff concluded that no changes have been made to the site or surrounding area that would impact the conclusion of the external events analyses.

E.5.1.6 USE OF EXTERNAL EVENTS IN THE HNP SAMA ANALYSIS

The IPEEE and Fire Re-Analysis were used in the HNP SAMA analysis primarily to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences. The types of events considered in the HNP external events analysis were identified by Supplement 4 of Generic Letter 88-20 (NRC 1991) and included:

- Internal Fires (Section E.5.1.6.1)
- Seismic Events (Section E.5.1.6.2)
- High Wind Events (Section E.5.1.6.3)
- External Flooding and Probable Maximum Precipitation (Section E.5.1.6.4)
- Transportation and Nearby Facility Accidents (Section E.5.1.6.5)

The generic letter also required that a review be performed to identify other types of potential hazards that could impact the plant to confirm that no plant specific issues were excluded by the IPEEE guidance that could initiate severe accidents at HNP. The following event types were included in the review and were screened using the criteria provided in the PRA Procedures Guide:

- Avalanche
- Biological Events
- Coastal Erosion
- Drought
- Fire
- Fog
- Forest Fire
- Frost
- High Tide/High Lake
- Ice Cover
- Landslide
- Low Lake or River Water Level
- Pipeline Accident

- River Diversion
- Seich Flooding
- Storm Surge
- Tsunami
- Toxic Gas
- Turbine Generated missiles
- Waves
- Severe temperature transients (extreme heat, extreme cold)
- Severe storm (ice, hail, snow, dust, and sand storms)
- Lightning
- External Fires
- Extraterrestrial Activity (meteor strikes, satellite falls)
- Volcanic activity
- Soil Shrink-Swell Consolidation

Based on the HNP review, no additional hazards were identified for analysis in the IPEEE.

The type of information available for the initiators that were evaluated by HNP varied due to the manner in which they were addressed in the IPEEE. For instance, the fire analysis used an approach that combined the deterministic evaluation techniques from the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology with classical PRA techniques. The HNP seismic analysis was performed using the EPRI Seismic Margins Assessment methodology (NP-6041-SL) as a “focused scope” analysis. Due to limitations of the Fire and Seismic modeling processes, however, the results of these kinds of analyses are not necessarily compatible with those of the internal events analysis. As a result, each of the external event contributors must be considered in a manner suiting the type of analysis performed. A summary of the review process used to identify SAMAs is provided for each of the external event types listed above followed by a description of the method used to quantitatively incorporate external events contributions into the SAMA analysis.

E.5.1.6.1 Internal Fires

As discussed above, the techniques used to model external events vary according to the type of initiator being analyzed. The HNP Fire Model shares many of the same characteristics as the internal events model, but limitations on the state of technology produce results that are more conservative than the internal events model. The following summarizes the fire PRA topics where quantification of the CDF may introduce different levels of modeling uncertainty than the internal events PRA.

In general, fire PRAs are useful tools to identify design or procedural items that could be clear areas of focus for improving the safety of the plant. Fire PRAs use a structure and quantification technique similar to that used in the internal events PRA. Since less attention historically has been paid to fire PRAs, conservative modeling is common in a number of areas of the fire analysis to provide a “bounding” methodology for fires. This concept is contrary to the base internal events PRA, which has had more analytical development and is judged to be closer to a realistic assessment (i.e., best estimate) of the plant. There are a number of fire PRA topics involving technical inputs, data, and modeling that prevent the effective comparison of the CDF between the internal events PRA and the fire PRA. These areas are identified as follows:

PSA Topic	Comment
Initiating Events:	The frequency of fires and their severity are generally conservatively overestimated. A revised NRC fire events database indicates the trend toward lower frequency and less severe fires. This trend reflects the improved housekeeping, reduction in transient fire hazards, and other improved fire protection (FP) steps at plants.
System Response:	FP measures such as sprinklers, CO_2, and fire brigades may be given minimal (conservative) credit in their ability to limit the spread of a fire.
Sequences:	Sequences may subsume a number of fire scenarios to reduce the analytic burden. The subsuming of initiators and sequences is done to envelope those sequences included. This results in additional conservatism.
Fire Modeling:	Fire damage and fire spread are conservatively characterized. Fire modeling presents bounding approaches regarding the immediate effects of a fire (e.g., all cables in a tray are always failed for a cable tray fire) and fire propagation.

PSA Topic	Comment
HRA:	There is little industry experience with crew actions under conditions of the types of fires modeled in fire PRAs. This has led to conservative characterization of crew actions in fire PRAs. Because the CDF is strongly correlated with crew actions, this conservatism has a profound effect on the calculated fire PRA results.
Level of Detail:	The fire PRAs may have reduced level of detail in the mitigation of the initiating event (IE) and consequential system damage.
Quality of Model:	The peer review process for fire PRAs is not as developed as internal events PRAs. For example, no industry standard, such as NEI 00-02, exists for the structured peer review of a fire PRA. This may lead to less assurance of the realism of the model.

In addition to modeling limitations, the fire PRA may be subject to more modeling uncertainty than the internal events PRA evaluations. While the fire PRA is generally self-consistent within its calculational framework, the fire PRA does not compare well with internal events PRAs because of the number of conservative assumptions that have been included in the fire PRA process. Therefore, the use of the fire PRA results as a reflection of CDF may be inappropriate. Any use of fire PRA results and insights should consider areas where the “state of the art” in fire PRAs is less evolved than other PRA topics.

While the ability to directly compare the results of the internal events and fire models is limited, information is available that may be used to identify the most important contributors for HNP. The IPEEE provides some information related to equipment failures by Fire Scenario. This information has been summarized in the table below for the Fire Scenarios that were not screened on low CDF.

Fire Area/Scenario	CDF	Major Equipment Failed
1-A-SWGRB/1	1.1E-06	1B-SB AC Emergency Bus (plus other minor contributors)
1-A-SWGRB/2	2.8E-06	Entire “B” division safe shutdown path, offsite power to 1A-SA without successful operator action.
1-A-SWGRA/FDS ASG1	4.4E-07	1A-SA AC Emergency Bus (plus other minor contributors)
1-A-SWGRA/FDS ASG2	2.6E-06	Entire “A” division safe shutdown path
1-A-SWGRA/FDS ASG3	7.6E-08	1A-SA AC Emergency Bus (plus other minor contributors), fire induced spurious open PORV
12-A-CR/1D1	1.3E-06	AFW SA/SB, CWS SA, EDG SB, ESW SA/SB, HCRC SB, HCRM SB, HDGB SB, RCSPC SB

Fire Area/Scenario	CDF	Major Equipment Failed
12-A-CR/6B	3.0E-06	No SSE damaged, but main control room evacuation and shutdown from the alternate control panel (ACP) are required.

The table above demonstrates that the total fire CDF of 1.1E-5 is distributed more or less evenly among the contributing Fire Scenarios and that there are no dominant scenarios that contribute nearly all of the fire risk. In addition, while fires in each of these areas results in the loss of a wide range of equipment, it is typically limited to a single division. As a result, redundant equipment is often available to mitigate the fire events. Further discussion is provided for each of the fire area/scenarios below.

Fire Area 1-A-SWGRB

There are two scenarios which contribute in this area. Scenario 1 corresponds to the cases in which the originating fire does not propagate from the initiating cabinet and Scenario 2 corresponds to the cases in which the fires do propagate.

For Scenario 1, the “B” 6.9kV emergency bus is lost and no power is available to the “B” division loads. While the “A” division is available, there are some single failures that would fail the remaining safe shutdown path. SAMA 8 provides a means of restoring seal injection and powering the 1B3-SB transformer to support continuted MCR operation of the TD AFW pump, which is considered to be a means of addressing this fire scenario.

For Scenario 2, the failure of all SSE cables may preclude SAMA 8 from being effective due to potential equipment damage from electrical shorts. SAMA 1 provides a means of maintaining the reactor in a stable state with only the TD AFW pump and the hydrostatic test pump given installation of a 480V AC generator. For cases where the control cables and support system cables for the start of the 480V AC generator are not impacted, this SAMA would provide a means of safe shutdown.

Fire Area 1-A-SWGRA

This area is almost identical to 1-A-SWGRB and the same SAMAs are considered to be applicable for scenarios ASG1 and ASG2. Scenario ASG3 is similar to ASG2, but with the additional complication of a stuck open PORV. However, the frequency of this scenario is a factor of 34 less than ASG2 and no SAMAs are considered to be required to address this evolution, especially given that the stuck open PORV was conservatively assumed to occur in the scenario.

Fire Area 12-A-CR, Scenario 1D1

These fires result in loss of a wide range of equipment which requires the use of the alternate control panel (ACP) to mitigate. The frequency reported in the IPEEE for this scenario is based on an assumption that the operators will use the ACP when they are unable to control AFW and ESW even though there are no explicit procedures directing this action. The HEP used for this action in the quantification was 1.5E-02 for the transient cases and 9.0E-02 for LOCA cases. These HEPs may be appropriate for proceduralized actions under these conditions, but without explicit guidance, the stated HEPs are likely optimistic.

While a potential enhancement would be to proceduralize the use of the ACP when control of the plant becomes impossible for any conditions, this enhancement was made subsequent to the IPEEE and HNP procedure AOP-004 now contains this type of guidance. No SAMA required.

Fire Area 12-A-CR, scenario 6B

These fire scenarios do not result in any equipment damage, but do require control room evacuation and control of the plant from the ACP. No credible means of reducing the initiating event frequency has been identified for these fires. The ACP training program could be enhanced at HNP, but no reliable means of quantifying the benefit of such an enhancement is available. As a result, no SAMAs are suggested for this fire scenario.

Fire SAMA Identification Summary

Based on the review of the HNP fire area results, two SAMAs have been identified as potentially cost beneficial methods of reducing fire risk:

- Hydrostatic Test Pump with 480V AC Generator for Seal Injection and "B" Battery Charger (SAMA 1)
- Alternate Seal Cooling and Direct Feed to Transformer 1B3-SB (SAMA 8)

Any SAMAs that improve the plant response to an accident have the potential for reducing fire risk through the same mechanisms; however, these SAMAs are considered to explicitly address the scenarios related to SAMAs 1 and 8. While these SAMAs have been identified as potential means of reducing fire risk, they were also identified to be based on the internal events importance list and are not unique to the fire review.

E.5.1.6.2 Seismic Events

The EPRI seismic margins methodology (EPRI 1991) is used to identify the minimal set of equipment required to safely shut the reactor down and to determine if that equipment is capable of surviving the Review Level Earthquake (RLE). Equipment that is not capable of withstanding the RLE is identified and required to be addressed. While methods exist for using this information to develop a seismically induced core damage frequency, this was not performed as part of the HNP IPEEE. It should also be noted that even in a seismic analysis developed to yield a CDF, the pedigree of information is not equivalent to what is used in the internal events models. Given that there is a limited amount of seismic response information available for nuclear power plants, analysis techniques developed to model the plant response often compensate by ingraining a conservative bias in their methodologies to prevent overestimating the capabilities of the plants. While seismic risk evaluations are helpful in the identification of potential plant weaknesses, the methodologies have not evolved to a point where the results can be directly compared with the internal events models.

With these limitations in mind, the HNP IPEEE seismic results and history were reviewed in order to determine if there were any unresolved issues that could impact HNP risk. The issues of interest included:

- Unfinished plant enhancements that were determined to be required to ensure the equipment on the Safe Shutdown List would be capable of withstanding the RLE,

- Additional plant enhancements that were identified as means of reducing seismic risk but were not implemented at the plant.

An effort was also made to use the results of the equipment and structural screening documentation to determine if any outlier issues that were screened in the IPEEE could impact seismic risk at HNP. The following subsections summarize this review.

E.5.1.6.2.1 Unfinished Plant Enhancements

Not all of the Safe Shutdown Equipment in the plant was determined to meet the HCLPF requirements for the 0.30 peak ground acceleration (pga) Review Level Earthquake. Five resolution categories were defined by the plant to help organize efforts to resolve the issues identified during the analysis. The following is a summary of the issues, by resolution category:

1. Thirteen items had minor interaction, housekeeping, or maintenance issues that were to be resolved through routine maintenance activities via work request/job orders. These items were mostly related to replacing missing or broken anchorage parts so that they would perform as designed. Work was completed to resolve these items by March 31, 1995.

2. Six items were identified for repair or modification. These items primarily consisted of equipment that was identified as being improperly secured such that alternate means of anchoring the equipment was required.

3. Interaction due to building displacement: The platform in the containment equipment hatch at elevation 286’ was identified as a potential interaction hazard given seismic displacement of the reactor building. The platform, which serves as a bridge between the interior and exterior containment structures, is supported/welded at the equipment hatch barrel and is anchored to the floor of the interior structure at elevation 286’. As documented in the IPEEE, an interaction analysis was performed for this bridge and it was determined not to pose threat to containment integrity.

4. HVAC interaction: Two different sections of HVAC duct were identified to have long runs over SSE without supports. The design information for these ducts was reviewed and the supports were determined to be adequate for the RLE.

5. HCLPF evaluations: Some equipment could not be screened from further review using only the information obtained from the plant walkdown and a review of design documentation. Sixteen items were identified requiring detailed HCLPF evaluations in order to determine if the equipment had HCLPF capacities of 0.30 pga or higher. With the exception of the RHR heat exchangers, all equipment was determined to have satisfactory HCLPF capacities. The RHR heat exchangers are discussed in Section E.5.1.6.2.2.

Other than the RHR heat exchanger issue, all plant issues were resolved and no unfinished repairs, modifications, or enhancements exist for HNP. As a result, no SAMAs have been identified related to resolving unfinished issues.

E.5.1.6.2.2 Additional Plant Enhancements

The equipment analysis identified few items that could not be assigned HCLPF capacities of at least 0.30 pga. The exceptions to this were as follows:

- RHR Heat Exchangers: The HCLPF evaluation of the RHR heat exchangers resulted in an estimated capacity of 0.29 pga. No physical changes to the heat exchangers were planned given that the HCLPF of 0.29 pga was viewed to be essentially the same as 0.30 pga and that removal of conservative assumptions related to the nozzle loads in the HCLPF analysis would likely increase the HCLPF estimate to something over 0.30 pga.

- Electrical Relays: Fifty one relays with low seismic ruggedness were initially identified for review. Twelve of the relays were determined not to be seismically vulnerable given that the configuration in which they were used was not subject to chatter. Twenty nine of the relays were determined to be non-essential relays for which chatter was not a concern. Four of the relays were determined to be essential. However, if was found that chatter of these four relays would not produce any unacceptable consequences. The remaining six relays were found to be essential relays that actuate the lockout relays on the two 6.9kV AC emergency buses. Chatter on two of the three relays for a given bus would result in a trip of the bus. A detailed analysis of the seismic qualification of the buses has determined that sufficient margin existed and that no changes were required.

For the purposes of the IPEEE, the RHR heat exchanger HCLPF evaluation yielded results that were sufficiently close to the RLE requirements that no changes were considered to be required. While it is likely that the RHR heat exchangers could definitively be shown to be adequate for the RLE, they are important to safe shutdown and because there are no quantitative assessments of the impact on CDF, this issue is examined further in the this analysis. Seismically induced loss of the RHR heat exchangers is functionally equivalent to loss of RHR events that were found to be important in the internal events analysis. For the Level 1 analysis, the prominent RHR failures required the addition of an alternate heat removal method for mitigation. For the seismic scenarios, installation of the upper lateral restraints on the heat exchangers (according to the original design) could increase the HCLPF capacity of these components such failure of these components would not be a concern in an RLE (SAMA 22).

The GE 12PVD21B1A relays were identified as low ruggedness relays based on an industry event in which one of these relays failed due to vibration. The chatter related failure was caused during a maintenance event when an electrical cabinet door, on which one of the relays was mounted, was bumped. It should be noted that the event that caused the relays to chatter was a high frequency vibration event, which is not necessarily equivalent to the vibrations that would be present in a seismic event. The subsequent seismic qualification testing of the GE 12PVD21B1A relays showed that the relays exceeded the RLE requirements by a factor of 2.4. Given the nature of the event that was use to identify GE 12PVD21B1A relays as low ruggedness relays and the margin in the related seismic qualification test results, no changes to these relays are believed to be required.

Seismic Summary

Based on the review of the HNP seismic analysis, one Seismic related SAMA has been identified:

- Install Upper Lateral Restraints on the RHR Heat Exchangers (SAMA 22)

E.5.1.6.3 High Wind Events

The IPEEE high winds analysis reviewed the design basis wind loading for HNP and concluded that the plant design was adequate to prevent damage to safety related systems in high wind events.

The design basis tornadoes for Region 1, in which HNP is located, have the following characteristics:

- Maximum wind speed: 360 mph
- Rotational wind speed: 290 mph
- Translational wind speed: 70 mph
- Radius of maximum rotational speed: 150 feet
- Pressure drop: 3.0 psi
- Rate of pressure drop 2.0 psi/second

The wind speeds corresponding to the design basis tornado were found to bound the "extreme-mile straight wind" and the hurricane wind. The most likely damage by a tornado strike was determined to be the loss of offsite power with a long recovery time, which was claimed to already be included in the internal events PRA. Even if the internal events LOOP evaluation were considered not to address tornado related initiating events, the IPEEE indicated that the frequency of a tornado strike at HNP is 1.06E-6/year, which is about 16 times less than the LOOP frequency used in the current PRA model. Given that the tornado strike frequency is much less than the plant's LOOP frequency and that SAMAs addressing LOOP events are addressed by the importance list review process, no additional SAMAs are considered to be required to address high wind events.

E.5.1.6.4 External Flooding and Probable Maximum Precipitation

The probable maximum flood and probable maximum precipitation events were examined to evaluate the risk related to flooding from both nearby water sources and ponding events. The results of the evaluation indicated that external flooding events do not pose a threat to the HNP safety related systems.

Review of the HNP site during the IPEEE confirmed that the site was designed to accommodate a rainfall intensity of up to 5 inches per hour, which would be sufficient for most events. It was also determined that overland flow would provide adequate drainage to the main reservoir or ESW intake/discharge canals in the event of excess flow or blockage of the drain system. It was concluded that storm runoff did not pose a threat to the safety related systems at HNP.

Site flooding from nearby water sources was also examined as part of the IPEEE. The Cape Fear River was excluded as a potential flood source due to the large difference in elevation between the river bank and the top of the main dam (100 feet). In addition, the water levels were examined in the main and auxiliary reservoirs under probable maximum flood conditions in conjunction with the effects of wave run up and wind setup. No conditions were identified in which water levels could reach plant grade and flooding from these sources was determined not to impact the HNP safety related systems.

Finally, on-site flooding and roof ponding from the probable maximum precipitation event were examined to determine if this type of flooding could impact plant operations. On-site flooding elevations were all determined to be below the elevations of spillways into buildings containing safety related equipment. Electrical manholes and ducts run for emergency power system cables were designed to be capable of normal operation while completely or partially submerged and site flooding was not expected to impact these lines even if they were flooded. The roofs of safety related structures are equipped with roof drains to prevent ponding, but were also designed to be capable of withstanding water retention to the top of the parapets. Site flooding from the probable maximum precipitation event was determined not to pose a threat to the HNP safety related systems.

For the SAMA analysis, these results were considered to be an acceptable basis for precluding the inclusion of plant changes related to External Flooding on the HNP SAMA list.

E.5.1.6.5 Transportation and Nearby Facility Accidents

Transportation and nearby facility accidents were included in the HNP IPEEE to account for human errors or equipment failures that may occur in events not directly related to the power generation process at the plant. The types of hazards identified for analysis included:

- Transportation Accidents
  - Aircraft Activity
  - Road and Rail
- Fixed Facility Accidents
  - Industrial Facilities
  - Military Facilities
  - Pipeline Accidents

It is recognized that the types of credible threats to nuclear facilities by aircraft have changed since the time the IPEEE was published. While this is true, efforts are underway within the industry to address this issue in conjunction with other forms of sabotage. Based on the fact that this topic is currently being analyzed in another forum and due to the complexity of the issue, aircraft impact events are considered to be out of the scope of the SAMA analysis.

Railway and highways were also examined to determine if any transportation accidents involving hazardous material could impact the HNP site. Three railroad lines were identified that pass within 5 miles of the site:

- The Bonsal-Durham segment, 2.5 miles NW
- The Fuquay-Varina-Brickhaven segment, 4.3 miles S
- The Raleigh-Moncure segment, 1.9 miles NW

Of the three lines, only the Raleigh-Moncure segment was found to carry hazardous material on a regular basis. Review of the combustible materials transported within a five mile radius of the plant identified rail or truck transportation of high explosives as the sources for a potential hazard. For the Raleigh-Moncure segment, the complete and instantaneous detonation of one train car load of TNT (200,000 lb) at the closest point to the plant was evaluated. The blast loading was determined for the critical plant structures and the maximum loads were found to be 0.4 psi or less within 6.2E-02 seconds. That loading, as well as any missiles generated by the explosion, were not a threat to HNP safety related components or the structures that house them.

Of the local highways, U.S. Highway 1 passes closed to HNP (6600 feet NNW of the plant site) and was determined to pose the largest potential threat to the plant. The complete an instantaneous detonation of one truckload of TNT (approximately 50,000 lb) was found to produce less severe blast loading on the safety related structures than the rail explosion and as a result, it was concluded that those explosions did not present a threat to the site.

In conjunction with the detonation of explosives on nearby rail and roadways, the release of toxic chemicals was reviewed in the IPEEE. The releases of two chemicals were considered for the evaluation (anhydrous ammonia and vinyl chloride), but the dose analysis was not performed for the chemicals due to the low frequency of occurrence of the release. For the rail system, the release frequency was estimated to be less than 1.0E-07 per year based on a comparison of the national average rail accident rate to the operating history of the local rail operator. The frequency of a highway based release was considered to be similarly low given that the area around the HNP site has no industrial development and that the volume of hazardous materials transported on U.S. Highway 1 would be correspondingly low. In addition, U.S.

Highway 1 is further from the plant than the Department of Transportation impact radius for any of its classes of hazardous materials. Finally, the analysis of a chlorine spill performed for the FSAR revealed no control room habitability concerns for HNP.

The IPEEE documents that there are several industrial facilities with a 50 mile radius of the HNP site, including mines, tobacco manufacturing and processing factories, electronic components manufacturers, an adhesive resin factory, and a pharmaceutical research site, but none within a 5 mile radius of HNP.

The nearest active military facility is Fort Bragg, located 35 miles south of HNP and a National Guard facility is located 19 miles NNE in at the Raleigh-Durham airport. The IPEEE concluded that these facilities did not pose a safety hazard to the HNP sire.

The Dixie Pipeline Company operates an 8 inch liquid petroleum gas pipeline located in excess of 8,500 feet west of the closest critical plant structure. The pipe is located 3 feet underground and passes about 1,600 barrels of liquid petroleum gas per hour at 1,440 psi. The effects on safety related structures resulting from a break in the pipeline were evaluated in the IPEEE based on the assumption of a double ended rupture or slot rupture with the slot size equal to twice the flow area of the pipeline in an instantaneous rupture at the closest location to the plant. The peak overpressure resulting from an explosion was determined to be up to 0.5 psi with a peak corresponding ground acceleration of 0.023 g. Critical plant structures are designed so that they are able to withstand these overpressures and ground motions. Therefore, it was concluded in the IPEEE that detonation of propane released from a break in the 8 inch liquid petroleum gas line would not result in unacceptable conditions at HNP. For a non-explosive release, the liquid petroleum gas cloud would fall below flammable limits beyond 2,200 feet from the nearest safety related structures due to dispersion. Fires from these clouds were determined not to pose a threat to HNP.

For the SAMA analysis, these results were considered to be an acceptable basis for precluding the inclusion of plant changes related to Transportation and Nearby Facility accidents on the HNP SAMA list.

E.5.1.7 QUANTITATIVE STRATEGY FOR EXTERNAL EVENTS

The quantitative methods available to evaluate external events risk at HNP are limited, as discussed above. In order to account for the external events contributions in the SAMA analysis, a multi-staged process has been implemented to provide gross estimates of the averted cost-risk based on external events accidents. Internal flooding is also addressed here as the internal flooding model has not been maintained with the internal events model.

The first part of this process is used in the Phase I analysis and is based on the assumption that the risk posed by external and internal events is approximately equal. For HNP, the external events analysis, which has been identified as a conservative analysis, yielded a CDF of 1.1E-05/yr for the quantified event types (Fire). While no CDF was quantified for the seismic, high wind, flood, and transportation and nearby facility event types, fire risk is typically the largest of these contributors. If it is assumed that fire risk is 85 percent of the total external events risk, the total external events CDF could be estimated to be 1.29E-5 (1.1E-05 / 0.85 = 1.29E-05).

As this is comparable to the internal events CDF of 9.24E-06 per year, the assumption that the external events contributions are equal to the internal events contributions is not considered to be unreasonable.

Given that the risk is assumed to be equal, the MACR calculated for the internal events model has been doubled to account for external events contributions. This total is referred to as the modified MACR (MMACR). The MMACR is used in the Phase I screening process to represent the maximum achievable benefit if all risk related to on-line power operations was eliminated. Therefore, those SAMAs with costs of implementation that are greater than the MMACR were eliminated from further review.

The second stage of this strategy is to also apply the doubling factor to the Phase II analysis. Any averted cost-risk calculated for a SAMA was multiplied by two to account for the corresponding reduction in external events risk.

The final stage of the process is used for SAMAs that were identified based on IPEEE insights. For these cases, IPEEE insights and the Internal Events PSA are used, as appropriate, to develop an averted cost-risk for the SAMA that accounts for the external and internal events risk reductions. For instance, the IPEEE typically provides information that can be used to estimate bounding changes in risk that would be realized if the SAMAs were implemented. These risk changes are used to approximate averted cost-risks based on external events contributions. Then, if it can be determined that the SAMA would impact the internal events model, the PSA is used to quantify the averted cost-risk based on its internal events contributions. The cost-risks from the external and internal events results are then added to yield the total for the SAMA. In some cases, the SAMAs do not impact the internal events models and the calculations do not require the use of the PSA model.

E.5.2 PHASE I SCREENING

The initial list of SAMA candidates is presented in Table E.5-3. The process used to develop the initial list is described in Section E.5.1.

The purpose of the Phase 1 analysis is to use high-level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. The following screening criteria were used:

- Applicability to the Plant: If a proposed SAMA does not apply to the HNP design, it is not retained.
- Implementation Cost Greater than Screening Cost: If the estimated cost of implementation is greater than the modified Maximum Averted Cost-Risk, the SAMA cannot be cost beneficial and is screened from further analysis.

Table E.5-3 provides a description of how each SAMA was dispositioned in Phase 1. Those SAMAs that required a more detailed cost-benefit analysis are evaluated in Section E.6.

E.6 PHASE II SAMA ANALYSIS

Not all of the Phase 2 SAMA candidates require detailed analysis. The Phase 2 process allows for the screening of SAMAs known to be related to non-risk significant systems or to components/functions with low importance rankings. Due to the nature of the PSA based process used to develop the HNP SAMA list, there are limited avenues for SAMAs of this type to be included in the list. However, potential pathways do exist:

- Inclusion of unresolved proposed plant changes from previous HNP risk analyses,
- Inclusion of SAMAs based on the results of conservative modeling methods.

While no calculations are required for eliminating a SAMA that is linked to a non-risk significant system or components, some quantitative efforts are usually required to screen SAMAs that were developed to address risk contributors based on conservative modeling techniques. These cases are identified in Table E.5-4 and discussed in detail in the SAMA specific subsections of E.6.

For the SAMAs requiring detailed analysis, a more detailed conceptual design was prepared along with a more detailed estimated cost. This information was then used to evaluate the effect of the candidates' changes upon the plant safety model.

The final cost-risk based screening method is defined by the following equation:

Net Value = Averted cost-risk – Cost of implementation

Where:

- Averted cost-risk = (baseline cost-risk of site operation (MMACR) – cost-risk of site operation with SAMA implemented)

If the net value of the SAMA is negative, the cost of implementation is larger than the benefit associated with the SAMA and the SAMA is not considered beneficial. The baseline cost-risk of plant operation was derived using the methodology presented in Section E.4. The cost-risk of plant operation with the SAMA implemented is determined in the same manner with the exception that the revised PRA results reflect implementation of the SAMA.

The implementation costs used in the Phase 2 analysis include both HNP specific estimates developed by plant personnel and estimates taken from other SAMA submittals for those SAMAs that were determined to be similar. It should be noted that the HNP specific implementation costs do include margin to account for unforeseen difficulties, but they do not account for any replacement power costs that may be incurred due to consequential shutdown time.

Sections E.6.1 – E.6.20 describe the detailed cost-benefit analysis that was used for each of the remaining candidates.

E.6.1 SAMA NUMBER 1: HYDROSTATIC TEST PUMP (OR ALTERNATE PUMP) WITH 480V AC GENERATOR FOR SEAL INJECTION AND "B" BATTERY CHARGERS

This change requires permanent installation of the hydrostatic test pump and a 480V AC generator such that the pump could rapidly be aligned to provide seal injection in an SBO. Rapid alignment capability will limit the size of any seal LOCA after the initial loss of seal cooling and is considered to be an integral part of this SAMA. Given that HNP has the ability to operate the turbine driven AFW pump after 125V DC battery depletion, this SAMA will allow for long term operation in an SBO. Providing power to the "B" battery chargers would eliminate the need to operate the TD AFW pump locally after battery depletion and would further reduce plant risk. In the event that additional seal injection flow margin is determined to be desirable, a new pump could be used in place of the Hydrostatic Test Pump.

Installation of piping between the hydrostatic test pump and the normal seal injection line upstream of valve 1CS-240 is assumed as part of this SAMA. Given that remote alignment of the flowpath is required to meet timing requirements, motor operated valve (MOV) isolation valves powered from the 480V AC generator would be needed to allow alignment of hydrostatic pump seal injection flow in an SBO. Controls for these valves must be installed in the main control room. The main control room would also have to be equipped with controls to allow for rapid start and alignment of the 480V AC generator to support this method of seal injection. Finally, an interface between the 480V AC generator and the station 125V DC battery chargers is necessary to support long term operation of the TD AFW pump without requiring local control of the pump.

Because this SAMA has been identified based on both the internal events model insights and Internal Fire events review, separate evaluations have been performed to quantify the averted cost-risk associated with the Fire and non-Fire contributors. These evaluations are discussed below.

E.6.1.1 INTERNAL EVENTS AND NON-FIRE EVALUATION

This subsection describes the calculation of the component of SAMA 1's averted cost-risk associated with the internal events and the non-fire external events. Consistent with the assumptions regarding the relative contributions of the fire events to the total external events risk, the non-fire contribution is assumed to be 15 percent of the total. Quantitatively, this is accounted for by multiplying the internal events based averted cost-risk by 1.15. This process is described below.

In order to represent this SAMA, model changes were made to address the impact of both improved seal injection capability and the ability to maintain TD AFW operation from the MCR after 125V DC battery depletion. A lumped event (ALTSEAL) with an assumed failure probability of 1.0E-01 is used to represent the contributing failures to alternate seal injection. This failure probability is considered to be optimistic in the context of the potential contributors to failure:

- Operator action to align the power source to the alternate pump and to start the pump to provide seal injection flow within 13 minutes of loss of normal seal cooling (likely approximately 1.0E-01),
- Hardware failure of the 480V AC power source,
- Hardware failure of the alternate pump,
- Hardware failure of the flowpath,

In addition, the availability of the 480V AC power source to provide power to the battery chargers improves the reliability of TD AFW operation in an SBO by allowing continued operation of the TD AFW pump from the MCR. A separate operator action would be required to align the 480V AC generator to the battery charger. This action is not time critical given that the batteries would be available for several hours before depletion, but it is assumed to require local manipulations. Once power to the battery chargers is established, the need for OPER-66 as it was originally modeled would be eliminated. In order to approximate the impact of precluding battery depletion, OPER-66 is used as a surrogate for the HEP to align the 480V AC generator to the chargers. Because OPER-66 is rarely, if ever, found without other potentially dependent operator actions in the cutsets, any change in the base value of OPER-66 would have to be carried through all of the dependent human action calculations. The HNP PRA documentation indicates that the base value for the original OPER-66 is 1.2E-02. Given the relatively long time available to align the 480V AC generator to the alternate battery charger, the HEP for this action could be several times smaller than 1.2E-02. This would impact the dependent HEPs differently depending on how each one is calculated. In order to approximate the change, it is assumed that all cutsets including OPER-66 are reduced by 50 percent. While this is method does not provide a high degree of accuracy, the impact of any changes to OPER-66 is small compared with the impact of the seal injection portion of this SAMA and is considered to be acceptable.

SAMA Number 1 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
ALTSEAL: FAILURE OF ALTERNATE SEAL INJECTION, HARDWARE AND OPERATOR ACTION	New basic event representing the failure probability of the alternate pump system to be aligned and operate to provide flow to the RCP seals within 13 minutes of loss of normal seal cooling (human and hardware error).
HCSIPSEAL: NO FLOW FROM EITHER CSIP TO RCP SEALs	Added new basic event ALTSEAL
Recovery File Modification: Reduce cutsets including OPER-66 by 50 percent.	Added the following logic to the end of the Level 1 and 2 recovery files: **SET EVENT PROBS** OPER-66 5.0E-1 **CLEAR RECOVERY FLAGS**

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 1 Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	6.22E-06	27.18	$38,179
Percent Change	-32.7%	-6.2%	-11.3%

A further breakdown of this information is provided below according to release category.

SAMA 1 Internal Events Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	2.32E-09	9.22E-11	1.59E-07	1.52E-08	5.96E-09	1.85E-08	2.12E-08	1.80E-08	1.62E-07	6.36E-09	1.76E-07	6.39E-07	3.21E-07	3.99E-07	**1.94E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.00	0.00	0.35	0.02	0.01	0.06	0.01	0.02	0.36	0.02	5.47	19.87	0.19	0.80	**27.18**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$6	$0	$964	$58	$25	$218	$3	$9	$1,038	$53	$7,216	$26,199	$152	$2,238	**$38,179**

Based on these results, the averted cost-risk for all non-Fire contributors can be calculated using the 1.15 multiplier on the internal events results:

Non-Fire Averted Cost-Risk

Base Case Internal Events Cost-Risk	Revised Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Averted Cost-Risk
$1,755,00	$1,550,969	$204,031	1.15	$234,636

E.6.1.2 FIRE EVALUATION

The IPEEE review specifically identified SAMA 1 as a means of reducing the risk of those switchgear room fires resulting in the failure of an entire division of SSE. In addition to this specific benefit, SAMA 1 is also considered to address most of the remaining fire scenarios. The exceptions are those fire events impacting potential control cables for the 480V AC generator and those requiring main control room evacuation as no provisions are included in the SAMA to incorporate 480V AC generator controls on the alternate shutdown panel. Because this SAMA addresses specific portions of the fire risk, a separate evaluation is used to estimate the impact of the internal fire based averted cost-risk for this SAMA rather than the “multiplier” method discussed in Section E.5.1.7. This process is described below.

Based on a review of the IPEEE, it was possible to identify all contributing fire scenarios and their fire based CDFs. In addition, the percent contribution to the total external events CDF of 1.29E-05 (see Section 5.1.7) can be determined for these contributors:

Fire Area/Scenario	CDF	Percent of Ext. Events CDF	Major Equipment Failed
1-A-SWGRB/1	1.1E-06	8.5%	1B-SB AC Emergency Bus (plus other minor contributors)
1-A-SWGRB/2	2.8E-06	21.7%	Entire “B” division safe shutdown path, offsite power to 1A-SA without successful operator action.
1-A-SWGRA/FDS ASG1	4.4E-07	3.4%	1A-SA AC Emergency Bus (plus other minor contributors)
1-A-SWGRA/FDS ASG2	2.6E-06	20.2%	Entire “A” division safe shutdown path
1-A-SWGRA/FDS ASG3	7.6E-08	0.6%	1A-SA AC Emergency Bus (plus other minor contributors), fire induced spurious open PORV
12-A-CR/1D1	1.3E-06	10.1%	AFW SA/SB, CWS SA, EDG SB, ESW SA/SB, HCRC SB, HCRM SB, HDGB SB, RCSPC SB
12-A-CR/6B	3.0E-06	23.2%	No SSE damaged, but main control room evacuation and shutdown from the ACP are required.

Of the fire scenarios identified in the table above, only 12-A-CR/1D1 and 12-A-CR/6B are control room evacuation scenarios. It is assumed that no risk reduction is possible for these scenarios and they are excluded from consideration. Scenarios 1-A-SWGRB/2, 1-A-SWGRA/FDS ASG2, and 1-A-SWGRA/FDS ASG3 each result in damage to all SSE cables for an entire division. For the scenario causing damage to the division containing the controls or support cables for the 480V AC generator (such as those related to DC power for system start), the 480V AC generator is considered to be failed. For the purposes of this analysis, all 480V AC generator cables are assumed to belong to the “A” division such that no credit is available for fire scenarios 1-A-

SWGRA/FDS ASG2 and 1-A-SWGRA/FDS ASG3. Therefore, the scenarios for which this SAMA can be credited include:

- 1-A-SWGRB/1: 8.5% of external event risk
- 1-A-SWGRB/2: 21.7% of external event risk
- 1-A-SWGRA/FDS ASG1: 3.4% of external event risk

As these sequences account for 33.6 percent of the total external events CDF, they could be assumed to account for 33.6 percent of the external events based cost-risk, which would amount to $589,680 ($1,755,000 * 0.336 = $589,680). However, a large portion of the HNP MACR corresponds to the risk associated with the radioactive releases from SGTR and ISLOCA scenarios. As these accident types are not related to fire events in a measurable way, the estimate of $589,680 is considered to be high.

In order to obtain a more realistic estimate of the cost-risk associated with the relevant fire scenarios, the SGTR and ISLOCA contributions were excluded from consideration. One hundred percent of the non-SGTR/ISLOCA cost-risk was then assumed to be attributable to fire events (subtractions not made for seismic, high winds, etc). Finally, this cost-risk was multiplied by the fraction of fires that could be mitigated by SAMA 1. The portion of the resulting cost risk that could be averted by this SAMA depends on the reliability of the SAMA. Based on the 1.0E-01 failure probability used for SAMA 1 in Section E.6.1.1, 90 percent of the cost-risk is assumed to be averted by the SAMA. The details of this calculation are provided below.

In order to obtain the non-SGTR/ISLOCA cost-risk, the internal events cutsets were modified to eliminate these contributors. The following events were set to 0.0:

- %R: STEAM GENERATOR TUBE RUPTURE
- %ISLOCAM: INTER-SYSTEM LOCA - MEDIUM BREAK LOCA VIA RHR HOT OR COLD LEG INJECTION LINES
- %ISLOCAL: INTER-SYSTEM LOCA - LARGE BREAK LOCA VIA RHR SUCTION LINES

The methodology described in Section E.4 was used with these results to produce a cost-risk in the same was as for the base case. The difference is that the results used here do not include SGTR or ISLOCA contributions. The following tables summarize the CDF, dose-risk and OECR results.

Non-SGTR/ISLOCA Summary

	CDF (/yr)	Dose-Risk	OECR
No SGTR/ISLOCA Results	8.26E-06	3.25	$8,517

The non-SGTR/ISLOCA events contribute a large majority of the CDF (89.4 percent), but only a relatively small portion of the dose-risk (11.2 percent) and OECR (19.8 percent). This is due to the fact that the HNP containment is an effective barrier in most CDF scenarios and that a large portion of the release related risk corresponds to accidents in which the containment is bypassed. A further breakdown of the release information for non-SGTR/ISLOCA events is provided below according to release category.

Non-SGTR/ISLOCA Contributions by Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.53E-08	4.37E-08	4.59E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.93E-07	9.54E-07	**1.90E-06**
Dose-Risk	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.00	0.00	0.00	0.00	0.24	1.91	**3.25**
OECR	$8	$0	$2,406	$83	$34	$417	$7	$23	$0	$0	$0	$0	$187	$5,352	**$8,517**

The cost-risk for HNP without SGTR or ISLOCA is $437,088, which is all attributed to fire risk for this evaluation. Given that the total IPEEE Fire CDF is 1.1E-05 and that the CDF associated with the fire scenarios that can be mitigated by SAMA 1 is 4.34E-06 (39.4%), the corresponding cost-risk is $172,213 ($437,088 * 0.394 = $172,213). Using the assumption that SAMA 1 is 90 percent reliable, the internal fire based averted cost-risk for the SAMA is $154,991 ($172,213 * 0.9 = $154,991).

E.6.1.3 COST OF IMPLEMENTATION

The cost of this SAMA has been estimated to be $1 million (PE 2006b).

E.6.1.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the non-Fire and fire based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA Number 1 Net Value

Non-Fire Based Averted Cost-Risk	Fire Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$234,636	$154,991	$389,627	$1,000,000	-$610,373

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.2 SAMA NUMBER 2: CHANGE 1D AND 1E BUSES TO BE NORMALLY ALIGNED TO AN OFF-SITE POWER SOURCE

The current 1D and 1E bus alignments require a set of breakers to change position in order to swap the power supplies from the unit auxiliary transformers to the startup transformers. If the non-vital DC power system fails during a plant trip, a LOOP will occur as the breakers will not operate automatically. While procedures exist to direct local operation of the breakers, if the emergency buses were normally aligned to their corresponding startup transformers, the dependence on the non-vital 125V DC power supply/operator action would be removed.

This SAMA would preclude a LOOP after plant trip when the non-vital 125V DC batteries have been depleted, but it would not prevent a plant trip from occurring as other systems required for BOP operations also rely on the non-vital DC system.

In order to represent this SAMA, model changes were made to exclude loss of non-vital 125V DC power as contributors to failures of buses 1D and 1E. In addition, loss of 125V DC has been removed as a failure contributor to providing power to emergency buses 1A-SA and 1B-SB:

SAMA Number 2 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
J1D: NO POWER ON 6.9 KV BUS 1D	Deleted the following gates: • J027 (FAILURE TO TRANSFER BUS 1D FROM UAT TO SAT) • J042 (FAILURE TO TRANSFER BUSES A&D FROM UAT TO SAT (NOT BREAKERS))
J023-S: NO POWER AT BKR 105-SA OUTPUT (short-term)	Deleted the following gates: • J027 (FAILURE TO TRANSFER BUS 1D FROM UAT TO SAT) • J042 (FAILURE TO TRANSFER BUSES A&D FROM UAT TO SAT (NOT BREAKERS))
J1E: NO POWER AT 6.9 KV BUS 1E	Deleted the following gates: • J028 (FAILURE TO TRANSFER BUS 1E FROM UAT TO SAT) • J043 (FAILURE TO TRANSFER BUSES B&E FROM UAT TO SAT (NOT BREAKERS))
J025-S: NO POWER AT BKR 125-SB OUTPUT (short-term)	Deleted the following gates: • J028 (FAILURE TO TRANSFER BUS 1E FROM UAT TO SAT) • J043 (FAILURE TO TRANSFER BUSES B&E FROM UAT TO SAT (NOT BREAKERS))

The cost of this SAMA has been estimated to be $200,000 (PE 2006b).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	9.07E-6	28.57	$42,355
Percent Change	-1.8%	-1.4%	-1.6%

A further breakdown of this information is provided below according to release category.

SAMA 2 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
$Freq.(/yr)_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
$Freq. (/yr)_{SAMA}$	3.22E-09	1.07E-10	3.84E-07	2.13E-08	8.13E-09	3.53E-08	4.36E-08	4.13E-08	1.62E-07	6.17E-09	1.75E-07	6.30E-07	3.93E-07	9.23E-07	**2.83E-06**
$Dose\text{-}Risk_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
$Dose\text{-}Risk_{SAMA}$	0.01	0.00	0.83	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.59	0.24	1.85	**28.57**
$OECR_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
$OECR_{SAMA}$	$8	$0	$2,327	$82	$34	$417	$7	$21	$1,038	$51	$7,175	$25,830	$187	$5,178	**$42,355**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 2 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,456,938	$53,062	$200,000	-$146,938

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.3 SAMA NUMBER 3: INCREASE THE CAPACITY OF THE CONTAINMENT FAN COOLERS FOR HEAT REMOVAL WHEN RHR COOLING IS UNAVAILABLE AND PROVIDE SUMP SUCTION FOR HPSI

RHR heat removal failures that do not initially impact injection capability could be mitigated by using the Containment Fan Coolers to remove decay heat and prevent containment failure if the heat removal capacity of the system were increased. The current heat removal capacity of 2 or more fan coolers with containment pressure near 45 psig should be great enough to remove decay heat, prevent further containment pressurization, and maintain core cooling. However, enhancing the system so that it could provide adequate heat removal at lower pressures would allow more margin for success. Installation of a sump suction path and a booster pump for HPSI is also required to address many of the failures that result in loss of the RHR heat removal function.

In order to represent this SAMA, model changes were made to include credit for injection and heat removal using portions of the existing CSIP pump and containment fan cooler logic (referred to as “special cooling” in the SAMA based model logic). Due to the difficulty of including the flowpath logic for the CSIPs, the logic representing the injection path for this SAMA was not included. However, the pump failures, including power dependencies, were included. A single event (ALT-PATH-SPC) with a failure probability of 1E-2 has been incorporated to account for failure of the new sump suction line and booster pump for the CSIPs. Consistent with MOR05, no credit has been taken for the “C” CSIP pump for post initiating event accident mitigation.

For the heat removal portion of the model, the existing logic for the containment fan coolers was also used, but even with the enhancements made as part of this SAMA, it was assumed that failure of any 1 CFC would fail the heat removal function. No changes were made to the CFC component failure logic as the failure probabilities of any larger sized components required for the SAMA are assumed to be comparable to the existing hardware. No other changes were assumed to be required to the CFC logic for this analysis.

The operator action to align the cooling mode suggested by this SAMA is assumed to be completely dependent on the existing operator action to align high head recirculation mode (OPER-17). These changes are summarized below:

SAMA Number 3 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
HRECIRC: FAILURE OF HIGH HEAD SI (recirculation)	Added new “OR” gate SPECIAL-COOL.
HRECIRC-CC: FAILURE OF HIGH HEAD SI (recirculation) - NO CCW DEPENDENCY	Added new “OR” gate SPECIAL-COOL.

SAMA Number 3 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
SPECIAL-COOL: FAILURE OF HHSI INJECTION WITH CFC CONTAINMENT COOLING	New “OR” gate representing CSIP injection from the sump with CFC heat removal from containment. Includes the following gates/events: • CSIP-SPC (new): NO FLOW FROM CSIP A OR B (NO CREDIT FOR C) • B1OF4 (existing): INSUFFICIENT CONTAINMENT COOLING FROM 1/4 FAN COOLERS • ALT-PATH-SPC (new): FAILURE OF THE CSIP BOOSTER PUMP OR SUCTION LINE TO THE SUMP
ALT-PATH-SPC: FAILURE OF THE CSIP SUCTION LINE TO THE SUMP	New BE representing failure of the SAMA derived CSIP sump suction line or booster pump. Failure probability: 1.0E-02.
CSIP-SPC: NO FLOW FROM CSIP A OR B (NO CREDIT FOR C)	New “AND” gate representing CSIP operation for Special Cooling. Includes the following gates: • CSIP-A-SPC (new): NO FLO W FROM CSIP A FOR SPECIAL COOLING • CSIP-B-SPC (new): NO FLO W FROM CSIP B FOR SPECIAL COOLING
CSIP-A-SPC: NO FLOW FROM CSIP A FOR SPECIAL COOLING	New “OR” gate representing “A” CSIP failures for Special Cooling. Include the following gates: • H189 (existing): LOSS OF FLOW FROM CSIP HEADER A • H008 (existing): LOSS OF CSIP A SUCTION PRIOR TO SI SIGNAL
CSIP-B-SPC: NO FLO W FROM CSIP B FOR SPECIAL COOLING	New “OR” gate representing “A” CSIP failures for Special Cooling. Include the following gates: • H202 (existing): LOSS OF FLOW FROM CSIP HEADER B • H024 (existing): LOSS OF CSIP B SUCTION PRIOR TO SI SIGNAL

The scope of this SAMA would likely require the replacement of the existing fan cooler units and potentially the piping to the units. In addition, a new sump suction line for HPCI would have to be installed in conjunction with a booster pump to provide adequate NPSH for the CSIPs. Finally, training and procedural development would be required to support the use of the upgraded fan coolers with HPCI suction from the sump. Calvert Cliffs estimated to cost of installing a hardpipe connection from the fire protection system to the RHR heat exchangers, SI pumps, and RCP seals to be $565,000. This is used as a lower bound cost for SAMA 3.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	8.62E-6	28.94	$43,007
Percent Change	-6.7%	-0.1%	<-0.1%

A further breakdown of this information is provided below according to release category.

SAMA 3 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	2.56E-09	1.02E-10	3.97E-07	2.17E-08	6.75E-09	3.54E-08	4.24E-08	4.59E-08	1.62E-07	6.09E-09	1.76E-07	6.39E-07	3.79E-07	9.54E-07	**2.87E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.00	0.00	0.86	0.03	0.01	0.12	0.02	0.04	0.36	0.02	5.47	19.87	0.23	1.91	**28.94**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$7	$0	$2,406	$83	$28	$418	$7	$23	$1,038	$50	$7,216	$26,199	$180	$5,352	**$43,007**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 3 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,475,796	$34,204	$565,000	-$530,796

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.4 SAMA NUMBER 4: AUTOMATE RWST MAKEUP WITH FIREWATER AND BORIC ACID ADDITION

Failure to isolate an SGTR will result in the depletion of the RWST in the long term if makeup from the Demineralized Water System (DWS) is not initiated or if the flowpath from the DWS to the RWST fails. Failure of flow from the boric acid transfer system to the blending tee is also considered to result in RWST makeup failure in the PRA. While makeup from the DWS is preferable, procedures could be developed to provide an alternate source of borated water to the CSIPs using the Emergency Boration path and the Firewater system:

- Direct local actions using fire hoses connected to the Firewater system to add water to the RWST,
- Direct alignment of the Emergency Boration path to the CSIP suction header so that borated water would be available in conjunction with the non-borated water from the RWST.

In order to represent this SAMA, model changes were made to include credit for makeup in SGTR events. For this analysis, a simplified modeling approach was taken as the number of sequences impacted by this SAMA is limited, which include:

- RWY (SGTR, failure to isolate faulted SG, failure to provide makeup to RWST)
- RPY (SGTR, failure to cooldown/depressurize RCS, failure to provide makeup to RWST)

Rather than change the sequence structure to include credit for this SAMA, the corresponding sequence flags were manipulated within the baseline cutset files to simulate the implementation of the RWST makeup enhancement. The sequence flag for each of the relevant contributors was changed to 1.0E-01, which is considered to be a reasonable estimate of the total failure probability of the alternate makeup alignment considering:

- Firewater system failures (pumps, check valves, MOVs, power supplies)
- Flow path (Fire system to RWST piping and valves, mixing eductor, power dependence for cross-tie valve, and tank integrity)

The following summarizes the changes made to the cutsets:

SAMA Number 4 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
XFL_RWY: RWY SEQUENCE FLAG	• Removed "TRUE" setting • Set probability to 1.0E-01
XFL_RPY: RPY SEQUENCE FLAG	• Removed "TRUE" setting • Set probability to 1.0E-01

In addition, the associated database was updated with the revised probabilities identified in the table above.

The cost of implementation for this SAMA is $150,000 for a procedure change and the supporting analysis (PE 2006a).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	8.60E-06	28.78	$42,429
Percent Change	-6.9%	-0.7%	-1.4%

A further breakdown of this information is provided below according to release category.

SAMA 4 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
$Freq.(/yr)_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
$Freq.(/yr)_{SAMA}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.36E-08	4.60E-08	6.27E-08	6.36E-09	1.76E-07	6.40E-07	3.93E-07	9.54E-07	**2.79E-06**
$Dose\text{-}Risk_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
$Dose\text{-}Risk_{SAMA}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.14	0.02	5.47	19.90	0.24	1.91	**28.78**
$OECR_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
$OECR_{SAMA}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$402	$53	$7,216	$26,240	$187	$5,352	**$42,429**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 4 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,447,762	$62,238	$150,000	-$87,762

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.5 SAMA NUMBER 6: FLOOD MITIGATION FOR SCENARIOS 6 AND 7

In order to mitigate the floods caused by breaks in the lines from ESW to the common NSW return, the following changes are suggested:

- Waterproof motor operators for valves 1SW-274 and 1SW-275 (1SW-276 is not included as it has manual isolation valve 1SW-656 available. Existing plant procedures direct closure of 1SW-656 as part of the flood mitigation process and closure of this valve would isolate backflow from the main reservoir.).

The waterproofing of the motor operators for valves 1SW-274 and 1SW-275 is suggested to protect against water spray resulting from flood scenarios 6 and 7. The valves should be capable of operating in fully submerged conditions as a result of the waterproofing changes, but the elevation of the valves is such that damage due to submergence of the valve operators is less of a concern than damage caused by spray from a break. Waterproofing the valves will provide a means of isolating flow from the NSW/ESW pumps to the break in flood conditions. Valve 1SW-656 can be closed manually to isolate flow from the main reservoir back through the break and can terminate the relevant flooding scenarios provided that existing procedures are followed and that the break location is correctly identified.

In the event that valves 1SW-274 and 1SW-275 are the sources of the break or are not functional, high water level trip logic for the ESW/NSW pumps could be used to prevent flow from the pumps, but it would not isolate backflow from the main reservoir. Because an operator action is required to close valve 1SW-656 in these circumstances, auto trip of the ESW/NSW pumps would provide limited benefit alone. A high dependence would exist between the actions to isolate 1SW-656 and ESW/NSW pump trip; therefore, for the cases where flooding is terminated from 1SW-656, the ESW/NSW pumps would also likely be tripped. As a result, auto ESW/NSW pump trip is not required for this SAMA.

In order to estimate the impact of this SAMA, cutset changes were made to mimic implementation of the proposed flood mitigation strategy. This strategy was chosen because the contributors for Flood Scenarios 6 and 7 are limited to a few contributors and the impact of this SAMA can easily be identified. The hardware failure probabilities related to the modified valves suggested by this SAMA are considered to be small and flood isolation failures are likely dominated by operator action. A failure probability of 1.0E-02 is assumed for the SAMA and it has been accounted for in the results by reducing the flood initiating event frequency by two orders of magnitude:

SAMA Number 6 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
WRAB236UN3: RAB 236 SW PIPING VERY LARGE UNISOLABLE BREAK	Event probability changed from 7.54E-07 to 7.54E-09 in the results cutsets.

In addition, the associated database was updated with the revised probability identified in the table above.

The cost of this SAMA was initially estimated to be $150,000 (PE 2006a). This estimate includes the cost of sealing valves 1SW-274 and 1SW-275 so that they are capable of operating in submerged conditions.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	8.49E-6	28.48	$41,587
Percent Change	-8.1%	-1.7%	-3.4%

A further breakdown of this information is provided below according to release category.

SAMA 6 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)_{BASE}	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
$\text{Freq. (/yr)}_{SAMA}$	3.22E-09	1.07E-10	3.32E-07	1.45E-08	8.13E-09	2.57E-08	4.37E-08	3.65E-08	1.61E-07	6.36E-09	1.76E-07	6.40E-07	3.93E-07	7.88E-07	**2.63E-06**
Dose-Risk_{BASE}	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk_{SAMA}	0.01	0.00	0.72	0.02	0.02	0.09	0.02	0.03	0.36	0.02	5.47	19.90	0.24	1.58	**28.48**
OECR_{BASE}	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR_{SAMA}	$8	$0	$2,012	$56	$34	$303	$7	$18	$1,032	$53	$7,216	$26,240	$187	$4,421	**$41,587**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 6 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,398,760	$111,240	$150,000	-$38,760

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.6 SAMA NUMBER 7: PASSIVE SECONDARY SIDE COOLING SYSTEM

Accident scenarios including loss of AFW often include failures to manually initiate AFW after auto start failure, operator failures to re-start MFW, and operator failures to initiate Feed & Bleed heat removal. SAMAs requiring further operator actions to provide heat removal would provide limited benefit due to operator dependence issues. A potential solution is to install a passive secondary side heat removal system consisting of a condenser and a heat sink that will perform without operator intervention. This would require a set of initiation sensors diverse from AFW (potentially high SG temperature in addition to level sensors) and valves that would automatically open on the initiation signal to allow hot leg flow to pass through the condenser. Makeup to the condenser is assumed to be provided by a motor driven pump that can be supplied by either vital AC division. Likewise, control logic and valve power is also assumed to be supplied by both divisions such that the system is fully capable of operating after loss of an entire AC division.

This system would not be capable of preventing a seal LOCA in an SBO, so no provisions are included in the SAMA design to allow for operation in blackout conditions. SAMA 1 is considered to be a more cost effective way to address SBO cases.

In order to estimate the impact of implementing this SAMA, a simplified fault tree structure was added to the model to mimic the availability of this SAMA. A lumped event with a failure probability of 1.0E-02 (PSSHRS-H) has been created to represent equipment failures related to operation of the passive secondary side heat removal system. The types of failures represented include: initiation logic failures, alignment failures of the flow path from the RCS to the system's condenser, failures of makeup to the condenser, and system integrity failures. Power dependence is represented by the inclusion of a new gate that combines EDG "A" and "B" failures. This power dependence arrangement is a simplified approach and does not include the contributions of vital 6.9kV AC failures and other distribution failures, but the main goal of precluding credit in most SBO scenarios is accomplished through the use of this structure. The following table summarizes the fault tree changes that have been made:

SAMA Number 7 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
#BR: LOSS OF SECONDARY SIDE HEAT REMOVAL	Added new "OR" gate #S7
#BS: LOSS OF SECONDARY SIDE HEAT REMOVAL	Added new "OR" gate #S7
#BT: LOSS OF SECONDARY SIDE HEAT REMOVAL	Added new "OR" gate #S7

SAMA Number 7 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
#S7: PSSHRS	New "OR" gate representing the Passive Secondary Side Heat Removal System. Inputs include: • New basic event PSSHRS-H • New "AND" gate S7-EDGS
PSSHRS-H: PSSHRS HARDWARE FAILS	New basic event representing hardware failure of the passive heat removal system. The failure probability is assumed to be 1.0E-02.
S7-EDGS: EDG SUPPLY	New "AND" gate to mimic the power supply to the passive heat removal system. Inputs include: • Gate PEDGA (existing) • Gate PEDGB (existing)

The cost of installing a passive secondary side heat removal system would likely exceed the HNP MMACR due to the need to make major changes to the primary containment and secondary side cooling loops. While no cost estimate has been identifed for installation of a passive heat removal system in an existing plant, Browns Ferry estimated the cost of installing a passive containment spray system to be $6 million per unit (TVA 2003), which could be similar in scope even though it is a BWR system. The cost of installing a passive injection system in the ABWR was estimated to be $1.7 million if done in the design phase (GE 1994). The cost of the proposed HNP system could be in the range of these types of changes, but it is not likely to be less than the ABWR estimate. The $1.7 million estimate is used as a lower bound cost for this case (not scaled to 2006 dollars).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	7.99E-06	28.79	$42,794
Percent Change	-13.5%	-0.6%	-0.6%

A further breakdown of this information is provided below according to release category.

SAMA 7 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	2.61E-09	3.88E-11	3.94E-07	2.13E-08	6.40E-09	3.50E-08	3.16E-08	4.60E-08	1.62E-07	0.00E+00	1.75E-07	6.39E-07	2.50E-07	9.48E-07	**2.71E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.00	0.00	0.85	0.03	0.01	0.12	0.02	0.04	0.36	0.00	5.44	19.87	0.15	1.90	**28.79**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$7	$0	$2,388	$82	$27	$413	$5	$23	$1,038	$0	$7,175	$26,199	$119	$5,318	**$42,794**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 7 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,428,140	$81,860	$1,700,000	-$1,618,140

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.7 SAMA NUMBER 8: ALTERNATE SEAL COOLING AND DIRECT FEED TO TRANSFORMER 1B3-SB

Loss of a vital 6.9kV AC bus has been identified as an important contributor to HNP risk. As this event impacts many systems, it cannot be comprehensively mitigated by a single plant change short of the installation of an alternate vital bus. This type of change would not be cost effective for HNP and it is not suggested as a SAMA. Instead, two separate changes have been proposed to address the largest contributors to Loss of Bus evolutions. These changes include:

- Providing the capability to align a direct feed to the 1B3-SB transformer to preclude battery depletion, and
- Providing the capability to align the “C” CSIP for seal injection.

Loss of bus 1B-SB results in loss of power to the 1B3-SB transformer, which powers the “1B-SB” battery charger. Without this charger, the DC support power to the TD AFW pump will eventually fail and local actions would be required to operate the pump. These events, in conjunction with failures of the “A” AFW pump and feed and beed cooling would lead to core damage. Improving the reliability of TD AFW operation is a means of reducing the CDF for these types of events. Aligning a direct feed from the “B” EDG to the 1B3-SB transformer (bypassing the failed bus) would allow the “B” EDG to support the 1B-SB battery charger and preclude the need to operate the TD AFW pump from outside the main control room. Loss of bus 1B-SB events also include seal LOCA evolutions similar to those described below for the loss of bus 1A-SA events.

Loss of the 1A-SA bus does not directly impact the 1B3-SB transformer and as a result, the availability of power to the 1B3-SB transformer is not a major issue. Instead, the largest contributors are failures of bus 1A-SA in conjunction with maintenance on the “B” ESW division (or failures that lead to “B” ESW unavailability) and RHR injection/recirculation failures. These events result in the loss of RCP seal cooling, a subsequent seal LOCA, and core damage. A potential means of mitigating the failure of bus 1A-SA is to proceduralize the use of existing equipment to delay RCP seal damage long enough to align the “C” CSIP for seal injection. For loss of bus events, this will require aligning power to the “C” CSIP from one division and ESW to the pump from the opposite division (for initiating events that do not cause safety injection signals, such as loss of vital bus cases, NSW is still available to the ESW system in the divison with the failed vital AC bus). Currently, HNP can swap the division to which the “C” CSIP is aligned in under 1 hour. While this is likely not fast enough to prevent RCP seal damage given complete loss of seal cooling, one division of CCW is available to circulate water to the thermal barrier coolers so that some seal cooling capability is available. It is believed that seal damage can be delayed long enough to align the “C” CSIP for seal cooling by:

- Circulating CCW inventory with the available division,
- Shedding unnecessary CCW loads,

- Starting the spare spent fuel pool pump to supplement heat removal.

While the diagnosis of the need for this action and its execution would be complex, it is possible that procedure changes diecting the actions identified above could provide a means of preventing seal LOCAs in these events as well as other non-SBO events.

Because this SAMA has been identified based on both the internal events model insights and Internal Fire events review, separate evaluations have been performed to quantify the averted cost-risk associated with the Fire and non-Fire contributors. These evaluations are discussed below.

E.6.7.1 INTERNAL EVENTS AND NON-FIRE EVALUATION

This subsection describes the calculation of the component of SAMA 8's averted cost-risk associated with the internal events and the non-fire external events. Consistent with the assumptions regarding the relative contributions of the fire events to the total external events risk, the non-fire contribution is assumed to be 15 percent of the total. Quantitatively, this is accounted for by multiplying the internal events based averted cost-risk by 1.15. This process is described below.

In order to estimate the impact of implementing this SAMA for the non-fire contributors, fault tree and recovery rule changes were made to address the major elements of the SAMA. The following table summarizes the changes made:

SAMA Number 8 Internal Events Model Changes

Gate and / or Basic Event ID and Description	Description of Change
HCSIPSEAL (existing): NO FLOW FROM EITHER CSIP TO RCP SEALs	Added new “OR” gate S8-CSIP-C
S8-CSIP-C (new): LOSS OF FLOW FROM CSIP C TO RCP SEALS	New “OR” gate including the following input: • Basic event HCCFPABCFTS (existing): CCF - 3 OF 3 CSIPs FAIL TO START OR CVs FAIL TO OPEN • Basic event HCCFPABCFTR (existing): CCF - 3 OF 3 CSIPs FAIL TO RUN • New basic event “S8-ALTSEAL-COOL”: OPERATORS FAIL TO IMPLEMENT ALTERNATE SEAL COOLING • Gate H050 (existing): SW FLOODS FAIL CSIPs • Gate H_VCT (existing): FAILURE TO CLOSE OF VCT ISOLATION VALVES • New “AND” gate S8-CSIP-C-PWR: POWER FAILS TO CSIP C • New “AND” gate S8-CSIP-C-ESW: ESW COOLING TO CSIP C • Gate H188 (existing): LOSS OF FLOW FROM RWST THROUGH 1CS-294
S8-ALTSEAL-COOL (new): OPERATORS FAIL TO IMPLEMENT ALTERNATE SEAL COOLING	New basic event representing operator error related to diagnosing and aligning the alternate seal cooling method. The failure probability is assumed to be 1.0E-01.
S8-CSIP-C-PWR (new): POWER FAILS TO CSIP C	New “AND” gate including the following input: • Gate J1ASA (existing): NO POWER ON 6.9 KV BUS 1A-SA • Gate J1BSB (existing): NO POWER ON 6.9 KV BUS 1B-SB
S8-CSIP-C-ESW (new): ESW COOLING TO CSIP C	New “AND” gate including the following input: • Gate WCVCSA-S (existing): LOSS OF ESW TO CSIP A (transient) • Gate WCVCSB-S (existing): LOSS OF ESW TO CSIP B (transient)

SAMA Number 8 Internal Events Model Changes

Gate and / or Basic Event ID and Description	Description of Change
Recovery File Modification: Reduce cutsets including OPER-66 by 50 percent.	Added the following logic to the end of the Level 1 and 2 recovery files: **SET EVENT PROBS** OPER-66 5.0E-1 **CLEAR RECOVERY FLAGS**

It is recognized that manipulation of the OPER-66 label impacts SBO sequences, which would not be addressed by this SAMA; however, they have not been corrected for simplicity.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 8 Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results (non-Fire)	8.74E-6	28.86	$42,836
Percent Change	-5.4%	-0.4%	-0.4%

A further breakdown of this information is provided below according to release category.

SAMA 8 Internal Events Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	2.41E-09	9.26E-11	3.88E-07	2.11E-08	6.66E-09	3.50E-08	3.71E-08	4.31E-08	1.61E-07	6.35E-09	1.75E-07	6.40E-07	3.39E-07	9.39E-07	**2.79E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.00	0.00	0.84	0.03	0.01	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.20	1.88	**28.86**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$6	$0	$2,351	$81	$28	$413	$6	$22	$1,032	$53	$7,175	$26,240	$161	$5,268	**$42,836**

Based on these results, the averted cost-risk for all non-Fire contributors can be calculated using the 1.15 multiplier on the internal events results:

Non-Fire Averted Cost-Risk

Base Case Internal Events Cost-Risk	Revised Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Averted Cost-Risk
$1,755,000	$1,735,987	$19,013	1.15	$21,865

E.6.7.2 FIRE EVALUATION

The IPEEE review specifically identified SAMA 8 as a means of reducing the risk of fire induced bus failures in "A" and "B" switchgear rooms. Because this SAMA addresses specific portions of the fire risk, a separate evaluation is used to estimate the impact of the external events based averted cost-risk for this SAMA rather than the "multiplier" method discussed in Section E.5.1.7.

Based on a review of the IPEEE, it was possible to identify the fire scenarios that were assumed to result in failure of buses 1A-SA and 1B-SB. In addition, the percent contribution to the total external events CDF of 1.29E-05 (see Section 5.1.7) can be determined for these contributors:

Fire Area/Scenario	CDF	Percent of Ext. Events CDF	Major Equipment Failed
1-A-SWGRB/1	1.1E-06	8.5%	1B-SB AC Emergency Bus (plus other minor contributors)
1-A-SWGRB/2	2.8E-06	21.7%	Entire "B" division safe shutdown path, offsite power to 1A-SA without successful operator action.
1-A-SWGRA/FDS ASG1	4.4E-07	3.4%	1A-SA AC Emergency Bus (plus other minor contributors)
1-A-SWGRA/FDS ASG2	2.6E-06	20.2%	Entire "A" division safe shutdown path
1-A-SWGRA/FDS ASG3	7.6E-08	0.6%	1A-SA AC Emergency Bus (plus other minor contributors), fire induced spurious open PORV
Total	7.02E-06	54.4%	

As these sequences account for 54.4 percent of the total external events CDF, they could be assumed to account for 54.4 percent of the external events based cost-risk, which would amount to $954,720 ($1,755,000 * 0.544 = $954,720). However, a large portion of the HNP MACR corresponds to the risk associated with the radioactive releases from SGTR and ISLOCA scenarios. As these accident types are not related to fire events in a measurable way, the estimate of $954,720 is considered to be high.

In order to obtain a more realistic estimate of the cost-risk associated with the relevant fire scenarios, the SGTR and ISLOCA contributions were excluded from consideration. One hundred percent of the non-SGTR/ISLOCA cost-risk was then assumed to be attributable to fire events (subtractions not made for seismic, high winds, etc). Finally, this cost-risk was multiplied by the fraction of fires that cause failure of the 1A-SA and 1B-SB buses. The averted cost-risk of a SAMA that could mitigate the fire induced bus failures would depend on the reliability of the SAMA, but for this analysis, the SAMA is assumed to be 100 percent reliable and that all of the associated risk could be removed through installation of the proposed direct feed lines. The details of this calculation are provided below.

In order to obtain the non-SGTR/ISLOCA cost-risk, the internal events cutsets were modified to eliminate these contributors. The following events were set to 0.0:

- %R: STEAM GENERATOR TUBE RUPTURE
- %ISLOCAM: INTER-SYSTEM LOCA - MEDIUM BREAK LOCA VIA RHR HOT OR COLD LEG INJECTION LINES
- %ISLOCAL: INTER-SYSTEM LOCA - LARGE BREAK LOCA VIA RHR SUCTION LINES

The methodology described in Section E.4 was used with these results to produce a cost-risk in the same was as for the base case. The difference is that the results used here do not include SGTR or ISLOCA contributions. The following tables summarize the CDF, dose-risk and OECR results.

Non-SGTR/ISLOCA Summary

	CDF (/yr)	Dose-Risk	OECR
No SGTR/ISLOCA Results	8.26E-06	3.25	$8,517

The non-SGTR/ISLOCA events contribute a large majority of the CDF (89.4 percent), but only a relatively small portion of the dose-risk (11.2 percent) and OECR (19.8 percent). This is due to the fact that the HNP containment is an effective barrier in most CDF scenarios and that a large portion of the release related risk corresponds to accidents in which the containment is bypassed. A further breakdown of the release information for non-SGTR/ISLOCA events is provided below according to release category.

Non-SGTR/ISLOCA Contributions by Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.53E-08	4.37E-08	4.59E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.93E-07	9.54E-07	**1.90E-06**
Dose-Risk	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.00	0.00	0.00	0.00	0.24	1.91	**3.25**
OECR	$8	$0	$2,406	$83	$34	$417	$7	$23	$0	$0	$0	$0	$187	$5,352	**$8,517**

The cost-risk for HNP without SGTR or ISLOCA is $437,088, which is all attributed to fire risk for this evaluation. Given that the total IPEEE Fire CDF is 1.1E-05 and that the CDF associated with the fire scenarios that cause bus failure is 7.02E-06, only 63.4 percent of the non-SGTR/ISLOCA cost-risk corresponds to the bus failure scenarios ($277,114). Using the assumption that SAMA 8 is 100 percent reliable, this total is also the fire based averted cost-risk for SAMA8.

E.6.7.3 COST OF IMPLEMENTATION

The cost of this SAMA has been estimated to be $300,000 (PE 2006a).

E.6.7.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the non-Fire and fire based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA Number 8 Net Value

Non-Fire Based Averted Cost-Risk	Fire Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$21,865	$277,144	$298,979	$300,000	-$1,021

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.8 SAMA NUMBER 9: PROCEDURALIZE ACTIONS TO OPEN EDG ROOM DOORS ON LOSS OF HVAC AND IMPLEMENT PORTABLE FANS

Loss of EDG Room HVAC is assumed to result in EDG failure during the summer months. Loss of EDG Room HVAC could be mitigated if plant operating procedures were enhanced to direct operators to open the EDG room doors when HVAC is lost during periods of expected high heat (between the March 28th and October 29th) or whenever room temperatures are high. As a room heatup analysis is not available to show that the EDG rooms would remain sufficiently cool without forced ventilation, portable fans are assumed to be required as part of the alternate cooling strategy.

Typically, the redundancy of the of the EDG HVAC system results in a low importance of EDG HVAC outside of the summer months; however, common cause failure of all 4 air handling units has been identified as a potential combination that is important for non-summer months. Ensuring that the proposed procedure changes include provisions to perform the alternate cooling alignment whenever high EDG room temperature conditions occur will address these failures.

In order to estimate the impact of implementing this SAMA, the cutsets were manipulated to simulate the capability of providing alternate EDG room cooling. The events representing the major contributors to loss of EDG HVAC were set to 0.0:

SAMA Number 9 Cutset Changes

Gate and / or Basic Event ID and Description	Description of Change
X-HVAC: SECOND FAN REQUIRED FOR EDG ROOM COOLING - SUMMER TIME	Probability changed from 0.59 to 0.0 (eliminates two train requirement)
PCCFDGAHUS: CCF - 4 OF 4 EDG E-86 AHUs FAIL TO START OR GDs FAIL TO OPEN	Probability changed from 1.10E-04 to 0.0 (eliminates contributions of EDG HVAC failures in non-summer months)

Two components are included in the cost estimate, procedure changes and the purchase of portable fans to provide temporary, forced ventilation. The cost of the procedure change is based on an industry estimate of $50,000 for a procedure change

(CPL 2004). An estimate of $20,000 is included to provide portable fans, which is considered to be a high estimate for fans. A total cost of $70,000 is used for this SAMA.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	8.56E-6	28.57	$41,874
Percent Change	-7.4%	-1.4%	-2.7%

A further breakdown of this information is provided below according to release category.

SAMA 9 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	3.22E-09	1.07E-10	3.40E-07	2.04E-08	8.13E-09	3.22E-08	4.36E-08	4.05E-08	1.61E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	8.20E-07	**2.68E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.01	0.00	0.74	0.03	0.02	0.11	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.64	**28.57**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$8	$0	$2,060	$78	$34	$380	$7	$20	$1,032	$53	$7,175	$26,240	$187	$4,600	**$41,874**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 9 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,416,386	$93,614	$70,000	$23,614

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.6.9 SAMA NUMBER 10: INSTALL A MAIN CONTROL ROOM POWER INTERRUPT SWITCH FOR ALTERNATE SCRAM CAPABILITY

Providing a switch within the MCR that could be used to interrupt power to the MCC that maintains the control rods in the withdrawn position would allow the operators to scram the reactor in a timely manner when the preferred methods fail. This action is currently possible through local action in a nearby room, but no credit is taken for ex-control room manipulations for this time sensitive action.

In order to estimate the impact of implementing this SAMA, the probability for the event representing the conditions under which the control room trip action is not possible (ERPS1) was changed from 1.60E-06 to 1.60E-8. This change simulates a 1.0E-02 failure probability for the operator to use the controls suggested by this SAMA to trip the MCC powering the control rods. The failure probability of 1.0E-02 is consistent with the probability that is used in the PRA for the operator action to perform this function using the normal trip controls when auto trip fails with an RPS trip signal present. An increased probability may be justifiable, but it is assumed that the training and procedures would direct this action to be taken immediately on failure of the standard trip action such no significant differences in timing or cues would exist (other than failure of the manual trip).

No plant specific cost estimate has been developed for this SAMA. The minimum implementation cost of a SAMA, which is assumed to be a procedural change at $50,000 (CPL 2004), has been used to reduce resources required to estimate a plant specific cost.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	9.02E-6	28.96	$43,051
Percent Change	-2.4%	<-0.1%	<-0.1%

A further breakdown of this information is provided below according to release category.

SAMA 10 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	2.93E-09	1.04E-10	3.98E-07	2.17E-08	7.87E-09	3.54E-08	4.34E-08	4.60E-08	1.61E-07	6.35E-09	1.76E-07	6.40E-07	3.43E-07	9.56E-07	**2.84E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.00	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.47	19.90	0.21	1.91	**28.96**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$8	$0	$2,412	$83	$33	$418	$7	$23	$1,032	$53	$7,216	$26,240	$163	$5,363	**$43,051**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 10 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,498,778	$11,222	$50,000	-$38,778

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.10 SAMA NUMBER 11: AUTOMATE EMERGENCY BORATION INITIATION

For ATWS contributors where the initial pressure spike is controlled, the reliability of shutting the reactor down with Emergency Boration could be improved by automating system initiation. Power level monitoring in conjunction with RPS/AMSAC signals could be used to satisfy logic that would initiate the Emergency Boration function. An inhibit switch could be provided to prevent unwanted injection in the event of initiation logic failures.

In order to estimate the impact of implementing this SAMA, the probability for the event representing manual emergency boration operation (OPER-36) was changed from 1.0 to 0.0 in the cutset files. This event is the unrecovered placeholder event used to identify the presence of the action in a scenario and does not represent the actual quantitative contribution of the action to the cutsets, but it can be used to modify the credit taken for the action. In this case, this SAMA is assumed to be 100 percent reliable and that no sequences requiring emergency boration result in core damage.

Browns Ferry estimated the cost for automating SLC initiation to be about $400,000 per unit (TVA 2003). This enhancement is similar in nature to automating emergency boration for HNP and this estimate is used as an approximation of the resources required for this SAMA.

Results

Implementation of this SAMA yields a reduction in the CDF, and Offsite Economic cost-risk, but no measurable change in Dose-Risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	9.10E-06	28.96	$43,002
Percent Change	1.52%	<-0.1%	-0.1%

A further breakdown of this information is provided below according to release category.

SAMA 11 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	3.19E-09	1.04E-10	3.96E-07	2.17E-08	8.07E-09	3.54E-08	4.31E-08	4.60E-08	1.61E-07	6.35E-09	1.75E-07	6.40E-07	3.85E-07	9.53E-07	**2.87E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.23	1.91	**28.96**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$8	$0	$2,400	$83	$34	$418	$7	$23	$1,032	$53	$7,175	$26,240	$183	$5,346	**$43,002**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 11 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,501,396	$8,604	$400,000	-$391,396

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.11 SAMA NUMBER 12: FLOOD MITIGATION FOR SCENARIOS 1, 2 AND 5

Flood Scenarios 1, 2, and 5 encompass breaks in the ESW system from the pump discharge through the system loads up to the return lines at valves 1SW-274 and 1SW-275. While several different areas are impacted by these flood scenarios, a common set of changes has been identified that would adequately mitigate these breaks:

- Waterproof motor operators for valves 1SW-39 and 40,
- Add sump level indication for the 216 foot level to the MCR.

The waterproofing of the motor operators for valves 1SW-39 and 1SW-40 is suggested to protect against water spray. The valves should be capable of operating in fully submerged conditions as a result of the waterproofing changes, but the elevation of the valves is such that damage due to submergence of the valve operators is less of a concern than damage caused by spray from a break. Waterproofing the valves will increase the reliability of the automatic isolation capability that is already part of the flood mitigating design for valves 1SW-39 and 40. Low ESW header pressure automatically starts the ESW pumps and closes valves 1SW-39 and 40, which terminates flow from NSW to the break.

To completely terminate the flood event, the ESW pump on the failed loop must also be tripped. Auto trip of the ESW pump is not suggested because the flood area is open both pumps, which implies that pressure sensors would have to be added to the ESW lines to aid in the automatic diagnosis and isolation of the break location. This would increase the cost of the SAMA. A less costly option that would trip both ESW pumps on high water level is an option, but it would require a subsequent restart of ESW. This is a time critical action when the EDGs are running and a delay in the restoration of ESW to the EDGs may result in unavailability of both EDGs. Procedures already exist that direct the operators to trip the ESW pump in the relevant flooding scenarios. This is considered to be the most appropriate means of terminating ESW flow out of the break. Additon of the sump level indication for the 216 foot level in the MCR will aid the operators in the diagnosis of the flooding event.

In order to estimate the impact of this SAMA, cutset changes were made to mimic implementation of the proposed flood mitigation strategy. This strategy was chosen because the contributors for Flood Scenarios 1, 2, and 5 are limited to a few contributors and the impact of this SAMA can easily be identified. The hardware failure probabilities related to changes suggested by this SAMA are considered to be small and are likely dominated by operator action. A failure probability of 1.0E-02 is assumed for the SAMA and it has been accounted for in the results by reducing the flood initiating event frequency by two orders of magnitude:

SAMA Number 12 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
WRAB236UN2: RAB 236 SW PIPING VERY LARGE UNISOLABLE BREAK	Event probability changed from 3.82E-07 to 3.82E-09 in the results cutsets.

In addition, the associated database was updated with the revised probability identified in the table above.

The cost of this SAMA has been estimated to be $275,000 (PE 2006a).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	8.86E-06	28.68	$42,242
Percent Change	-4.1%	-1.0%	-1.8%

A further breakdown of this information is provided below according to release category.

SAMA 12 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	3.22E-09	1.07E-10	3.64E-07	1.81E-08	8.14E-09	3.04E-08	4.38E-08	4.12E-08	1.62E-07	6.36E-09	1.75E-07	6.39E-07	3.93E-07	8.71E-07	**2.76E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.01	0.00	0.79	0.02	0.02	0.11	0.02	0.04	0.36	0.02	5.44	19.87	0.24	1.74	**28.68**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$8	$0	$2,206	$69	$34	$359	$7	$21	$1,038	$53	$7,175	$26,199	$187	$4,886	**$42,242**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 12 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,449,416	$60,584	$275,000	-$214,416

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.12 SAMA NUMBER 13: FLOOD MITIGATION FOR SCENARIOS 3 AND 4

These flood events are caused by breaks in the NSW supply to ESW (from the tank building to 1SW-39 and 40). In order to mitigate a flood event caused by these breaks, the following changes are suggested:

- Waterproof motor operators for valves 1SW-39 and 40,
- Add logic and sensors to trip NSW pumps on high water level in the Service Water Pipe Tunnel (216' elevation) and the RAB near the 1SW-39 and 40 valves.
- Add sump level indication for the 216 foot level to the MCR.

The waterproofing of the motor operators for valves 1SW-39 and 1SW-40 is suggested to protect against water spray. The valves should be capable of operating in fully submerged conditions as a result of the waterproofing changes, but the elevation of the valves is such that damage due to submergence of the valve operators is less of a concern than damage caused by spray from a break. Waterproofing the valves will provide a means of isolating flow from the ESW pumps to the break in flood conditions (an ESW system start automatically isolates these valves and successful operation would close the path to the break location). High water level trip logic for the NSW pumps is suggested to provide a means of eliminating flow from the NSW pumps to the break area. Securing NSW is required because no isolation valve upstream of the break location is available. It should be noted that a trip required due to the loss of normal service water is very challenging. This is because loss of NSW requires a trip of secondary pumps, and also results in loss of cooling to the turbine lube oil and DEH oil, as well as loss of condenser vacuum. This could result in permanent damage to the main turbine, and also removes the capability of using main feedwater as a backup to AFW for secondary heat sink level control

In order to estimate the impact of this SAMA, cutset changes were made to mimic implementation of the proposed flood mitigation strategy. This strategy was chosen because the contributors for Flood Scenarios 3 and 4 are limited to a few contributors and the impact of this SAMA can easily be identified. Based on the changes proposed for this SAMA, no operator action would be required for isolation of this flood: 1) Low ESW header pressure would start the ESW system after the initiating break and the waterproofed 1SW-39 and 40 valves would automatically close. High water level in the break area would trip NSW and terminate flow from that system. The initiating event frequency for flood scenario 1/2/5 has been multiplied by 5.0E-03 to represent failures of the valve mechanisms, logic, and power support.

It should be noted that the changes suggested for SAMA 13 envelope the changes suggested for SAMA 12. As a result, the same changes made for the quantification of SAMA 12 are also performed here::

SAMA Number 13 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
WRAB236UN4: RAB 236 SW PIPING VERY LARGE UNISOLABLE BREAK	Event probability changed from 3.50E-07 to 1.75E-09 in the results cutsets.
WRAB236UN2: RAB 236 SW PIPING VERY LARGE UNISOLABLE BREAK	Event probability changed from 3.82E-07 to 3.82E-09 in the results cutsets.

In addition, the associated database was updated with the revised probability identified in the table above.

The cost of the logic changes for this SAMA has been estimated to be $75,000 (PE 2006a). From the cost estimate prepared for SAMA 12 (PE 2006a), the waterprofing of 1SW-39 and 1-SW40 is estimated to require an additional $150,000 for a total of $225,000.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	8.51E-06	28.46	$41,596
Percent Change	-7.9%	-1.8%	-3.3%

A further breakdown of this information is provided below according to release category.

SAMA 13 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	3.22E-09	1.07E-10	3.34E-07	1.47E-08	8.13E-09	2.60E-08	4.36E-08	3.69E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	7.93E-07	**2.64E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.01	0.00	0.72	0.02	0.02	0.09	0.02	0.03	0.36	0.02	5.44	19.90	0.24	1.59	**28.46**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$8	$0	$2,024	$56	$34	$307	$7	$18	$1,038	$53	$7,175	$26,240	$187	$4,449	**$41,596**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 13 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,398,852	$111,148	$225,000	-$113,852

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.13 SAMA NUMBER 14: ALTERNATE AFW SUCTION

HNP has a connection between the ESW system and each of the AFW pump suction lines. Current procedures direct the use of this connection (from the main control room) when the CST level is low (<10%) or unavailable. While this is true, the PRA does not credit this connection for the following reasons:

- In the event of CST suction failure, the AFW pumps would trip off on low suction pressure and require re-start in order to restore secondary side cooling. For rapidly evolving accidents such as ATWS scenarios, timing limitations were assumed to preclude alignment of the ESW system as a viable mitigation strategy. As no logic was included in the model to distinguish between accident types for use of this suction path, it was not considered for any initiating event type.

- CST depletion: Other than draindown cases, the CST volume was determined to be adequate for the 24 hour mission time, so no refill cases were assumed to be required for non-path related issues.

The importance list review that was performed as part of the SAMA identification process identified loss of the CST suction path as one of the larger contributors to CDF (basic event FXVCE-34FN). However, review of the results indicated that none of the cutsets including this event were ATWS sequences, which implies that ESW would be available as an alternate AFW suction source for the cases contributing to the PRA. If credit is taken for the existing hardware and procedures at HNP, the importance of the CST suction path failures will be reduced below the RRW review threshold used for the SAMA analysis demonstrating that no SAMAs are required to improve the AFW suction configuration.

In order to more accurately reflect the current plant configuration for the evaluation, the PRA model was changed to allow credit for the alignment of ESW to the AFW pump suction lines in non-ATWS conditions. Logic for the ESW cross-tie exists in the PRA model for cases when the CST is unavailable for maintenance or when the CST drains down due to inadvertent valve operation. This logic has been used to address the CST suction path failure cases, including the HEP (OPER-29) used to represent the probability that the operator would fail to properly perform the suction swap. The timing for OPER-29 does not match the conditions of CST suction failure exactly, but the results are considered to be reasonable for this evaluation. The current OPER-29 action is based on a cue of low level and an available time of 88 minutes to perform the action. Early losses of the CST, when decay heat loads are highest, may require completion of the suction swap in less time, but over the spectrum of potential failure times during the 24 hour mission time, the use of 88 minutes for the available time in not unreasonable. The cues for the action are considered to be comparable and no reason has been identified to modify the probability for OPER-29 by any margin that would impact the conclusions of this evaluation. The following table summarizes the changes that were made to the PRA:

SAMA Number 14 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
F048 (existing): MOTOR-DRIVEN PUMP A SUCTION SOURCES UNAVAILABLE	• Deleted gate F029 • Added new "AND" gate ALT-ESW-A
ALT-ESW-A (new): CST AND ESW SUCTION PATHS FAIL	New "AND" gate including the following input gates: • F029 (existing): MOTOR-DRIVEN PUMP A SUCTION FROM CST UNAVAILABLE • F066 (existing): ESW BACKUP SOURCE TO MOTOR-DRIVEN PUMP A FAILS
F061 (existing): MOTOR-DRIVEN PUMP B SUCTION SOURCES UNAVAILABLE	• Deleted gate F030 • Added new "AND" gate ALT-ESW-B
ALT-ESW-B (new): CST AND ESW SUCTION PATHS FAIL	New "AND" gate including the following input gates: • F067 (existing): ESW BACKUP SOURCE TO MOTOR-DRIVEN PUMP B FAILS • F030 (existing): MOTOR-DRIVEN PUMP B SUCTION FROM CST UNAVAILABLE
F087 (existing): TURBINE-DRIVEN PUMP SUCTION SOURCES UNAVAILABLE	• Deleted gate F031 • Added new "AND" gate ALT-ESW-TD
ALT-ESW-TD (new): CST AND ESW SUCTION PATHS FAIL	New "AND" gate including the following input gates: • F068 (existing): ESW BACKUP SOURCE TO TURBINE-DRIVEN PUMP FAILS • F031 (existing): TURBINE-DRIVEN PUMP SUCTION FROM CST UNAVAILABLE

Results

Crediting the existing procedures and equipment for the ESW to AFW suction line at HNP results in the truncation of most CST flow path failures. Some individual pump suction line failures were above the truncation, but these events had RRW values of 1.000. Neither the CDF nor the composite level 2 cutset files included any failure combinations including the basic event FXVCE-34FN, which demonstrates that the importance of the CST suction line is far below the SAMA review cutoff value. No further investigation is required.

E.6.14 SAMA NUMBER 15: CHANGE LOGIC FOR VALVES 1SW-274 AND 1SW-275 TO PREVENT LOSS OF DISCHARGE PATH

Failure of valves 1SW-270 and 1SW-271 to open in conjunction with the normal isolation of discharge path to the NSW return (valves 1SW-274 and 275) on ESW start results in the isolation of all discharge paths. Changing the logic so that valves 1SW-274 and 275 do not receive a signal to close until valves 1SW-270 and 1SW-271 are full open would preclude the loss of a discharge path in the cases where 1SW-270 and or 1SW-271 fail to open. Changes to procedures and/or the addition of any interlock bypass equipment that might be needed to allow re-opening of 1SW-274 and 1SW-275 would provide a means of re-establishing an ESW discharge pathway, but in situations where the EDGs are running, the time available to re-establish cooling is short. The logic changes proposed in this SAMA would preclude the need for any operator actions to maintain cooling to the EDGs in most cases.

In order to estimate the impact of this SAMA, cutset changes were made to mimic implementation of the proposed logic changes. This strategy was chosen because the contributors to the types of failures that lead to loss of the return path to NSW are represented by only five valve failure events. The failure probability for each of these events was set to 0.0, representing 100 percent reliability of the SAMA. The following table summarizes the changes that were made:

SAMA Number 15 Cutset Changes

Basic Event ID and Description	Description of Change
WCCFAUXRES: CCF - 2 OF 2 MOVs (1SW-270 AND 1SW-271) FAIL TO OPEN	Event probability changed from 9.9E-05 to 0.0 in the results cutsets.
WMVSW270FN: MOV 1SW-270 ESW A TO AUX RESERVOIR TRANSFERS CLOSED	Event probability changed from 4.8E-06 to 0.0 in the results cutsets.
WMVSW270NN: MOV 1SW-270 ESW A TO AUX RESERVOIR FAILS TO OPEN	Event probability changed from 3.1E-03 to 0.0 in the results cutsets.
WMVSW271FN: MOV 1SW-271 ESW B TO AUX RESERVOIR TRANSFERS CLOSED	Event probability changed from 4.8E-06 to 0.0 in the results cutsets.
WMVSW271NN: MOV 1SW-271 ESW B TO AUX RESERVOIR FAILS TO OPEN	Event probability changed from 3.1E-03 to 0.0 in the results cutsets.

The cost of the logic changes for this SAMA has been estimated to be $250,000 (PE 2006a).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	8.59E-06	28.52	$41,911
Percent Change	-7.0%	-1.6%	-2.6%

A further breakdown of this information is provided below according to release category.

SAMA 15 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)_{BASE}	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
$\text{Freq. (/yr)}_{SAMA}$	3.18E-09	1.05E-10	3.52E-07	2.06E-08	7.93E-09	3.28E-08	4.29E-08	4.16E-08	1.56E-07	6.36E-09	1.75E-07	6.36E-07	3.84E-07	8.48E-07	**2.71E-06**
Dose-Risk_{BASE}	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk_{SAMA}	0.01	0.00	0.76	0.03	0.02	0.12	0.02	0.04	0.35	0.02	5.44	19.78	0.23	1.70	**28.52**
OECR_{BASE}	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR_{SAMA}	$8	$0	$2,133	$79	$33	$387	$7	$21	$1,000	$53	$7,175	$26,076	$182	$4,757	**$41,911**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 15 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,416,026	$93,974	$250,000	-$156,026

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.15 SAMA NUMBER 16: AMSAC BACKUP TO RPS SCRAM

For RPS failure scenarios, manual actions are currently required to take the reactor to a sub-critical state. The AMSAC signal, which is separate from the RPS logic other than the sensors used as input, could be used as a backup to the RPS scram signal. Use of this signal would provide an alternate means of generating an automated scram signal to the reactor in ATWS scenarios. Because AMSAC only actuates on ATWS conditions, the proposed changes would not provide a redundant scram signal for typical plant trips. No credit is taken for this SAMA for cases in which an RPS signal is present, but automatic scram is not possible. This is because the same issues that prevent a scram when an RPS signal is present would prevent a scram from a similar signal generated by AMSAC.

In order to estimate the impact of this SAMA, the PRA model was modified to include credit for the AMSAC signal to generate a scram signal. The existing AMSAC logic (a single event) was included in the logic with the operator action for manually tripping the reactor given RPS failure. The table below summarizes the fault tree changes that were made:

SAMA Number 16 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
#RT3: RECTOR FAILS TO TRIP AND NOT MANUALLY TRIPPED - RPS SIGNAL NOT PRESENT	Added existing gate #AMSAC.

Browns Ferry estimated the cost for automating SLC initiation to be about $400,000 per unit (TVA 2003). This enhancement is similar in scope to using AMSAC to operate as a secondary scram signal and this estimate is used as an approximation of the resources required for HNP to implement this SAMA.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	9.14E-06	28.96	$43,019
Percent Change	-1.1%	<-0.1%	<-0.1%

A further breakdown of this information is provided below according to release category.

SAMA 16 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
$Freq.(/yr)_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
$Freq.\ (/yr)_{SAMA}$	3.18E-09	1.05E-10	3.97E-07	2.17E-08	8.06E-09	3.53E-08	4.30E-08	4.59E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.85E-07	9.54E-07	**2.88E-06**
$Dose\text{-}Risk_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
$Dose\text{-}Risk_{SAMA}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.23	1.91	**28.96**
$OECR_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
$OECR_{SAMA}$	$8	$0	$2,406	$83	$34	$417	$7	$23	$1,038	$53	$7,175	$26,240	$183	$5,352	**$43,019**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 16 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,503,952	$6,048	$400,000	-$393,952

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.16 SAMA NUMBER 17: REPLACE 2 OF THE 5 HIGH PRESSURE INJECTION VALVES WITH AN ALTERNATE TYPE OF VALVE

Common cause failure of the high pressure injection valves is a potential failure mode that can lead to core damage in some cases. The potential for this type of failure could be reduced by changing a subset of the injection valves to a different type of valve. In this case, it is suggested that valves 1SI-107 and 1SI-3 be replaced with an alternate type of MOV. These changes would provide diverse pathways into the Hot Leg (using "A" division) and the Cold leg (using "B" division").

In order to estimate the impact of this SAMA, the PRA model was modified to remove common cause failures involving these valves. A simplified, conservative approach was used to represent this SAMA in order to eliminate the need to recalculate different common cause failure probabilities for the injection valves based on the changes to the common cause group:

- All 5 of 5 injection valve common cause failure events were removed,
- All sub group common cause events including valves 1SI-107 and 1SI-3 were removed,
- No common cause was added to account for CCF between replacement valves 1SI-107 and 1SI-3.

The table below summarizes the fault tree changes that were made:

SAMA Number 17 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
H033: MOV 1SI-107 HHSI TO HL UNABLE TO OPEN	Deleted the following event: • HCCFSIMOVS: CCF - 5 OF 5 MOVs (1SI-3, 4, 52, 86 AND 107) FAIL TO OPEN
H038: LOSS OF FLOW THROUGH MOV 1SI-3	Deleted the following events: • HCCFSIMOVS: CCF - 5 OF 5 MOVs (1SI-3, 4, 52, 86 AND 107) FAIL TO OPEN • HCCFSI3&52: CCF - 2 OF 5 MOVs (1SI-3 AND 1SI-52) FAIL TO OPEN • HCCFSI3&4: CCF - 2 OF 5 MOVs (1SI-3 AND 1SI-4) FAIL TO OPEN
H045: MOV 1SI-52 ALT CL SI UNABLE TO OPEN	Deleted the following events: • HCCFSIMOVS: CCF - 5 OF 5 MOVs (1SI-3, 4, 52, 86 AND 107) FAIL TO OPEN • HCCFSI3&52: CCF - 2 OF 5 MOVs (1SI-3 AND 1SI-52) FAIL TO OPEN
H042: LOSS OF FLOW THROUGH MOV 1SI-4	Deleted the following events: • HCCFSIMOVS: CCF - 5 OF 5 MOVs (1SI-3, 4, 52, 86 AND 107) FAIL TO OPEN • HCCFSI3&4: CCF - 2 OF 5 MOVs (1SI-3 AND 1SI-4) FAIL TO OPEN

SAMA Number 17 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
H044: MOV 1SI-86 HHSI TO HL UNABLE TO OPEN	Deleted the following event: • HCCFSIMOVS: CCF - 5 OF 5 MOVs (1SI-3, 4, 52, 86 AND 107) FAIL TO OPEN

The cost of this SAMA has been estimated to be $500,000 (PE 2006b).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	9.03E-06	28.56	$42,451
Percent Change	2.3%	-1.4%	-1.4%

A further breakdown of this information is provided below according to release category.

SAMA 17 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	3.18E-09	1.03E-10	3.98E-07	2.17E-08	7.79E-09	3.54E-08	4.07E-08	4.60E-08	1.48E-07	6.35E-09	1.76E-07	6.27E-07	3.81E-07	9.56E-07	**2.85E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.33	0.02	5.47	19.50	0.23	1.91	**28.56**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$8	$0	$2,412	$83	$32	$418	$6	$23	$949	$53	$7,216	$25,707	$181	$5,363	**$42,451**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 17 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,457,180	$52,820	$500,000	-$447,180

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.17 SAMA NUMBER 18: PROCEDURALIZE ALIGNMENT OF HHSI TO THE RHR HEAT EXCHANGERS DURING INJECTION PHASE

In the event that the HHSI pump suction path from the RWST fails, procedures could be written to direct the alignment of the HHSI pumps to the RHR heat exchangers during the injection phase. This would require the availability of the RWST suction path to the RHR pumps. It is assumed that this alignment can be used for either high pressure makeup or for maintaining seal injection in the event that the normal supply path fails.

In order to estimate the impact of this SAMA, the PRA model was modified to allow an RHR train to supply water to the CSIP suction header of the same division. For the purposes of this evaluation, it was assumed that this alignment could be performed in time to prevent seal damage in the event that the normally running seal injection path fails (within 13 minutes of loss of cooling). As with the normal injection path, failure to isolate the Volume Control Tank is considered to fail the unisolated suction paths. A single operator action governing the alignment of this path is used with an assumed HEP of 1.0E-1. While lower values may be appropriate for the case governing makeup injection, a relatively high HEP must be used as to address the short time available in the seal injection cases. In fact, values higher than 1.0E-01 for HEP may be reasonable for the seal injection application if the alignment time for this SAMA is close to 10 minutes, but 1.0E-01 is used to show increased benefit.

The table below summarizes the fault tree changes that were made:

SAMA Number 18 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
H200 (existing): LOSS OF FLOW TO CSIP HEADER A FROM THE RWST	Added new “OR” gate RHR-CSIPA

SAMA Number 18 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
RHR-CSIPA (new): RHR SUCTION SOURCE FAILS FOR A HEADER	New "OR" gate including the following input: • New basic event "RHR-SUCTION-ALG" • Gate H_VCT (existing): FAILURE TO CLOSE OF VCT ISOLATION VALVES • Basic event OPER-42 (existing) • New "OR" gate H137-CC-SAMA18: LOSS OF RHR A FLOW TO CSIP A SUCTION - NO CCW DEPENDENCY – RWST SUCTION Gate H137-CC-SAMA18 is used to simulate the fact that cooling flow is not needed when the suction is from the RWST. The suction source in the existing logic was changed from H137-CC to include the RWST as the suction source.
RHR-SUCTION-ALG (new): OPERATOR FAILS TO ALIGN RHR AS SUCTION SOURCE	Basic event representing the probability that the operators fail to align an RHR path to a CSIP suction header. Used for both makeup and seal injection. The same event is used for both divisions to force complete dependence between the trains. • Failure Probability = 1.0E-01
H137-CC-SAMA18 (new): LOSS OF RHR A FLOW TO CSIP A SUCTION - NO CCW DEPENDENCY- RWST SUCTION	New "OR" gate including the following input: • Basic event "HMV1RH25NN" (existing) • Basic Event "HCVCS775NN" (existing) • Basic Event "HMV1RH25TS" (existing) • Basic event "LPMRHA-2LS" (existing) • Basic event "HMV1RH25FN" (existing) • Basic event "HCCFSI/RHR" (existing) • "OR" gate "J1A35SA" (existing) • New "OR" gate "LPACSIP-CC-S18"
LPACSIP-CC-S18 (new): RHR PUMP A OR FLOWPATH TO CSIPs FAIL - NO CCW DEPENDENCY-RWST SCT	New "OR" gate including the following input: • Basic event "LCCFPA/B" (existing) • Basic event "LCCFRPA/B" (existing) • "OR" gate "#ISLOCA" (existing) • "OR" gate "L156" (existing) • "OR" gate "L092-CC" (existing) • "OR" gate "LMMRWSTA" (existing)

SAMA Number 18 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
H037 (existing): CSIP 'B' LOSES SUCTION FROM VCT FOLLOWED BY CSIP 'A' FROM RWST	Added new “OR” gate RHR-CSIPA1
RHR-CSIPA1 (new): RHR SUCTION SOURCE FAILS FOR A HEADER - NO VCT ISOLATION FAILURES	New “OR” gate including the following input: • Basic event “RHR-SUCTION-ALG” (new) • Basic event “OPER-42” (existing) • New “OR” gate “H137-CC-SAMA18”
H212 (existing): LOSS OF FLOW TO CSIP HEADER B FROM THE RWST	Added new “OR” gate RHR-CSIPB
RHR-CSIPB (new): RHR SUCTION SOURCE FAILS FOR B HEADER	New “OR” gate including the following input: • New basic event “RHR-SUCTION-ALG” • Gate H_VCT (existing): FAILURE TO CLOSE OF VCT ISOLATION VALVES • Basic event OPER-42 (existing) • New “OR” gate H167-CC-SAMA18: LOSS OF RHR B FLOW TO CSIP B SUCTION - NO CCW DEPENDENCY - RWST SUCTION Gate H167-CC-SAMA18 is used to simulate the fact that cooling flow is not needed when the suction is from the RWST. The suction source in the existing logic was changed from H167-CC to include the RWST as the suction source.
H167-CC-SAMA18 (new): LOSS OF RHR B FLOW TO CSIP B SUCTION - NO CCW DEPENDENCY - RWST SUCTION	New “OR” gate including the following input: • Basic event “LPMRHB-2LS” (existing) • Basic Event “HMV1RH63FN” (existing) • Basic Event “HMV1RH63TS” (existing) • Basic event “HCVCS776NN” (existing) • Basic event “HMV1RH63NN” (existing) • Basic event “HCCFSI/RHR” (existing) • “OR” gate “J1B35SB” (existing) • New “OR” gate “LPBCSIP-CC-S18”

SAMA Number 18 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
LPBCSIP-CC-S18 (new): RHR PUMP B OR FLOWPATH TO CSIPs FAIL - NO CCW DEPENDENCY- RWST SUCTION	New “OR” gate including the following input: • Basic event “LCCFPA/B” (existing) • Basic event “LCCFRPA/B” (existing) • “OR” gate “#ISLOCA” (existing) • “OR” gate “L156” (existing) • “OR” gate “L093-CC” (existing) • “OR” gate “LMMRWSTA” (existing)
H032 (existing): CSIP 'A' LOSES SUCTION FROM VCT FOLLOWED BY CSIP 'B' FROM RWST	Added new “OR” gate RHR-CSIPB1
RHR-CSIPB1 (new): RHR SUCTION SOURCE FAILS FOR B HEADER - NO VCT ISOLATION FAILURES	New “OR” gate including the following input: • Basic event “RHR-SUCTION-ALG” (new) • Basic event “OPER-42” (existing) • New “OR” gate “H167-CC-SAMA18”

These changes conservatively credit the use of this SAMA given RWST failure, which would preclude use of RHR for this application, but the impact is less than 10 percent of the reduction shown for the SAMA and it is not considered to impact the conclusions of the analysis.

The cost of implementation for this SAMA is based on multiple contributors, including:

- Procedure updates: $50,000 (CPL 2004)
- Training material/simulator logic update: $25,000 (estimate)
- Modification of interlocks to allow the suggested alignment: $50,000 (estimate)
- Analysis to validate the concept of the change and plant capability: $50,000 (estimate)

The total cost of implementation is $175,000. This cost is based on what are considered to be low end cost estimates for the components identified as part of the implementation process. The costs may be higher and there may be other contributors that are not accounted for here, such as the resources required to interface with the NRC.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	9.09E-06	28.68	$42,672
Percent Change	-1.6%	-1.0%	-0.8%

A further breakdown of this information is provided below according to release category.

SAMA 18 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	3.18E-09	1.05E-10	3.98E-07	2.18E-08	7.87E-09	3.54E-08	4.13E-08	4.59E-08	1.63E-07	6.37E-09	1.75E-07	6.31E-07	3.83E-07	9.56E-07	**2.87E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.62	0.23	1.91	**28.68**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$8	$0	$2,412	$83	$33	$418	$6	$23	$1,045	$53	$7,175	$25,871	$182	$5,363	**$42,672**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 18 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,474,114	$35,886	$175,000	-$139,114

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.6.18 SAMA NUMBER 19: REPLACE "A" AND "B" INSTRUMENT AIR COMPRESSORS WITH 100 PERCENT CAPACITY COMPRESSORS

Failure of the running compressor(s) when another compressor is in maintenance results in a Loss of IA initiating event. The remaining compressor can supply post trip IA loads, but not before the plant systems are challenged from the trip. Compressors "A" and "B" could be replaced with 100 percent capacity compressors so that loss of the running compressor does not result in an initiating event when one of the compressors is in maintenance.

In order to estimate the impact of this SAMA, the PRA model was modified to allow either the “A” or “B” air compressor to carry the balance of plant loads such that either the “A” or “B” compressor can be used to maintain the plant on-line and avoid a plant trip. The “C” compressor is a 100 percent capacity compressor and is already credited with this ability and no changes are required to that train.

The table below summarizes the fault tree changes that were made:

SAMA Number 19 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
A%T13-4 (existing): IA COMPRESSOR 1A OR 1B FAILS TO OPERATE OR FAILS TO SUPPLY BACKUP	Changed gate from an “OR” gate to an “AND” gate.

No plant specific cost estimate has been developed for this SAMA. The minimum implementation cost of a SAMA, which is assumed to be a procedural change at $50,000 (CPL 2004), has been used to reduce the resources required for this evaluation and to show that the SAMA would not be cost effective under any circumstances for HNP.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	9.10E-06	28.95	$42,996
Percent Change	-1.5%	-0.1%	-0.1%

A further breakdown of this information is provided below according to release category.

SAMA 19 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	3.13E-09	1.02E-10	3.96E-07	2.17E-08	8.04E-09	3.54E-08	4.37E-08	4.60E-08	1.61E-07	6.35E-09	1.75E-07	6.40E-07	3.73E-07	9.53E-07	**2.86E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk$_{SAMA}$	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.22	1.91	**28.95**
OECR$_{BASE}$	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR$_{SAMA}$	$8	$0	$2,400	$83	$34	$418	$7	$23	$1,032	$53	$7,175	$26,240	$177	$5,346	**$42,996**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 19 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,500,616	$9,384	$50,000	-$40,616

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.19 SAMA NUMBER 21: SWING 6.9KV AC EDG

While more cost effective solutions are believed to be available to address other HNP SBO conditions, failure of the TD AFW train leaves the plant without a decay heat removal source. The most effective means of restoring this function as well as primary side injection is considered to be the installation of a 6.9kV AC EDG that can be aligned to either AC division. The benefit of this change would be greatly enhanced if the EDG could be rapidly aligned from the MCR. This capability would allow the operators to reduce the risk of developing a seal LOCA when loss of AC power events interrupt seal cooling. The effectiveness of this SAMA would also be enhanced the following capabilities were incorporated into the SAMA design:

- Connections to both the “A” and “B” 6.9kV emergency AC buses so that either division could be powered by the EDG,
- Integrated radiators system for cooling so that no service water systems are required to be available to operate the EDG.

In order to estimate the impact of this SAMA, cutset changes were made to remove the types of failures that would typically be mitigated by the availability of a swing EDG. These changes include the elimination of all Loss of Offsite Power (LOOP) contributors, all loss of buss contributors, and all failure combinations including EDG “start” and “run” failures. This quantification strategy does not account for:

- The fact that LOOP events are conservatively deleted in which on-site AC power is available but core damage ensues due to other equipment failures,
- The fact that loss of bus events are conservatively deleted in which equipment failures on one division coupled with bus failures on the opposite division are deleted when AC power availability is not a critical issue.

It should be noted that this strategy does not account for the benefit that might be gained through the use of the swing EDG to address EDG support system failures in non-LOOP/loss of bus cases (those on-site power unavailability’s not characterized by the EDG “start” and “run” terms). These oversights are small in comparison to the major contributors to the EDG benefit that is captured by eliminating LOOP and Loss of Bus events and do not impact the conclusions of this evaluation. The following table summarizes the changes made to the cutset files:

SAMA Number 21 Cutset Changes

Basic Event ID and Description	Description of Change
%T5: LOSS OF OFFSITE POWER	Event probability changed from 1.72E-02 to 0.0 in the results cutsets.
PDGE1ASAFS:	Event probability changed from 6.28E-03 to 0.0 in the results cutsets.

SAMA Number 21 Cutset Changes

Basic Event ID and Description	Description of Change
PDGE1BSBFS:	Event probability changed from 6.28E-03 to 0.0 in the results cutsets.
PDGE1ASAFR:	Event probability changed from 3.49E-02 to 0.0 in the results cutsets.
PDGE1BSBFR:	Event probability changed from 3.49E-02 to 0.0 in the results cutsets.

Several different costs have been documented in the industry SAMA submittals for additional EDGs, including the Calvert Cliffs estimate of over $20 million (BGE 1998). This estimate included auto start and alignment capability and is likely at the high end of the installation cost spectrum. Browns Ferry provided a cost of implementation of $6 million in 2003 dollars (TVA 2003), which may be closer to the cost required for HNP. However, Calvert Cliffs also suggested the installation of a lower cost gas combustion turbine as an alternate AC source for $3,350,000. This cost is still greater than the HNP MMACR, but it has been used here in conjunction with a phase 2 analysis to quantify the AC power risk at HNP.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	9.24E-06	28.97	$43,030
SAMA Results	6.34E-06	27.16	$38,036
Percent Change	-31.4%%	-6.2%	-11.6%

A further breakdown of this information is provided below according to release category.

SAMA 21 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Freq. (/yr)$_{SAMA}$	3.20E-09	1.07E-10	1.51E-07	1.58E-08	8.11E-09	2.04E-08	4.37E-08	1.99E-08	1.62E-07	6.36E-09	1.75E-07	6.39E-07	3.92E-07	3.76E-07	**2.01E-06**

SAMA 21 Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Dose-Risk_{BASE}	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Dose-Risk_{SAMA}	0.01	0.00	0.33	0.02	0.02	0.07	0.02	0.02	0.36	0.02	5.44	19.87	0.23	0.75	**27.16**
OECR_{BASE}	$8	$0	$2,406	$83	$34	$418	$7	$23	$1,038	$53	$7,175	$26,240	$187	$5,358	**$43,030**
OECR_{SAMA}	$8	$0	$915	$61	$34	$241	$7	$10	$1,038	$53	$7,175	$26,199	$186	$2,109	**$38,036**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 21 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$3,510,000	$3,102,572	$407,428	$3,350,000	-$2,942,572

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.20 SAMA NUMBER 22: INSTALL UPPER LATERAL RESTRAINTS ON THE RHR HEAT EXCHANGERS

The seismic ruggedness of the heat exchangers could be improved through the installation of the restraints.

As discussed in Section E.5.1.6, no PRA based quantitative means are available to estimate the contributions of seismic contributors. For the purposes of this analysis, an approximation of the potential averted cost-risk associated with the RHR heat exchangers has been developed using the quantification strategy presented in Section E.5.1.7 and a set of general assumptions. The details of this approximation are provided below.

As discussed in Section E.5.1.7, 85 percent of the external events contributions were assumed to be due to fire events and 15 percent due to the remaining initiating event types, which include the following major categories:

- Seismic Events

- High Winds Events
- External Flooding Events
- Transportation and Nearby Facility Events

Given that no reliable quantitative means have been identified to determine the relative importance of these events for HNP, it is assumed that 100 percent of the non-fire external events contributions are due to seismic events. Given that the total external events contributions are assumed to be equivalent to the internal events, the total seismic based cost-risk would be $263,250 ($1,755,000 * 0.15 = $263,250).

Because a seismic margins analysis was performed for the IPEEE, no information is available about the relative contributions of the systems and components to the total seismic risk. While there may be many contributors to the risk profile, 25 percent of the total seismic risk is assumed to be attributable to the RHR heat exchangers, which corresponds to a cost-risk of $65,813 ($263,250 * 0.25 = $65,813). Assuming that the lateral restraints are 100 percent effective at preventing seismically induced failure, this is also the averted cost-risk for this SAMA.

The cost of this SAMA has been estimated to be $350,000 (PE 2006b).

The net value for this SAMA is the difference between the averted cost-risk and the cost of implementation. The following table summarizes these results:

SAMA Number 22 Net Value

Averted Cost-Risk	Cost of Implementation	Net Value
$65,813	$350,000	-$284,188

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.7 UNCERTAINTY ANALYSIS

Sensitivity cases were run for the following conditions to assess their impact on the overall SAMA evaluation:

- Use a real discount rate of 7 percent, instead of the 3 percent value used in the base case analysis.
- Use the 95th percentile PRA results in place of the mean PRA results.
- Use alternate MACCS2 input variables for selected cases.

E.7.1 REAL DISCOUNT RATE

A sensitivity study has been performed in order to identify how the conclusions of the SAMA analysis might change based on the value assigned to the real discount rate (RDR). The original RDR of 3 percent, which could be viewed as conservative, has been changed to 7 percent and the modified maximum averted cost-risk was re-calculated using the methodology outlined in Section E.4. The Phase 1 screening against the MMACR was re-examined using the revised MMACR to identify any SAMA candidates that could be screened from further analysis based on the premise that their costs of implementation exceeded all possible benefit. In addition, the Phase 2 analysis was re-performed using the 7 percent RDR.

Implementation of the 7 percent RDR reduced the MMACR by 27.6 percent compared with the case where a 3 percent RDR was used. This corresponds to a decrease in the MMACR from $3,510,000 to $2,540,000. The Phase 1 SAMA list was reviewed to determine if such a decrease in the MMACR would impact the disposition of any SAMAs. It was determined that only SAMA 21 could have been screened in the Phase 1 if an RDR of 7 percent were used in place of the 3 percent value.

The Phase 2 SAMAs are dispositioned based on PRA insights or detailed analysis. All of the PRA insights used to screen the SAMAs are still applicable given the use of the 7 percent real discount rate as the change only strengthens the factors used to screen them. The SAMA candidate screened based on these insights (SAMA 14) is considered to be addressed and is not investigated further.

The remaining Phase 2 SAMAs were dispositioned based on the results of a SAMA specific cost-benefit analysis. This step has been re-performed using the 7 percent real discount rate to calculate the net values for the SAMAs.

As shown below, the determination of cost effectiveness changed for one Phase 2 SAMA when the 7 percent RDR was used in lieu of 3 percent. However, the margin by which the SAMA becomes “not cost beneficial” is small and it does not mean that these SAMAs would be screened from consideration if a 7 percent real discount rate were applied in the SAMA analysis as other factors influence the decision making process, such as the 95th percentile sensitivity analysis.

Phase 2 Results Summary for 7 Percent RDR Sensitivity

SAMA ID	Cost of Implement-ation	Averted Cost-Risk (3 percent RDR)	Net Value (3 percent RDR)	Averted Cost- Risk (7 percent RDR)	Net Value (7 percent RDR)	Change in Cost Effective-ness?
SAMA 1	$1,000,000	$389,627	-$610,373	$288,390	-$711,610	No
SAMA 2	$200,000	$53,062	-$146,938	$38,478	-$161,522	No
SAMA 3	$565,000	$34,204	-$530,796	$26,330	-$538,670	No
SAMA 4	$150,000	$62,238	-$87,762	$46,450	-$103,550	No
SAMA 6	$150,000	$111,240	-$38,760	$81,844	-$68,156	No
SAMA 7	$1,700,000	$81,860	-$1,618,140	$62,312	-$1,637,688	No
SAMA 8	$300,000	$298,979	-$1,021	$222,637	-$77,363	No
SAMA 9	$70,000	$93,614	$23,614	$69,024	-$976	Yes
SAMA 10	$50,000	$11,222	-$38,778	$8,684	-$41,316	No
SAMA 11	$400,000	$8,604	-$391,396	$6,576	-$393,424	No
SAMA 12	$275,000	$60,584	-$214,416	$44,492	-$230,508	No
SAMA 13	$225,000	$111,148	-$113,852	$81,720	-$143,280	No
SAMA 15	$250,000	$93,974	-$156,026	$69,190	-$180,810	No
SAMA 16	$400,000	$6,048	-$393,952	$4,626	-$395,374	No
SAMA 17	$500,000	$52,820	-$447,180	$38,426	-$461,574	No
SAMA 18	$175,000	$35,886	-$139,114	$26,128	-$148,872	No
SAMA 19	$50,000	$9,384	-$40,616	$7,134	-$42,866	No
SAMA 21	$3,350,000	$407,428	-$2,942,572	$300,230	-$3,049,770	No
SAMA 22	$350,000	$65,813	-$284,188	$47,625	-$302,375	No

E.7.2 95TH PERCENTILE PSA RESULTS

The results of the SAMA analysis can be impacted by implementing conservative values from the PRA's uncertainty distribution. If the best estimate failure probability values were consistently lower than the "actual" failure probabilities, the PRA model would underestimate plant risk and yield lower than "actual" averted cost-risk values for potential SAMAs. Re-assessing the cost benefit calculations using the high end of the failure probability distributions is a means of identifying the impact of having consistently underestimated failure probabilities for plant equipment and operator actions included in the PRA model. This sensitivity uses the 95th percentile results to examine the impact of uncertainty in the PRA model.

For HNP, the UNCERT32 software code was used to perform the Level 1 internal events model uncertainty analysis. The results of the calculation are provided below:

PARAMETER	VALUE
Mean	9.42E-06
5 percent	6.46E-06
50 percent	8.87E-06
95 percent	1.38E-05
Standard Deviation	3.66E-06

The PRA uncertainty calculation identifies the 95th percentile CDF as 1.38E-05 per year. This is a factor of 1.5 greater than the CDF point estimate produced by the HNP PRA (9.24E-06).

E.7.2.1 PHASE I IMPACT

For Phase I screening, use of the 95th percentile PRA results will increase the MMACR and may prevent the screening of some of the higher cost modifications. However, the impact on the overall SAMA results due to the retention of the higher cost SAMAs for Phase II analysis is typically small. This is due to the fact that the benefit gleaned from the implementation of those SAMAs must be extremely large in order to be cost beneficial.

The impact of uncertainty in the PRA results on the Phase I SAMA analysis has been examined. The MMACR is the primary Phase I criteria affected by PRA uncertainty. Thus, this portion of this sensitivity is focused on recalculating the MMACR using the 95th percentile PRA results and re-performing the Phase I screening process.

As discussed above, the 95th PRA results are approximately a factor of 1.5 greater than point estimate CDF. The uncertainty analyses that are available for the Level 1 models are not available for Level 2 and 3 PRA models. In order to simulate the use of the 95th percentile results for the Level 2 and 3 models, the same scaling factor calculated for the Level 1 results was assumed to apply to the Level 2 and 3 models. Because the MMACR calculations scale linearly with the CDF, dose-risk, and offsite economic cost-risk, the 95th percentile MMACR can be calculated by multiplying the base case MMACR by 1.5. This results in a 95th percentile MMACR of $5,265,000.

The initial SAMA list has been re-examined using the revised MMACR to identify SAMAs that would be retained for the Phase 2 analysis. Those SAMAs that were previously screened due to costs of implementation that exceeded $3.51 million are now retained if the costs of implementation are less than about $5.26 million. Of the SAMAs screened in the Phase 1 analysis, only SAMA 20 would be retained based on the use of the 95th percentile MMACR. However, the $5 million implementation cost estimate for SAMA 20 is 95 percent of the MMACR. This implies that the SAMA would only be cost beneficial if it could eliminate 95 percent of the MMACR, which is not possible for a high pressure injection system that does not at least include a dedicated power source, heat removal capability, and a means of addressing long term SGTR and ISLOCA cases. In addition, the $5 million implementation cost represents the low end of the implementation cost estimate range for SAMA 20 and the actual implementation cost would likely exceed the $5.26 million MMACR. SAMA 20 is not investigated further.

E.7.2.2 PHASE II IMPACT

As mentioned above, the 95th percentile PRA results are not available for the Level 2 and 3 models. In order to estimate the impact of using the 95th percentile PRA results in the Phase 2 SAMA analysis, the same process used to calculate the revised MMACR was applied to each of the Phase 2 SAMAs (the averted cost-risk for each SAMA was increased by a factor of 1.5 over the base case).

The following table provides a summary of the impact of using the 95th percentile PSA results in the detailed cost-benefit calculations that have been performed.

Results Summary for the 95th Percentile PSA Results

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
SAMA 1	$1,000,000	$389,627	-$610,373	$584,441	-$415,560	No
SAMA 2	$200,000	$53,062	-$146,938	$79,593	-$120,407	No
SAMA 3	$565,000	$34,204	-$530,796	$51,306	-$513,694	No
SAMA 4	$150,000	$62,238	-$87,762	$93,357	-$56,643	No
SAMA 6	$150,000	$111,240	-$38,760	$166,860	$16,860	Yes
SAMA 7	$1,700,000	$81,860	-$1,618,140	$122,790	-$1,577,210	No
SAMA 8	$300,000	$298,979	-$1,021	$448,469	$148,469	Yes
SAMA 9	$70,000	$93,614	$23,614	$140,421	$70,421	No
SAMA 10	$50,000	$11,222	-$38,778	$16,833	-$33,167	No
SAMA 11	$400,000	$8,604	-$391,396	$12,906	-$387,094	No
SAMA 12	$275,000	$60,584	-$214,416	$90,876	-$184,124	No
SAMA 13	$225,000	$111,148	-$113,852	$166,722	-$58,278	No
SAMA 15	$250,000	$93,974	-$156,026	$140,961	-$109,039	No
SAMA 16	$400,000	$6,048	-$393,952	$9,072	-$390,928	No
SAMA 17	$500,000	$52,820	-$447,180	$79,230	-$420,770	No
SAMA 18	$175,000	$35,886	-$139,114	$53,829	-$121,171	No
SAMA 19	$50,000	$9,384	-$40,616	$14,076	-$35,924	No
SAMA 21	$3,350,000	$407,428	-$2,942,572	$611,142	-$2,738,858	No
SAMA 22	$350,000	$65,813	-$284,188	$98,719	-$251,281	No

Of the SAMAs classified as “not cost beneficial” in the baseline Phase 2 analysis, two SAMAs (SAMAs 6 and 8) were found to be cost beneficial when the 95th percentile PRA results were applied. The use of the 95th percentile PRA results is not considered to provide the most realistic assessment of the cost effectiveness of a SAMA; however, these additional SAMAs could be considered for implementation to address the uncertainties inherent in the SAMA analysis.

E.7.3 MACCS2 INPUT VARIATIONS

The MACC2 model was developed using the best information available for the HNP site; however, reasonable changes to modeling assumptions can lead to variations in the Level 3 results. In order to determine how certain assumptions could impact the SAMA results, a sensitivity analysis was performed on a group of parameters that has previously been shown to impact the Level 3 results. These parameters include:

- Meteorological data
- Radionuclide release height
- Population estimates
- Evacuation effectiveness

The risk metrics produced by MACCS2 that are evaluated in the sensitivity analyses are the 50 mile population dose and the 50 mile offsite economic cost. The subsections below discuss the changes in these results for each of the sensitivity cases identified above. The final subsection, E.7.3.7, correlates the worst case changes identified in the sensitivity runs to a change in the site's averted cost-risk and discusses the implications of the sensitivity analysis on the SAMA analysis. The following table summarizes the results of the HNP MACCS2 outputs for the sensitivity cases analyzed:

Case	Description	Pop. Dose Risk Δ Base	Cost Risk Δ Base
Base Case	Base Case (Year 2003 meteorological (MET) data)	--	--
MET2005	Use of Year 2005 MET data in place of 2003 data	-6.78 (-23.4%)	-$9,871 (-22.9%)
Elevated Release	Release height set to 66 meters (plant stack)	+4.63 (+16.0%)	+$5,230 (+12.2%)
1.3POP+Elevated Release	Year 2040 population values increased uniformly by a factor of 1.3 over base case with all releases at 66 meters.	+14.45 (+49.9%)	+$19,700 (45.8%)
50EVAC+Elevated Release	Evacuation speed decreased by 50% with all releases at 66 meters	+14.02 (48.4%)	+$5,230 (+12.2%)

E.7.3.1 Meteorological Sensitivity

In addition to the base case meteorological data (year 2003), data was also available for the years 2001, 2002, 2004, and 2005. As no particular criteria have been defined by the industry related to determining which meteorological data set should be used as a base case for a site, the year 2003 data was conservatively chosen for HNP given that it yielded the highest dose and offsite economic costs.

Of the remaining data sets, year 2005 data yielded the lowest dose and offsite economic costs. This data was chosen for this sensitivity in order to show the maximum variation is results based on weather changes over the years for which data was available. The results of the analysis show that use of the 2005 data reduces the dose by 23.4 percent and the offsite economic cost by 22.9 percent. These are non-negligible changes that indicate the results of the SAMA analysis could be influenced by the choice of meteorological data. As stated above, the HNP analysis incorporated the most conservative data set available. This maximized the benefits shown for each SAMA.

E.7.3.2 Radioactive Release Height Sensitivity

This sensitivity case quantifies the impact of the assumptions related to the height of the release. This sensitivity case assumes that all HNP releases occur from the top of the plant stack (66 meters) rather than at ground level.

The ground level release was used as the base case for the HNP SAMA analysis as the largest contributors to the release consequences are SGTR and ISLOCA events, which do not release through the plant stack. Some ambiguity exists for the treatment of the SGTR scenarios as the steam generator PORV release points are on the Reactor Auxiliary Building roof rather than at the foot of the building, but the ground level release is considered to be more representative of the HNP conditions than a stack release.

The results of this analysis show that use of a higher release height increases the dose-risk by 16.0 percent and the OECR by 12.2 percent.

E.7.3.3 Population Sensitivity (with elevated release)

Because there is some ambiguity in the treatment of the SGTR releases for HNP, the population sensitivity was performed in conjunction with the elevated release height sensitivity to show the combined impact of the two variables. The results demonstrate a significant dependence on population estimates, which was expected given that the population dose and offsite economic costs are primarily driven by the regional population.

Use of the 66 meter release height and a uniform 30 percent increase in the population over all sectors in the 50 mile increased the estimated population dose-risk by 49.9 percent over the base case. Similarly, the offsite economic cost-risk increased 45.8 percent over the base case.

The impact of population estimate variations on the results can be isolated from the impact of elevation height changes by comparing the results of the “population and elevation” sensitivity case to the “elevation” sensitivity case. It can be seen that a 30 percent increase in population corresponds to approximately the same change in the dose-risk and OECR (increases of over 33 percent each).

E.7.3.4 Evacuation Sensitivity

Because there is some ambiguity in the treatment of the SGTR releases for HNP, the evacuation sensitivity was performed in conjunction with the elevated release height sensitivity to show the combined impact of the two variables.

The evacuation sensitivity case demonstrates significant population dose-risk impacts associated with evacuation assumptions due to the relatively high population impacted by evacuation effects. While evacuation assumptions can impact the population dose-risk estimates, they do not impact MACCS2 offsite economic cost-risk estimates because MACCS2 calculated cost-risks are based on land contamination levels which remain unaffected by evacuation assumptions and the number of people evacuating.

For HNP, reducing the evacuation speed from 1.2 meters per second to 0.6 meters per second in conjunction with an elevated release height increased the dose-risk over the base case by 48.4 percent while the increase in the OECR was only 12.2 percent. The total percent choosing to evacuate (95 percent) is not impacted by this sensitivity case.

The impact of evacuation speed variations on the results can be isolated from the impact of elevation height changes by comparing the results of the "evacuation and elevation" sensitivity case to the "elevation" sensitivity case. It can be seen that a 50 percent reduction in evacuation speed increases the dose-risk by 32.4 percent. OECR is not impacted (0.0 percent change) as the evacuation speed does not impact the interaction of the release with the land.

E.7.3.5 Impact on SAMA Analysis

Several different Level 3 input parameters have been examined as part of the HNP MACCS2 sensitivity analysis. The primary reason for performing these sensitivity runs was to identify any reasonable changes that could be made to the Level 3 input parameters that would impact the conclusions of the SAMA analysis. While the table in Section E.7.3 summarizes the changes to the dose-risk and OECR estimates for each sensitivity case, it was necessary to determine if any of these changes would result in the retention of the SAMAs that were screened using the baseline results.

Of all the MACCS2 sensitivity cases, the largest increase in both dose-risk and OECR was shown in case "1.3POP+Elevated Release" (49.9 and 45.8 percent, respectively). The HNP MMACR was recalculated using these results to determine the impact of using the worst case for each parameter simultaneously. The resulting MMACR was $4,972,146, which is less than $5,265,000 calculated in Section E.7.2 for the 95th percentile PRA results. The 95th percentile PRA results sensitivity is considered to bound this case and no SAMAs would be retained based on this sensitivity that were not already identified in Section E.7.2.

E.8 CONCLUSIONS

The benefits of revising the operational strategies in place at HNP and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. Use of the PRA in conjunction with cost-benefit analysis methodologies has, however, provided an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on offsite dose and economic impacts. The results of this study indicate that of the identified potential improvements that can be made at HNP, three are cost beneficial based on the methodology applied in this analysis and the cost estimates that have been developed for the SAMA analysis.

The baseline Phase II analysis indicates that the following SAMA has a positive net value:

- SAMA 9: Proceduralize Actions to Open EDG Room Doors on Loss of HVAC and Implement Portable Fans

SAMA 9 is an inexpensive change that would provide a means of mitigating loss of EDG HVAC scenarios. It is not likely that alternate EDG room cooling would be required during the life of the plant to prevent core damage, but the proposed procedure change provides a low cost, viable strategy for addressing the loss of a critical system in an accident scenario. It is recommended that this SAMA be considered for implementation at HNP.

The 95th percentile PRA results show that the following additional SAMAs are cost beneficial:

- SAMA 6: Flood Mitigation for Scenarios 6 and 7
- SAMA 8: Alternate Seal Cooling and Direct Feed to Transformer 1B3-SB

SAMA 6 requires minor changes to two motor operated valves that are located in an area identified as a potential flooding risk for HNP. Discussions with the HNP MOV engineer indicate that valves 1SW-274 and 275 are likely to function in their current configuration in the conditions that would be present in the relevant flooding scenarios; however, confidence in the capabilities of these valves could be increased by waterproofing the motor operators. This is a relatively low cost change that should be considered for implementation.

SAMA 8 is a combination of two changes to address specific evolutions resulting from vital 6.9kV AC bus failures. While the frequency of such events may be the subject of continuing analysis, the consequences are well defined and the proposed plant changes could reduce the likelihood of core damage in those circumstances for a relatively low cost. While there are some core damage scenarios resulting from bus failures that are not addressed by this SAMA, no single, potentially cost effective means of addressing all of the bus failure scenarios has been identified. It is suggested that this SAMA be considered for potential implementation.

In summary, three relatively low cost SAMAs (SAMAs 6, 8, and 9) have been identified as cost beneficial and are suggested for potential implementation at HNP. While these results are believed to accurately reflect potential areas for improvement at the plant, PE notes that this analysis should not necessarily be considered a formal disposition of these proposed changes as other engineering reviews are necessary to determine the ultimate resolution. PE will consider the three SAMAs (6, 8 and 9) identified in the analysis using the appropriate HNP design process.

E.9 FIGURES

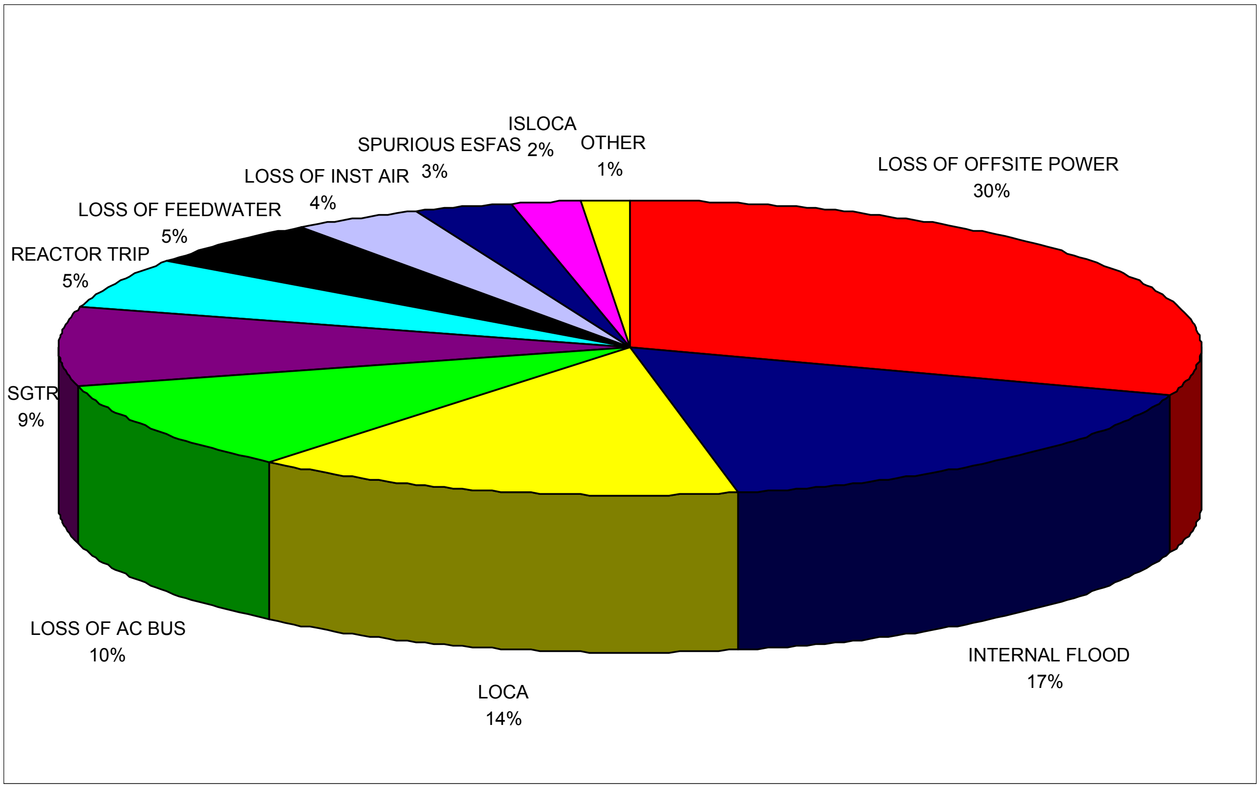


Figure E.2-1
Contribution to CDF by Initiator

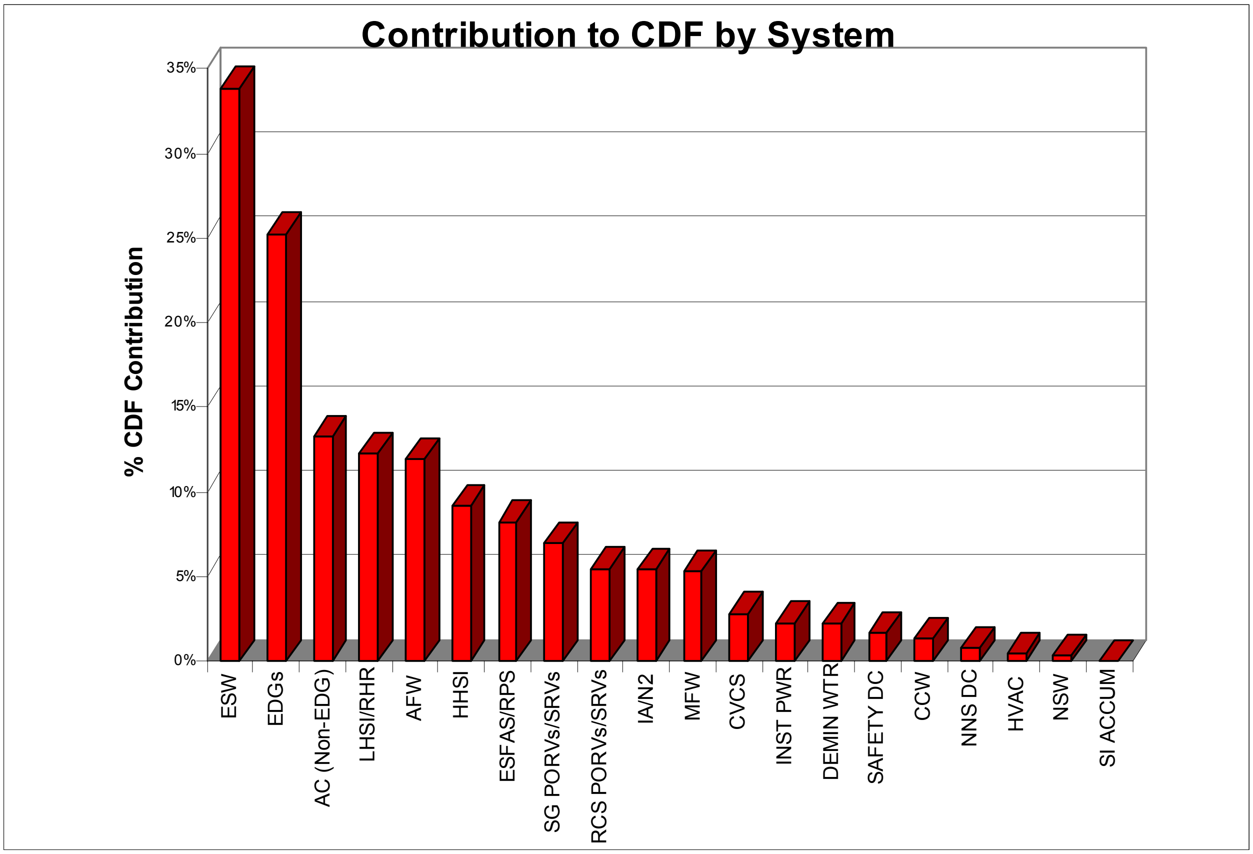


Figure E.2-2
Contribution to CDF by System

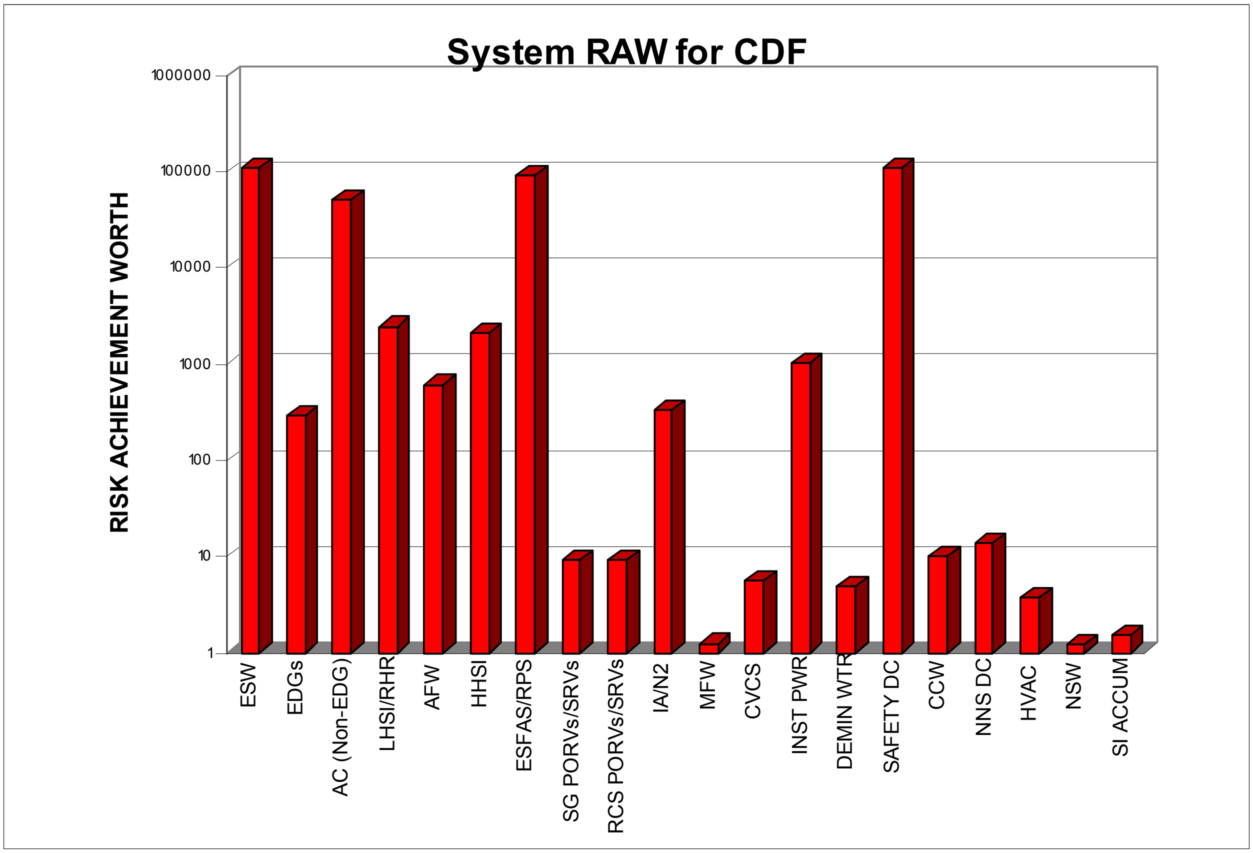


Figure E.2-3
System RAW for CDF

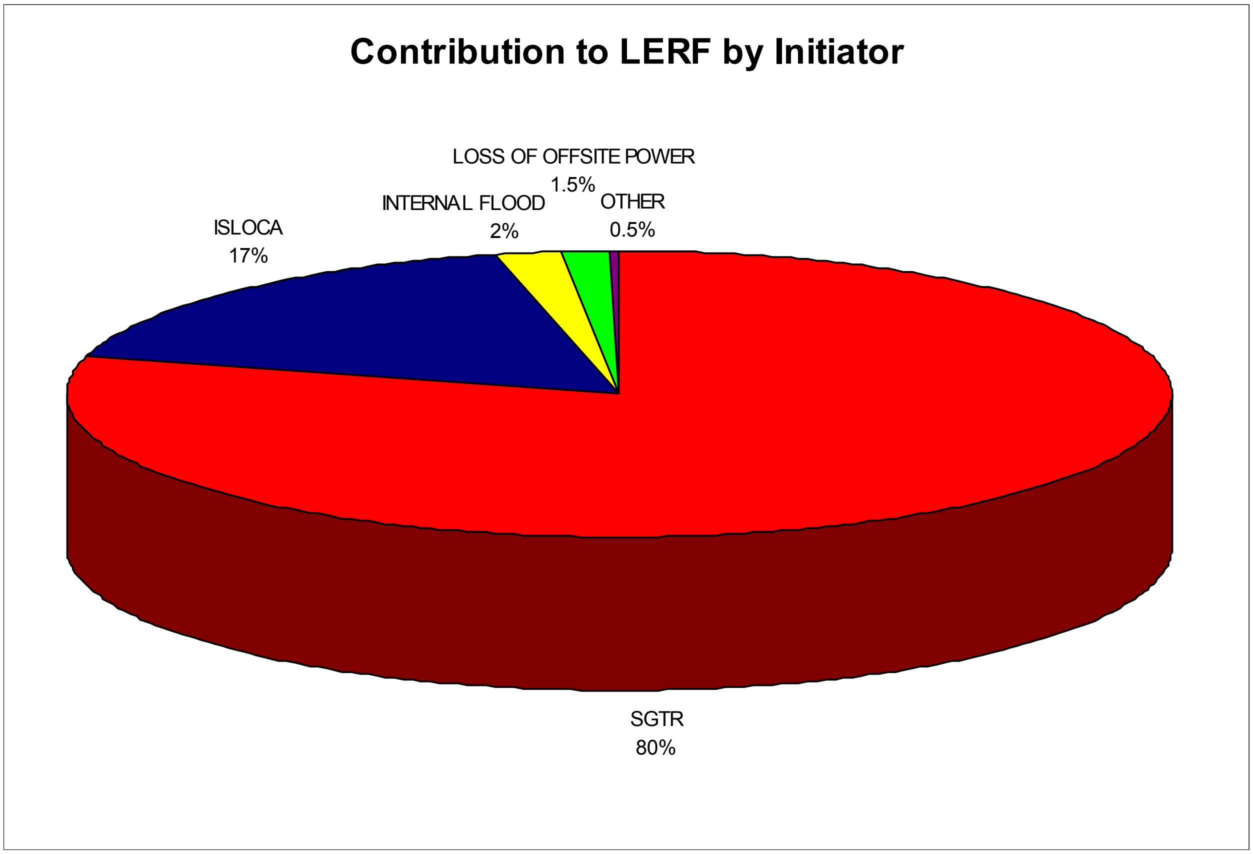


Figure E.2-4
Contribution to LERF by Initiator

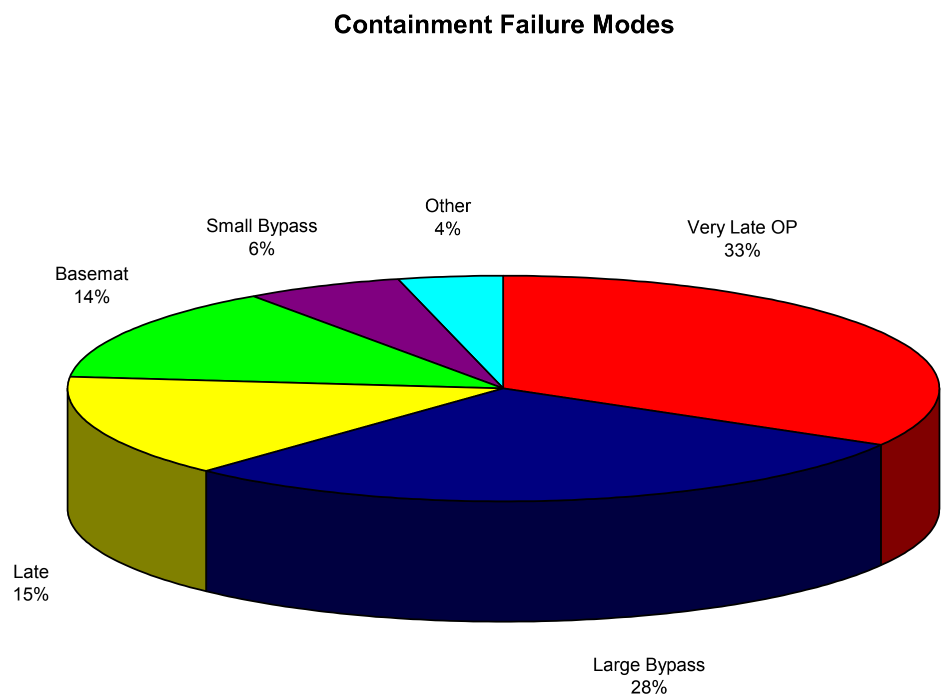


Figure E.2-5
Containment Failure Modes

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E.10 TABLES

TABLE E.3-1
HNP POPULATION PROJECTION FOR 2040

Radius (miles)	Direction	2040 Projected Population	Radius (miles)	Direction	2040 Projected Population
1	N	0	4	N	916
1	NNE	0	4	NNE	1265
1	NE	0	4	NE	370
1	ENE	0	4	ENE	48
1	E	0	4	E	48
1	ESE	0	4	ESE	250
1	SE	0	4	SE	67
1	SSE	0	4	SSE	41
1	S	0	4	S	46
1	SSW	0	4	SSW	57
1	SW	0	4	SW	219
1	WSW	0	4	WSW	49
1	W	0	4	W	373
1	WNW	0	4	WNW	205
1	NW	0	4	NW	764
1	NNW	0	4	NNW	246
2	N	183	5	N	758
2	NNE	5	5	NNE	611
2	NE	82	5	NE	1020
2	ENE	10	5	ENE	188
2	E	82	5	E	784
2	ESE	14	5	ESE	784
2	SE	34	5	SE	591
2	SSE	38	5	SSE	92
2	S	14	5	S	49
2	SSW	29	5	SSW	67
2	SW	24	5	SW	24
2	WSW	28	5	WSW	143
2	W	697	5	W	197

TABLE E.3-1
HNP POPULATION PROJECTION FOR 2040

Radius (miles)	Direction	2040 Projected Population	Radius (miles)	Direction	2040 Projected Population
2	WNW	32	5	WNW	262
2	NW	751	5	NW	70
2	NNW	3343	5	NNW	259
3	N	135	10	N	4260
3	NNE	957	10	NNE	49062
3	NE	390	10	NE	75426
3	ENE	231	10	ENE	45272
3	E	43	10	E	46676
3	ESE	58	10	ESE	54863
3	SE	67	10	SE	9384
3	SSE	94	10	SSE	3236
3	S	62	10	S	1204
3	SSW	36	10	SSW	1749
3	SW	29	10	SW	665
3	WSW	55	10	WSW	2432
3	W	38	10	W	4130
3	WNW	124	10	WNW	1277
3	NW	72	10	NW	1620
3	NNW	180	10	NNW	1455

TABLE E.3-1
HNP POPULATION PROJECTION FOR 2040

Radius (miles)	Direction	2040 Projected Population	Radius (miles)	Direction	2040 Projected Population
20	N	63726	50	N	23029
20	NNE	114528	50	NNE	167
20	NE	501058	50	NNE	25319
20	ENE	359418	50	NNE	30
20	E	124078	50	NNE	752
20	ESE	68771	50	NE	52609
20	SE	34894	50	NE	1567
20	SSE	21200	50	NE	2539
20	S	13579	50	ENE	26740
20	SSW	17217	50	ENE	3651
20	SW	41129	50	ENE	14062
20	WSW	13226	50	ENE	4324
20	W	5488	50	E	56009
20	WNW	14121	50	E	1023
20	NW	13520	50	E	597
20	NNW	85620	50	E	7049
30	N	301634	50	ESE	45331
30	NNE	115391	50	ESE	143
30	NE	777763	50	ESE	5584
30	ENE	497397	50	SE	1984
30	E	158868	50	SE	17617
30	ESE	78417	50	SE	129
30	SE	86329	50	SSE	28852
30	SSE	18044	50	S	130904
30	S	47024	50	S	95448
30	SSW	35450	50	S	12039
30	SW	18453	50	SSW	99659
30	WSW	5645	50	SSW	12
30	W	16475	50	SW	5111
30	WNW	26273	50	SW	965

TABLE E.3-1
HNP POPULATION PROJECTION FOR 2040

Radius (miles)	Direction	2040 Projected Population	Radius (miles)	Direction	2040 Projected Population
30	NW	15055	50	SW	61301
30	NNW	79892	50	SW	535
40	N	53216	50	SW	24
40	NNE	49785	50	WSW	3350
40	NE	149869	50	WSW	13628
40	ENE	146524	50	WSW	23
40	E	123631	50	W	1438
40	ESE	112108	50	W	1025
40	SE	46540	50	W	78390
40	SSE	16317	50	WNW	20386
40	S	207173	50	WNW	32554
40	SSW	12626	50	NW	85430
40	WSW	15063	50	NW	56104
40	W	15346	50	NNW	7168
40	WNW	27865	50	NNW	4509
40	NW	76313	50	NNW	3577
40	NNW	55589	50	NNW	1176

TABLE E.3-2
HNP RELEASE DATA

HNP Source Term	Release Category[1]						
	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3
Bin Frequency	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08
MAAP Run	H13A1BX	H9A1AX	HRC1B	(2)	HRC2	HRC22	H13A4
Run Duration	70 hr	96 hr	48 hr	48 hr	11 hr	9 hr	13 hr
Time after Scram when General Emergency is declared in hours (4)	5.00E-01	6.10E+00	5.00E-01	5.00E-01	1.70E+00	2.00E-01	6.50E+00
Fission Product Group:							
1) Noble							
Total Release Fraction	9.20E-01	2.20E-03	1.00E+00	2.20E-03	4.20E-01	7.60E-01	1.00E+00
Start of Release (hr)	61.00	6.60	32.00	6.60	6.30	0.50	8.50
End of Release (hr)	61.00	96.00	32.00	96.00	6.30	9.00	48 (4)
2) CsI							
Total Release Fraction	1.62E-03	1.80E-06	1.30E-02	1.80E-06	8.50E-03	6.60E-02	9.20E-04
Start of Release (hr)	61.00	6.60	32.00	6.60	6.30	0.50	8.50
End of Release (hr)	61.00	40.00	40.00	40.00	6.30	9.00	13.00
3) TeO2							
Total Release Fraction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Release (hr)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
End of Release (hr)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4) SrO							
Total Release Fraction	2.00E-07	6.50E-10	2.00E-07	2.10E-04	1.00E-07	4.00E-05	5.00E-07
Start of Release (hr)	61.00	6.60	32.00	46.00	6.30	0.50	8.50
End of Release (hr)	61.00	20.00	32.00	46.00	6.30	4.00	11.00
5) MoO2							
Total Release Fraction	1.20E-08	1.60E-09	2.40E-07	1.30E-02	5.00E-06	2.00E-05	3.00E-07
Start of Release (hr)	61.00	6.60	32.00	46.00	6.30	0.50	8.50
End of Release (hr)	61.00	6.60	32.00	46.00	6.30	4.00	10.00

TABLE E.3-2
HNP RELEASE DATA

HNP Source Term	Release Category[1]						
	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3
6) CsOH							
Total Release Fraction	5.50E-03	1.70E-06	1.90E-02	1.70E-06	1.00E-02	5.50E-02	9.00E-04
Start of Release (hr)	61.00	6.60	32.00	6.60	6.30	0.50	8.50
End of Release (hr)	61.00	40.00	40.00	40.00	6.30	9.00	13.00
7) BaO							
Total Release Fraction	1.60E-06	3.00E-09	1.20E-06	1.40E-03	1.00E-06	2.70E-04	4.00E-06
Start of Release (hr)	61.00	6.60	32.00	46.00	6.30	0.50	8.50
End of Release (hr)	61.00	6.60	32.00	46.00	6.30	4.00	11.00
8) La2O3							
Total Release Fraction	2.00E-09	1.00E-11	4.00E-09	6.00E-08	1.00E-09	3.00E-07	5.00E-09
Start of Release (hr)	61.00	6.60	32.00	46.00	6.30	0.50	8.50
End of Release (hr)	61.00	20.00	32.00	46.00	6.30	4.00	11.00
9) CeO2							
Total Release Fraction	2.00E-09	1.00E-10	4.00E-09	8.00E-07	1.00E-09	9.00E-07	5.00E-09
Start of Release (hr)	61.00	15.00	32.00	46.00	6.30	0.50	8.50
End of Release (hr)	61.00	15.00	32.00	46.00	6.30	4.00	11.00
10) Sb							
Total Release Fraction	1.50E-02	2.00E-07	2.00E-03	1.70E-02	4.60E-04	2.20E-02	1.00E-04
Start of Release (hr)	61.00	6.60	32.00	46.00	6.30	0.50	8.50
End of Release (hr)	61.00	40.00	40.00	46.00	6.30	9.00	11.00
11) Te2							
Total Release Fraction	0.00E+00	4.00E-08	0.00E+00	8.00E-04	0.00E+00	3.30E-04	2.00E-08
Start of Release (hr)	0.00	15.00	0.00	46.00	0.00	1.50	11.00
End of Release (hr)	0.00	15.00	0.00	46.00	0.00	4.00	11.00
12) UO2							
Total Release Fraction	0.00E+00	4.00E-13	0.00E+00	1.00E-09	0.00E+00	1.70E-09	1.00E-13
Start of Release (hr)	0.00	15.00	0.00	46.00	0.00	1.50	11.00
End of Release (hr)	0.00	15.00	0.00	46.00	0.00	4.00	11.00

TABLE E.3-2
HNP RELEASE DATA

HNP Source Term	Release Category[1]						
	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7
Bin Frequency	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07
MAAP Run	HRC3B	HRC4	HRC4C2	H16B1	H16B1	(3)	H1P5
Run Duration	8 hr	17 hr	48 hr	48 hr	48 hr	48 hr	48 hr
Time after Scram when General Emergency is declared in hours (4)	5.30E+00	9.90E+00	3.30E+00	3.90E+00	3.90E+00	5.30E+00	5.30E+00
Fission Product Group:							
1) Noble							
Total Release Fraction	1.00E+00	5.20E-01	4.60E-01	1.00E+00	1.00E+00	1.00E+00	1.00E+00
Start of Release (hr)	6.20	13.00	4.20	4.70	4.70	46.00	46.00
End of Release (hr)	24 (4)	17.00	4.20	4.70	4.70	46.00	46.00
2) CsI							
Total Release Fraction	1.90E-03	1.90E-02	2.40E-02	7.80E-01	7.80E-01	2.10E-04	2.10E-03
Start of Release (hr)	6.20	13.00	4.20	4.70	4.70	46.00	46.00
End of Release (hr)	8.00	15.00	4.20	4.70	4.70	46.00	46.00
3) TeO2							
Total Release Fraction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Release (hr)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
End of Release (hr)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4) SrO							
Total Release Fraction	3.00E-07	3.60E-06	3.00E-06	1.00E-01	1.00E-01	2.10E-05	2.10E-04
Start of Release (hr)	6.20	13.00	4.20	4.70	4.70	46.00	46.00
End of Release (hr)	8.00	15.00	4.20	48.00	48.00	46.00	46.00
5) MoO2							
Total Release Fraction	8.00E-07	1.00E-07	1.60E-05	4.10E-01	4.10E-01	1.30E-03	1.30E-02
Start of Release (hr)	6.20	13.00	4.20	8.00	8.00	46.00	46.00
End of Release (hr)	8.00	15.00	4.20	20.00	20.00	46.00	46.00

TABLE E.3-2
HNP RELEASE DATA

HNP Source Term	Release Category[1]						
	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7
6) CsOH							
Total Release Fraction	1.90E-03	1.60E-02	2.10E-02	8.10E-01	8.10E-01	6.30E-04	6.30E-03
Start of Release (hr)	6.20	13.00	4.20	4.70	4.70	46.00	46.00
End of Release (hr)	8.00	15.00	4.20	4.70	4.70	46.00	46.00
7) BaO							
Total Release Fraction	2.00E-06	2.00E-05	2.00E-05	4.10E-01	4.10E-01	1.40E-04	1.40E-03
Start of Release (hr)	6.20	13.00	4.20	8.00	8.00	46.00	46.00
End of Release (hr)	8.00	15.00	4.20	48.00	48.00	46.00	46.00
8) La2O3							
Total Release Fraction	3.00E-09	4.00E-08	1.30E-05	1.90E-03	1.90E-03	6.00E-09	6.00E-08
Start of Release (hr)	6.20	13.00	4.20	8.00	8.00	46.00	46.00
End of Release (hr)	8.00	15.00	4.20	48.00	48.00	46.00	46.00
9) CeO2							
Total Release Fraction	3.00E-09	4.00E-08	1.00E-04	1.90E-03	1.90E-03	8.00E-08	8.00E-07
Start of Release (hr)	6.20	13.00	4.20	8.00	8.00	46.00	46.00
End of Release (hr)	8.00	15.00	4.20	48.00	48.00	46.00	46.00
10) Sb							
Total Release Fraction	1.10E-04	1.40E-03	6.60E-03	6.10E-01	6.10E-01	1.70E-03	1.70E-02
Start of Release (hr)	6.20	13.00	4.20	8.00	8.00	46.00	46.00
End of Release (hr)	8.00	15.00	4.20	10.00	10.00	46.00	46.00
11) Te2							
Total Release Fraction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.00E-05	8.00E-04
Start of Release (hr)	0.00	0.00	0.00	0.00	0.00	46.00	46.00
End of Release (hr)	0.00	0.00	0.00	0.00	0.00	46.00	46.00
12) UO2							
Total Release Fraction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.00E-10	1.00E-09
Start of Release (hr)	0.00	0.00	0.00	0.00	0.00	46.00	46.00
End of Release (hr)	0.00	0.00	0.00	0.00	0.00	46.00	46.00

TABLE E.3-2
HNP RELEASE DATA

HNP Source Term	Release Category[1]						
	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7

(1) Puff releases are denoted in the table by those entries with equivalent start and end times.

(2) Use volatiles from H9A1AX and non-volatiles from H1P5 - Ref. Section 9: Release Category & LERF Development, RCS 01-05

(3) Use H1P5 (i.e.RC-7) with releases reduced by a factor of 10 - Ref. Section 9: Release Category & LERF Development, RCS 01-05

(4) Assumed to be onset of core damage, Ref. Harris Nuclear Plant Emergency Action Level Flow Path, Rev 05-1

TABLE E.3-3
RESULTS OF HNP LEVEL 3 PSA ANALYSIS

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Release Category Frequency (/yr)	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07	**2.89E-06**
Conditional Dose within 50 miles (Sv)	1.64E+04	2.08E+01	2.17E+04	1.25E+04	2.17E+04	3.51E+04	5.13E+03	9.11E+03	2.23E+04	3.01E+04	3.11E+05	3.11E+05	5.99E+03	2.00E+04	**Not Used**
Dose-Risk within 50 miles (person-rem)	0.01	0.00	0.86	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.44	19.90	0.24	1.91	**28.97**
Conditional Cost within 50 miles ($)	2.58E+09	1.40E-01	6.06E+09	3.83E+09	4.17E+09	1.18E+10	1.56E+08	5.01E+08	6.41E+09	8.27E+09	4.10E+10	4.10E+10	4.75E+08	5.61E+09	**Not Used**
Cost-Risk within 50 miles ($)	8	0	2,406	83	34	418	7	23	1,038	53	7,175	26,240	187	5,358	**$43,030**

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
X-CNDSL	1.00E+00	1.486	CONDITIONAL SEAL LOCA PROBABILITY GIVEN THE RCP ARE TRIPPED	The largest contributors to seal LOCAs for HNP are sequences where an SBO leads to a loss of seal cooling. A means of providing seal injection in an SBO could be provided using the plant hydrostatic test pump with a 480V AC generator. The capability to rapidly align this pump for seal cooling is integral to limiting the size of the seal LOCA. Permanently installing the hydrostatic test pump and the supporting generator with control capability in the main control room is a potential way to provide this capability (SAMA 1).
%T5	1.72E-02	1.432	LOSS OF OFFSITE POWER	The importance of the LOOP event provides limited information about plant risk given that the LOOP category is broad and includes several different contributors. These contributors are typically represented by other events in this importance list that better define specific failures that can be investigated to identify means of reducing plant risk; however, there is a particular issue at HNP that could impact the LOOP frequency. The requirement for breakers to re-align to provide ESF power after a plant trip adds an extra dependence on non-vital 125V DC power to prevent a LOOP. Procedures to direct the local re-alignment of these breakers given remote operation failure are in place to mitigate 125V DC failures, which reduces the importance of remote operation failures; however, if the breakers were normally aligned to provide off-site power to the ESF buses, this dependence could be removed (SAMA 2). The IPE suggested that this issue be addressed through battery monitoring instruments, but re-alignment of the breakers is considered to be a more effective solution.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
X-OPR0RSL	1.02E-01	1.314	FAILURE TO RECOVER OFFSITE AC POWER - 0HRS	About 95% of the cutsets including this event are related to the development of a seal LOCA after a LOOP combined with other AC power and equipment failures. A means of providing seal injection in an SBO could be provided using the plant hydrostatic test pump with a 480V AC generator. The capability to rapidly align this pump for seal cooling is integral to limiting the size of the seal LOCA. Permanently installing the hydrostatic test pump and the supporting generator with control capability in the main control room is a potential way to provide this capability (SAMA 1).
%S1	5.00E-04	1.107	SMALL BREAK LOCA (CLASS 1)	Small LOCA contributors consist of a variety of pump, valve, heat exchanger, and power failures that lead to the unavailability of the injection or recirculation functions. These failures ultimately result in the loss of core cooling. Increasing the heat removal capability of the Containment Fan Coolers (CFCs) and using them for containment heat removal in conjunction with injection from existing high pressure pumps for core cooling would provide a means of reducing Small LOCA risk for HNP provided that a suction path is made available to the HPSI pumps (SAMA 3).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
%R	3.10E-03	1.095	STEAM GENERATOR TUBE RUPTURE	The importance of this general initiating event category suggests that mitigating enhancements could address a variety of aspects related to SGTR accidents: improved detection and isolation capabilities, enhancing makeup capabilities to the RPV, greater primary side depressurization reliability, or means of reducing the initiating event frequency. For HNP, however, over 79 percent of the SGTR contribution comes from failure to isolate the faulted SG in conjunction with RWST makeup failure. Potential enhancements that could mitigate these scenarios include: -Use of Firewater with alternate boration method as a backup RWST makeup source (SAMA 4), - Install primary side SG isolation valves (SAMA 5). As the SGs were recently replaced, this is not suggested as a potential means of reducing the initiating event frequency.
X-PROTB	5.00E-01	1.089	CONDITIONAL PROBABILITY SAFETY TRAIN B PROTECTED	This event is used to help quantify maintenance configurations in the average maintenance model. No specific risk insights have been identified related to this event.
%SWF-3U	1.00E+00	1.089	FLOOD - UNISOLABLE RAB 236 SW PIPE BREAK - SCENARIOS 6, 7	These flood events are caused by breaks in the piping from ESW to the common NSW return (including the 1SW-274, 275, and 276 valves). In order to mitigate a flood event, the following changes are suggested (SAMA 6): - Waterproof motor operators for valves 1SW-274 and 1SW-275 (1SW-276 is not included as it has manual isolation valve 1SW-656 available. Existing plant procedures direct closure of 1SW-656 as part of the flood mitigation process and closure of this valve would isolate backflow from the main reservoir.).
WRAB236UN3	7.54E-07	1.089	RAB 236 SW PIPING VERY LARGE UNISOLABLE BREAK	This event is directly tied to %SWF-3U, which is addressed above.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
X-PROTA	5.00E-01	1.086	CONDITIONAL PROBABILITY SAFETY TRAIN A PROTECTED	This event is used to help quantify maintenance configurations in the average maintenance model. No specific risk insights have been identified related to this event.
OPER-46	1.00E+00	1.075	FAILURE TO ALIGN MFW AFTER TRIP	Over 70 percent of the contributors including this event also include failure to initiate Feed and Bleed (OPER-3). SAMAs requiring additional operator actions will be of limited benefit due to operator dependence. A potential means of providing heat removal and eliminating an operator dependence would be to change the HNP operating logic so that MFW stays on-line after a trip instead of defaulting to AFW for secondary side heat removal (SAMA 7).
OPER-3	1.00E+00	1.07	FAILURE TO IMPLEMENT FEED-AND-BLEED COOLING	Over 75 percent of the contributors including this event also include failure to align MFW after trip. SAMAs requiring additional operator actions will be of limited benefit due to operator dependence. A potential means of providing heat removal and eliminating an operator dependence would be to change the HNP operating logic so that MFW stays on-line after a trip instead of defaulting to AFW for secondary side heat removal (SAMA 7).
XSEAL	2.10E-01	1.06	CONDITIONAL SEAL LOCA PROBABILITY GIVEN THE RCP ARE TRIPPED	This event is linked to the seal LOCA model and represents the probability of a seal LOCA given a successful trip of the RCP (not forced by LOOP). Over 77 percent of the contributors are linked to Service Water system flooding initiators (%SWF-2U, 3U, and 4U). These initiators are explicitly addressed in this importance list and are not discussed again here.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
%T12B	1.00E+00	1.058	LOSS OF 6.9 KV EMERGENCY BUS 1B-SB	Loss of a vital 6.9kV AC bus has been identified as an important contributor to HNP risk. As this event impacts many systems, it cannot be comprehensively mitigated by a single plant change short of the installation of an alternate vital bus. This type of change would not be cost effective for HNP and it is not suggested as a SAMA. Instead, two separate changes have been proposed to address the largest contributors to Loss of Bus evolutions. These changes include (SAMA 8): • Providing the capability to align a direct feed to the 1B3-SB transformer to preclude battery depletion, and • Providing the capability to align the “C” CSIP for seal injection.
J1BSBINIT	7.50E-03	1.058	6.9 KV BUS 1B-SB DE-ENERGIZED (INITIATING EVENT)	This event is directly tied to %T12B, which is addressed above.
X-HVAC	5.90E-01	1.051	SECOND FAN REQUIRED FOR EDG ROOM COOLING - SUMMER TIME	Enhancing procedures to direct operators to open EDG room doors is a means of providing alternate cooling to the EDG rooms when EDG HVAC has failed during the summer (SAMA 9).
QSGSRVFTC	7.70E-03	1.049	ANY SRV ON RUPTURED SG FAILS TO CLOSE	Over 93 percent of the contributors including this event include a failure to provide makeup to the RWST after depletion of the nominal inventory through the open PORV. The Firewater system and the emergency boration path could be used as an alternate source of RWST makeup. (SAMA 4). Inventory loss through the PORV could be prevented by installing SG isolation valves on the primary side piping (SAMA 5).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
%T4P	1.00E+00	1.047	PARTIAL LOSS OF MAIN FEEDWATER	About 65% of the cutsets including this event are related to the failure to re-start MFW after AFW fails to maintain steam generator level. Changing plant logic so that MFW is retained as the operating secondary side heat removal system would eliminate an unnecessary AFW challenge and the potential need to restart MFW (SAMA 7). The remaining contributors are mostly composed of ATWS scenarios to which there are multiple contributors to failure. About 40 percent of these ATWS failures are related to conditions in which the MG sets must be locally tripped to allow control rod insertion. Ex-control room action is not credited for this task due to timing issues, but if a power interrupt switch was provided in the main control room, this action could be taken in a timely manner (SAMA 10). Other ATWS contributors for which the initial pressure spike is controlled could be addressed by automating emergency boration to improve shutdown reliability (SAMA 11).
MPLFW	3.51E-01	1.047	EVENTS WHICH CAUSE A PARTIAL LOSS OF MAIN FW	This event is directly tied to %T4P, which is addressed above.
%T12A	1.00E+00	1.047	LOSS OF 6.9 KV EMERGENCY BUS 1A-SA	Loss of a vital 6.9kV AC bus has been identified as an important contributor to HNP risk. As this event impacts many systems, it cannot be comprehensively mitigated by a single plant change short of the installation of an alternate vital bus. This type of change would not be cost effective for HNP and it is not suggested as a SAMA. Instead, two separate changes have been proposed to address the largest contributors to Loss of Bus evolutions. These changes include (SAMA 8): • Providing the capability to align a direct feed to the 1B3-SB transformer to preclude battery depletion, and • Providing the capability to align the “C” CSIP for seal injection.
J1ASAINIT	7.50E-03	1.047	6.9 KV BUS 1A-SA DE-ENERGIZED (INITIATING EVENT)	This event is directly tied to %T12A, which is addressed above.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
%T3	6.14E-01	1.047	AUTOMATIC REACTOR TRIP	Over 55 percent of the contributors including this event are ATWS sequences. The ATWS contributors for which the pressure spike is controlled could be addressed by automating emergency boration initiation (SAMA 11). Other ATWS cases, those that do not include operator based trip failures, could be mitigated by alternate trip capability (SAMA 10).
PCCFEDGFTS	2.00E-04	1.046	CCF - 2 OF 2 EDGs FAIL TO START	Over 86 percent on the contribution is the result of a seal LOCA when seal cooling is lost in an SBO (RCPs are tripped). A means of providing seal injection in an SBO could be provided using the plant hydrostatic test pump with a 480V AC generator. The capability to rapidly align this pump for seal cooling is integral to limiting the size of the seal LOCA. Permanently installing the hydrostatic test pump and the supporting generator with control capability in the main control room is a potential way to provide this capability (SAMA 1).
%SWF-2U	1.00E+00	1.043	FLOOD - UNISOLABLE RAB 236 SW PIPE BREAK - SCENARIOS 1, 2, 5	These flood events are caused by breaks in the ESW piping between the pumps and the NSW confluence as well as in a specific ESW load path. In order to mitigate a flood event, the following changes are suggested (SAMA 12): - Waterproof motor operators for valves 1SW-39 and 40, - Add sump level indication for the 216 foot level to the MCR. Auto trip of the ESW pump is not suggested as it would require the operators tore-start the intact ESW train after the trip, which is a time critical action when the EDGs are running.
WRAB236UN2	3.82E-07	1.043	RAB 236 SW PIPING VERY LARGE UNISOLABLE BREAK	This event is directly tied to %SWF-2U, which is addressed above.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
XOPER-3	3.40E-03	1.042	OPER-3	This event is used in the post processing routine to apply the nominal value of OPER-3 to the cutset in which OPER-3 is included. In this case, over 88 percent of the cutsets that include XOPER-3 are tied to failure to align MFW after trip (OPER-46). Given that the same relationship drives the importance of event OPER-3, the SAMA suggested for event OPER-3 is also applicable here (SAMA 7).
PDGE1ASAFS	6.28E-03	1.041	EDG 1A-SA FAILS TO START	About 90% of the cutsets including this event also include failures of the opposite division of emergency power that result in an SBO and consequential seal LOCA. A means of providing seal injection in an SBO could be provided using the plant hydrostatic test pump with a 480V AC generator. The capability to rapidly align this pump for seal cooling is integral to limiting the size of the seal LOCA. Permanently installing the hydrostatic test pump and the supporting generator with control capability in the main control room is a potential way to provide this capability (SAMA 1).
PDGE1BSBFS	6.28E-03	1.041	EDG 1B-SB FAILS TO START	About 90% of the cutsets including this event also include failures of the opposite division of emergency power that result in an SBO and consequential seal LOCA. A means of providing seal injection in an SBO could be provided using the plant hydrostatic test pump with a 480V AC generator. The capability to rapidly align this pump for seal cooling is integral to limiting the size of the seal LOCA. Permanently installing the hydrostatic test pump and the supporting generator with control capability in the main control room is a potential way to provide this capability (SAMA 1).
XFL-VBBDEP	1.00E+00	1.04	FLAG - BATTERY 1B-SB FAILS DUE TO DEPLETION (4 HOURS)	About 12% of the cutsets including this event include AFW failures due to the common CST suction valves. As ESW is available as an alternate suction path, the contribution of the AFW failures is conservative. In the remaining cases, battery depletion cases force local operation of the TD AFW pump and could be addressed using a portable 480V AC generator to power the station battery chargers, which is addressed by SAMA 1.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
%T13	1.00E+00	1.04	LOSS OF INSTRUMENT AIR	About 60 percent of the cutsets including this event include failure to re-establish MFW as the secondary side heat removal system after failure of AFW. A potential means of providing heat removal and eliminating an operator dependence would be to change the HNP operating logic so that MFW stays on-line after a trip instead of defaulting to AFW for secondary side heat removal (SAMA 7).
%SWF-4U	1.00E+00	1.039	FLOOD - UNISOLABLE RAB 236 SW PIPE BREAK - SCENARIOS 3, 4	These flood events are caused by breaks in the NSW supply to ESW (from the tank building to 1SW-39 and 40). In order to mitigate a flood event caused by these breaks, the following changes are suggested (SAMA 13): - Waterproof motor operators for valves 1SW-39 and 40, - Add sump level indication for the 216 foot level to the MCR, - Add logic and sensors to trip NSW pumps on high water level in the Service Water Pipe Tunnel (216' elevation) and the RAB near the 1SW-39 and 40 valves.
WRAB236UN4	3.50E-07	1.039	RAB 236 SW PIPING VERY LARGE UNISOLABLE BREAK	This event is directly tied to %SWF-4U, which is addressed above.
FXVCE-34FN	5.94E-05	1.037	MANUAL VALVE 1CE-34 CST OUTLET TRANSFERS CLOSED	This event results in the loss of AFW as it fails the CST suction path. ESW is available as an alternate suction source; however, this event is not included in current quantification. If the ESW connection was credited, the importance of the CST suction path would be reduced. In order to demonstrate this, SAMA 14 is used to calculate the importance of this event after credit to the ESW suction path has been taken.
OPER-66	1.00E+00	1.036	FAILURE TO LOCALLY OPERATE TDAFW PUMP AFTER POWER FAILURE	56 percent of the contribution from this event is related to "B" 6.9kV bus failures, which could be mitigated by cross-tying the "B" battery chargers to the "A" division at the 480V AC level. However, providing alternate power to the "B" battery charger using a 480V AC generator would also address SBO conditions and is considered to be a more complete mitigation strategy. This change is included in the scope of SAMA 1.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
WCCFAUXRES	9.90E-05	1.03	CCF - 2 OF 2 MOVs (1SW-270 AND 1SW-271) FAIL TO OPEN	Failure of these valves to open in conjunction with the normal isolation of discharge path to the NSW return (valves 1SW-274 and 275) on ESW start results in the isolation of all discharge paths. For LOOP cases in which the EDGs are required, rapid recovery of cooling is essential to restoring a source of AC power. Changing the logic so that valves 1SW-274 and 275 do not receive a signal to close until valves 1SW-270 and 1SW-271 are full open would preclude the loss of a discharge path in the cases where 1SW-270 and or 1SW-271 fail to open (SAMA 15).
OPER-32	1.00E+00	1.03	FAILURE TO ACCOMPLISH MRI SHUTDOWN	Additional reactivity control strategies that require operator action will be of limited benefit due to operator dependence issues. This is true even for cases where OPER-32 is the only human action in the cutset, but even more limiting for the cases where at least one other reactivity control action is already taken with OPER-32. As a result, only automated systems are considered to have the potential to further reduce ATWS risk for the accident scenarios where the operators fail to perform MRI. A potential means of providing an additional automated shutdown method would be to use existing AMSAC logic to provide a backup scram signal (SAMA 16). This would bypass failures specific to the RPS system, which are large contributors to OPER-32 cutsets.
%T7	8.77E-02	1.029	REACTOR TRIP WITH SAFETY INJECTION	This initiating event is included in a diverse set of core damage evolutions that can not necessarily be treated with a single type of plant change. However, the operator action to restore CCW after closure from a containment isolation signal (OPER-20) is included in about 51 percent of the contributors with %T7. CCW isolation fails thermal barrier cooling and will eventually result in loss of seal injection due to failure of CSIP room cooling. While any plant enhancement requiring operator action will have limited impact due to operator dependencies, SAMA 1 provides an alternate means of seal injection in the event that the currently available means have been lost.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
JBSLSHEDOP	3.60E-03	1.028	ANY BREAKER FAILS TO OPEN FOR OPERATING TRAIN (3 BREAKERS)	These types of failures are important to HNP due to the role they play in developing an SBO after a LOOP IE. For most of these cases, the SBO results in a seal LOCA and core damage ensues. SAMA 1 addresses SBO survivability and is considered to address the conditions that make this event important.
LCCFPA/B	2.00E-04	1.027	CCF - 2 OF 2 RHR PUMPS FAIL TO START OR DISCH CVs FAIL TO OPEN	This event is primarily important after high pressure injection has successfully operated and the RHR pumps are required for recirculation mode when the RWST is depleted. Providing an alternate means of heat removal and injection from the sump provides a success path for these scenarios (SAMA 3).
PTMEDGB	1.06E-02	1.025	EDG B UNAVAILABLE - MAINTENANCE	This event is important to HNP due to the role it plays in developing an SBO after a LOOP IE. For most of these cases, the SBO results in a seal LOCA and core damage ensues. SAMA 1 addresses SBO survivability and is considered to address the conditions that make this event important.
PDGE1BSBFR	3.49E-02	1.025	EDG 1B-SB FAILS TO RUN	This event is important to HNP due to the role it plays in developing an SBO after a LOOP IE. For most of these cases, the SBO results in a seal LOCA and core damage ensues. SAMA 1 addresses SBO survivability and is considered to address the conditions that make this event important.
PTMEDGA	1.06E-02	1.025	EDG A UNAVAILABLE - MAINTENANCE	This event is important to HNP due to the role it plays in developing an SBO after a LOOP IE. For most of these cases, the SBO results in a seal LOCA and core damage ensues. SAMA 1 addresses SBO survivability and is considered to address the conditions that make this event important.
PDGE1ASAFR	3.49E-02	1.025	EDG 1A-SA FAILS TO RUN	This event is important to HNP due to the role it plays in developing an SBO after a LOOP IE. For most of these cases, the SBO results in a seal LOCA and core damage ensues. SAMA 1 addresses SBO survivability and is considered to address the conditions that make this event important.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
XFL-VBADEP	1.00E+00	1.025	FLAG - BATTERIES 1A-SA AND 1A-N FAIL DUE TO DEPLETION @ 4 AND 2 HOURS	About 20% of the cutsets including this event include AFW failures due to the common CST suction valves. As ESW is available as an alternate suction path, the contribution of the AFW failures is conservative. In the remaining cases, battery depletion is important because it leads to loss of MFW as a secondary side heat removal method. These failures are typically compounded by AFW hardware failures and primary side faults that prevent injection or heat removal. SAMA 3 provides a means of restoring both primary side makeup and heat removal using the HPSI pumps for injection and the CFCs as an alternate heat removal source.
PCCFDGAHUS	1.10E-04	1.025	CCF - 4 OF 4 EDG E-86 AHUs FAIL TO START OR GDs FAIL TO OPEN	Over 87 percent of the CDF contribution including this event is linked to SBO with initial success of the TD AFW pump. While secondary side heat removal is available in these cases, no seal cooling is possible and the resulting inventory loss leads to core damage. SAMA 1 provides a means of rapidly restoring seal injection in an SBO and maintaining TD AFW available. Alternatively, the EDG room doors can be opened to provide alternate room cooling (SAMA 9).
ERPS1	1.60E-06	1.024	RPS AUTO TRIP FAILURE AND NOT ABLE TO BE MANUALLY TRIPPED FROM MCB	Installation of a means to remove power from the CRDMs from the MCR would allow a rapid response to these types of failures (SAMA 10). Alternatively, emergency boration could be automated to provide a more reliable shutdown method for those ATWS sequences for which the initial pressure spike is controlled (SAMA 11).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
X-OPR12RSL	5.96E-03	1.024	FAILURE TO RECOVER OFFSITE AC POWER - 12HRS	These recovery failures are applicable to cases where the EDGs fail to run after initial success. Ultimately, the failure of on-site AC power and off-site power recovery results in a seal LOCA due to lack of seal cooling. Without a means of providing seal cooling, core damage will ensue. Permanently installing a 480V AC generator and the Hydrostatic Test Pump so that they can be rapidly aligned for seal cooling after an AC power failure would provide a means of averting a seal LOCA and limited primary makeup capability. Including the capability of powering the station battery chargers from the 480V AC generator would preclude the need to operate the TD AFW pump locally (SAMA 1).
RCOND3CLOS	2.31E-02	1.023	CONDITIONAL PROBABILITY OF 3/3 BLK VLV CLOSED	Over 75 percent of the contributors including this event include failures to establish LP recirculation due to RHR failures. SAMA 3 includes a means of providing primary side injection and heat removal without the RHR system.
HCCFSIMOVS	3.40E-04	1.023	CCF - 5 OF 5 MOVs (1SI-3, 4, 52, 86 AND 107) FAIL TO OPEN	Over 81 percent of the contribution related to this event is based on a small LOCA (class 1) in which the CCF of the high head injection valves fails injection. Installing an alternate depressurization system that would allow use of the LPSI system is a potential means of providing injection. While still costly, replacing a subset of the high pressure injection valves with a different type of valve would reduce the common cause failure probability and provide a diverse injection path (SAMA 17).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
OPER-11	1.00E+00	1.023	FAILURE TO SWITCH INST BUS TO BACKUP AC POWER SUPPLY	This operator action is always included in cutsets with other operator actions. An additional operator action to mitigate the loss of power to the instrument panels would likely have limited benefit due to dependence issues. Enhancing the man-machine interface is a potential means of improving the reliability of OPER-11, but it is difficult to quantify the improvement. One other action that is included in about 60% of the OPER-11 contributors is OPER-46, which represents the operator's ability to re-start MFW as a secondary side heat removal source after AFW failure. If MFW was retained as the secondary side heat removal source after a trip (SAMA 7), most of the risk for these sequences would be eliminated.
WMVSW270NN	3.10E-03	1.022	MOV 1SW-270 ESW A TO AUX RESERVOIR FAILS TO OPEN	This is the single valve failure variation of the CCF term WCCFAUXRES, which is addressed above. The single valve failure causes the same problems on a single train basis and can be addressed with the same SAMA (SAMA 15).
OPER-35	1.00E+00	1.022	FAILURE TO MANUALLY START AFW PUMP	Over 76% of the contribution related to this event also includes the failure to re-start MFW as the secondary heat removal source after AFW failure. If MFW was retained as the secondary side heat removal source, most of the risk associated with OPER-35 would be eliminated (SAMA 7).
HCVCS294NN	2.80E-04	1.022	CHECK VALVE 1CS-294 RWST TO CSIP SUCTION FAILS TO OPEN	Failure of the CSIP suction from the RWST could be mitigated by proceduralizing the alignment of the RHR pumps to the suction of the CSIPs during the injection phase (SAMA 18).
WMVSW271NN	3.10E-03	1.022	MOV 1SW-271 ESW B TO AUX RESERVOIR FAILS TO OPEN	This is the single valve failure variation of the CCF term WCCFAUXRES, which is addressed above. The single valve failure causes the same problems on a single train basis and can be addressed with the same SAMA (SAMA 15).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
ATMCPR1C	7.46E-02	1.021	COMPRESSOR 1C OUT OF SERVICE - MAINTENANCE	Failure of the running compressor(s) when another compressor is in maintenance results in a Loss of IA initiating event. The remaining compressor can supply post trip IA loads, but not before the plant systems are challenged from the trip. Compressors "A" and "B" could be replaced with 100 percent capacity compressors so that loss of the running compressor does not result in an initiating event when one of the compressors is in maintenance (SAMA 19).
OPER-42	1.00E+00	1.021	FAILURE TO ALIGN CSIP SUCTION FOR SI	This action is required when the CSIP is required for injection and the RWST suction valves do not open or the VCT isolation valves do not close. The failure of either of these automatic alignment actions requires the operators to perform the task, but the available time to perform the action is short and an operator failure leads to loss of the CSIPs. Changing the order of the procedural steps to direct the check of the valve alignment earlier in the scenario may be possible, but given the limited time available for action (5 minutes from failure of suction transfer), a large reduction in the OPER-42 HEP would be difficult to justify. In the relevant sequences, loss of the HHSI system requires either an additional high pressure injection system or an effective rapid depressurization system for success. SAMA 20 suggests an alternate HHSI system.
ERPS3	1.30E-05	1.02	RPS AUTO TRIP FAILURE AND ABLE TO BE MANUALLY TRIPPED FROM MCB W/O RPS SIG	This event is related to ATWS scenarios caused by failure of RPS to automatically scram the reactor. Some improvements in manual scram reliability may theoretically be possible through improved training, but no reliable means of quantifying such an improvement are available. However, using the existing AMSAC logic to backup the RPS scram signal is a potential means of improving scram reliability (SAMA 16).
OPER-54	1.00E+00	1.02	FAILURE TO MANUALLY TRIP REACTOR AT MCB - RPS SIGNAL NOT PRESENT	This event is directly tied to event ERPS3, which is addressed above.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
%S2	2.40E-05	1.02	SMALL BREAK LOCA (CLASS 2)	About 85% of the Class 2 SLOCA contribution comes from failure to establish high head recirculation mode. Many recirculation mode failures could be addressed by increasing the CFC heat removal capacity and installing a suction path from the sump to the HHSI pumps to bypass RHR failures (SAMA 3).
WCCFESWFTS	6.40E-05	1.019	CCF - 2 OF 2 ESW PUMPS FAIL TO START OR DISCH CVs FAIL TO OPEN	About 70% of the contributors including this event are SBO events that lead to seal LOCAs and subsequent core damage. SAMA 1 provides a means of maintaining seal cooling and long term TD AFW operation that will prevent core damage.
FCCFCVQABC	3.20E-05	1.019	CCF - 3 OF 3 SG INLET CHECK VALVES	Over 62 percent of these contributors including this event also include the failure to re-establish MFW as the primary secondary side heat removal source. Maintaining MFW as the primary secondary side heat removal source after a trip would reduce most of the risk associated with these scenarios (SAMA 7). The remaining cases include a variety of hardware failures that fail MFW. In order to address the wide range of failures in these cases, a diverse secondary side heat removal method would be required. SAMA 7 is considered to be a more appropriate change for this case.
WTMESWHDRA	2.40E-03	1.018	ESW HEADER A UNAVAILABLE - MAINTENANCE	This event is important to HNP due to its contribution to the development of seal LOCAs. Loss of bus or LOOP initiating events result in the failure of power to the CSIPs, which provide seal injection. A means of providing seal injection in these scenarios could be provided using the plant hydrostatic test pump with a 480V AC generator. The capability to rapidly align this pump for seal cooling is integral to limiting the size of the seal LOCA. Permanently installing the hydrostatic test pump and the supporting generator with control capability in the main control room is a potential way to provide this capability (SAMA 1).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
WTMESWHDRB	2.40E-03	1.018	ESW HEADER B UNAVAILABLE - MAINTENANCE	This event is important to HNP due to its contribution to the development of seal LOCAs. Loss of bus or LOOP initiating events result in the failure of power to the CSIPs, which provide seal injection. A means of providing seal injection in these scenarios could be provided using the plant hydrostatic test pump with a 480V AC generator. The capability to rapidly align this pump for seal cooling is integral to limiting the size of the seal LOCA. Permanently installing the hydrostatic test pump and the supporting generator with control capability in the main control room is a potential way to provide this capability (SAMA 1).
X-RCSPC	4.50E-02	1.018	CONDITIONAL PROBABILITY OF RCS PRESSURE CHALLENGE	These challenges result in a stuck open primary safety relief valve that eventually require RHR operation for heat removal. The availability of an alternate means of containment heat removal with an injection path that does not require RHR would provide a method for mitigating these sequences. SAMA 3 addresses these issues.
X-OPR0	3.30E-01	1.017	FAILURE TO RECOVER OFFSITE AC POWER - 0HRS (NO TDAFW)	This event is used in scenarios where the TD AFW pump has failed to provide secondary side heat removal after a LOOP. These are essentially all SBO scenarios, which means that no other form of heat removal is available. SAMA 1 provides a primary side SBO injection method, but no means of containment heat removal. The most effective plant enhancement for mitigating these conditions is considered to be the installation of an alternate 6.9kV AC emergency diesel generator. The benefit of the EDG would be enhanced if it could be rapidly aligned to either division from the MCR (SAMA 21).
OPER-20	1.00E+00	1.016	FAILURE TO REOPEN RCP ISOL VALVES FOLLOWING CI	The cutsets including this event contain both OPER-20 and OPER-20s cases. This means that any proposed changes should address the scenarios in which seal injection is lost at or about the same time as the loss of CCW to the thermal barrier coolers (OPER-20s cases). SAMA 1 provides a means of rapidly aligning alternate seal injection that would reduce the risk of loss of seal cooling sequences.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
CCCF4/4BUS	1.50E-05	1.015	CCF - 4 OF 4 INSTRUMENT BUS INVERTERS	Loss of these instrument bus inverters requires operators to switch the power supply to an alternate source (OPER-11) to maintain AFW operability. However, as with the OPER-11 cutsets, a large portion (76%) of the contributors including CCCF4/4BUS also include OPER-46, which represents the operator's ability to re-start MFW as a secondary side heat removal source after AFW failure. If MFW was retained as the secondary side heat removal source after a trip (SAMA 7), most of the risk for these sequences would be eliminated.
OPER-36	1.00E+00	1.015	FAILURE TO INITIATE EMERGENCY BORATION	Providing a valid scram signal would eliminate most of the risk from the sequences including OPER-36. Using the existing AMSAC circuitry to backup the RPS logic is a potential means of providing an alternate scram signal (SAMA 16).
ACPRACOMNN	5.40E-02	1.015	IA COMPRESSOR 1C FAILS TO START	Failure of compressor "C" to start from standby mode after failure of the "A" or "B" compressors to run results in a Loss of IA initiating event. The remaining compressor can supply post trip IA loads, but not before the plant systems are challenged from the trip. Compressors "A" and "B" could be replaced with 100 percent capacity compressors so that any single compressor could supply full the full BOP load (SAMA 19).
QSGMSIVFTC	2.40E-03	1.015	SG MSIV ON RUPTURED SG FAILS TO CLOSE	This event is important when it occurs in conjunction with an SGTR initiating event as it prevents isolation of the faulted SG. Installing primary side SG isolation valves is a means of mitigating this accident (SAMA 5); however, providing makeup to the RWST is likely a more cost effective means of reducing the risk from these scenarios (SAMA 4).
OPER-9	1.00E+00	1.015	FAILURE TO INITIATE RCS COOLDOWN TO USE LPSI/RHR	About 70% of the contributors including this event include seal cooling failures that lead to seal LOCAs and subsequent core damage. SAMA 1 provides a means of alternate seal injection that will prevent core damage.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
ACP1ANS%FN	9.64E-01	1.014	IA COMPRESSOR 1A-NNS FAILS TO RUN (ANNUAL)	This event is related to the Loss of IA initiating event in which one of the running compressors fails and the "C" compressor is in maintenance or fails to operate. Neither the "A" nor the "B" compressor can provide normal operating loads alone, so loss of "A" or "B" in conjunction with the unavailability of the "C" compressor results in a plant trip. Compressors "A" and "B" could be replaced with 100 percent capacity compressors so that any single compressor could supply full the full BOP load (SAMA 19).
ACP1BNS%FN	9.64E-01	1.014	IA COMPRESSOR 1B-NNS FAILS TO RUN (ANNUAL)	This event is related to the Loss of IA initiating event in which one of the running compressors fails and the "C" compressor is in maintenance or fails to operate. Neither the "A" nor the "B" compressor can provide normal operating loads alone, so loss of "A" or "B" in conjunction with the unavailability of the "C" compressor results in a plant trip. Compressors "A" and "B" could be replaced with 100 percent capacity compressors so that any single compressor could supply full the full BOP load (SAMA 19).
FPT1XSABFS	8.48E-03	1.014	AFW TURBINE-DRIVEN PUMP FAILS TO START	The contributors including failure of the TD AFW pump to start include LOOP events in which the subsequent loss of on-site AC power in conjunction with other hardware failures results in the failure of both primary and secondary side cooling. These contributors could be addressed by the installation of a swing EDG that would serve as an alternate on-site AC power source (SAMA 22). Loss of AC bus and loss of Main Feedwater initiating events include combinations of secondary side hardware failures and primary cooling failures. This diverse set of failures could be addressed through the addition of a passive secondary side cooling system that could be used for heat removal (SAMA 7).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
%ISLOCAL	1.28E-07	1.014	INTER-SYSTEM LOCA - LARGE BREAK LOCA VIA RHR SUCTION LINES	ISLOCA events present a continuous challenge that is not considered to be stabilized until the break is isolated. Continuing makeup to an RCS that has not been isolated may delay core damage, but the flow out of the break may also cause additional failures of required equipment due to flooding or steam environment related issues. Without a detailed analysis of the scenario, it is not clear that actions such as refilling the RWST would be effective solutions. The addition of another isolation valve in series with the two existing valves is a possible solution, but CCF factors may limit the effectiveness of the SAMA even if "diverse" valves were used. Moving RHR inside containment would be an effective SAMA, but this type of change is known not to be cost effective based on previous studies and is not suggested. No potentially cost-effective SAMAs have been identified for ISLOCAs, especially given that the contributions are based single event cutsets with highly uncertain frequencies.
X-OPR18RSL	2.32E-03	1.014	FAILURE TO RECOVER OFFSITE AC POWER - 18HRS	These recovery failures are applicable to cases where the EDGs fail to run after initial success. Ultimately, the failure of on-site AC power and off-site power recovery results in a seal LOCA due to lack of seal cooling. Without a means of providing seal cooling, core damage will ensue. Permanently installing a 480V AC generator and the Hydrostatic Test Pump so that they can be rapidly aligned for seal cooling after an AC power failure would provide a means of averting a seal LOCA and limited primary makeup capability. Including the capability of powering the station battery chargers from the 480V AC generator would preclude the need to operate the TD AFW pump locally (SAMA 1).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
ECCFAFWABC	1.20E-03	1.014	CCF - 9 OF 9 LEVEL TRANSMITTERS SGs A, B, C	100% of the contributors including ECCFAFWAC include the operator action to manually start AFW. About 88 percent also include the operator error to recover MFW after the initial loss of the system. Over 70% of the contributors include the operator error to align Feed and Bleed cooling. The preponderance of operator errors in the cutsets including ECCFAFWAC indicates that any SAMAs requiring additional operator actions to initiate heat removal will be of limited benefit due to dependence issues. A passive secondary side heat removal system that requires no additional operator actions for initiation would provide a potential means of mitigating the scenarios in which the SG level transmitters fail (SAMA 7).

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
%R	3.10E-03	4.646	STEAM GENERATOR TUBE RUPTURE	Addressed in the Level 1 importance list.
XFL_PDSX16C	1.00E+00	4.624	PLANT DAMAGE STATE FLAG - X16C	This PDS flag is used to identify unisolated SGTR sequences. The contributors include both cases in which RWST makeup is not available and where HHSI fails to inject. RWST makeup is addressed by SAMA 4 and SG isolation is treated by SAMA 5.
XFL_RWY	1.00E+00	3.77	CORE DAMAGE SEQUENCE FLAG - RWY	This sequence is used to identify unisolated SGTR sequences (through stuck open relief valve) in which RWST makeup is not available. RWST makeup is addressed by SAMA 4 and SG isolation is treated by SAMA 5.
QSGSRVFTC	7.70E-03	2.15	ANY SRV ON RUPTURED SG FAILS TO CLOSE	Addressed in the Level 1 importance list.
XFL_ISLOCA	1.00E+00	1.274	CORE DAMAGE SEQUENCE FLAG - ISLOCA	ISLOCA events present a continuous challenge that is not considered to be stabilized until the break is isolated. Continuing makeup to an RCS that has not been isolated may delay core damage, but the flow out of the break may also cause additional failures of required equipment due to flooding or steam environment related issues. Without a detailed analysis of the scenario, it is not clear that actions such as refilling the RWST would be effective solutions. The addition of another isolation valve in series with the two existing valves is a possible solution, but CCF factors may limit the effectiveness of the SAMA even if "diverse" valves were used. Moving RHR inside containment would be an effective SAMA, but this type of change is known not to be cost effective based on previous studies and is not suggested. No potentially cost-effective SAMAs have been identified for ISLOCAs, especially given that the contributions are based single event cutsets with highly uncertain frequencies.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
XFL_PDSB18O	1.00E+00	1.262	PLANT DAMAGE STATE FLAG - B18O	For the release categories considered here (RC-5, RC-5C), this flag is tied directly to the %ISLOCAL and %ISLOCAM initiating events, which are specifically addressed elsewhere in this list.
%ISLOCAL	1.28E-07	1.196	INTER-SYSTEM LOCA - LARGE BREAK LOCA VIA RHR SUCTION LINES	Addressed in the Level 1 importance list.
QSGMSIVFTC	2.40E-03	1.195	SG MSIV ON RUPTURED SG FAILS TO CLOSE	Addressed in the Level 1 importance list.
UAVCS151NN	2.40E-03	1.116	PNEUMATIC VALVE 1CS-151 RMW TO BLENDING TEE FAILS TO OPEN	This event results in the failure of DWS makeup to the RWST in SGTR scenarios, which leads to the loss of primary side injection. SAMA 4 provides an alternate means of providing makeup to the RWST.
UAVCS283NN	2.40E-03	1.116	PNEUMATIC VALVE 1CS-283 BA TO BLENDING TEE FAILS TO OPEN	This event results in the failure of DWS makeup to the RWST in SGTR scenarios, which leads to the loss of primary side injection. SAMA 4 provides an alternate means of providing makeup to the RWST.
YAV1DW-8NN	2.40E-03	1.116	PNEUMATIC VALVE 1DW-8 (LCV-8901) DWS TO RMWST FAILS TO OPEN	This event results in the failure of DWS makeup to the RWST in SGTR scenarios, which leads to the loss of primary side injection. SAMA 4 provides an alternate means of providing makeup to the RWST.
YAVDW533NN	2.40E-03	1.116	PNEUMATIC VALVE 1DW-533 (FCV-9562) DWS PUMPS DISCH FAILS TO OPEN	This event results in the failure of DWS makeup to the RWST in SGTR scenarios, which leads to the loss of primary side injection. SAMA 4 provides an alternate means of providing makeup to the RWST.
QSGPORVFTC	1.30E-03	1.095	SG PORV ON RUPTURED SG FAILS TO CLOSE	This event results in an unisolated SGTR sequence. The contributors include both cases in which RWST makeup is not available and where HHSI fails to inject. RWST makeup is addressed by SAMA 4 and SG isolation is treated by SAMA 5.
OPER-64	1.00E+00	1.081	FAILURE TO OPEN DW SUPPLY TO RMWST FOR LONG-TERM MAKE-UP SUPPLY	This event results in the failure of DWS makeup to the RWST in SGTR scenarios, which leads to the loss of primary side injection. SAMA 4 provides an alternate means of providing makeup to the RWST.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
XOPER-64	1.70E-03	1.081	OPER-64	This is a recovery event used to apply the correct HEP value to OPER-64 and in this case, it is directly tied to event OPER-64, which is addressed above.
%ISLOCAM	4.11E-08	1.054	INTER-SYSTEM LOCA - MEDIUM BREAK LOCA VIA RHR HOT OR COLD LEG INJECTION LINES	ISLOCA events present a continuous challenge that is not considered to be stabilized until the break is isolated. Continuing makeup to an RCS that has not been isolated may delay core damage, but the flow out of the break may also cause additional failures of required equipment due to flooding or steam environment related issues. Without a detailed analysis of the scenario, it is not clear that actions such as refilling the RWST would be effective solutions. The addition of another isolation valve in series with the two existing valves is a possible solution, but CCF factors may limit the effectiveness of the SAMA even if "diverse" valves were used. Moving RHR inside containment would be an effective SAMA, but this type of change is known not to be cost effective based on previous studies and is not suggested. No potentially cost-effective SAMAs have been identified for ISLOCAs, especially given that the contributions are based single event cutsets with highly uncertain frequencies.
XFL_RUW	1.00E+00	1.053	CORE DAMAGE SEQUENCE FLAG - RUW	This sequence deals with a loss of SI and the failure of a steam generator SRV to close after it has opened. The AFW system operates as required. The failure of SI combined with the steam generator backpressure being essentially atmospheric causes a continual loss of inventory and the RCS inventory will eventually deplete. The plant is placed into shutdown, using the RHR system but the operators fail to provide adequate long-term inventory management and core damage occurs. RWST makeup is addressed by SAMA 4 and SG isolation is treated by SAMA 5.
ACCFCABFS	5.40E-03	1.032	CCF - 2 OF 2 AIR COMPRESSORS (1A AND 1B) FAIL TO START	This event results in the failure of DWS makeup to the RWST in SGTR scenarios, which leads to the loss of primary side injection. SAMA 4 provides an alternate means of providing makeup to the RWST.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
ATMCPR1C	7.46E-02	1.018	COMPRESSOR 1C OUT OF SERVICE - MAINTENANCE	Addressed in the Level 1 importance list.
UXVCS160FN	3.56E-04	1.016	VALVE 1CS-160 BLENDED FLOW TO RWST TRANSFERS CLOSED	This event results in the failure of DWS makeup to the RWST in SGTR scenarios, which leads to the loss of primary side injection. SAMA 4 provides an alternate means of providing makeup to the RWST.
UXVCS164FN	3.56E-04	1.016	VALVE 1CS-164 RWST MAKEUP FROM CVCS TRANSFERS CLOSED	This event results in the failure of DWS makeup to the RWST in SGTR scenarios, which leads to the loss of primary side injection. SAMA 4 provides an alternate means of providing makeup to the RWST.
HCCFSIMOVS	3.40E-04	1.015	CCF - 5 OF 5 MOVs (1SI-3, 4, 52, 86 AND 107) FAIL TO OPEN	Addressed in the Level 1 importance list.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
1	Hydrostatic Test Pump (or Alternate Pump) with 480V AC Generator for Seal Injection and "B" Battery Charger	This SAMA requires permanent installation of the hydrostatic test pump and a 480V AC generator such that the pump could rapidly be aligned to provide seal injection in an SBO. Rapid alignment capability will limit the size of any seal LOCA after the initial loss of seal cooling and is considered to be an integral part of this SAMA. Given that HNP has the ability to operate the turbine driven AFW pump after 125V DC battery depletion, this SAMA will allow for long term operation in an SBO. Providing power to the "B" battery chargers would eliminate the need to operate the TD AFW pump locally after battery depletion and would further reduce plant risk. In the event that additional flow margin is determined to be desirable, a new pump could be used in place of the Hydrostatic Test Pump.	HNP Level 1 Importance List, IPEEE (Fire)	The cost of this SAMA has been estimated to be $1 million (PE 2006b).	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
2	Change 1E Buses to be Normally Aligned to an Off-Site Power Source	The current 1E bus alignment requires a set of breakers to change position in order to swap the 1E bus power supply from the unit auxiliary transformers to the startup transformers. If the non-vital DC power system fails during a plant trip, a LOOP will occur as the breakers will not operate automatically. While procedures exist to direct local operation of the breakers, this SAMA would eliminate a dependence on 125V DC power and a manual action to recover from the failure.	HNP IPE, HNP Level 1 Importance List	The cost of this SAMA has been estimated to be $200,000 (PE 2006b).	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
3	Increase the Capacity of the Containment Fan Coolers for Heat Removal when RHR Cooling is Unavailable and Provide Sump Suction for HPSI	RHR heat removal failures that do not initially impact injection capability could be mitigated by using the Containment Fan Coolers to prevent containment overpressurization failure if the heat removal capacity of the system were increased. The current heat removal capacity of 2 or more fan coolers with containment pressure near 45 psig may be great enough to remove decay heat, prevent further containment pressurization, and maintain core cooling. However, enhancing the system so that it could provide adequate heat removal at lower pressures would allow more margin for success. Installation of a sump suction path and a booster pump for HPSI is also required to address many of the failures that result in loss of the RHR heat removal function.	HNP Level 1 Importance List	The scope of this SAMA would likely require the replacement of the existing fan cooler units and potentially the piping to the units. In addition, a new sump suction line for HPCI would have to be installed in conjunction with a booster pump to provide adequate NPSH for the CSIPs. Finally, training and procedural development would be required to support the use of the upgraded fan coolers with HPCI suction from the sump. Calvert Cliffs estimated to cost of installing a hardpipe connection from the fire protection system to the RHR heat exchangers, SI pumps, and RCP seals to be $565,000. This is used as a lower bound cost for SAMA 3.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
4	RWST Makeup with Firewater and Boric Acid Addition	Failure to isolate an SGTR will result in the depletion of the RWST in the long term if makeup from the Demineralized Water System (DWS) is not initiated or if the flowpath from the DWS to the RWST fails. Failure of flow from the boric acid transfer system to the blending tee is also considered to result in RWST makeup failure in the PRA. While makeup from the DWS is preferable, procedures could be developed to provide an alternate source of borated water to the CSIPs using the Emergency Boration path and the Firewater system: • Direct local actions using fire hoses connected to the Firewater system to add water to the RWST, • Direct alignment of the Emergency Boration path to the CSIP suction header so that borated water would be available in conjunction with the non-borated water from the RWST	HNP Level 1 and Level 2 Importance Lists	The cost of this SAMA has been estimated to be $150,000 (PE 2006a).	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
5	Primary Side Steam Generator Isolation Valves	Installation of primary side isolation valves on the steam generators would provide an additional means of isolating SGTR events.	HNP Level 1 and Level 2 Importance Lists	The cost of this SAMA has been estimated to be between $6 million and $8 million (PE 2006b).	As the cost of implementation is greater than the MMACR, this SAMA has not been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
6	Flood Mitigation for Scenarios 6 and 7	In order to mitigate a the floods caused by breaks in the lines from ESW to the common NSW return, the following changes are suggested: - Waterproof motor operators for valves 1SW-274 and 1SW-275 (1SW-276 is not included as it has manual isolation valve 1SW-656 available. Existing plant procedures direct closure of 1SW-656 as part of the flood mitigation process, which would isolate backflow from the main reservoir.).	HNP Level 1 Importance List	The cost of this SAMA was initially estimated to be $150,000 (PE 2006a). This estimate includes the cost of sealing valves 1SW-274 and 1SW-275 so that they are capable of operating in submerged conditions.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
7	Passive Secondary Side Cooling System	Accident scenarios including loss of AFW often include failures to manually initiate AFW after auto start failure, operator failures to re-start MFW, and operator failures to initiate Feed & Bleed heat removal. SAMAs requiring further operator actions to provide heat removal would provide limited benefit due to operator dependence issues. A potential solution is to install a passive secondary side heat removal system consisting of a condenser and a heat sink that will perform without operator intervention.	HNP Level 1 Importance List	The cost of installing a passive secondary side heat removal system would likely exceed the HNP MMACR due to the need to make major changes to the primary containment and secondary side cooling loops. While no cost estimate has been identified for installation of a passive heat removal system in an existing plant, Browns Ferry estimated the cost of installing a passive containment spray system to be $6 million per unit (TVA 2003), which could be similar in scope even though it is a BWR system. The cost of installing a passive injection system in the ABWR was estimated to be $1.7 million if done in the design phase (GE 1994). The cost of the proposed HNP system could be in the range of these types of changes, but it is not likely to be less than the ABWR estimate. The cost of $1.7 million is used as a lower bound cost for this case (not scaled to 2006 dollars).	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
8	Alternate Seal Cooling and Direct Feed to Transformer 1B3-SB	Loss of a vital 6.9kV AC bus has been identified as an important contributor to HNP risk. As this event impacts many systems, it cannot be comprehensively mitigated by a single plant change short of the installation of an alternate vital bus. This type of change would not be cost effective for HNP and it is not suggested as a SAMA. Instead, two separate changes have been proposed to address the largest contributors to Loss of Bus evolutions. These changes include: • Providing the capability to align a direct feed to the 1B3-SB transformer to preclude battery depletion, and • Providing the capability to align the “C” CSIP for seal injection.	HNP Level 1 Importance List, IPEEE (Fire)	The cost of this SAMA has been estimated to be $300,000 (PE 2006a).	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
9	Proceduralize Actions to Open EDG Room Doors on Loss of HVAC and Implement Portable Fans	Loss of EDG Room HVAC is assumed to result in EDG failure during the summer months. Loss of EDG Room HVAC could be mitigated if plant operating procedures were enhanced to direct operators to open the EDG room doors when HVAC is lost during periods of expected high heat (between the March 28th and October 29th) or whenever room temperatures are high. As a room heatup analysis is not available to show that the EDG rooms would remain sufficiently cool without forced ventilation, portable fans are assumed to be required as part of the alternate cooling strategy.	HNP Level 1 Importance List	Two components are included in the cost estimate, procedure changes and the purchase of portable fans to provide temporary, forced ventilation. The cost of the procedure change is based on an industry estimate of $50,000 for a procedure change (CPL 2004). An estimate of $20,000 is included to provide portable fans, which is considered to be a high estimate for fans. A total cost of $70,000 is used for this SAMA.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
10	Install a Main Control Room Power Interrupt Switch for Alternate SCRAM Capability	Providing a switch within the MCR that could be used to interrupt power to the MCC that maintains the control rods in the withdrawn position would allow the operators to scram the reactor in a timely manner when the preferred methods fail.	HNP Level 1 Importance List	No plant specific cost estimate has been developed for this SAMA. The minimum implementation cost of a SAMA, which is assumed to be a procedural change at $50,000 (CPL 2004), has been used to reduce resources required to estimate a plant specific cost.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
11	Automate Emergency Boration Initiation	For ATWS contributors where the initial pressure spike in controlled, the reliability of shutting the reactor down with Emergency Boration could be improved by automating system initiation. Power level monitoring in conjunction with RPS/AMSAC signals could be used to satisfy logic that would initiate the Emergency Boration function.	HNP Level 1 Importance List	Browns Ferry estimated the cost for automating SLC initiation to be about $400,000 per unit (TVA 2003). This enhancement is similar in nature to automating emergency boration for HNP and this estimate is used as an approximation of the resources required for this SAMA.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
12	Flood Mitigation for Scenarios 1, 2 and 5	These flood events are caused by breaks in the ESW piping between the pumps and the NSW confluence as well as in a specific ESW load path. In order to mitigate a flood event, the following changes are suggested (SAMA 12): - Waterproof motor operators for valves 1SW-39 and 40, - Add sump level indication for the 216 foot level to the MCR. Auto trip of the ESW pump is not suggested as it would require the operators tore-start the intact ESW train after the trip, which is a time critical action when the EDGs are running.	HNP Level 1 Importance List	The cost of this SAMA has been estimated to be $275,000 (PE 2006a). Procedure changes and logic modifications were estimated to be $125,000 and the waterproofing of the two valves was estimated to be an additional $150,000.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
13	Flood Mitigation for Scenarios 3 and 4	These flood events are caused by breaks in the NSW supply to ESW (from the tank building to 1SW-39 and 40). In order to mitigate a flood event caused by these breaks, the following changes are suggested: - Waterproof motor operators for valves 1SW-39 and 40, - Add sump level indication for the 216 foot level to the MCR, - Add logic and sensors to trip NSW pumps on high water level in the Service Water Pipe Tunnel (216' elevation) and the RAB near the 1SW-39 and 40 valves.	HNP Level 1 Importance List	The cost of the logic changes for this SAMA has been estimated to be $75,000 (PE 2006a). From the cost estimate prepared for SAMA 12 (PE 2006a), the waterproofing of 1SW-39 and 1-SW40 is estimated to require an additional $150,000 for a total of $225,000.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
14	Alternate AFW Suction	This SAMA is specifically related to the failure of a valve in the CST suction path for AFW. The current PRA model does not credit the existing ESW cross-tie lines to the AFW suction paths. If those cross-ties are credited, the importance of the CST suction path will be greatly reduced.	HNP Level 1 Importance List	N/A - PRA analysis will be used to demonstrate that the current model conservatively assigns a high importance to the CST suction path and that no plant changes are required.	This SAMA has been retained for Phase 2 analysis to demonstrate that no changes to the AFW suction design would be cost beneficial.
15	Change Logic for Valves 1SW-274 and 1SW-275 to Prevent Loss of Discharge Path	Failure of valves 1SW-270 and 1SW-271 to open in conjunction with the normal isolation of discharge path to the NSW return (valves 1SW-274 and 275) on ESW start results in the isolation of all discharge paths. Changing the logic so that valves 1SW-274 and 275 do not receive a signal to close until valves 1SW-270 and 1SW-271 are full open would preclude the loss of a discharge path in the cases where 1SW-270 and or 1SW-271 fail to open.	HNP Level 1 Importance List	The cost of the logic changes for this SAMA has been estimated to be $250,000 (PE 2006a).	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
16	AMSAC Backup to RPS Scram	For RPS failure scenarios, manual actions are currently required to take the reactor to a sub-critical state. The AMSAC signal, which is separate from the RPS logic other than the sensors used as input, could be used as a backup to the RPS scram signal.	HNP Level 1 Importance List	Browns Ferry estimated the cost for automating SLC initiation to be about $400,000 per unit (TVA 2003). This enhancement is similar in scope to using AMSAC to operate as a secondary scram signal and this estimate is used as an approximation of the resources required for HNP to implement this SAMA.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
17	Replace 2 of the 5 High Pressure Injection Valves with and Alternate Type of Valve	Common cause failure of the high pressure injection valves is a potential failure mode that can lead to core damage in some cases. The potential for this type of failure could be reduced by changing a subset of the injection valves to a different type of valve.	HNP Level 1 Importance List	The cost of this SAMA has been estimated to be $500,000 (PE 2006b).	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
18	Proceduralize Alignment of HHSI to the RHR Heat Exchangers During Injection Phase	In the event that the HHSI pump suction path from the RWST fails, procedures could be written to direct the alignment of the HHSI pumps to the RHR heat exchanges during the injection phase. This would require the availability of the RWST suction path to the RHR pumps.	HNP Level 1 Importance List	The cost of implementation for this SAMA is based on multiple contributors, including: -Procedure updates: $50,000 (CPL 2004) -Training material/simulator logic update: $25,000 (estimate) -Modification of interlocks to allow the suggested alignment: $50,000 (estimate) -Analysis to validate the concept of the change and plant capability: $50,000 (estimate) The total cost of implementation is $175,000. This cost is based on what are considered to be low end cost estimates for the components identified as part of the implementation process. The costs may be higher and there may be other contributors that are not accounted for here, such as the resources required to interface with the NRC.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
19	Replace "A" and "B" Instrument Air Compressors with 100 Percent Capacity Compressors	Failure of the running compressor(s) when another compressor is in maintenance results in a Loss of IA initiating event. The remaining compressor can supply post trip IA loads, but not before the plant systems are challenged from the trip. Compressors "A" and "B" could be replaced with 100 percent capacity compressors so that loss of the running compressor does not result in an initiating event when one of the compressors is in maintenance.	HNP Level 1 Importance List	No plant specific cost estimate has been developed for this SAMA. The minimum implementation cost of a SAMA, which is assumed to be a procedural change at $50,000 (CPL 2004), has been used to reduce the resources required for this evaluation and to show that the SAMA would not be cost effective under any circumstances for HNP.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
20	Diverse High Pressure Injection System	In order to address high pressure injection failures, including injection path faults, an alternate high pressure system could be installed that injects into a unique point in the hot and cold legs. Increased benefit would be realized if the pump and valves could easily be aligned to either power division.	HNP Level 1 Importance List	Calvert Cliffs estimated the cost of installing an additional primary side high pressure injection system with dedicated EDG support to be between $5 and $10 million (BGE 1998). For HNP, a dedicated EDG is not required, but the ability to use either AC division is suggested. This ability requires additional cabling and controls that would not be required for single division use. The HNP implementation cost is take to be the lower end of the Calvert Cliffs estimate in order to account for the lack of a dedicated EDG in the HNP design ($5 million).	As the cost of implementation is greater than the MMACR, this SAMA has not been retained for Phase 2 analysis.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
21	Swing 6.9kV AC EDG or use of the Cape Fear Combustion Turbines	While more cost effective solutions are believed to be available to address other HNP SBO conditions, failure of the TD AFW train leaves the plant without a decay heat removal source. The most effective means of restoring this function as well as primary side injection is considered to be the installation of a 6.9kV AC EDG that can be aligned to either AC division. The benefit of this change would be greatly enhanced if the EDG could be rapidly aligned from the MCR. This capability would allow the operators to reduce the risk of developing a seal LOCA when loss of power events interrupt seal cooling. Alternatively, the internal combustion turbines at the Cape Fear Plant could be used in conjunction with a dedicated line to the HNP site.	HNP Level 1 Importance List	Several different costs have been documented in the industry SAMA submittals for additional EDGs, including the Calvert Cliffs estimate of over $20 million (BGE 1998). This estimate included auto start and alignment capability and is likely at the high end of the installation cost spectrum. Browns Ferry provided a cost of implementation of $6 million in 2003 dollars (TVA 2003), which may be closer to the cost required for HNP. However, Calvert Cliffs also suggested the installation of a lower cost gas combustion turbine as an alternate AC source for $3,350,000. This cost is still greater than the HNP MMACR, but it has been used here for demonstration purposes. This is considered to be a lower cost and more effective change than providing a dedicated line from the Cape Fear site.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.
22	Install Upper Lateral Restraints on the RHR Heat Exchangers	The vertical RHR heat exchangers were installed without the upper lateral restraints that were included in the original RHR design based on analyses that justified the configuration for DBE levels. Installation of the upper lateral restraints would ensure adequate margin for the RLE.	HNP IPEEE (Seismic)	The cost of this SAMA has been estimated to be $350,000 (PE 2006b).	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION
1	Hydrostatic Test Pump (or Alternate Pump) with 480V AC Generator for Seal Injection and "B" Battery Charger	This SAMA requires permanent installation of the hydrostatic test pump and a 480V AC generator such that the pump could rapidly be aligned to provide seal injection in an SBO. Rapid alignment capability will limit the size of any seal LOCA after the initial loss of seal cooling and is considered to be an integral part of this SAMA. Given that HNP has the ability to operate the turbine driven AFW pump after 125V DC battery depletion, this SAMA will allow for long term operation in an SBO. Providing power to the "B" battery chargers would eliminate the need to operate the TD AFW pump locally after battery depletion and would further reduce plant risk. In the event that additional flow margin is determined to be desirable, a new pump could be used in place of the Hydrostatic Test Pump.	HNP Level 1 Importance List, IPEEE (Fire)	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
2	Change 1E Buses to be Normally Aligned to an Off-Site Power Source	The current 1E bus alignment requires a set of breakers to change position in order to swap the 1E bus power supply from the unit auxiliary transformers to the startup transformers. If the non-vital DC power system fails during a plant trip, a LOOP will occur as the breakers will not operate automatically. While procedures exist to direct local operation of the breakers, this SAMA would eliminate a dependence on 125V DC power and a manual action to recover from the failure.	HNP IPE, HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
3	Increase the Capacity of the Containment Fan Coolers for Heat Removal when RHR Cooling is Unavailable and Provide Sump Suction for HPSI	RHR heat removal failures that do not initially impact injection capability could be mitigated by using the Containment Fan Coolers to prevent containment overpressurization failure if the heat removal capacity of the system were increased. The current heat removal capacity of 2 or more fan coolers with containment pressure near 45 psig may be great enough to remove decay heat, prevent further containment pressurization, and maintain core cooling. However, enhancing the system so that it could provide adequate heat removal at lower pressures would allow more margin for success. Installation of a sump suction path and a booster pump for HPSI is also required to address many of the failures that result in loss of the RHR heat removal function.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION
4	RWST Makeup with Firewater and Boric Acid Addition	Failure to isolate an SGTR will result in the depletion of the RWST in the long term if makeup from the Demineralized Water System (DWS) is not initiated or if the flowpath from the DWS to the RWST fails. Failure of flow from the boric acid transfer system to the blending tee is also considered to result in RWST makeup failure in the PRA. While makeup from the DWS is preferable, procedures could be developed to provide an alternate source of borated water to the CSIPs using the Emergency Boration path and the Firewater system: • Direct local actions using fire hoses connected to the Firewater system to add water to the RWST, • Direct alignment of the Emergency Boration path to the CSIP suction header so that borated water would be available in conjunction with the non-borated water from the RWST	HNP Level 1 and Level 2 Importance Lists	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
6	Flood Mitigation for Scenarios 6 and 7	In order to mitigate a the floods caused by breaks in the lines from ESW to the common NSW return, the following changes are suggested: - Waterproof motor operators for valves 1SW-274 and 1SW-275 (1SW-276 is not included as it has manual isolation valve 1SW-656 available. Existing plant procedures direct closure of 1SW-656 as part of the flood mitigation process, which would isolate backflow from the main reservoir.).	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
7	Passive Secondary Side Cooling System	Accident scenarios including loss of AFW often include failures to manually initiate AFW after auto start failure, operator failures to re-start MFW, and operator failures to initiate Feed & Bleed heat removal. SAMAs requiring further operator actions to provide heat removal would provide limited benefit due to operator dependence issues. A potential solution is to install a passive secondary side heat removal system consisting of a condenser and a heat sink that will perform without operator intervention.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION
8	Alternate Seal Cooling and Direct Feed to Transformer 1B3-SB	Loss of a vital 6.9kV AC bus has been identified as an important contributor to HNP risk. As this event impacts many systems, it cannot be comprehensively mitigated by a single plant change short of the installation of an alternate vital bus. This type of change would not be cost effective for HNP and it is not suggested as a SAMA. Instead, two separate changes have been proposed to address the largest contributors to Loss of Bus evolutions. These changes include: • Providing the capability to align a direct feed to the 1B3-SB transformer to preclude battery depletion, and • Providing the capability to align the “C” CSIP for seal injection.	HNP Level 1 Importance List, IPEEE (Fire)	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
9	Proceduralize Actions to Open EDG Room Doors on Loss of HVAC and Implement Portable Fans	Loss of EDG Room HVAC is assumed to result in EDG failure during the summer months. Loss of EDG Room HVAC could be mitigated if plant operating procedures were enhanced to direct operators to open the EDG room doors when HVAC is lost during periods of expected high heat (between the March 28th and October 29th) or whenever room temperatures are high. As a room heatup analysis is not available to show that the EDG rooms would remain sufficiently cool without forced ventilation, portable fans are assumed to be required as part of the alternate cooling strategy.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is greater than the cost of implementation and the SAMA is cost beneficial.
10	Install a Main Control Room Power Interrupt Switch for Alternate SCRAM Capability	Providing a switch within the MCR that could be used to interrupt power to the MCC that maintains the control rods in the withdrawn position would allow the operators to scram the reactor in a timely manner when the preferred methods fail.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
11	Automate Emergency Boration Initiation	For ATWS contributors where the initial pressure spike in controlled, the reliability of shutting the reactor down with Emergency Boration could be improved by automating system initiation. Power level monitoring in conjunction with RPS/AMSAC signals could be used to satisfy logic that would initiate the Emergency Boration function.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION
12	Flood Mitigation for Scenarios 1, 2 and 5	These flood events are caused by breaks in the ESW piping between the pumps and the NSW confluence as well as in a specific ESW load path. In order to mitigate a flood event, the following changes are suggested (SAMA 12): - Waterproof motor operators for valves 1SW-39 and 40, - Add sump level indication for the 216 foot level to the MCR. Auto trip of the ESW pump is not suggested as it would require the operators tore-start the intact ESW train after the trip, which is a time critical action when the EDGs are running.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
13	Flood Mitigation for Scenarios 3 and 4	These flood events are caused by breaks in the NSW supply to ESW (from the tank building to 1SW-39 and 40). In order to mitigate a flood event caused by these breaks, the following changes are suggested: - Waterproof motor operators for valves 1SW-39 and 40, - Add sump level indication for the 216 foot level to the MCR, - Add logic and sensors to trip NSW pumps on high water level in the Service Water Pipe Tunnel (216' elevation) and the RAB near the 1SW-39 and 40 valves.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
15	Change Logic for Valves 1SW-274 and 1SW-275 to Prevent Loss of Discharge Path	Failure of valves 1SW-270 and 1SW-271 to open in conjunction with the normal isolation of discharge path to the NSW return (valves 1SW-274 and 275) on ESW start results in the isolation of all discharge paths. Changing the logic so that valves 1SW-274 and 275 do not receive a signal to close until valves 1SW-270 and 1SW-271 are full open would preclude the loss of a discharge path in the cases where 1SW-270 and or 1SW-271 fail to open.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
16	AMSAC Backup to RPS Scram	For RPS failure scenarios, manual actions are currently required to take the reactor to a sub-critical state. The AMSAC signal, which is separate from the RPS logic other than the sensors used as input, could be used as a backup to the RPS scram signal.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION
17	Replace 2 of the 5 High Pressure Injection Valves with and Alternate Type of Valve	Common cause failure of the high pressure injection valves is a potential failure mode that can lead to core damage in some cases. The potential for this type of failure could be reduced by changing a subset of the injection valves to a different type of valve.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
18	Proceduralize Alignment of HHSI to the RHR Heat Exchangers During Injection Phase	In the event that the HHSI pump suction path from the RWST fails, procedures could be written to direct the alignment of the HHSI pumps to the RHR heat exchanges during the injection phase. This would require the availability of the RWST suction path to the RHR pumps.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
19	Replace "A" and "B" Instrument Air Compressors with 100 Percent Capacity Compressors	Failure of the running compressor(s) when another compressor is in maintenance results in a Loss of IA initiating event. The remaining compressor can supply post trip IA loads, but not before the plant systems are challenged from the trip. Compressors "A" and "B" could be replaced with 100 percent capacity compressors so that loss of the running compressor does not result in an initiating event when one of the compressors is in maintenance.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
21	Swing 6.9kV AC EDG or use of the Cape Fear Combustion Turbines	While more cost effective solutions are believed to be available to address other HNP SBO conditions, failure of the TD AFW train leaves the plant without a decay heat removal source. The most effective means of restoring this function as well as primary side injection is considered to be the installation of a 6.9kV AC EDG that can be aligned to either AC division. The benefit of this change would be greatly enhanced if the EDG could be rapidly aligned from the MCR. This capability would allow the operators to reduce the risk of developing a seal LOCA when loss of power events interrupt seal cooling. Alternatively, the internal combustion turbines at the Cape Fear Plant could be used in conjunction with a dedicated line to the HNP site.	HNP Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.
22	Install Upper Lateral Restraints on the RHR Heat Exchangers	The vertical RHR heat exchangers were installed without the upper lateral restraints that were included in the original RHR design based on analyses that justified the configuration for DBE levels. Installation of the upper lateral restraints would ensure adequate margin for the RLE.	HNP IPEEE (Seismic)	The averted cost-risk for this SAMA is less than the cost of implementation and the SAMA is not cost beneficial.

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ADDENDUM 1 TO ATTACHMENT E
SELECTED PREVIOUS INDUSTRY SAMAS

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to RCP Seal LOCAs (Loss of CC or SW)		
1	Cap downstream piping of normally closed component cooling water drain and vent valves.	SAMA would reduce the frequency of a loss of component cooling event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.
2	Enhance loss of component cooling procedure to facilitate stopping reactor coolant pumps.	SAMA would reduce the potential for reactor coolant pump (RCP) seal damage due to pump bearing failure.
3	Enhance loss of component cooling procedure to present desirability of cooling down reactor coolant system (RCS) prior to seal LOCA.	SAMA would reduce the potential for RCP seal failure.
4	Provide additional training on the loss of component cooling.	SAMA would potentially improve the success rate of operator actions after a loss of component cooling (to restore RCP seal damage).
5	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	SAMA would reduce effect of loss of component cooling by providing a means to maintain the centrifugal charging pump seal injection after a loss of component cooling.
6	Procedure changes to allow cross connection of motor cooling for residual heat removal service water (RHRSW) pumps.	SAMA would allow continued operation of both RHRSW pumps on a failure of one train of PSW.
7	Proceduralize shedding component cooling water loads to extend component cooling heatup on loss of essential raw cooling water.	SAMA would increase time before the loss of component cooling (and reactor coolant pump seal failure) in the loss of essential raw cooling water sequences.
8	Increase charging pump lube oil capacity.	SAMA would lengthen the time before centrifugal charging pump failure due to lube oil overheating in loss of CC sequences.
9	Eliminate the RCP thermal barrier dependence on component cooling such that loss of component cooling does not result directly in core damage.	SAMA would prevent the loss of recirculation pump seal integrity after a loss of component cooling. Watts Bar Nuclear Plant IPE said that they could do this with essential raw cooling water connection to RCP seals.
10	Add redundant DC control power for PSW pumps C & D.	SAMA would increase reliability of PSW and decrease CDF due to a loss of SW.
11	Create an independent RCP seal injection system, with a dedicated diesel.	SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of component cooling or SW or from a SBO event.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
12	Use existing hydro-test pump for RCP seal injection.	SAMA would provide an independent seal injection source, without the cost of a new system.
13	Replace ECCS pump motor with air-cooled motors.	SAMA would eliminate ECCS dependency on component cooling system (but not on room cooling).
14	Install improved RCS pumps seals.	SAMA would reduce probability of RCP seal LOCA by installing RCP seal O-ring constructed of improved materials
15	Install additional component cooling water pump.	SAMA would reduce probability of loss of component cooling leading to RCP seal LOCA.
16	Prevent centrifugal charging pump flow diversion from the relief valves.	SAMA modification would reduce the frequency of the loss of RCP seal cooling if relief valve opening causes a flow diversion large enough to prevent RCP seal injection.
17	Change procedures to isolate RCP seal letdown flow on loss of component cooling, and guidance on loss of injection during seal LOCA.	SAMA would reduce CDF from loss of seal cooling.
18	Implement procedures to stagger high-pressure safety injection (HPSI) pump use after a loss of SW.	SAMA would allow HPSI to be extended after a loss of SW.
19	Use FPS pumps as a backup seal injection and high-pressure makeup.	SAMA would reduce the frequency of the RCP seal LOCA and the SBO CDF.
20	Enhance procedural guidance for use of cross-tied component cooling or SW pumps.	SAMA would reduce the frequency of the loss of component cooling water and SW.
21	Procedure enhancements and operator training in support system failure sequences, with emphasis on anticipating problems and coping.	SAMA would potentially improve the success rate of operator actions subsequent to support system failures.
22	Improved ability to cool the residual heat removal (RHR) heat exchangers.	SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the FPS or by installing a component cooling water cross-tie.
23	8.a. Additional SW Pump	SAMA would conceivably reduce common cause dependencies from SW system and thus reduce plant risk through system reliability improvement.
24	Create an independent RCP seal injection system, without dedicated diesel	This SAMA would add redundancy to RCP seal cooling alternatives, reducing the CDF from loss of CC or SW, but not SBO.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to Heating, Ventilation, and Air Conditioning		
25	Provide reliable power to control building fans.	SAMA would increase availability of CR ventilation on a loss of power.
26	Provide a redundant train of ventilation.	SAMA would increase the availability of components dependent on room cooling.
27	Procedures for actions on loss of HVAC.	SAMA would provide for improved credit to be taken for loss of HVAC sequences (improved affected electrical equipment reliability upon a loss of control building HVAC).
28	Add a diesel building switchgear room high temperature alarm.	SAMA would improve diagnosis of a loss of switchgear room HVAC. Option 1: Install high temp alarm. Option 2: Redundant louver and thermostat
29	Create ability to switch fan power supply to DC in an SBO event.	SAMA would allow continued operation in an SBO event. This SAMA was created for reactor core isolation cooling (RCIC) system room at Fitzpatrick Nuclear Power Plant.
30	Enhance procedure to instruct operators to trip unneeded RHR/CS pumps on loss of room ventilation.	SAMA increases availability of required RHR/CS pumps. Reduction in room heat load allows continued operation of required RHR/CS pumps, when room cooling is lost.
31	Stage backup fans in switchgear (SWGR) rooms	This SAMA would provide alternate ventilation in the event of a loss of SWGR Room ventilation
Improvements Related to Ex-Vessel Accident Mitigation/Containment Phenomena		
32	Delay containment spray actuation after large LOCA.	SAMA would lengthen time of refueling water storage tank (RWST) availability.
33	Install containment spray pump header automatic throttle valves.	SAMA would extend the time over which water remains in the RWST, when full CS flow is not needed
34	Install an independent method of suppression pool cooling.	SAMA would decrease the probability of loss of containment heat removal. For PWRs, a potential similar enhancement would be to install an independent cooling system for sump water.
35	Develop an enhanced drywell spray system.	SAMA would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
36	Provide dedicated existing drywell spray system.	SAMA would provide a source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. This would use an existing spray loop instead of developing a new spray system.
37	Install an unfiltered hardened containment vent.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products not being scrubbed.
38	Install a filtered containment vent to remove decay heat.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products being scrubbed. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber
39	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.
40	Create/enhance hydrogen recombiners with independent power supply.	SAMA would reduce hydrogen detonation at lower cost, Use either 1) a new independent power supply 2) a nonsafety-grade portable generator 3) existing station batteries 4) existing AC/DC independent power supplies.
41	Install hydrogen recombiners.	SAMA would provide a means to reduce the chance of hydrogen detonation.
42	Create a passive design hydrogen ignition system.	SAMA would reduce hydrogen denotation system without requiring electric power.
43	Create a large concrete crucible with heat removal potential under the basemat 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 basemat.
44	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.
45	Provide modification for flooding the drywell head.	SAMA would help mitigate accidents that result in the leakage through the drywell head seal.
46	Enhance FPS and/or standby gas treatment system hardware and procedures.	SAMA would improve fission product scrubbing in severe accidents.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
47	Create a reactor CFS.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
48	Create other options for reactor cavity flooding.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
49	Enhance air return fans (ice condenser plants).	SAMA would provide an independent power supply for the air return fans, reducing containment failure in SBO sequences.
50	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 form the vitrified compound would be facilitated, and concrete attack would not occur
51	Provide a containment inerting capability.	SAMA would prevent combustion of hydrogen and carbon monoxide gases.
52	Use the FPS as a backup source for the containment spray system.	SAMA would provide redundant containment spray function without the cost of installing a new system.
53	Install a secondary containment filtered vent.	SAMA would filter fission products released from primary containment.
54	Install a passive containment spray system.	SAMA would provide redundant containment spray method without high cost.
55	Strengthen primary/secondary containment.	SAMA would reduce the probability of containment overpressurization to failure.
56	Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur.	SAMA would prevent basemat melt-through.
57	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.
58	Construct a building to be connected to primary/secondary containment that is maintained at a vacuum.	SAMA would provide a method to depressurize containment and reduce fission product release.
59	Refill CST	SAMA would reduce the risk of core damage during events such as extended SBOs or LOCAs which render the suppression pool unavailable as an injection source due to heat up.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
60	Maintain ECCS suction on CST	SAMA would maintain suction on the CST as long as possible to avoid pump failure as a result of high suppression pool temperature
61	Modify containment flooding procedure to restrict flooding to below TAF	SAMA would avoid forcing containment venting
62	Enhance containment venting procedures with respect to timing, path selection and technique.	SAMA would improve likelihood of successful venting strategies.
63	1.a. Severe Accident EPGs/AMGs	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
64	1.h. Simulator Training for Severe Accident	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
65	2.g. Dedicated Suppression Pool Cooling	SAMA would decrease the probability of loss of containment heat removal. While PWRs do not have suppression pools, a similar modification may be applied to the sump. Installation of a dedicated sump cooling system would provide an alternate method of cooling injection water.
66	3.a. Larger Volume Containment	SAMA increases time before containment failure and increases time for recovery
67	3.b. Increased Containment Pressure Capability (sufficient pressure to withstand severe accidents)	SAMA minimizes likelihood of large releases
68	3.c. Improved Vacuum Breakers (redundant valves in each line)	SAMA reduces the probability of a stuck open vacuum breaker.
69	3.d. Increased Temperature Margin for Seals	This SAMA would reduce containment failure due to drywell head seal failure caused by elevated temperature and pressure.
70	3.e. Improved Leak Detection	This SAMA would help prevent LOCA events by identifying pipes which have begun to leak. These pipes can be replaced before they break.
71	3.f. Suppression Pool Scrubbing	Directing releases through the suppression pool will reduce the radionuclides allowed to escape to the environment.
72	3.g. Improved Bottom Penetration Design	SAMA reduces failure likelihood of RPV bottom head penetrations
73	4.a. Larger Volume Suppression Pool (double effective liquid volume)	SAMA would increase the size of the suppression pool so that heatup rate is reduced, allowing more time for recovery of a heat removal system

TABLE A-1
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SAMA ID number	SAMA title	Result of potential enhancement
74	5.a/d. Unfiltered Vent	SAMA would provide an alternate decay heat removal method with the released fission products not being scrubbed.
75	5.b/c. Filtered Vent	SAMA would provide an alternate decay heat removal method with the released fission products being scrubbed.
76	6.a. Post Accident Inerting System	SAMA would reduce likelihood of gas combustion inside containment
77	6.b. Hydrogen Control by Venting	Prevents hydrogen detonation by venting the containment before combustible levels are reached.
78	6.c. Pre-inerting	SAMA would reduce likelihood of gas combustion inside containment
79	6.d. Ignition Systems	Burning combustible gases before they reach a level which could cause a harmful detonation is a method of preventing containment failure.
80	6.e. Fire Suppression System Inerting	Use of the FPS as a back up containment inerting system would reduce the probability of combustible gas accumulation. This would reduce the containment failure probability for small containments (e.g. BWR MKI).
81	7.a. 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.
82	7.b. Containment Spray Augmentation	This SAMA would provide additional means of providing flow to the containment spray system.
83	12.b. Integral Basemat	This SAMA would improve containment and system survivability for seismic events.
84	13.a. Reactor Building Sprays	This SAMA provides the capability to use firewater sprays in the reactor building to mitigate release of fission products into the Rx Bldg following an accident.
85	14.a. Flooded Rubble Bed	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.
86	14.b. Reactor Cavity Flooder	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
87	14.c. Basaltic Cements	SAMA minimizes carbon dioxide production during core concrete interaction.

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SAMA ID number	SAMA title	Result of potential enhancement
88	Provide a core debris control system	(Intended for ice condenser plants): This SAMA would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and the containment shell.
89	Add ribbing to the containment shell	This SAMA would reduce the risk of buckling of containment under reverse pressure loading.
Improvements Related to Enhanced AC/DC Reliability/Availability		
90	Proceduralize alignment of spare diesel to shutdown board after LOOP and failure of the diesel normally supplying it.	SAMA would reduce the SBO frequency.
91	Provide an additional DG.	SAMA would increase the reliability and availability of onsite emergency AC power sources.
92	Provide additional DC battery capacity.	SAMA would ensure longer battery capability during an SBO, reducing the frequency of long-term SBO sequences.
93	Use fuel cells instead of lead-acid batteries.	SAMA would extend DC power availability in an SBO.
94	Procedure to cross-tie high-pressure core spray diesel.	SAMA would improve core injection availability by providing a more reliable power supply for the high-pressure core spray pumps.
95	Improve 4.16-kV bus cross-tie ability.	SAMA would improve AC power reliability.
96	Incorporate an alternate battery charging capability.	SAMA would improve DC power reliability by either cross-tying the AC busses, or installing a portable diesel-driven battery charger.
97	Increase/improve DC bus load shedding.	SAMA would extend battery life in an SBO event.
98	Replace existing batteries with more reliable ones.	SAMA would improve DC power reliability and thus increase available SBO recovery time.
99	Mod for DC Bus A reliability.	SAMA would increase the reliability of AC power and injection capability. Loss of DC Bus A causes a loss of main condenser, prevents transfer from the main transformer to off-site power (OSP), and defeats one half of the low vessel pressure permissive for low pressure coolant injection (LPCI)/CS injection valves.
100	Create AC power cross-tie capability with other unit.	SAMA would improve AC power reliability.
101	Create a cross-tie for diesel fuel oil.	SAMA would increase diesel fuel oil supply and thus DG, reliability.

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SAMA ID number	SAMA title	Result of potential enhancement
102	Develop procedures to repair or replace failed 4-kV breakers.	SAMA would offer a recovery path from a failure of the breakers that perform transfer of 4.16-kV non-emergency busses from unit station service transformers, leading to loss of emergency AC power.
103	Emphasize steps in recovery of OSP after an SBO.	SAMA would reduce HEP during OSP recovery.
104	Develop a severe weather conditions procedure.	For plants that do not already have one, this SAMA would reduce the CDF for external weather-related events.
105	Develop procedures for replenishing diesel fuel oil.	SAMA would allow for long-term diesel operation.
106	Install gas turbine generator.	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.
107	Create a backup source for diesel cooling. (Not from existing system)	This SAMA would provide a redundant and diverse source of cooling for the DGs, which would contribute to enhanced diesel reliability.
108	Use FPS as a backup source for diesel cooling.	This SAMA would provide a redundant and diverse source of cooling for the DGs, which would contribute to enhanced diesel reliability.
109	Provide a connection to an alternate source of OSP.	SAMA would reduce the probability of a LOOP event.
110	Bury OSP lines.	SAMA could improve OSP reliability, particularly during severe weather.
111	Replace anchor bolts on DG oil cooler.	Millstone Nuclear Power Station found a high seismic SBO risk due to failure of the diesel oil cooler anchor bolts. For plants with a similar problem, this would reduce seismic risk. Note that these were Fairbanks Morse DGs.
112	Change undervoltage (UV), AFW actuation signal (AFAS) block and high pressurizer pressure actuation signals to 3-out-of-4, instead of 2-out-of-4 logic.	SAMA would reduce risk of 2/4 inverter failure.
113	Provide DC power to the 120/240-V vital AC system from the Class 1E station service battery system instead of its own battery.	SAMA would increase the reliability of the 120-VAC Bus.
114	Bypass DG Trips	SAMA would allow D/Gs to operate for longer.
115	2.i. 16 hour SBO Injection	SAMA includes improved capability to cope with longer SBO scenarios.

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SAMA ID number	SAMA title	Result of potential enhancement
116	9.a. Steam Driven Turbine Generator	This SAMA would provide a steam driven turbine generator which uses reactor steam and exhausts to the suppression pool. If large enough, it could provide power to additional equipment.
117	9.b. 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 OSP.
118	9.d. Additional DG	SAMA would reduce the SBO frequency.
119	9.e. Increased Electrical Divisions	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.
120	9.f. Improved Uninterruptible Power Supplies	SAMA would provide increased reliability of power supplies supporting front-line equipment, thus reducing core damage and release frequencies.
121	9.g. AC Bus Cross-Ties	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.
122	9.h. Gas Turbine	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.
123	9.i. Dedicated RHR (bunkered) Power Supply	SAMA would provide RHR with more reliable AC power.
124	10.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).
125	10.b. Additional Batteries/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).
126	10.c. Fuel Cells	SAMA would extend DC power availability in an SBO.
127	10.d. DC Cross-ties	This SAMA would improve DC power reliability.
128	10.e. Extended SBO Provisions	SAMA would provide reduction in SBO sequence frequencies.
129	Add an automatic bus transfer feature to allow the automatic transfer of the 120V vital AC bus from the on-line unit to the standby unit	Plants are typically sensitive to the loss of one or more 120V vital AC buses. Manual transfers to alternate power supplies could be enhanced to transfer automatically.
Improvements in Identifying and Mitigating Containment Bypass		

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
130	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture (SGTR).	SAMA would enhance depressurization during a SGTR.
131	Improve SGTR coping abilities.	SAMA would improve instrumentation to detect SGTR, or additional system to scrub fission product releases.
132	Add other SGTR coping abilities.	SAMA would decrease the consequences of an SGTR.
133	Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	SAMA would eliminate direct release pathway for SGTR sequences.
134	Replace steam generators (SG) with a new design.	SAMA would lower the frequency of an SGTR.
135	Revise emergency operating procedures to direct that a faulted SG be isolated.	SAMA would reduce the consequences of an SGTR.
136	Direct SG flooding after a SGTR, prior to core damage.	SAMA would provide for improved scrubbing of SGTR releases.
137	Implement a maintenance practice that inspects 100% of the tubes in a SG.	SAMA would reduce the potential for an SGTR.
138	Locate RHR inside of containment.	SAMA would prevent intersystem LOCA (ISLOCA) out the RHR pathway.
139	Install additional instrumentation for ISLOCAs.	SAMA would decrease ISLOCA frequency by installing pressure of leak monitoring instruments in between the first two pressure isolation valves on low-pressure inject lines, RHR suction lines, and HPSI lines.
140	Increase frequency for valve leak testing.	SAMA could reduce ISLOCA frequency.
141	Improve operator training on ISLOCA coping.	SAMA would decrease ISLOCA effects.
142	Install relief valves in the CC System.	SAMA would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA.
143	Provide leak testing of valves in ISLOCA paths.	SAMA would help reduce ISLOCA frequency. At Kewaunee Nuclear Power Plant, four MOVs isolating RHR from the RCS were not leak tested.
144	Revise EOPs to improve ISLOCA identification.	SAMA would ensure LOCA outside containment could be identified as such. Salem Nuclear Power Plant had a scenario where an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.
145	Ensure all ISLOCA releases are scrubbed.	SAMA would scrub all ISLOCA releases. One example is to plug drains in the break area so that the break point would be covered with water.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
146	Add redundant and diverse limit switches to each containment isolation valve.	SAMA could reduce the frequency of containment isolation failure and ISLOCAs through enhanced isolation valve position indication.
147	Early detection and mitigation of ISLOCA	SAMA would limit the effects of ISLOCA accidents by early detection and isolation
148	8.e. Improved MSIV Design	This SAMA would improve isolation reliability and reduce spurious actuations that could be initiating events.
149	Proceduralize use of pressurizer vent valves during steam generator tube rupture (SGTR) sequences	Some plants may have procedures to direct the use of pressurizer sprays to reduce RCS pressure after an SGTR. Use of the vent valves would provide a back-up method.
150	Implement a maintenance practice that inspects 100% of the tubes in an SG	This SAMA would reduce the potential for a tube rupture.
151	Locate RHR inside of containment	This SAMA would prevent ISLOCA out the RHR pathway.
152	Install self-actuating containment isolation valves	For plants that do not have this, it would reduce the frequency of isolation failure.
Improvements in Reducing Internal Flooding Frequency		
153	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	SAMA would prevent flood propagation, for a plant where internal flooding from turbine building to safeguards areas is a concern.
154	Improve inspection of rubber expansion joints on main condenser.	SAMA would reduce the frequency of internal flooding, for a plant where internal flooding due to a failure of circulating water system expansion joints is a concern.
155	Implement internal flood prevention and mitigation enhancements.	This SAMA would reduce the consequences of internal flooding.
156	Implement internal flooding improvements such as those implemented at Fort Calhoun.	This SAMA would reduce flooding risk by preventing or mitigating rupture in the RCP seal cooler of the component cooling system an ISLOCA in a shutdown cooling line, an AFW flood involving the need to remove a watertight door.
157	Shield electrical equipment from potential water spray	SAMA would decrease risk associated with seismically induced internal flooding
158	13.c. Reduction in Reactor Building Flooding	This SAMA reduces the Reactor Building Flood Scenarios contribution to core damage and release.

TABLE A-1
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SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to Feedwater/Feed and Bleed Reliability/Availability		
159	Install a digital feedwater upgrade.	This SAMA would reduce the chance of a loss of main feedwater following a plant trip.
160	Perform surveillances on manual valves used for backup AFW pump suction.	This SAMA would improve success probability for providing alternative water supply to the AFW pumps.
161	Install manual isolation valves around AFW turbine-driven steam admission valves.	This SAMA would reduce the dual turbine-driven AFW pump maintenance unavailability.
162	Install accumulators for turbine-driven AFW pump flow control valves (CVs).	This SAMA would provide control air accumulators for the turbine-driven AFW flow CVs, the motor-driven AFW pressure CVs and SG power-operated relief valves (PORVs). This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP.
163	Install separate accumulators for the AFW cross-connect and block valves	This SAMA would enhance the operator's ability to operate the AFW cross-connect and block valves following loss of air support.
164	Install a new CST	Either replace the existing tank with a larger one, or install a back-up tank.
165	Provide cooling of the steam-driven AFW pump in an SBO event	This SAMA would improve success probability in an SBO by: (1) using the FP system to cool the pump, or (2) making the pump self cooled.
166	Proceduralize local manual operation of AFW when control power is lost.	This SAMA would lengthen AFW availability in an SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.
167	Provide portable generators to be hooked into the turbine driven AFW, after battery depletion.	This SAMA would extend AFW availability in an SBO (assuming the turbine driven AFW requires DC power)
168	Add a motor train of AFW to the Steam trains	For PWRs that do not have any motor trains of AFW, this would increase reliability in non-SBO sequences.
169	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate	This SAMA would be a back-up water supply for the feedwater/condensate systems.
170	Use FP system as a back-up for SG inventory	This SAMA would create a back-up to main and AFW for SG water supply.
171	Procure a portable diesel pump for isolation condenser make-up	This SAMA would provide a back-up to the city water supply and diesel FP system pump for isolation condenser make-up.
172	Install an independent DG for the CST make-up pumps	This SAMA would allow continued inventory make-up to the CST during an SBO.

TABLE A-1
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SAMA ID number	SAMA title	Result of potential enhancement
173	Change failure position of condenser make-up valve	This SAMA would allow greater inventory for the AFW pumps by preventing CST flow diversion to the condenser if the condenser make-up valve fails open on loss of air or power.
174	Create passive secondary side coolers.	This SAMA would reduce CDF from the loss of Feedwater by providing a passive heat removal loop with a condenser and heat sink.
175	Replace current PORVs with larger ones such that only one is required for successful feed and bleed.	This SAMA would reduce the dependencies required for successful feed and bleed.
176	Install motor-driven feedwater pump.	SAMA would increase the availability of injection subsequent to MSIV closure.
177	Use Main feedwater pumps for a Loss of Heat Sink Event	This SAMA involves a procedural change that would allow for a faster response to loss of the secondary heat sink. Use of only the feedwater booster pumps for injection to the SGs requires depressurization to about 350 psig; before the time this pressure is reached, conditions would be met for initiating feed and bleed. Using the available turbine driven feedwater pumps to inject water into the SGs at a high pressure rather than using the feedwater booster alone allows injection without the time consuming depressurization.
Improvements in Core Cooling Systems		
178	Provide the capability for diesel driven, low pressure vessel make-up	This SAMA would provide an extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., FP system)
179	Provide an additional HPSI pump with an independent diesel	This SAMA would reduce the frequency of core melt from small LOCA and SBO sequences
180	Install an independent AC HPSI system	This SAMA would allow make-up and feed and bleed capabilities during an SBO.
181	Create the ability to manually align ECCS recirculation	This SAMA would provide a back-up should automatic or remote operation fail.
182	Implement an RWT make-up procedure	This SAMA would decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR.
183	Stop LPSI pumps earlier in medium or large LOCAs.	This SAMA would provide more time to perform recirculation swap over.
184	Emphasize timely swap over in operator training.	This SAMA would reduce HEP of recirculation failure.

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SAMA ID number	SAMA title	Result of potential enhancement
185	Upgrade Chemical and Volume Control System to mitigate small LOCAs.	For a plant like the AP600 where the Chemical and Volume Control System cannot mitigate a Small LOCA, an upgrade would decrease the Small LOCA CDF contribution.
186	Install an active HPSI system.	For a plant like the AP600 where an active HPSI system does not exist, this SAMA would add redundancy in HPSI.
187	Change "in-containment" RWT suction from 4 check valves to 2 check and 2 air operated valves.	This SAMA would remove common mode failure of all four injection paths.
188	Replace 2 of the 4 safety injection (SI) pumps with diesel-powered pumps.	This SAMA would reduce the SI system CCF probability. This SAMA was intended for the System 80+, which has four trains of SI.
189	Align low pressure core injection or core spray to the CST on loss of suppression pool cooling.	This SAMA would help to ensure low pressure ECCS can be maintained in loss of suppression pool cooling scenarios.
190	Raise high pressure core injection/RCIC backpressure trip setpoints	This SAMA would ensure high pressure core injection/RCIC availability when high suppression pool temperatures exist.
191	Improve the reliability of the ADS.	This SAMA would reduce the frequency of high pressure core damage sequences.
192	Disallow automatic vessel depressurization in non-ATWS scenarios	This SAMA would improve operator control of the plant.
193	Create automatic swap over to recirculation on RWT depletion	This SAMA would reduce the human error contribution from recirculation failure.
194	Proceduralize intermittent operation of high pressure coolant injection (HPCI).	SAMA would allow for extended duration of HPCI availability.
195	Increase available NPSH for injection pumps.	SAMA increases the probability that these pumps will be available to inject coolant into the vessel by increasing the available NPSH for the injection pumps.
196	Modify Reactor Water Cleanup (RWCU) for use as a decay heat removal system and proceduralize use.	SAMA would provide an additional source of decay heat removal.
197	Control Rod Drive (CRD) Injection	SAMA would supply an additional method of level restoration by using a non-safety system.
198	Condensate Pumps for Injection	SAMA to provide an additional option for coolant injection when other systems are unavailable or inadequate

TABLE A-1
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SAMA ID number	SAMA title	Result of potential enhancement
199	Align EDG to CRD for Injection	SAMA to provide power to an additional injection source during loss of power events
200	Re-open MSIVs	SAMA to regain the main condenser as a heat sink by re-opening the MSIVs.
201	Bypass RCIC Turbine Exhaust Pressure Trip	SAMA would allow RCIC to operate longer.
202	2.a. Passive High Pressure System	SAMA will improve prevention of core melt sequences by providing additional high pressure capability to remove decay heat through an isolation condenser type system
203	2.c. Suppression Pool Jockey Pump	SAMA will improve prevention of core melt sequences by providing a small makeup pump to provide low pressure decay heat removal from the RPV using the suppression pool as a source of water.
204	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.
205	2.e. Additional Active High Pressure System	SAMA will improve reliability of high pressure decay heat removal by adding an additional system.
206	2.f. Improved Low Pressure System (Firepump)	SAMA would provide FPS pump(s) for use in low pressure scenarios.
207	4.b. CUW Decay Heat Removal	This SAMA provides a means for Alternate Decay Heat Removal.
208	4.c. High Flow Suppression Pool Cooling	SAMA would improve suppression pool cooling.
209	8.c. Diverse Injection System	SAMA will improve prevention of core melt sequences by providing additional injection capabilities.
210	Alternate Charging Pump Cooling	This SAMA will improve the high pressure core flooding capabilities by providing the SI pumps with alternate gear and oil cooling sources. Given a total loss of Chilled Water, abnormal operating procedures would direct alignment of preferred Demineralized Water or the Fire System to the Chilled Water System to provide cooling to the SI pumps' gear and oil box (and the other normal loads).
Instrument Air/Gas Improvements		
211	Modify EOPs for ability to align diesel power to more air compressors.	For plants that do not have diesel power to all normal and back-up air compressors, this change would increase the reliability of IA after a LOOP.

TABLE A-1
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SAMA ID number	SAMA title	Result of potential enhancement
212	Replace old air compressors with more reliable ones	This SAMA would improve reliability and increase availability of the IA compressors.
213	Install nitrogen bottles as a back-up gas supply for SRVs.	This SAMA would extend operation of SRVs during an SBO and loss of air events (BWRs).
214	Allow cross connection of uninterruptible compressed air supply to opposite unit.	SAMA would increase the ability to vent containment using the hardened vent.
ATWS Mitigation		
215	Install MG set trip breakers in CR	This SAMA would provide trip breakers for the MG sets in the CR. In some plants, MG set breaker trip requires action to be taken outside of the CR. Adding control capability to the CR would reduce the trip failure probability in sequences where immediate action is required (e.g., ATWS).
216	Add capability to remove power from the bus powering the control rods	This SAMA would decrease the time to insert the control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has a rapid pressure excursion)
217	Create cross-connect ability for standby liquid control trains	This SAMA would improve reliability for boron injection during an ATWS event.
218	Create an alternate boron injection capability (back-up to standby liquid control)	This SAMA would improve reliability for boron injection during an ATWS event.
219	Remove or allow override of low pressure core injection during an ATWS	On failure on high pressure core injection and condensate, some plants direct reactor depressurization followed by 5 minutes of low pressure core injection. This SAMA would allow control of low pressure core injection immediately.
220	Install a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	This SAMA would improve equipment availability after an ATWS.
221	Create a boron injection system to back up the mechanical control rods.	This SAMA would provide a redundant means to shut down the reactor.
222	Provide an additional instrument system for ATWS mitigation (e.g., ATWS mitigation scram actuation circuitry).	This SAMA would improve instrument and control redundancy and reduce the ATWS frequency.
223	Increase the SRV reseat reliability.	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
224	Use CRD for alternate boron injection.	SAMA provides an additional system to address ATWS with SLC failure or unavailability.
225	Bypass MSIV isolation in Turbine Trip ATWS scenarios	SAMA will afford operators more time to perform actions. The discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities
226	Enhance operator actions during ATWS	SAMA will reduce human error probabilities during ATWS
227	Guard against SLC dilution	SAMA to control vessel injection to prevent boron loss or dilution following SLC injection.
228	11.a. ATWS Sized Vent	This SAMA would provide the ability to remove reactor heat from ATWS events.
229	11.b. Improved ATWS Capability	This SAMA includes items which reduce the contribution of ATWS to core damage and release frequencies.
Other Improvements		
230	Provide capability for remote operation of secondary side relief valves in an SBO	Manual operation of these valves is required in an SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability.
231	Create/enhance RCS depressurization ability	With either a new depressurization system, or with existing PORVs, head vents, and secondary side valve, RCS depressurization would allow earlier low pressure ECCS injection. Even if core damage occurs, low RCS pressure would alleviate some concerns about HPME.
232	Make procedural changes only for the RCS depressurization option	This SAMA would reduce RCS pressure without the cost of a new system
233	Defeat 100% load rejection capability.	This SAMA would eliminate the possibility of a stuck open PORV after a LOOP, since PORV opening would not be needed.
234	Change CRD flow CV failure position	Change failure position to the "fail-safest" position.

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SAMA ID number	SAMA title	Result of potential enhancement
235	Install secondary side guard pipes up to the MSIVs	This SAMA would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. This SAMA would also guard against or prevent consequential multiple SGTR following a Main Steam Line Break event.
236	Install digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (leak before break).
237	Increase seismic capacity of the plant to a high confidence, low pressure failure of twice the Safe Shutdown Earthquake.	This SAMA would reduce seismically -induced CDF.
238	Enhance the reliability of the demineralized water (DW) make-up system through the addition of diesel-backed power to one or both of the DW make-up pumps.	Inventory loss due to normal leakage can result in the failure of the CC and the SRW systems. Loss of CC could challenge the RCP seals. Loss of SRW results in the loss of three EDGs and the containment air coolers (CACs).
239	Increase the reliability of SRVs by adding signals to open them automatically.	SAMA reduces the probability of a certain type of medium break LOCA. Hatch evaluated medium LOCA initiated by an MSIV closure transient with a failure of SRVs to open. Reducing the likelihood of the failure for SRVs to open, subsequently reduces the occurrence of this medium LOCA.
240	Reduce DC dependency between high-pressure injection system and ADS.	SAMA would ensure containment depressurization and high-pressure injection upon a DC failure.
241	Increase seismic ruggedness of plant components.	SAMA would increase the availability of necessary plant equipment during and after seismic events.
242	Enhance RPV depressurization capability	SAMA would decrease the likelihood of core damage in loss of HPCI scenarios
243	Enhance RPV depressurization procedures	SAMA would decrease the likelihood of core damage in loss of HPCI scenarios
244	Replace mercury switches on FPSs	SAMA would decrease probability of spurious fire suppression system actuation given a seismic event+D114
245	Provide additional restraints for CO_2 tanks	SAMA would increase availability of FP given a seismic event.
246	Enhance control of transient combustibles	SAMA would minimize risk associated with important fire areas.
247	Enhance fire brigade awareness	SAMA would minimize risk associated with important fire areas.
248	Upgrade fire compartment barriers	SAMA would minimize risk associated with important fire areas.

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SAMA ID number	SAMA title	Result of potential enhancement
249	Enhance procedures to allow specific operator actions	SAMA would minimize risk associated with important fire areas.
250	Develop procedures for transportation and nearby facility accidents	SAMA would minimize risk associated with transportation and nearby facility accidents.
251	Enhance procedures to mitigate Large LOCA	SAMA would minimize risk associated with Large LOCA
252	1.b. Computer Aided Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.
253	1.c/d. Improved Maintenance Procedures/Manuals	SAMA will improve prevention of core melt sequences by increasing reliability of important equipment
254	1.e. Improved Accident Management Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.
255	1.f. Remote Shutdown Station	This SAMA would provide the capability to control the reactor in the event that evacuation of the MCR is required.
256	1.g. Security System	Improvements in the site's security system would decrease the potential for successful sabotage.
257	2.b. Improved Depressurization	SAMA will improve depressurization system to allow more reliable access to low pressure systems.
258	2.h. Safety Related CST	SAMA will improve availability of CST following a Seismic event
259	4.d. Passive Overpressure Relief	This SAMA would prevent vessel overpressurization.
260	8.b. Improved Operating Response	Improved operator reliability would improve accident mitigation and prevention.
261	8.d. Operation Experience Feedback	This SAMA would identify areas requiring increased attention in plant operation through review of equipment performance.
262	8.e. Improved SRV Design	This SAMA would improve SRV reliability, thus increasing the likelihood that sequences could be mitigated using low pressure heat removal.
263	12.a. Increased Seismic Margins	This SAMA would reduce the risk of core damage and release during seismic events.
264	13.b. System Simplification	This SAMA is intended to address system simplification by the elimination of unnecessary interlocks, automatic initiation of manual actions or redundancy as a means to reduce overall plant risk.

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SAMA ID number	SAMA title	Result of potential enhancement
265	Train operations crew for response to inadvertent actuation signals	This SAMA would improve chances of a successful response to the loss of two 120V AC buses, which may cause inadvertent signal generation.
266	Install tornado protection on gas turbine generators	This SAMA would improve onsite AC power reliability.