Applicant's Environmental Report - Operating License Renewal Stage

Brunswick

Steam Electric Plant

Applicant's Environmental Report –
Operating License Renewal Stage
Brunswick Steam Electric Plant
Progress Energy

Unit 1
Docket No. 50-325
License No. DPR-71

Unit 2
Docket No. 50-324
License No. DPR-62

TABLE OF CONTENTS

Section | Page

ACRONYMS AND ABBREVIATIONS AA-1

1.0 INTRODUCTION 1-1
- 1.1 Purpose of and Need for Action 1-1
- 1.2 Environmental Report Scope and Methodology 1-2
- 1.3 Brunswick Steam Electric Plant Licensee and Ownership 1-3
- 1.4 References 1-6

2.0 SITE AND ENVIRONMENTAL INTERFACES 2-1
- 2.1 Location and Features 2-1
- 2.2 Aquatic Communities 2-3
- 2.3 Groundwater Resources 2-6
- 2.4 Critical and Important Terrestrial Habitats 2-8
- 2.5 Threatened or Endangered Species 2-10
- 2.6 Regional Demography and Minority and Low-Income Populations 2-13
  - 2.6.1 General 2-13
  - 2.6.2 Minority and Low-Income Populations 2-15
    - 2.6.2.1 Minority Populations 2-16
    - 2.6.2.2 Low-Income Populations 2-17
- 2.7 Taxes 2-19
- 2.8 Land Use Planning 2-20
- 2.9 Social Services and Public Facilities 2-25
  - 2.9.1 Public Water Supply 2-25
  - 2.9.2 Transportation 2-27
- 2.10 Meteorology and Air Quality 2-28
- 2.11 Historic and Archaeological Resources 2-29
- 2.12 Other Projects and Activities 2-33
- 2.13 References 2-52

3.0 PROPOSED ACTION 3-1
- 3.1 General Plant Information 3-1
  - 3.1.1 Reactor and Containment Systems 3-1
  - 3.1.2 Cooling and Auxiliary Water Systems 3-3
    - 3.1.2.1 Surface Water 3-3
    - 3.1.2.2 Groundwater 3-5
  - 3.1.3 Transmission Facilities 3-6
- 3.2 Refurbishment Activities 3-9
- 3.3 Programs and Activities for Managing the Effects of Aging 3-11
- 3.4 Employment 3-12
- 3.5 References 3-16

TABLE OF CONTENTS (Continued)

Section		Page
4.0	ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION AND MITIGATING ACTIONS	4-1
4.1	Water Use Conflicts (Plants With Cooling Ponds or Cooling Towers Using Makeup Water from a Small River with Low Flow)	4-6
4.2	Entrainment of Fish and Shellfish in Early Life Stages	4-7
4.3	Impingement of Fish and Shellfish	4-9
4.4	Heat Shock	4-11
4.5	Groundwater Use Conflicts (Plants Using > 100 gpm of Groundwater)	4-13
4.6	Groundwater Use Conflicts (Plants Using Cooling Towers Withdrawing Makeup Water from a Small River)	4-14
4.7	Groundwater Use Conflicts (Plants Using Ranney Wells)	4-15
4.8	Degradation of Groundwater Quality	4-16
4.9	Impacts of Refurbishment On Terrestrial Resources	4-17
4.10	Threatened and Endangered Species	4-18
4.11	Air Quality during Refurbishment (Non-Attainment Areas)	4-20
4.12	Microbiological Organisms	4-21
4.13	Electric Shock from Transmission-Line-Induced Currents	4-22
4.14	Housing Impacts	4-25
4.15	Public Utilities: Public Water Supply Availability	4-26
4.16	Education Impacts from Refurbishment	4-27
4.17	Offsite Land Use	4-28
4.17.1	Offsite Land Use - Refurbishment	4-28
4.17.2	Offsite Land Use - License Renewal Term	4-29
4.18	Transportation	4-32
4.19	Historic and Archaeological Resources	4-33
4.20	Severe Accident Mitigation Alternatives	4-35
4.21	References	4-38
5.0	ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION	5-1
5.1	Discussion	5-1
5.2	References	5-3
6.0	SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS	6-1
6.1	License Renewal Impacts	6-1
6.2	Mitigation	6-2
6.3	Unavoidable Adverse Impacts	6-3
6.4	Irreversible and Irretrievable Resource Commitments	6-4
6.5	Short-term Use versus Long-term Productivity of the Environment	6-5
6.6	References	6-9

TABLE OF CONTENTS (Continued)

Section	Page
7.0 ALTERNATIVES TO THE PROPOSED ACTION	7-1
7.1 No-Action Alternative	7-3
7.2 Alternatives that Meet System Generating Needs	7-5
7.2.1 Alternatives Considered	7-7
7.2.1.1 Construct and Operate Fossil-Fuel-Fired Generation	7-9
7.2.1.2 Purchase Power	7-10
7.2.1.3 Reduce Demand	7-11
7.2.1.4 Other Alternatives	7-12
7.2.2 Environmental Impacts of Alternatives	7-17
7.2.2.1 Coal-Fired Generation	7-17
7.2.2.2 Gas-Fired Generation	7-20
7.2.2.3 Purchased Power	7-21
7.3 References	7-28
8.0 COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES	8-1
8.1 References	8-10
9.0 STATUS OF COMPLIANCE	9-1
9.1 Proposed Action	9-1
9.1.1 General	9-1
9.1.2 Threatened or Endangered Species	9-1
9.1.3 Coastal Zone Management Program Compliance	9-2
9.1.4 Historic Preservation	9-2
9.1.5 Water Quality (401) Certification	9-2
9.2 Alternatives	9-4
9.3 References	9-9

List of Appendices

Appendix A - NRC NEPA ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS
Appendix B - NPDES PERMIT
Appendix C - SPECIAL-STATUS SPECIES CORRESPONDENCE
Appendix D - STATE HISTORIC PRESERVATION OFFICER CORRESPONDENCE
Appendix E - COASTAL ZONE CONSISTENCY CERTIFICATION
Appendix F - SEVERE ACCIDENT MITIGATION ALTERNATIVES

TABLE OF CONTENTS (Continued)

List of Tables

Table		Page
1-1	Environmental Report Responses to License Renewal Environmental Regulatory Requirements	1-4
2-1	Endangered and Threatened Species Known to Occur in Brunswick County or in Counties Crossed by BSEP-Associated Transmission Lines	2-34
2-2	Federally Listed Terrestrial Species Found in the Vicinity of BSEP or in the Vicinity of BSEP Transmission Lines	2-37
2-3	Estimated Populations and Annual Growth Rates	2-38
2-4	Minority and Low-Income Population Census Block Groups and Tracts	2-39
2-5	Property Tax Revenues Generated in Brunswick County; Property Taxes Paid to Brunswick County by Brunswick Steam Electric Plant, 1997 – 2002	2-40
2-6	Brunswick County Public Water Suppliers and Capacities	2-41
2-7	New Hanover County Public Water Suppliers and Capacities	2-42
2-8	Traffic Counts for Roads in the Vicinity of BSEP	2-43
2-9	Sites Listed in the National Register of Historic Places that Fall within a 6-Mile Radius of BSEP	2-44
4-1	Results of Induced Current Analysis	4-37
6-1	Environmental Impacts Related to License Renewal at BSEP	6-7
7-1	Coal-Fired Alternative	7-23
7-2	Gas-Fired Alternative	7-24
7-3	Air Emissions from Coal-Fired Alternative	7-25
7-4	Solid Waste from Coal-Fired Alternative	7-26
7-5	Air Emissions from Gas-Fired Alternative	7-27
8-1	Impacts Comparison Summary	8-2
8-2	Impacts Comparison Detail	8-3
9-1	Environmental Authorizations for Current BSEP Units 1 and 2 Operations	9-5
9-2	Environmental Authorizations for BSEP Units 1 and 2 License Renewal	9-8

TABLE OF CONTENTS (Continued)

List of Figures

Figure		Page
2-1	50-Mile Vicinity Map	2-45
2-2	6-Mile Vicinity Map	2-46
2-3	Site Boundary Map	2-47
2-4	American Indian and Alaskan Native Minority Populations	2-48
2-5	Black Races Minority Populations	2-49
2-6	Aggregate Minority Populations	2-50
2-7	Low-Income Households	2-51
3-1	General Plant Layout	3-14
3-2	Transmission Line Map	3-15
7-1	North Carolina Utility Generating Capacity, 2002	7-5
7-2	South Carolina Utility Generating Capacity, 2002	7-5
7-3	North Carolina Utility Generation by Fuel Type, 2002	7-6
7-4	South Carolina Utility Generation by Fuel Type, 2002	7-6
7-5	Progress Energy Generating Capacity in North and South Carolina, 2002	7-7
7-6	Progress Energy Generation by Fuel Type in North and South Carolina, 2002	7-7

ACRONYMS AND ABBREVIATIONS

AQCR	Air Quality Control Region
BSEP	Brunswick Steam Electric Plant
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
cfs	cubic feet per second
CP&L	Carolina Power & Light Company
CWA	Clean Water Act
DSM	demand-side management
EPA	U.S. Environmental Protection Agency
°F	degrees Fahrenheit
FES	Final Environmental Statement
FWS	U.S. Fish and Wildlife Service
GEIS	Generic Environmental Impact Statement for License Renewal of Nuclear Plants
gpm	gallons per minute
IPA	Integrated Plant Assessment
kV	kilovolt
LCFWSA	Lower Cape Fear Water and Sewer Authority
MOTSP	Military Ocean Terminal Sunny Point
msl	mean sea level
MW	megawatt
MWe	megawatts-electrical
NCDENR	North Carolina Department of Environment and Natural Resources
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
ROW	right-of-way
SAMA	Severe Accident Mitigation Alternatives
SHPO	State Historic Preservation Officer
SMITTR	surveillance, monitoring, inspections, testing, trending, and recordkeeping
SO_2	sulfur dioxide
SO_x	oxides of sulfur

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 Brunswick Steam Electric Plant Units 1 and 2 (BSEP), pursuant to NRC Operating Licenses DPR-71 and DPR-62, respectively. The Unit 1 license will expire September 8, 2016, and the Unit 2 license will expire December 27, 2014. Progress Energy has prepared this environmental report in conjunction with its application to NRC to renew the BSEP Units 1 and 2 operating licenses, 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 Requirements 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 BSEP, 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 BSEP licensed operating periods 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 BSEP 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, NRC 1996b, NRC 1996c, and NRC 1999a)
- *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996d and NRC 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 BRUNSWICK STEAM ELECTRIC PLANT LICENSEE AND OWNERSHIP

CP&L is the NRC licensee for BSEP, as well as the H. B. Robinson Nuclear Plant and the Shearon Harris Nuclear Power Plant. CP&L, now doing business as Progress Energy Carolinas, Inc., will submit the BSEP license renewal application to the NRC. Progress Energy Carolinas, Inc., which serves more than 1.3 million customers in North and South Carolina, is a wholly owned subsidiary of Progress Energy, Inc., a diversified energy services company headquartered in Raleigh, North Carolina.

BSEP is co-owned by Progress Energy (81.7 percent) and North Carolina Eastern Municipal Power Agency (18.3 percent) but Progress Energy (CP&L is the licensee) has sole responsibility for management and operation of the plant.

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 Water 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 Archeological 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.

2.0 SITE AND ENVIRONMENTAL INTERFACES

2.1 LOCATION AND FEATURES

Brunswick Steam Electric Plant (BSEP) is located in Brunswick County in southeastern, North Carolina, near the mouth of the Cape Fear River. The city limits of the nearest major metropolitan area, Wilmington, North Carolina, are approximately 15 miles north of the BSEP site. Myrtle Beach, South Carolina, a major regional tourist destination, lies approximately 50 miles to the southwest. Figures 2-1 and 2-2 are the 50-mile and 6-mile vicinity maps, respectively.

The Plant is situated on approximately 1,200 acres of land (CP&L 2001, Rev. 17B, pg. 1-1). The facility includes the powerblock area and support facilities, the nuclear exclusion zone, a buffer zone, a 3-mile-long intake canal that is used to withdraw cooling water from the Cape Fear River, and a 6-mile-long discharge canal that conveys heated effluent to the Atlantic Ocean (Figure 2-2).

Figure 3-1 shows the general plant layout. Major facilities in the central industrial portion of the plant include two reactor buildings, the turbine building, the control building, the radwaste building, and the diesel generator building. All of these facilities lie within the Protected Area, which is surrounded by a perimeter fence. The main (off-gas) stack stands in the southeast corner of the Protected Area, adjacent to the intake canal. Major administrative and support facilities including the Technical Administrative Control (TAC) Building, Technical Training Center, and Operator Training Building lie just outside the Protected Area, but within the larger Nuclear Exclusion Zone (Figure 2-3), which is posted and patrolled by security personnel.

Figure 2-3 shows the BSEP site boundary. The area within the site boundary, the Nuclear Exclusion Zone, totals 962 acres (AEC 1974, Table II-2). Approximately 130 acres of this total are occupied by generating facilities, support facilities, warehouses, parking areas, construction laydown areas, equipment storage areas, and roads. An open area of approximately 10 acres northeast of Warehouse H was used as a landfill for office wastes (mainly paper), but was closed in 1997 (see Figure 3-1). The remaining acreage consists of woodlands (mostly pine forests in upland areas), open (old) fields, wetlands, or marshlands, depending on their soils, their elevation, and their historic use.

The area immediately surrounding the plant is a mix of agricultural lands, woodlands, swamps, and marshes. Military Ocean Terminal Sunny Point (MOTSP), a 16,000-acre facility owned and operated by the U.S. Army, lies immediately north of the BSEP site. Although MOTSP's primary mission is the shipment of munitions and materiel for the Department of Defense (Global Security 2001), it has received recognition from state resource agencies and the Army for its conservation efforts, including enhancement of habitat for several endangered species (USAEC 1998).

The nearest incorporated community to BSEP is the town of Southport, located approximately 2.5 miles south of the BSEP site, which has a year-round population of

2,351. The area within a 6-mile radius includes the town of Southport; the resort communities of Caswell Beach, Oak Island, and Bald Head Island; and the community of Boiling Spring Lakes (Figure 2-2). Aside from these villages and several small communities that have grown up around crossroads of major thoroughfares, the area is rural in character, with privately-owned tracts of forestland, forested wetlands, and agricultural lands dominating the landscape.

Section 3.1 describes key features of BSEP, including reactor and containment systems, cooling water system, and transmission system.

2.2 AQUATIC COMMUNITIES

BSEP operations have been scrutinized by state and federal resource agencies since Unit 2 came on line in 1974, focusing on potential impacts of the plant's cooling water systems on the Cape Fear estuary. Background information on the aquatic communities of the Cape Fear estuary can be found in the Final Environmental Statement (AEC 1974), Brunswick Steam Electric Plant Cape Fear Studies Interpretive Reports (CP&L 1980; CP&L 1985), annual biological monitoring reports prepared by CP&L and Progress Energy since 1981, and numerous "gray literature" monographs (e.g., EPRI reports) and journal articles.

The Lower Cape Fear River below Wilmington, North Carolina, ranges from one to two miles wide and is mostly shallow, except for a shipping channel dredged and maintained by the U.S. Army Corps of Engineers that extends from the mouth of the river to the Port of Wilmington (CP&L 1980, pp. 4-3 and 4-4). The Corps of Engineers is deepening the shipping channel by four feet (to a depth of 42 feet) to accommodate larger cargo ships (USACE 2003). This project, officially referred to as the Wilmington Harbor Project, was authorized in 1998 and is expected to be completed in 2005.

The estuary includes 22,000 acres of salt marshes and 18,000 acres of tidal flats and small tidal streams. The Cape Fear estuary is a "partially mixed estuary," meaning its water shows a gradual increase in salinity and density with depth (CP&L 1980, pg. 4-3). It has a net seaward displacement in its surface waters and a net landward displacement in its deeper waters, which has implications with respect to the transport of plankton and other organisms in and out of the estuary.

The average daily freshwater flow into the Cape Fear estuary is around 10,000 cubic feet per second, but there is considerable variability. The distribution and quantity of rainfall in the watershed are the main determinants of annual and seasonal variation (CP&L 1980, pg. 4-5). Flows in the Cape Fear River are highest in late winter and lowest in late-summer and fall. During periods of average freshwater inflow (after the ebb tide) surface salinities range from 8 parts per thousand (Sunny Point) to 24 parts per thousand (Bald Head), while bottom salinities range from 15 parts per thousand (Sunny Point) to 29 parts per thousand (Bald Head) (CP&L 1980, pg. 4-20).

Tidal height (amplitude) decreases as the tidal pulse moves up-river. The average tidal amplitude in the lower river, (near its mouth) is approximately four feet (CP&L 1980, pg. 4-5). Tidal currents in the estuary average 3.4 feet per second, thus the movement of water in the channel during a six-hour ebb or flood tide is approximately 14 miles. This tidal excursion is large compared to the length of the estuary, and as a result water and associated organisms can be moved through the system in a few days.

The portion of the estuary seaward of Sunny Point, in which BSEP is located (essentially the first tidal reach), is characterized by complex water circulation patterns, vigorous tidal action, turbulence, fluctuating salinity levels, and high exchange ratios with the ocean. In many respects, this reach of the estuary acts as an extension of the nearby coastal zone. The distribution and abundance of aquatic organisms in the lower

Cape Fear estuary are determined largely by these highly variable physical and chemical factors.

The major categories of aquatic biota found in the Cape Fear estuary are phytoplankton (microscopic plants), zooplankton (microscopic animals), planktonic or semiplanktonic larvae and postlarvae of fish and shellfish (growth stages between the egg and juvenile stage), and nekton (juvenile and adult fish and shellfish). Planktonic organisms are waterborne and are found in both the estuary and the adjacent ocean. The nekton consists of a mixture of (a) sea-spawned species, (b) a few anadromous species, and (c) resident (estuary-spawned) species.

Most of the important Cape Fear nektonic organisms are the sea-spawned type. These organisms are spawned in great numbers over large areas offshore (frequently many miles offshore) for an extended period (3-6 months in most cases). Currents carry the resulting larvae and postlarvae into the nursery grounds of various estuaries, including those of the Cape Fear estuary. Nursery areas in the Cape Fear estuary include the marshes, shallow fringe areas, and tidal creeks (and, in the case of some species, the open waters of the river). All of these early life stage organisms are subject to high natural mortality rates that decrease over time; that is, at each life stage the survivors to that point have a better chance of survival than do younger life stages (e.g., juvenile natural mortality is less than larval natural mortality).

In the Cape Fear estuary, there are two periods of larval abundance each year associated with the spawning of nearshore marine and estuarine species. A summer peak is associated with the presence mostly of anchovies and gobies. Seatrout also spawn during this period, and large numbers of pink and white shrimp are recruited to the estuary. A second peak of seasonal abundance usually occurs in winter and early spring, coincident with the spawning of spot, menhaden, striped mullet, croaker, brown shrimp, and flounders. Maximum abundance of these taxa within the estuary is usually observed in March and early April.

Species spawned in the ocean face the task of reaching the mouth of the estuary and then migrating to primary nursery zones. During the oceanic phase of migration, the swimming ability of the larvae is limited and transport inshore occurs primarily through wind action and current patterns. Natural mortality is believed to be very high during this period, and consequently survivors of the inshore migration reaching the Cape Fear estuary and other estuaries constitute only a small fraction of the eggs spawned in the ocean. It is noteworthy that the Cape Fear estuary is an “open system” with regard to the origin of recruits. That is, many individuals arriving at the mouth of the estuary probably do not originate from spawning Cape Fear populations. The migratory phase for these young organisms continues inside the estuary until suitable nursery habitat is found.

The two Brunswick Steam Electric Plant Cape Fear Studies Interpretive Reports (CP&L 1980; CP&L 1985) are perhaps the most comprehensive and useful sources of information on the distribution and abundance of important aquatic species at all life stages (larvae, juveniles and adults) in the Cape Fear estuary. These reports,

supplemented by CP&L and Progress Energy annual biological monitoring reports prepared since 1981, provide a detailed record of population trends of numerically dominant and commercially and recreationally important species (e.g., spot, croaker, Atlantic menhaden, bay anchovy, Southern flounder, striped mullet, gobies, three shrimp species, and blue crab) at all life stages over an almost 30 year period.

Beginning in 1994, CP&L reduced the biological monitoring with the approval of the North Carolina Department of Environment and Natural Resources (CP&L 2002). Based on almost two decades of BSEP operation with no adverse impact on fish and shellfish populations in the Cape Fear estuary, the monitoring program was modified to focus on impingement and entrainment of organisms. Although Progress Energy no longer monitors fish and shellfish populations in the Cape Fear estuary (limited population data were collected in 1999, 2001, and 2002), monitoring of these populations continues under the auspices of the Lower Cape Fear River Program. The Lower Cape Fear River Program is a large-scale water quality and environmental assessment program focused on the lower Cape Fear River watershed and the Cape Fear estuary (Lower Cape Fear River Program 2003). The Program is administered by the Center for Marine Science at the University of North Carolina at Wilmington and has its offices there. The Program prepares an annual report on the state of the Cape Fear River system that includes results of water quality and fisheries monitoring in the Lower Cape Fear River (Lower Cape Fear River Program 2003).

2.3 GROUNDWATER RESOURCES

BSEP is located approximately 9,000 feet west of the lower Cape Fear River (Cape Fear estuary) in the Atlantic Coastal Plain. The upper layers of geologic strata underlying the site consist of argillaceous sands and sandy clays; plastic clay; well-compacted sand; and Oligocene deposited limestone. These layers extend to a depth of approximately 115 feet below the surface and overlie the Castle Hayne formation. The Castle Hayne is approximately 115 feet thick and overlies hard calcareous clay and Cretaceous rocks extending down to crystalline basement at a depth of approximately 1,500 feet. (CP&L 2001, Rev. 17B, pg. 1-2). The upper portion of the Castle Hayne formation consists of well-consolidated shell limestone. The lower portion consists of a well-compacted to semi-consolidated sandstone (CP&L 1971, pg. 9.3-4). The Castle Hayne formation outcrops at the ground surface approximately 7 miles northwest of the plant. This outcrop area acts as a recharge area for the aquifer. East of the outcrop the aquifer dips toward the Cape Fear River and the Atlantic Ocean (AEC 1974, pp. II-9 to II-10).

Water from wells is used for consumptive use throughout the Cape Fear region. In the vicinity of the site, shallow wells in the surficial deposits are adequate for small potable water supplies, but for larger water yields the Castle Hayne formation is the most important aquifer (AEC 1974, pp. II-9 to II-10).

The Castle Hayne aquifer provides water to the Sunny Point Military Ocean Terminal and to the municipalities of Long Beach and Southport (AEC 1974, pg. II-9). Southport, the larger of the two municipalities, uses three groundwater wells capable of producing a total of up to 180 gallons per minute. Other water wells installed in the Castle Hayne aquifer in the Southport area yield groundwater at rates of 12 to 416 gallons per minute (CP&L 1971, pg. X.1-20).

Residents of New Hanover County get their drinking water primarily from water wells with the exception of the City of Wilmington that gets its water from the lower Cape Fear River. Wells in New Hanover County used for domestic purposes are in the surficial sand aquifer and for larger yields, are located in the Castle Hayne (AEC 1974, pg. II-9).

In 2000 Brunswick County Public Utilities provided 11.6 million gallons per day (MGD) of treated water to its customers (NCDENR 2002b, page 35). Of this, approximately 8.2 MGD of raw water comes from the Cape Fear River via the Lower Cape Fear Water and Sewer Authority (LCFWSA 2002a). Brunswick County Public Utilities also treats and uses approximately 3.4 MGD of groundwater from the Castle Hayne formation (Brunswick County 2001).

BSEP currently has four water wells (Wells 2, 4, 5 and a well that serves the biology laboratory) in the Castle Hayne aquifer (Gunter 2002a). Wells 2 and 4 were installed in 1972 and Well 5 was installed in 1974. Wells 2, 4, 5 were used until the early 1980s when they were capped and removed from service after the plant began receiving water from Brunswick County Public Utilities (Gunter 2002b). The biology laboratory well was installed when the laboratory was constructed in 1983. This well has a pumping

capacity of 30 gallons per minute (gpm). Due to the intermittent use of the biology laboratory by a limited number of people, the actual production of this well is probably much less than the pump capacity.

2.4 CRITICAL AND IMPORTANT TERRESTRIAL HABITATS

The BSEP site (Figure 2-3) covers approximately 1,200 acres (CP&L 2001, Rev. 17B, pg. 1-1). The industrial portion of the site comprises approximately 130 acres and consists of generating facilities, office buildings, warehouses, parking lots, and equipment storage areas.

Most upland portions of the BSEP site consist of planted loblolly pine (*Pinus taeda*) forest. Other habitats at the site include pine-hardwood forests, longleaf pine-wiregrass communities, pine savannas, pocosins, dune-strand communities, and salt marshes. The following discussion on the habitats and representative species is taken from the Final Environmental Statement for the Brunswick Plant (AEC 1974).

Pine-hardwood forests at BSEP are mixtures of loblolly pine with hardwoods such as sweet gum (*Liquidamber styraciflua*), blackgum (*Nyssa sylvatica*), hickory (*Carya* spp.) and oak (*Quercus* spp.). Forests dominated by longleaf pine (*Pinus palustris*), turkey oak (*Quercus laevis*), and wiregrass (*Aristida stricta*) occur in well drained areas such as along ancient dunes. A few remnants of pine savannas occur in periodically flooded areas. Pine savannas are characterized by an open canopy of longleaf pine or pond pine (*Pinus serotina*) with a dense ground cover of herbs and shrubs. Pocosins are wetland depressions characterized by thickets of various evergreen shrubs and small trees such as red bay (*Persea borbonia*) and sweet bay (*Magnolia virginiana*).

Dune-strand communities occur at the interface between the sea and land. Vegetation on the seaward side of dunes is typically sparse as a result of wind and salt spray. Sea oats (*Uniola paniculata*) is the major dune species. A variety of herbaceous shrubs tend to develop on the more-protected landward sides of dunes, creating maritime shrub thickets. The predominant trees in these thickets are sabal palm (*Sabal palmetto*) and live oak (*Quercus virginiana*).

Salt marshes at the BSEP site are composed primarily of cordgrass (*Spartina alterniflora*), with needlerush (*Juncus romerianus*) dominant in some areas. The marshes provide habitat for many aquatic organisms (see Section 2.2) that are preyed upon by a variety of wildlife species.

The habitats support a variety of wildlife species typical in the southeastern Coastal Plain. Pine-hardwood, pine-wiregrass, pine savannah, maritime forests, and pocosin communities support many species of birds, including hawks, woodpeckers, warblers, sparrows, and others. Animals in these habitats include white-tailed deer, opossums, raccoons, squirrels, skunks, bobcats, snakes, toads, frogs and lizards. Salt-marshes support three species of commercially valuable shrimp (white [*Litopenaeus setiferus*], brown [*Farfantepenaeus aztecus*], and pink [*F. duorarum*]), blue crab, spot, croaker, flounder, and numerous other fish species. They also provide habitat for American alligators, raccoons, otters, and many species of wading birds.

Section 3.1.3 describes the eight transmission lines that were constructed to connect BSEP to the transmission system. All eight lines share the first 1.3 miles of corridor. At

that point, the Whiteville, Delco East, Delco West and Weatherspoon lines veer to the northwest, and divide again with the Whiteville line traveling parallel to and south of the Weatherspoon and Delco lines which share a corridor to the Delco Substation and then the Weatherspoon lines continues to the Weatherspoon Substation (see Figure 3-2). The Whiteville line crosses several pocosins and the Green Swamp, which has been designated a National Natural Landmark. It passes about 2 miles south of Lake Waccamaw and approximately one mile west of Lake Waccamaw State Park. The Weatherspoon and Delco lines both cross the Little Green swamp. The Wallace, Jacksonville, Castle Hayne East and Wilmington Corning lines travel northeast from the split near BSEP (see Figure 3-2). The Jacksonville line crosses the Holly Shelter Game Land in the Holly Shelter swamp. The Wallace line crosses the B. W. Wells Savannah, a 117-acre remnant of wetland savannah, in northwest Pender County (NCCLT 2001). The tract supports 170 native plant species, some of which are rare (NCCLT 2001). Progress Energy has partnered with the N. C. Coastal Land Trust, the Conservation Trust for North Carolina, and the N. C. Wild Flower Preservation Society to preserve this unique property. The transmission corridors do not cross any federal or state parks.

The U.S. Fish and Wildlife Service (USFWS) has designated areas of Brunswick, New Hanover, Pender, and Onslow counties as “critical habitat” for the piping plover (66 FR 36038); however, all of the areas designated critical habitat are along Atlantic Ocean beaches. None occurs at BSEP or adjacent to associated transmission lines.

2.5 THREATENED OR ENDANGERED SPECIES

Species that are state- or federally-listed as threatened or endangered are known to occur, at least occasionally, on or near the BSEP site and transmission corridors. Table 2-1 lists the federally- and state-listed threatened and endangered species that are known to occur in the seven counties of interest (Bladen, Brunswick, Columbus, New Hanover, Onslow, Pender, and Robeson).

In 1998, CP&L conducted a self-assessment that evaluated more than 90 sensitive plant and animal species that could occur in the vicinity of BSEP (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 BSEP (CP&L 1998).

The self-assessment identified three federally listed terrestrial species (Table 2-2) that could potentially be affected by BSEP operations, future facility expansion, or other activities: the red-cockaded woodpecker (*Picoides borealis*), Cooley's meadowrue (*Thalictrum cooleyi),* and rough-leaved loosestrife (*Lysimachia asperulaefolia*). Red-cockaded woodpeckers, federally listed as endangered, are found in eastern North Carolina in mature pine forests (generally longleaf pine) with sparse understory vegetation. Suitable nesting habitat for this species is not found at BSEP, but birds may forage in the area. Rough-leaved loosestrife, a federally endangered species, is a perennial herb that occurs in pocosins in eastern North Carolina (Radford et al. 1968). Eight populations of rough-leaved loosestrife are known from Brunswick County; one occurs in a BSEP transmission corridor north of the plant in the Boiling Spring Lakes area (corridor that contains Castle Hayne East, Wilmington Corning, Wallace, and Jacksonville lines). Three more populations are associated with Progress Energy transmission corridors in Pender County (Wallace and Jacksonville lines). Cooley's meadowrue, a federally endangered species, is a perennial herb that occurs in pine savannahs in eastern North Carolina (Radford et al. 1968). Two populations have been found on a Progress Energy transmission corridor (Jacksonville line) in Onslow County.

A single population of golden sedge (*Carex lutea*) was recorded along a transmission corridor (Jacksonville line) in Onslow County in 1996, but the species did not receive federal protection until 2002 (Federal Register, Volume 67, No. 15, pg. 3120) and as a result was not one of the federally listed species evaluated in the 1998 CP&L self assessment. This federally endangered plant is a perennial found in coastal (wet) savannahs underlain by calcareous (limestone) deposits (USFWS 2002b). This rare species is found only in Pender and Onslow Counties in North Carolina.

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 (BSEP 2003, pg. 5). The company also maintains Best Management Practices for Management of Rare Plants on Progress Energy Rights-of-Way (BSEP 2002, pp. 10-14). Table 2-2 describes the protective measures taken by Progress Energy to protect these populations.

The 1998 self-assessment also identified three federally listed aquatic species that could potentially be affected by BSEP operations, future facility expansion, or other activities: the loggerhead sea turtle (*Caretta caretta*), the green sea turtle (*Chelonias mydas*), and the Kemp's Ridley sea turtle (*Lepidochelys kempi*). The loggerhead sea turtle, the sea turtle most commonly observed along the south Atlantic coast, nests as far north as Ocracoke Inlet, North Carolina in late spring and early summer (Martof et al. 1980). The Kemp's Ridley sea turtle is an uncommon visitor to the coast of North Carolina (immature and sub-adult individuals); it nests almost exclusively along the northern Gulf Coast of Mexico and on Padre Island, Texas (Martof et al. 1980, Ogren 1992). The green sea turtle migrates along the North Carolina coast and occasionally comes ashore to bask, but does not normally nest in the Carolinas (Martof et al. 1980).

BSEP has a permit issued annually by the North Carolina Wildlife Resources Commission for the capture, tagging and relocation to open ocean of sea turtles that occasionally move into the intake canal through breaches in the diversion structure. The permit imposes certain compliance provisions for handling endangered sea turtles. To mitigate potential impacts, Progress Energy has installed and maintains blocker panels in the diversion structure. Site personnel patrol the intake canal daily during the turtle season in order to find and return to the open ocean sea turtles that get past the diversion structure.

In compliance with the provisions of the Endangered Species Act that require Federal agencies to consult with the USFWS and NMFS when actions potentially jeopardize listed species, NRC in 1998 initiated a formal Section 7 consultation with the NMFS regarding the effects of BSEP operations on sea turtles. The NMFS reviewed data on incidental takes of sea turtles at BSEP and the operation of the cooling water intake system and issued a final Biological Opinion (with an incidental take statement) in January 2000 that concluded:

"…operation of the water intake system of the Brunswick Steam Electric Plant…is not likely to jeopardize the continued existence of the loggerhead, leatherback, green, hawksbill, or Kemp's ridley sea turtles. No critical habitat has been designated for these species in the action area; therefore, none will be affected. This conclusion is based on the proposed action's (operation of the cooling water intake system) anticipated effects on each of these species being limited to the incidental take, through death or injury, on a small number of immature sea turtles per year over the next 20 years." (NMFS 2000, pg. 25).

The 1998 CP&L self-assessment did not list the shortnose sturgeon (*Acipenser brevirostrum*) as a federally protected species with significant potential for being affected by BSEP operations, facility expansion, or other activities, but did note that "this species is known from the lower Cape Fear River and thus…could be vulnerable to plant impact during spawning in late winter to early spring" (CP&L 1998). The shortnose sturgeon was not included in the list of species requiring action to prevent impacts because the Cape Fear River population was known to be very small and to

inhabit portions of the river upstream of the BSEP intake canal. Further, no shortnose sturgeon had been collected in decades of sampling at BSEP.

The shortnose sturgeon was believed to be extremely rare or to have been extirpated from the Cape Fear River until 1987, when a gravid female was captured in the Brunswick River, a relatively undisturbed tributary of the lower Cape Fear River (Moser and Ross 1995). Researchers sampled the lower Cape Fear River drainage intensively from 1990 to 1992 and found small numbers of shortnose sturgeon in both the Brunswick River and the main stem of the Cape Fear River (Moser and Ross 1995). Some of these fish were fitted with sonic transmitters and showed directed upstream movement indicative of spawning migrations. Spawning appeared to be hindered or prevented by gill nets set by commercial fishermen (targeting striped bass and American shad) and by Lock and Dam No. 1, a low-head dam at River Kilometer 96. Because the population is small, probably less than 50 individuals, almost nothing is known of the population dynamics of the Cape Fear River population of shortnose sturgeon (NMFS 1998).

No other federally- or state-listed threatened or endangered species are known to occur at BSEP 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 (BSEP 2002; BSEP 2003).

2.6 REGIONAL DEMOGRAPHY AND MINORITY AND LOW-INCOME POPULATIONS

2.6.1 GENERAL

The *Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants* (GEIS) presents a population characterization method that is based on two factors: "sparseness" and "proximity" (NRC 1996). "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.

Progress Energy used 2000 census data from the U.S. Census Bureau website (USCB 2001a) and geographic information system (GIS) software (ArcView®) to determine demographic characteristics in the BSEP vicinity. The Census Bureau provides updated annual projections, in addition to decennial data, for selected portions of its demographic information.

As derived from 2000 Census Bureau information, 133,286 people lived within 20 miles of BSEP. Applying the GEIS sparseness measures, BSEP has a population density of 226 persons per square mile within 20 miles and falls into a least sparse category, Category 4 (greater than or equal to 120 persons per square mile within 20 miles). To determine accurate population densities Progress Energy used GIS software to exclude any area within the BSEP 50 mile radius which was covered by water.

Based on the 2000 Census Bureau information, 361,216 people lived within 50 miles of BSEP. This equates to a population density of 111 persons per square mile within 50 miles (excluding area covered by water). Applying the GEIS proximity measures, BSEP is classified as Category 2 (no city with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles). According to the GEIS sparseness and proximity matrix, the BSEP ranks of sparseness Category 4 and proximity Category 2 result in the conclusion that BSEP is located in a medium population area.

All or parts of seven North Carolina counties, one South Carolina county, the City of Wilmington (NC), and a small portion of the City of Myrtle Beach (SC) lie within the

50 mile radius of BSEP (Figure 2-1). Approximately 92 percent of the station employees reside within 2 counties in North Carolina: Brunswick and New Hanover. The remaining 8 percent are distributed across 15 other counties, with numbers ranging from 1 to 26 employees per county.

The Wilmington MSA, which contains both Brunswick and New Hanover Counties, is characterized by urban, suburban, and rural areas, with a total population of 233,450, making it the 154th largest MSA in the United States (USCB 2001b). The Wilmington MSA ranked 14th among U.S. Metropolitan areas in rate (percent) of population growth between 1990 and 2000 (USCB 2001b)

Both Brunswick and New Hanover Counties are 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 (USCB 2001c), while Brunswick County increased by 4.4 percent and New Hanover County increased by 3.3 percent (USCB 2001d).

In 2000, North Carolina reported a population count 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 2001c).

Table 2-3 shows population estimates and annual growth rates for the two counties that have the greatest potential to be socioeconomically affected by license renewal activities at BSEP. Values for the State of North Carolina and are provided for comparison's sake. The table is based on U.S. Census Bureau (USCB) data for 1980, 1990, and 2000, North Carolina Office of State Budget and Management projections through 2030, and a Progress Energy projection to 2040 that is based on linear regression techniques.

2.6.2 MINORITY AND LOW-INCOME POPULATIONS

Background

When NRC performed environmental justice analyses for previous license renewal applications it used a 50-mile radius as the overall area that could contain environmental impact sites and the state as the geographic area for comparative analysis. Progress Energy has adopted this approach for identifying the BSEP minority and low-income populations that could be affected by BSEP 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 on a block group level. Low-income demographic data is not available on a block group level; therefore, USCB TIGER line data is combined with USCB 2000 census tract level demographic data to determine the low-income characteristics. Progress Energy included all block groups or census tracts if any of their area lay within 50 miles of BSEP. The 50-mile radius includes 257 block groups and 82 census tracts.

Progress Energy defines the geographic area for BSEP as North and South Carolina independently, for block groups or tracts in the two states.

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; or Black races; other; multi-racial; or the aggregate of all minority races; or Hispanic ethnicity (NRC 2001; Appendix D). The guidance indicates that a minority population exists if either of the following two conditions exists:

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

2. The minority population percentage of the environmental impact area is significantly greater (typically at least 20 points) than the minority population percentage in the geographic area chosen for comparative analysis.

NRC guidance calls for use of the most recent U.S. Census Bureau decennial census data. Progress Energy used 2000 census data from the USCB website (USCB 2000a; USCB 2000b) in determining the percentage of the total population within the two states for each minority category, and in identifying minority populations within 50 miles of BSEP.

Progress Energy divided USCB population numbers for each minority population within each block group by the total population for that block group to obtain the percent of the block group's population represented by each minority. For each of the 257 block groups within 50 miles of BSEP, 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 BSEP as the entire State of North Carolina when the block group is contained within North Carolina and the entire State of South Carolina when the block group is contained within South Carolina.

North Carolina contains the largest portion of the geographic area, and approximately 84 percent of the block groups. USCB data (USCB 2000a) for North Carolina characterizes 1.2 percent as American Indian or Alaskan Native; 1.4 percent Asian; 0.00 percent Native Hawaiian or other Pacific Islander; 21.6 percent Black races; 2.3 percent all other single minorities; 1.3 percent multi-racial; 27.8 percent aggregate of minority races; and 4.7 percent Hispanic ethnicity. South Carolina comprises the remainder of the geographic area with approximately 16 percent of the block groups. USCB data (USCB 2000b) for South Carolina characterizes 0.3 percent as American Indian or Alaskan Native; 0.9 percent Asian; 0.00 percent Native Hawaiian or other Pacific Islander; 29.5 percent Black races; 1.0 percent all other single minorities; 1.0 percent multi-racial; 32.7 percent aggregate of minority races; and 2.4 percent Hispanic ethnicity.

Based on the “more than 20 percent” criterion, American Indian or Alaskan Native minority populations are found in a total of 2 block groups located in Columbus County, North Carolina (Table 2-4). Figure 2-4 displays the location of this minority block. This area is home to the Waccamaw-Siouan Tribe, whose 2,000 or so members live in small communities around Lake Waccamaw in eastern Columbus County and southeastern Bladen County, North Carolina (J. Smith 2002). Although not recognized by the Federal government, the Waccamaw-Siouan Tribe has received legal recognition from the North Carolina Commission of Indian Affairs (North Carolina Commission of Indian Affairs undated).

Based on the “more than 20 percent” criterion, Black Races minority populations occur in 44 block groups (Table 2-4), 41 of which are located in the state of North Carolina. These block groups are distributed among six North Carolina counties. The remaining three block groups are located in Horry County, South Carolina. Figure 2-5 displays the location of these minority block groups.

Based on the “more than 20 percent” criterion, the Aggregate of Minority Races populations exist in 41 block groups (Table 2-4), 38 of which are located in the state of North Carolina. The remaining three block groups are located in the state of South Carolina. The Aggregate of Minority Races minority block groups are displayed on Figure 2-6.

Based on the “more than 20 percent” or the “exceeds 50 percent” criteria, no Asian, Native Hawaiian or other Pacific Islander or Multi-racial minorities exist in the geographic area. In addition, no populations defined as “All Other Single Minority Races” or Hispanic Ethnicity exceed these criteria. Table 2-4 presents the numbers of block groups within each county that exceed the threshold for determining the presence of populations.

2.6.2.2 Low-Income Populations

NRC guidance defines “low-income” by using U.S. Census Bureau statistical poverty thresholds (NRC 2001, Appendix D). U.S. Census Bureau (USCB 2000c) characterizes 12.4 percent of North Carolina and 14.2 percent of South Carolina households as low-income.

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

The low-income population of the census tract or environmental impact site exceeds 50 percent, or

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.

Based on the “more than 20 percent” criterion, three census tracts in the Wilmington North Carolina area (New Hanover County) contain low-income populations (USCB 2002). Figure 2-7 identifies low-income household tracts.

2.7 TAXES

BSEP pays annual property taxes to Brunswick County. Taxes fund Brunswick County operations, including the school system, public safety, hospitals, human services, emergency management services, and recreation facilities (NC State Treasurer 2003). For the years 1997 to 2002, BSEP's property taxes provided 7.5 to 13.5 percent of Brunswick County's property tax revenues. The average contribution over the six-year period was 9.4 percent. If the operating license for BSEP was not renewed and the plant was decommissioned, then the tax base of the surrounding communities and their economic structures could experience some adverse impact, as discussed in Section 8.4.7 of the GEIS (NRC 1996).

BSEP'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. In the future, deregulation could affect utilities' tax payments to counties. However, any changes to BSEP tax rates due to deregulation would be independent of license renewal. Table 2-5 compares BSEP's property tax payments to Brunswick County property tax revenues.

2.8 LAND USE PLANNING

This section focuses on Brunswick and New Hanover Counties because the majority (approximately 90 percent) of the permanent BSEP workforce lives in these counties (see Section 3.4) and because Progress Energy pays property taxes in Brunswick County. Both counties have experienced rapid growth over the last several decades. From 1990 to 2000, Brunswick County's population growth rate averaged 4.4 percent per year and New Hanover County's population growth rate averaged 3.3 percent per year, while the population of the state of North Carolina grew an average of 2.1 percent per year (USCB 2001c; USCB 2001d). Over the same period, 1990 to 2000, the number of housing units in Brunswick County increased by 38.6 percent and the number of housing units in New Hanover County increased by 39.5 percent, while the total number of units in the state increased by 25.0 percent (USCB 1990; USCB 2000d).

Since both counties have experienced rapid growth, their respective comprehensive land use plans focus on growth-related issues and the implementation of future conservation efforts to protect natural resources. These plans reflect 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 by both counties to control development. Both counties encourage growth in areas where public facilities, such as water and sewer systems, exist or are scheduled to be built in the future. Both plans promote the preservation of the communities' natural resources, resources that make the areas attractive to current and prospective residents.

North Carolina has issued guidelines for classifying land use within the state. Brunswick and New Hanover Counties have adopted these guidelines and the general categories are as follows: Developed, Urban Transition, Limited Transition, Community, Rural, Conservation and Resource Management (or Protection). The Developed classification is for areas already urbanized, while the Urban Transition and Limited Transition classifications are used to designate areas with future urban potential, but with controlled densities. The Rural classification is for areas not planned for urbanization within the next decade and is comprised mainly of agriculture, forestry, and other agrarian uses (Brunswick County 1997). The purpose of the Conservation and Resource Management Classification is to provide for the effective long-term management and protection of significant, limited, or irreplaceable land and resources (Brunswick County 1997). For the purposes of this section, there is a distinction made between a land classification and an actual land use. There may be more than one land use within one land use class designation. For example, in the Rural classification, low-density residential, agricultural, and forestry land uses are co-existent. In the remainder of this section, actual land uses are detailed. They should not be confused with land use classifications.

Brunswick County

Brunswick County occupies roughly 855 square miles of land area, making it the sixth largest of 100 North Carolina counties (USCB 2000d). The majority of the land in the

County is rural; classified either as rural, conservation, or transitional. The Brunswick County Planning Department does not currently maintain percentage breakdown data for current land uses within the County (Stewart 2003).

The City of Southport provides land use classification information in percentage form in its Comprehensive Plan. Approximately 45 percent of Southport's planning jurisdiction (the incorporated portions of the City plus the extraterritorial jurisdiction area) is developed. As a result, there are 1,879 acres in the planning jurisdiction that are vacant and potentially suitable for development. The presence of jurisdictional wetlands reduces the acreage that is actually available, however (City of Southport 2001). Of the total acreage in the Southport planning jurisdiction, approximately 18 percent is Single- and Multi-family Residential; 14 percent Transportation and Utility; 4 percent Industrial; 3 percent Commercial; 2 percent Public and Institutional; 3 percent Parks and Open Space; and 1 percent Water Dependent Commercial (City of Southport 2001).

Due to its large size, Brunswick County has implemented a "Geographic Areas of General Recognition" program. This program is used by administrators and the public to identify subsections of the County for planning purposes. Seven areas are delineated by their regional significance. These areas are: Area 1, Shallotte to the State Line; Area 2, Shallotte River to Lockwood Folly River; Area 3, Southport/Oak Island; Area 4, Belville-Leland-Navassa; Area 5, Town Creek/Winnabow/Mill Creek; Area 6, Ash/Waccamaw; and Area 7, Supply/Sunset Harbor (Brunswick County 1997).

- Area 1 is the fastest growing subsection of the County due to its close proximity to the Grand Strand/Myrtle Beach area. This subsection has numerous golf course communities ranging from 500 to 1,250 acres in size. Housing densities in these golf course communities are low, in the range of 1.5 to 2.0 housing units per acre, but their development has been accompanied by convenience stores, specialty shops, and small shopping centers anchored by chain grocery and drug stores. Large tracts of land have been developed as a result (Brunswick County 1997).

- Area 2, which includes Holden Beach, is the second fastest growing section of Brunswick and is comprised of inexpensive lots and homes, manufactured housing, and a predominance of vacation homes. Commercial activity in this area is mostly scattered, with the largest concentration of activity near Supply, an unincorporated village located at the intersection of US 17 and NC 211 (Brunswick County 1997).

- Area 3 is a mixed land use area with major industrial uses (BSEP, Archer Daniels Midland, Cogentrix Cogenerating Facility), a military installation (Military Ocean Terminal Sunny Point), commercial strip development, and permanent and seasonal housing. Permanent housing is concentrated in the City of Southport and the Town of Long Beach, while seasonal housing is found at Caswell Beach. Several "planned communities" are located in Area 3 (Brunswick County 1997).

- Area 4 has three municipalities which are primarily residential and serve as bedroom communities for New Hanover County. The area also hosts some manufacturing,

including the Dupont plant which employs a large number of residents from the Wilmington area (Brunswick County 1997).

- Area 5 has a few residential communities along US 17, a public golf course and little industrial, office, or retail development (Brunswick County 1997).

- Area 6 is dominated by farming and timber activities (Brunswick County 1997).

- Area 7 is predominantly residential. It includes the area south and east of Supply and the eastern side of the Lockwood Folly River, which has experienced significant growth in recent years that is predicted to continue. The growth is evidenced by the development of the large planned residential community, Winding River Plantation, and the approval of subdivisions along Sunset Harbor Road. Additionally, there is considerable interest in commercial development near the US 17/NC 211 intersection (Brunswick County 1997).

With respect to residential development, most of the neighborhood subdivisions have occurred along the coast, in beach and intracoastal waterway areas. Single-unit detached dwellings comprise 55.7 percent of the 51,431 housing units in the County. Manufactured housing comprises 35.9 percent (USCB 2000e).

The large influx of seasonal residents has a large impact on Brunswick's infrastructure, with the ratio of seasonal to permanent residences increasing to 3:1 in the summer months (Brunswick County 1997). Even with the widening of US 17, which relieved some of the congestion, secondary roads and bridges to the coastal beaches continue to be congested on peak weekends (Brunswick County 1997). The community is considering adding a second bridge to Oak Island to alleviate traffic congestion.

The Brunswick County Land Use Plan (1997) acknowledges that growth and development have increased in recent years, and continued growth is inevitable, "predominantly in the form of a growing tourism economy, rapidly rising seasonal and permanent populations, and related residential and commercial development." The Land Use Plan notes (pg. 8-28) that the County's overall land use policy "calls for continued efforts to diversify the local economy, protect area resources, and improve the quality of life. A particular point of emphasis for this plan is the desire to foster…a distinct 'town and county' development pattern." The intent of the County's land use policy is to allow for the preservation of open space and productive farm and timber land, to minimize costs of extending infrastructure and services, to avoid higher taxes, and minimize traffic congestion associated with urban sprawl (Brunswick County 1997, pg. 8-30).

New Hanover County

New Hanover County occupies approximately 199 square miles of land area, making it one of the smallest (99th of 100) counties in North Carolina (USCB 2000d). New Hanover County, which is dominated by the City of Wilmington and its suburbs, is one of the most urbanized counties in North Carolina (Wilmington-New Hanover County

1999). Among 100 North Carolina counties, only Mecklenburg County, which contains the city of Charlotte and its 540,000 residents, has higher population and housing densities than New Hanover County (USCB 2000d, f).

Currently, New Hanover County is 32 percent Developed. The land use breakdown percentages for the developed areas of the County are as follows: 17 percent Residential (single-family comprises 15 percent), 2 percent Office and Institutional, 1 percent Commercial, 4 percent Transportation and Utility, 5 percent Industrial, and 2 percent Recreation. The breakdown for the remainder of the county is as follows: 4 percent Agriculture, 50 percent Undeveloped, 2 percent Water, and 11 percent Other (O'Keefe 2003).

Developed, Urban Transition, and Limited Transition land classifications are areas of high-medium density in which the concentration of development and redevelopment is encouraged. Public services such as sewer and water are either in place or future extensions are planned for these services. Densities are greater in the Developed and Urban Transition areas and may exceed 2.5 housing units per acre while the Limited Transition area cannot exceed this limit. The City of Wilmington is primarily Developed (Wilmington-New Hanover County 1999).

Community and Rural land classifications are areas of low density and may not exceed the 2.5 units per acre limit. Currently, the only area designated as Community is Castle Hayne, which supports mixed land uses providing housing, retail shopping, employment, and public services for the rural areas in the County (Wilmington-New Hanover County 1999). The Rural areas include agricultural, forest management, and mineral extraction. Urban uses are discouraged in Rural areas. Land designated as Rural is generally located east of I-40 and west of NC 17 in the northern portion of the County and in selected areas near the Cape Fear River.

To protect the County from increased urbanization and to preserve its remaining resources of environmental, scenic, recreational and cultural importance, Conservation and Resource Protection classifications have been created. These areas have a density limit requirement of 2.5 units per acre or less, but may be as low as 1.0 unit per acre. Conservation areas encompass areas that are environmentally fragile and considered too important to endanger with development. These lands are usually defined by the State of North Carolina as estuarine Areas of Environmental Concern (AECs) and adjacent lands within the 100-year floodplain (Wilmington-New Hanover County 1999). The majority of these areas are located along the coastal wetlands and the banks of the Cape Fear River.

Future land use concerns for the County include conservation and preservation of the natural resources which contributed to the County's prosperity. These resources include the beaches, rivers, sounds, aquifers, and other natural areas. Also, the County would like to contain existing urban areas, preserve the rural lifestyle for residents while providing a strong economic base and affordable housing, maintain and enhance fiscal sustainability and community infrastructure supports, protect the area's historical

heritage, and ensure citizen protection against natural disasters such as hurricanes (Wilmington-New Hanover County 1999).

2.9 SOCIAL SERVICES AND PUBLIC FACILITIES

2.9.1 PUBLIC WATER SUPPLY

Most (92 percent) of the permanent employees of BSEP reside in Brunswick and New Hanover Counties (Ahern 2002, all); therefore, the discussion of public water supply systems will focus on these two counties.

Regional

The Lower Cape Fear Water and Sewer Authority (LCFWSA) was established in 1970 to supply raw surface water to local governments and industry in Bladen, Brunswick, Columbus, New Hanover, and Pender Counties. The LCFWSA currently supplies raw surface water to Brunswick County and to the City of Wilmington in New Hanover County. The LCFWSA also provides raw surface water to KoSa and Praxair, Inc., two industries located along US Highway 421 in New Hanover County. Raw surface water supplied by the LCFWSA is withdrawn from an intake located above Lock and Dam #1 on the Cape Fear River in Bladen County. The LCFWSA currently produces 13.7 million gallons per day (MGD) and has a production capacity of 45 MGD. Surface water use forecast for clients of the LCFWSA is projected to increase from 13.7 MGD for fiscal year 2001-02 to 28 MGD for the fiscal year 2009-10 (LCFWSA 2002b).

The City of Wilmington also has a raw water intake located above the lock and dam near the LCFWSA intake. The Cape Fear River at this location is capable of supplying 53 MGD of raw water at each of the two intakes (NCDENR 2002b, pg. 62).

Groundwater is also a major source of water for residents and municipalities within the region. The counties of Bladen, Columbus, Pender, and New Hanover (with exception of the City of Wilmington) use groundwater as the major source of potable water for their residents. The wells for New Hanover County are located primarily within the Castle Hayne, Pee Dee and other surficial aquifers (NHC 2002, all).

The State of North Carolina considers all systems that currently obtain water from Wilmington or from the LCFWSA and other local government water systems in New Hanover and Brunswick Counties as a regional group. The 27 systems included in this group have a combined projected 2050 average daily demand of 73.4 MGD. They currently have a 115.5 MGD available supply when the supply from existing wells is combined with the 106 MGD that is available at the Cape Fear River intakes. Therefore, there appears to be enough available water to meet the projected demands of these systems (NCDENR 2002b, pg. 62).

Brunswick County

In 2000, Brunswick County Public Utilities supplied 11.6 MGD of potable water (NCDENR 2002b, pg. 35) to its water clients. Brunswick County receives the majority of its potable water (8.2 MGD) from the LCFWSA (LCFWSA 2002a). Brunswick County receives raw surface water from the LCFWSA that it treats at the County's Northwest

Water Treatment Facility. This facility has a capacity of 24 MGD. The remainder of water supplied by Brunswick County, approximately 3.4 MGD, is groundwater produced from 15 deep wells that tap into the Castle Hayne aquifer (Brunswick County 2001). The wells have a total capacity of 3.4 MGD (NCDENR 2002b, pg. 62). Water from this groundwater source is treated at the 211 Water Treatment Facility. The facility has a capacity of 6 MGD and serves residents and businesses in the vicinity of Highway 211 (Brunswick County 2001, all).

Treated water from Brunswick County Public Utilities serves Carolina Shores, Caswell Beach, Holden Beach, Long Beach, North Brunswick Sanitary District, Ocean Isle Beach, Shallotte, Southport, Sunset Beach, and Yaupon Beach. Southport and Yaupon Beach also have wells that supply water to their systems (NCDENR 2002b, pg. 62).

BSEP receives water from Brunswick County Public Utilities. From 1996 through 2001, BSEP's water use ranged from approximately 0.22 million gallons per day (MGD) to approximately 0.25 MGD with an average consumption of 0.23 MGD (L. Smith 2002, all). The BSEP average use over the six-year period represents two percent of the total water supplied to customers by Brunswick County Public Utilities in 2000 and one percent of the utility's total production capacity over the same period.

New Hanover County

The public water supply system in New Hanover County, with the exception of the City of Wilmington, is a groundwater system (NHC 2002, all). The New Hanover County Water and Sewer District (NHCWSD) provides treated water through four water systems including the New Hanover County Water System, New Hanover County 421 Water System, Kings Grant Water System, and the Monterey Heights Water System (Blanchard 2002). The water is produced from 30 wells (Blanchard 2002, all) located within the Castle Hayne, Pee Dee, and other surficial aquifers (NHC 2002, all). The NHCWSD also provides service to county residents not supplied by a private or municipal supplier (NHC 2002). From November 2001 to October 2002, the county system provided treated water to its customers at a rate of approximately 2.4 MGD (Blanchard 2002, all).

The City of Wilmington is the largest supplier of treated water within the county and is considered part of the LCFWSA group because it received approximately 11.5 MGD of raw water in 2000 from the Cape Fear River from an intake located above Lock and Dam #1. The City of Wilmington also has a 53 MGD capacity available to it through its own river water intake located above Lock and Dam #1. The city has an available raw water capacity of 15 MGD supplied by the LCFWSA (NCDENR 2002b, all). Wilmington's daily use rate capacity is limited by its water treatment capacity. Wilmington's current water treatment capacity is 25 MGD (Wilmington 2002).

Tables 2-6 and 2-7 provide details of Brunswick and New Hanover Counties' respective water suppliers and capacities.

2.9.2 TRANSPORTATION

The entrance to BSEP is off N.C. 87 just north of Southport (Figure 2-2).

N.C. 133 crosses N.C. 87 so that access to N.C. 87 from N.C. 133 can be from the northeast or the southwest (Figure 2-2). Employees traveling to the site from the Wilmington area or points north access N.C. 87 via N.C. 133 or U.S. 17 (Figure 2-1). Employees from Oak Island, southwest of the site, access N.C. 87 from the southern end of N.C. 133. Employees traveling from the west access N.C. 87 from N.C. 211, via N.C. 133. Employees from Southport travel a short distance north on N.C. 211 to N.C. 87.

Traffic count data for each of these roads in the vicinity of BSEP is shown in Table 2-8. 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 it necessary (Hensdale 2002).

2.10 METEOROLOGY AND AIR QUALITY

BSEP is located in Brunswick County, North Carolina, which is part of the Southern Coastal Plain Intrastate Air Quality Control Region (AQCR). All counties in the AQCR are designated as being in attainment for all criteria pollutants, as are all counties in North Carolina and South Carolina (40 CFR 81.152, 40 CFR 81.334 and 40 CFR 81.341). The nearest non-attainment area is the Northeastern Virginia Intrastate AQCR, approximately 350 miles northwest of BSEP, which is a one-hour ozone non-attainment area (40 CFR 81.347).

In July 1997, the U.S. Environmental Protection Agency (EPA) issued final rules establishing a new eight-hour ozone standard and a standard for particulate matter with a nominal size of less than 2.5 microns (PM-2.5). 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). Based on data collected between 1999 and 2001, several counties in South and North Carolina, including one (Wayne County, North Carolina) in the Southern Coastal Plain AQCR, could be designated as non-attainment areas under the new PM-2.5 and 8-hour ozone standards.

2.11 HISTORIC AND ARCHAEOLOGICAL RESOURCES

Area History in Brief

Pre-History and History

PaleoIndians (10,000 BC), the first people known to the Carolina region, were well adapted, technologically and socially, to the Pleistocene, when the climate and plant and animal populations were very different from those of today. Wetter, cooler weather conditions were the general rule for areas like the Eastern Seaboard, which was some distance from the southern reaches of the glacial ice. PaleoIndians preyed on elephants (mastodons and mammoths), wild horses, ground sloths, camels, giant bison, moose, caribou, elk and porcupine, using their meat, skins and other parts for food, clothing, tools and other needs. They also devoted considerable time to gathering wild plant foods and likely fished and gathered shellfish in coastal and riverine environments (Claggett 1996).

Archaic Indians (9,000 to 2,000 BC), direct descendants of the PaleoIndians, improved the techniques of fishing, gathering, and hunting for post-glacial environments, which differed from the Pleistocene. Archaic people made a wide variety of basketry and used stone and wooden tools that reflect the varied subsistence patterns of fishing, gathering and hunting of the many different species of plants and animals that shared their post-glacial environments. Their camps and villages occur as archaeological sites throughout North Carolina, on high mountain ridges, along river banks, and across the Piedmont hills (Claggett 1996).

Woodland Indians (2,000 BC) continued to follow most of the subsistence practices of their Archaic forebears, hunting, fishing, and gathering during periods of seasonal abundance of deer, turkeys, shad, and acorns (Claggett 1996). Bow and arrow equipment was also an innovation of the Woodland stage, although the ultimate origin of that hunting technology is unknown (Claggett 1996). There was a tendency to settle in larger, semi-permanent villages along stream valleys, where soils were suitable for Woodland farming practices utilizing hoes and digging sticks (Claggett 1996). The house patterns, defensive walls (or palisades), and substantial storage facilities also demonstrate that Woodland Indians were more committed to settled village life than their Archaic predecessors (Claggett 1996). Woodland cultures dominated most of North Carolina well into the historic period. Most Indian groups met by early European explorers followed Woodland economic and settlement patterns (Claggett 1996).

Mississippian culture can be described neatly as an intensification of Woodland practices of pottery-making, village life, and agriculture. Mississippian societies were organized along strict lines of social hierarchies determined by heredity or exploits in war. Military aggressiveness was an important part of Mississippian culture, serving to gain and defend territories, enhance group prestige, and maintain favored trade and tribute networks. Pottery vessels were made in new and elaborate shapes, often as animal and human effigy forms; other artifacts of exotic copper, shell, wood and feathers mirror the emblematic needs of the noble classes to confirm their status.

Mississippian-type town centers typically included one or more flat-topped, earthen "temple" mounds, public areas and buildings ("council houses") used for religious and political assemblies. Wooden palisades, earthen moats or embattlements were placed around many villages for defensive purposes (Claggett 1996).

During the 1540s, Spanish explorers under the leadership of Hernando de Soto "discovered" several Indian groups occupying the interior regions of the Carolinas (Claggett 1996). Today, it is known that the coastal Indians were part of a larger group occupying the entire mid-Atlantic coastal area, identifiable by a shared language and culture called Algonkian (Claggett 1996). The Native Americans whom de Soto met included Siouan, Iroquoian and Muskogean speakers, whose descendants are now recognized as the historic tribes of the Catawba, Cherokee and Creek Indians. Within a very short period of time--some 50 years--after those first contacts, the early European explorers of North Carolina had met, interacted with, and begun the process of significant cultural displacement of all the major native groups in the state (Claggett 1996).

A number of modern Native American groups currently occupy North Carolina. State or Federally recognized groups include the Haliwa-Saponi, Coharie, Lumbee, Waccamaw-Siouan, Meherrin, and the Eastern Band of Cherokee Indians. Some 80,000 Native Americans now reside in North Carolina and are represented by tribal governments or corporate structures and through the North Carolina Commission of Indian Affairs (North Carolina Commission of Indian Affairs Undated).

The first known European exploration of North Carolina occurred during the early-to-mid-16th century. A Florentine navigator named Giovanni da Verrazano, in the service of France, explored the coastal area of North Carolina between the Cape Fear River area and Kitty Hawk. No attempt was made to colonize the area (State Library of North Carolina 1998).

From the mid-to-late-16th century several Spanish explorers from the Florida Gulf region explored portions of North Carolina, but again no permanent settlements were established (State Library of North Carolina 1998).

Coastal North Carolina was the scene of the first attempt to colonize America by English-speaking people. Two colonies were begun in the 1580s under a charter granted by Queen Elizabeth to Sir Walter Raleigh and both ended in failure (State Library of North Carolina 1998).

The first permanent English settlers in North Carolina were immigrants from the Tidewater area of southeastern Virginia. The first of these "overflow" settlers moved into the Albemarle area of northeast North Carolina around 1650 (State Library of North Carolina 1998).

In 1663, Charles II granted a charter to eight English gentlemen who had helped him regain the throne of England. The territory was called Carolina in honor of Charles the First. Until the Declaration of Independence in 1776 and the conclusion of the

Revolutionary War in 1783, North Carolina remained under England's control (State Library of North Carolina 1998).

Maritime History

Throughout the centuries the people of North Carolina have depended on the waters of the state. Indian inhabitants relied upon the rivers and sounds as a source of food, and a means of transportation and trade. The Indians built wooden dugout canoes and developed a variety of ways to catch fish. During the winter, many tribes would camp along the coastal sounds living off the readily available supply of oysters and other shellfish (North Carolina Division of Archives and History 1985).

Early European settlers used the water as a means to explore and settle the interior of the state. Down these rivers traveled the products of the new land: lumber, naval stores, tobacco and cotton. In exchange, ships from the other colonies, the West Indies and Europe brought to the major ports manufactured goods and other materials needed by the colonists (North Carolina Division of Archives and History 1985).

During the nineteenth century, paddlewheel steamboats came into use on the rivers of the state. Carrying passengers and cargo, often with a barge in tow, the steamers made their way well into the interior of the state on major rivers and their tributaries such as the Cape Fear, the Neuse, the Tar, the Roanoke, and the Chowan. Numerous shipwrecks and abandoned vessels have been located and studied. These include everything from dugout canoes, ferries, and fishing boats to coastal schooners and river steamboats (North Carolina Division of Archives and History 1985).

Coupled with this active maritime heritage, the unique and hazardous geography of the North Carolina coast has earned it the reputation as "Graveyard of the Atlantic." Three capes characterize North Carolina's coast: Cape Hatteras, Cape Lookout, and Cape Fear. The capes arc far into the Atlantic, with submerged shoals extending even further. Historical sources indicate that over 1,000 vessels have been lost off the North Carolina coast (North Carolina Division of Archives and History 1985). Naval warfare has also left a legacy of shipwrecks and other underwater archaeological sites. This is particularly true of the Civil War (North Carolina Division of Archives and History 1985).

Initial Operation

The Final Environmental Statement (FES) for the construction and operation of BSEP Units 1 and 2 (AEC 1974) listed 7 properties on the National Historic Register within the "vicinity" of BSEP. The FES notes that commenters on the Draft Environmental Statement evidenced concern that the proposed placement of the Brunswick to Barnard Creek dual 230 kV lines might impact cultural resources. They expressed concern that the route selected across the Cape Fear River might place these lines (the corridor) in close proximity to the "potentially rich archaeological site" of Old Town (AEC 1974). CP&L responded by contracting with the North Carolina Department of Archives and History to perform an archaeologic survey of the area. Upon completion of the survey, the Archaeologist, Survey Specialist, and State Historian concluded that the lines were

not likely to impact Old Town because (a) the Town's exact location was not known and (b) the surveyors did not find any archaeological remains near the proposed location. These statements were supported in letters from Stuart C. Schwartz, Archaeologist, Janet K. Seapker, Survey Specialist, and H. G. Jones, State Historian/Administrator, dated August 18, 1972, July 21, 1972, and November 17, 1972, respectively (AEC 1974). Likewise, the North Carolina Department of Art, Culture, and History did not object to the project (AEC 1974). As a result, NRC concluded that "the plant will not impose unacceptable impact upon National Register properties" (AEC 1974, pg. XII-5).

More recently, Progress Energy contracted with a research firm to conduct a marine remote sensing survey of a proposed realignment corridor of a power cable crossing in the Cape Fear River (to Bald Head Island) to determine if cultural resources were present. A total of five magnetic anomalies were recorded during the remote sensing survey. It was concluded that all five of the magnetic anomalies had only limited potential to be associated with significant submerged cultural resources. No additional mitigation or investigations were recommended (Mid-Atlantic Technology and Environmental Research, Inc. 2001).

Current Status

As of 2004, the National Register of Historic Places lists 12 locations in Brunswick County and 28 locations in New Hanover County, North Carolina (U.S. Department of the Interior 2004). Of these 40 locations, 13 fall within a 6-mile radius of BSEP. Table 2-9 lists the 13 National Register of Historic Places sites within the 6-mile radius of BSEP.

The Cape Fear Civil War Shipwreck Discontiguous District includes the wrecks of 21 Civil War vessels that lie along the coasts of Brunswick, New Hanover, and Pender counties and have been assigned one of five addresses by the National Park Service: Brunswick County --- Holden Beach vicinity, New Hanover County ---Wilmington Beach vicinity, New Hanover County --- Wrightsville Beach vicinity, New Hanover County --- Kure Beach vicinity, and Pender County --- Topsail Beach vicinity (Hall 1986; Philadelphia Architects and Buildings 2003). The New Hanover County --- Kure Beach site may lie within 6 miles of BSEP. The 21 sunken vessels associated with the Cape Fear Civil War Shipwreck District include 15 steam-powered and one (British) sail-powered blockade runners, four Union navy vessels, and one Confederate navy vessel (Hall 1986). Many of the blockade runners were lost when they ran aground on shoals at the mouth of the Cape Fear River and sank or were stranded in shallow water.

2.12 OTHER PROJECTS AND ACTIVITIES

BSEP is located in Brunswick County, North Carolina, near the mouth of the Cape Fear River. The 3-mile-long BSEP intake canal extends from the main channel of the Cape Fear River to the mainland, and then to the Plant. The Cape Fear River is regularly dredged by the U. S. Army Corps of Engineers, which maintains a ship channel from the mouth of the river to the Port of Wilmington (USACE 2003).

Military Ocean Terminal Sunny Point (MOTSP), a 16,000 acre facility owned and operated by the U.S. Army, lies immediately north of and adjacent to the BSEP site (Global Security 2001). MOTSP is the most important ammunition-handling port in the U.S., and the Army's main deep-water port on the east coast. In addition to world-wide transshipments of Department of Defense munitions, MOTSP supports Fort Bragg, North Carolina, home of the 82nd Airborne Division and other units (Global Security 2001). When the 82nd Airborne Division is mobilized, its heavy equipment and supplies are shipped out of MOTSP. Periodic dredging is required to keep this facility's basins and entrance channels accessible to the large, deep-draft vessels that it serves (USACE 2000; Global Security 2001).

An Archer Daniels Midland (ADM) chemical processing plant lies approximately one-half mile southeast of the BSEP site boundary. The Southport ADM facility is the largest producer of citric acid in the U.S. (Reed Business Information 1998). It is also Brunswick County's largest industrial (wholesale) water customer, purchasing more than 300 million gallons annually (Calhoun 2002). Citric acid is a preservative and stabilizer that is widely used in foods, pharmaceuticals, and cosmetics.

The Southport Cogeneration Plant, located approximately one-half mile south of the developed portion of the BSEP site, is owned and operated by Cogentrix Energy, Inc., one of the country's leading independent power producers. This 120 megawatt coal-fired facility sells electricity to Progress Energy and process steam to the nearby ADM processing plant (Cogentrix undated). The Southport Cogeneration Plant is Brunswick County's second largest industrial (wholesale) water customer (Calhoun 2002). The Cogentrix facility has an NPDES-permitted outfall that discharges to the BSEP discharge canal, just outside of the Nuclear Exclusion Zone at the point where the railroad trestle crosses the canal.

TABLE 2-1
ENDANGERED AND THREATENED SPECIES KNOWN TO OCCUR IN BRUNSWICK COUNTY OR IN COUNTIES CROSSED BY BSEP-ASSOCIATED TRANSMISSION LINES[a]

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Mammals			
Neotoma floridana haematoreia	Eastern woodrat – Coastal Plain population	-	T
Puma concolor couguar	Eastern cougar	E	E
Trichechus manatus	Manatee	E	E
Birds			
Charadrius melodus	Piping plover	T	T
Falco peregrinus	Peregrine falcon	-	E
Haliaeetus leucocephalus	Bald eagle	T	E
Mycteria americana	Wood stork	E	E
Picoides borealis	Red-cockaded woodpecker	E	E
Sterna nilotica	Gull-billed tern	-	T
Reptiles and Amphibians			
Alligator mississippiensis	American alligator	T(S/A)	T
Ambystoma tigrinum	Tiger salamander	-	T
Caretta caretta	Loggerhead sea turtle	T	T
Chelonia mydas	Green sea turtle	T	T
Dermochelys coriacea	Leatherback sea turtle	E	E
Eretmochelys imbricate	Hawksbill sea turtle	E	E
Lepidochelys kempii	Kemp's ridley sea turtle	E	E
Rana capito	Carolina gopher frog	-	T
Fish			
Acipenser brevirostrum	Shortnose sturgeon	E	E
Elassoma boehlkei	Carolina pygmy sunfish	-	T
Etheostoma perlongum	Waccamaw darter	-	T
Menidia extensa	Waccamaw silverside	T	T
Invertebrates			
Anodonta couperiana	Barrel floater (mussel)	-	E
Catinella vermata	Suboval ambersnail	-	T
Elliptio marsupiobesa	Cape Fear spike (mussel)	-	T
E. roanokensis	Roanoke slabshell (mussel)	-	T
E. waccamawensis	Waccamaw spike (mussel)	-	T

**TABLE 2-1
ENDANGERED AND THREATENED SPECIES KNOWN TO OCCUR IN BRUNSWICK COUNTY OR IN COUNTIES CROSSED BY BSEP-ASSOCIATED TRANSMISSION LINES[a] (Continued)**

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Fusconaia masoni	Atlantic pigtoe (mussel)	-	T
Lampsilis cariosa	Yellow lampmussel	-	T
L. fullerkati	Waccamaw fatmucket (mussel)		
Planorbella magnifica	Magnificent rams-horn (snail)	-	E
Toxolasma pullus	Savannah lilliput (mussel)	-	T
Triodopsis soelneri	Cape Fear threetooth (snail)	-	T
Plants			
Adiantum capillus-veneris	Venus hair fern	-	E
Amaranthus pumilus	Seabeach amaranth	T	T
Amorpha georgiana var *confusa*	Savanna indigo-bush	-	T
A. g. var *georgiana*	Georgia indigo-bush	-	E
Asplenium heteroresiliens	Carolina spleenwort	-	E
Astragalus michauxii	Sandhills milk-vetch	-	T
Calopogom multiflorus	Many-flowered grass-pink	-	E
Carex lutea	Golden sedge	E	E
Carya myristiciformis	Nutmeg hickory	-	T
Chrysoma pauciflosculosa	Woody goldenrod	-	E
Fimbristylis perpusilla	Harper's fimbry	-	T
Helenium brevifolium	Littleleaf sneezeweed	-	E
H. vernale	Dissected sneezeweed		E
Lindera melissifolia	Southern spicebush	E	E
L. subcoriacea	Bog spicebush	-	E
Lilaeopsis carolinensis	Carolina grasswort	-	T
Lophiola aurea	Golden crest	-	E
Lysimachia asperulaefolia	Rough-leaved loosestrife	E	E
Macbridea caroliniana	Carolina bogmint	-	T
Muhlenbergia torreyana	Pinebarren smokegrass	-	E
Myriophyllum laxum	Loose watermilfoil	-	T
Panicum hirstii	Hirsts' panic grass	C	E
Parnassia caroliniana	Carolina grass-of-parnassus	-	E
P. grandifolia	Large-leaved grass-of-parnassus	-	T

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

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Plantago sparsiflora	Pineland plantain	-	E
Plantanthera integra	Yellow fringeless orchid	-	T
P. nivea	Snowy orchid		T
Pteroglossapsis ecristata	Spiked medusa	-	E
Rhexia aristosa	Awned meadow-beauty	-	T
Rhus michauxii	Michaux’s sumac	E	E
Rhynchospora thornei	Thorne’s beaksedge	-	E
Schwalbea americana	American chaffseed	E	E
Solidago pulchra	Carolina goldenrod	-	E
Sporobolus teretifolius	Wireleaf dropseed	-	T
Stylisma pickeringii var *pickeringii*	Pickering’s dawnflower	-	E
Thalictrum cooleyi	Cooley’s meadowrue	E	E
Trillium pusillum var *pusillum*	Carolina least trillium	-	E
Utricularia olivacea	Dwarf bladderwort	-	T

Source: USFWS 2002a, CP&L 1998, NCDENR 2001, NCDENR 2002a

a. Bladen, Brunswick, Columbus, New Hanover, Pender, Onslow, and Robeson counties.

b. E = Endangered; T = Threatened; T(S/A) = Threatened due to similarity of appearance; a species which is protected because it is very similar in appearance to a listed species; - = Not listed.

TABLE 2-2
FEDERALLY-LISTED TERRESTRIAL SPECIES FOUND IN THE VICINITY OF BSEP OR IN THE VICINITY OF BSEP TRANSMISSION LINES

Species	Federal status	Reason for concern at BSEP	Protective measures taken by Progress Energy
Rough-leaved loosestrife	Endangered	Four populations occur on BSEP rights-of-way (offsite).	These populations are protected and managed by Progress Energy by agreement with NC Natural Heritage Program.
Cooley's meadowrue	Endangered	Two populations occur on BSEP rights-of-way (offsite).	These populations are protected and managed by Progress Energy by agreement with NC Natural Heritage Program.
Golden sedge	Endangered	A population occurs on a BSEP right-of-way	The population is protected and managed by Progress Energy by agreement with NC Natural Heritage Program.
Red-cockaded woodpecker	Endangered	Known to occur in mature pine forests in Brunswick County and regularly observed in Southport-Oak Island area.	Any facility expansion involving removal of mature longleaf pine would require surveys for this species to ensure that no red-cockaded woodpeckers or trees with their nest-cavities are harmed.

Source: CP&L 1998.

TABLE 2-3
ESTIMATED POPULATIONS AND ANNUAL GROWTH RATES

	Population and Average Annual Growth Rate					
	New Hanover County		Brunswick County		North Carolina	
Year	Number	Percent	Number	Percent	Number	Percent
1980[a]	103,471	2.5	35,777	4.8	5,881,766	1.6
1990[a]	120,284	1.6	50,985	4.3	6,628,637	1.3
2000[b]	160,307	3.3	73,143	4.3	8,049,313	2.1
2010[c]	196,508	2.3	93,776	2.8	9,491,372	1.8
2020[c]	231,402	1.8	112,992	2.0	10,966,139	1.6
2030[c]	264,231	1.4	130,688	1.6	12,447,597	1.4
2040[d]	290,713	1.0	148,314	1.3	13,382,140	0.8

a. U.S. Census Bureau 1995.
b. U.S. Census Bureau 2001c,d.
c. North Carolina Office of State Budget and Management 2002.
d. Tetra Tech NUS 2002.

TABLE 2-4
MINORITY AND LOW-INCOME POPULATION CENSUS BLOCK GROUPS AND TRACTS

County	State	2000 Block Groups	American Indian or Alaskan Native	Asian	Native Hawaiian or other Pacific Islander	Black Races	All Other Single Minorities	Multi-racial Minorities	Aggregate of Minority Races	Hispanic Ethnicity	2000 Tracts	2000 Tracts Low-Income
Bladen	NC	8	0	0	0	5	0	0	5	0	2	0
Brunswick	NC	49	0	0	0	2	0	0	2	0	11	0
Columbus	NC	33	2	0	0	9	0	0	9	0	11	0
New Hanover	NC	99	0	0	0	20	0	0	19	0	33	3
Onslow	NC	3	0	0	0	0	0	0	0	0	2	0
Pender	NC	22	0	0	0	4	0	0	2	0	7	0
Sampson	NC	1	0	0	0	1	0	0	1	0	1	0
Horry	SC	42	0	0	0	3	0	0	3	0	15	0
TOTALS		257	2	0	0	44	0	0	41	0	82	3

State Averages

States	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
North Carolina	1.2%	1.4%	0.0%	21.6%	2.3%	1.3%	27.9%	4.7%	12.4%
South Carolina	0.3%	0.9%	0.0%	29.5%	1.0%	1.0%	32.8%	2.4%	14.2%

TABLE 2-5
PROPERTY TAX REVENUES GENERATED IN BRUNSWICK COUNTY; PROPERTY TAXES PAID TO BRUNSWICK COUNTY BY BRUNSWICK STEAM ELECTRIC PLANT, 1997 – 2002

Year	Total Brunswick County Property Tax Revenues[a]	Property Tax Paid By BSEP	Percent of Total Property Taxes
1997	$42,384,960	$5,700,000	13.45
1998	$44,837,765	$4,500,000	10.04
1999	$45,270,251	$4,200,000	9.28
2000	$52,822,490	$4,200,000	7.95
2001	$55,689,742	$4,600,000	8.26
2002	$60,982,737	$4,600,000	7.54

a. N.C. Department of State Treasurer 2003.

TABLE 2-6
BRUNSWICK COUNTY PUBLIC WATER SUPPLIERS AND CAPACITIES

Water Supplier	Customer Average Daily Use (Million Gallons per Day)	Maximum Daily Capacity Supplied by Brunswick County[a] (Million Gallons per Day)
Brunswick County Water & Sewer Authority	11.628	30.0 [b]
City of Southport	0.660	0.418
Long Beach Water	0.822	1.321
Yaupon Beach	0.167	0.052
Town of Shallotte	0.217	0.180
Ocean Isle Beach Water System	0.490	0.386
Town of Sunset Beach	0.584	1.085
Town of Caswell Beach	0.169	0.260
Town of Holden Beach	0.411	0.822
Town of Navassa	0.047	0.133
North Brunswick Sanitary District	0.494	0.455

Source: NCDENR 2002b (pg. 35 and Appendix C).

a. Capacity based on water supplied by Brunswick County only. No data currently available for groundwater use by water supplier other than Brunswick County.

b. Groundwater and surface water capacity.

TABLE 2-7
NEW HANOVER COUNTY PUBLIC WATER SUPPLIERS AND CAPACITIES

Water Supplier	Average Daily Use (Million Gallons per Day)	Maximum Daily Capacity (Million Gallons per Day)
New Hanover County [a]	2.35	Not available
Wilmington [b]	11.543	25
Carolina Beach [b]	0.312	0.564
Kure Beach [b]	0.357	0.824
Figure Eight Island [b]	0.355	0.564
Wrightsville Beach [b]	1.005	1.222
Flemington [b]	0.312	0.432

a. Blanchard 2002.
b. NCDENR 2002b.

TABLE 2-8
TRAFFIC COUNTS FOR ROADS IN THE VICINITY OF BSEP

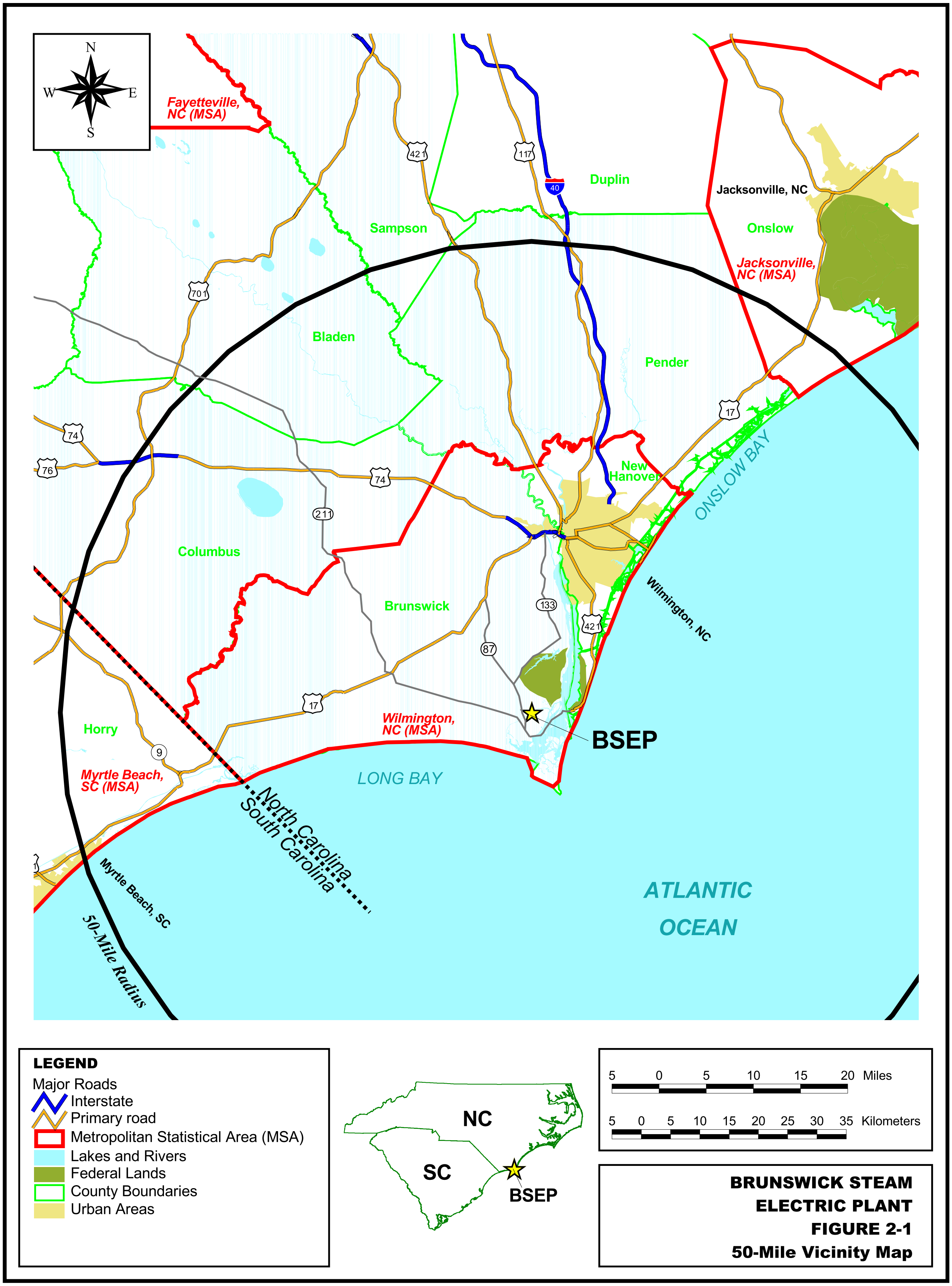
Route No.	Vicinity of	Est. AADT[a]	Location
N.C. 211	Southport to N.C. 87	16,000	Figure 2-2
N.C. 211	NC 87 to NC 133	17,000	Figure 2-2
N.C. 211	East of Long Beach Road	22,000	Figure 2-2
N.C. 133	Long Beach Road just south of N.C. 211	19,000	Figure 2-2
N.C. 133	N.C. 211 to N.C. 87	9,500	Figure 2-2
N.C. 87/N.C. 133	Just west of the merger of N.C 87 & N.C. 133	14,000	Figure 2-2
N.C. 87/N.C. 133	Just south of N.C 87/133 split	13,000	Figure 2-2
N.C. 87	From N.C. 87/133 split to Boiling Spring Lakes	6,900	Figure 2-2
N.C. 87	Just north of Boiling Spring Lakes	5,100	Figure 2-2
N.C. 133	U.S. Transportation Railroad	5,900	Figure 2-2
N.C. 133	Town of Orton	4,800	Figure 2-2

AADT = Annual Average Daily Traffic volumes, 2001.
SSR = Secondary State Route.
N.C. = State primary road.
U.S. = United States highway.
a. NCDOT 2002.

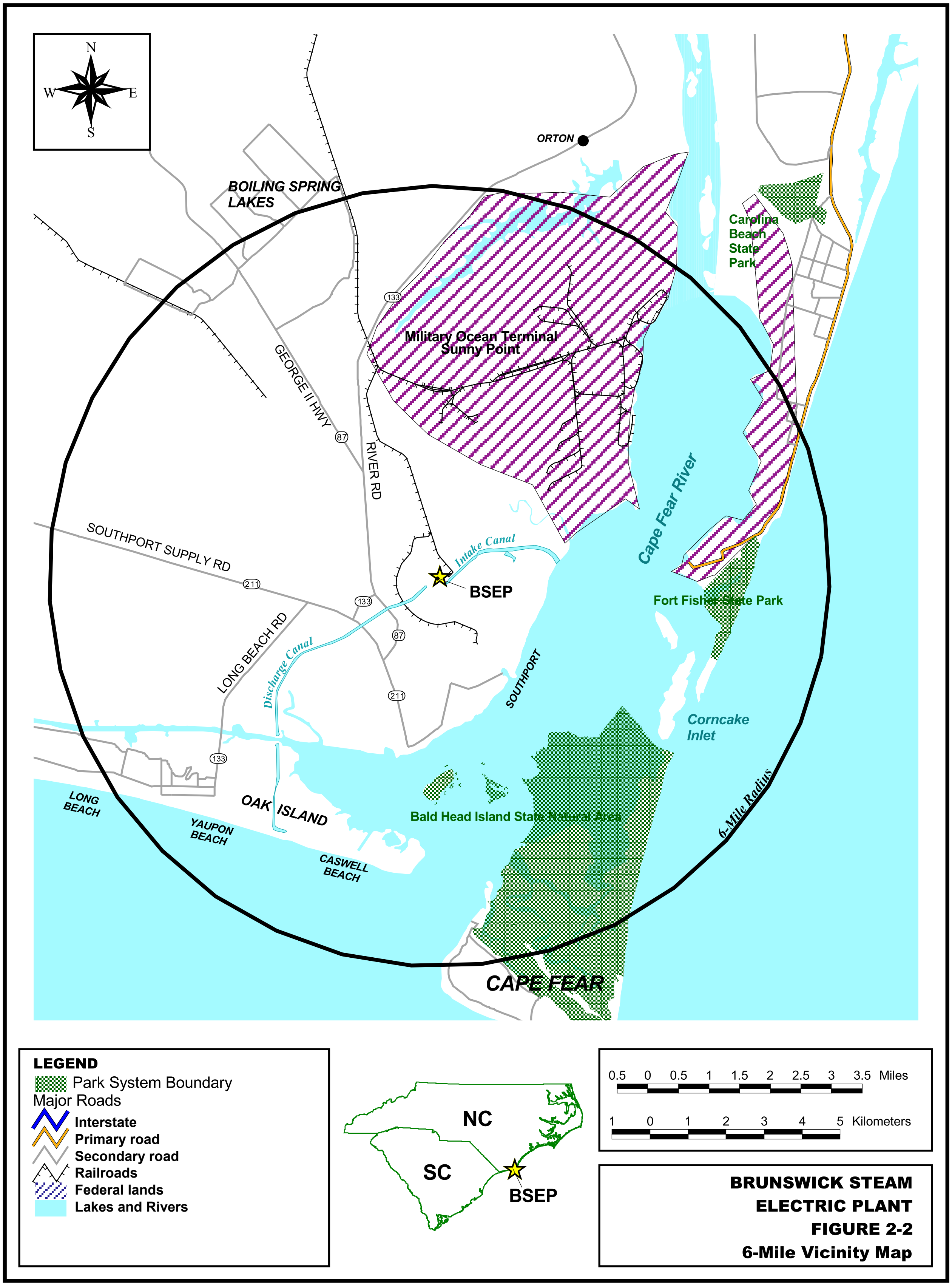
TABLE 2-9
SITES LISTED IN THE NATIONAL REGISTER OF HISTORIC PLACES THAT FALL WITHIN A 6-MILE RADIUS OF BSEP

Site Name	Location
Brunswick County	
Bald Head Creek Boat House	Smith Island, mouth of the Cape Fear River
Bald Head Island Lighthouse	South of Southport on Smith Island at Bald Head
Brunswick County Courthouse	Davis and Moore Streets, Southport
Brunswick Town Historic District	North of Southport off of SR 133
Cape Fear Lighthouse Complex	South of Kure Beach, Kure Beach
Fort Johnston	Moore Street, Southport
Oak Island Life Saving Station	217 Caswell Beach Road, Caswell Beach
Orton Plantation	On Cape Fear River at junction of NC 1530 and 1529, Smithville Township
Southport Historic District	Roughly bounded by Cape Fear River, Rhett, Bay, Short, and Brown Streets, Southport
St. Philip's Church Ruins	South of Orton off of NC 1533, Orton
New Hanover County	
Cape Fear Civil War Shipwreck Discontiguous District	Address Restricted, Kure Beach
Fort Fisher	18 miles south of Wilmington on U.S. 421, Wilmington
U.S.S. Peterhoff	Address Restricted, Fort Fisher

Source: U.S. Department of the Interior 2004.



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2-1
50-Mile Vicinity Map



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2-2
6-Mile Vicinity Map

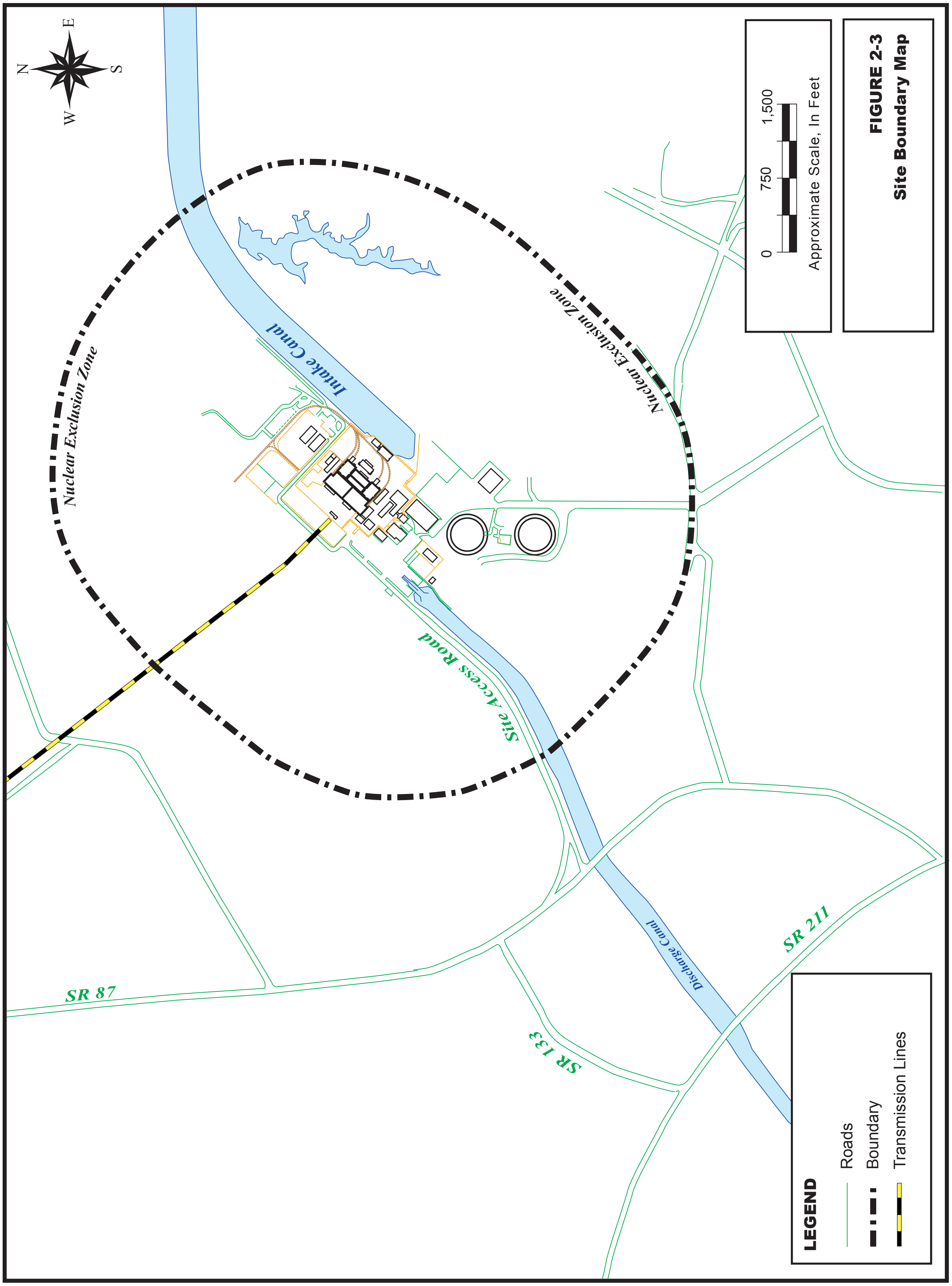
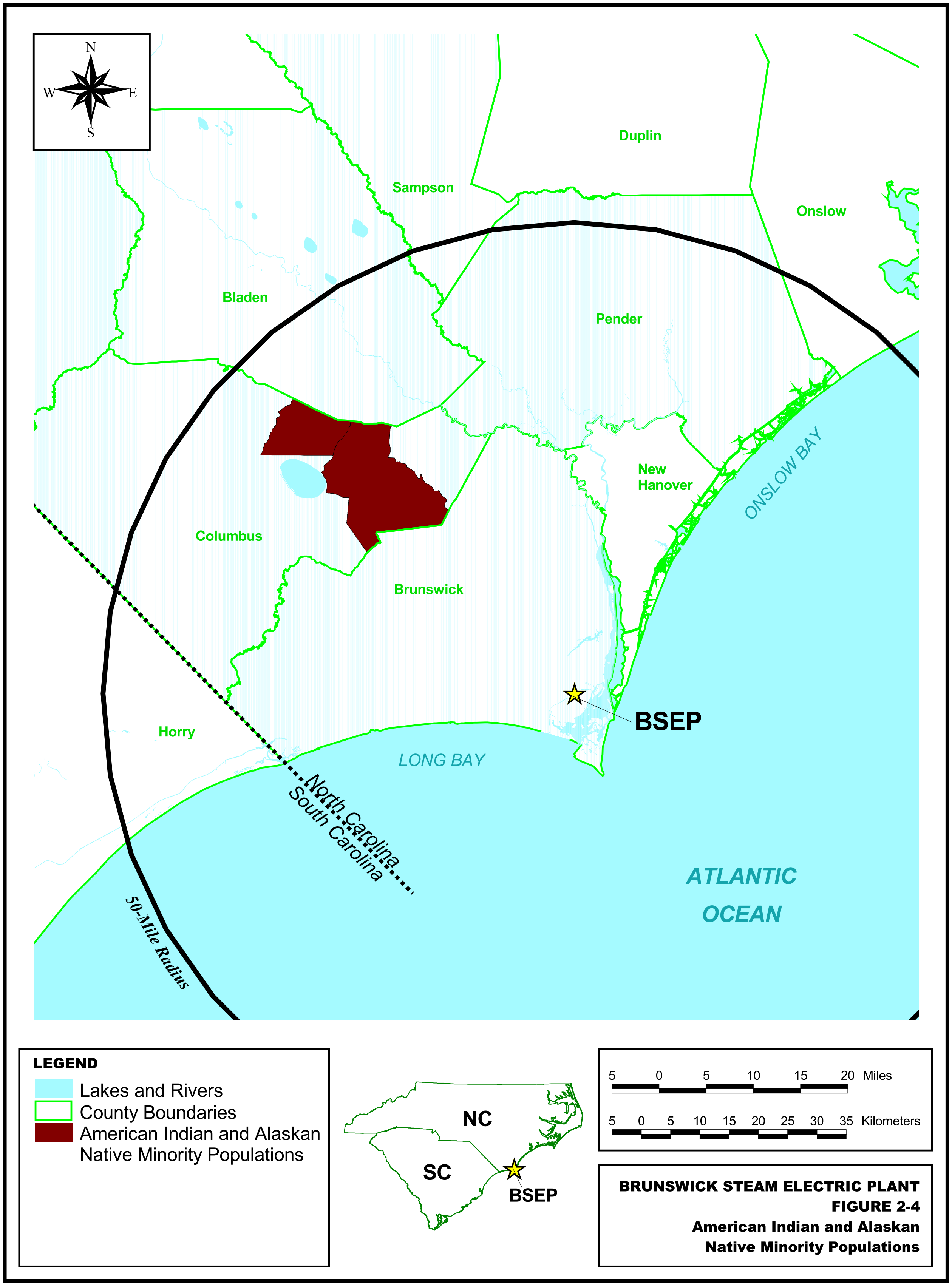
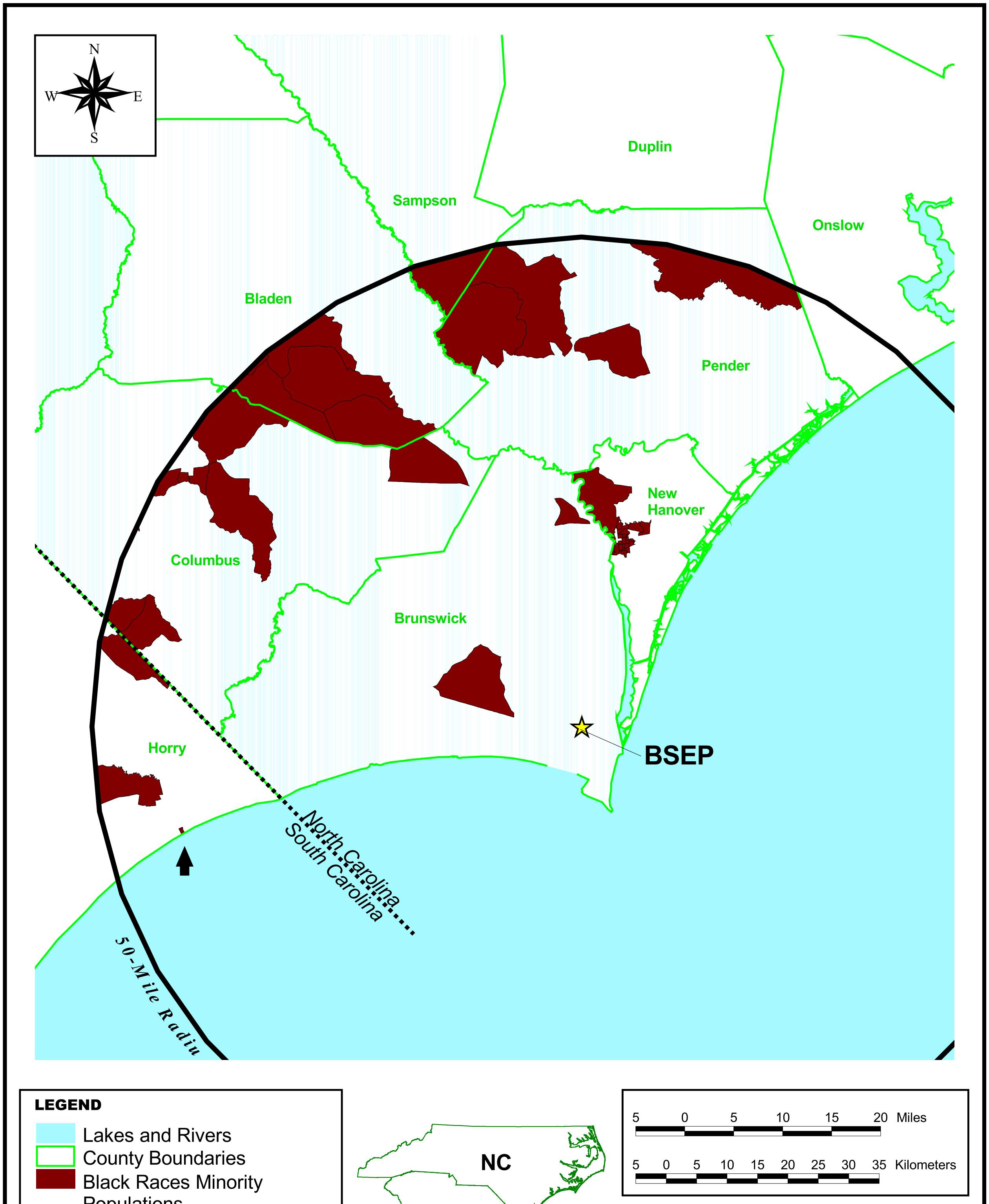


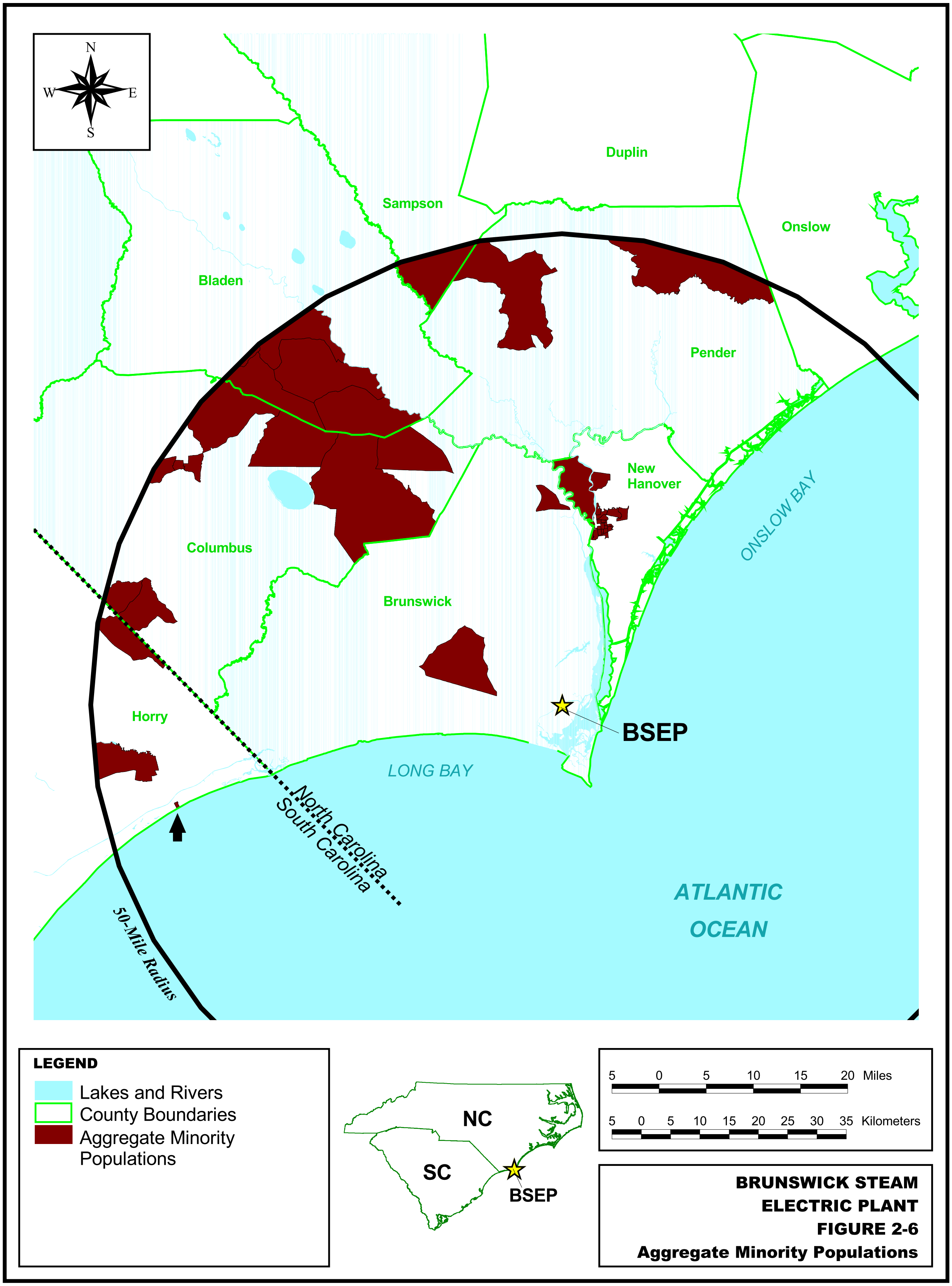
FIGURE 2-3
Site Boundary Map



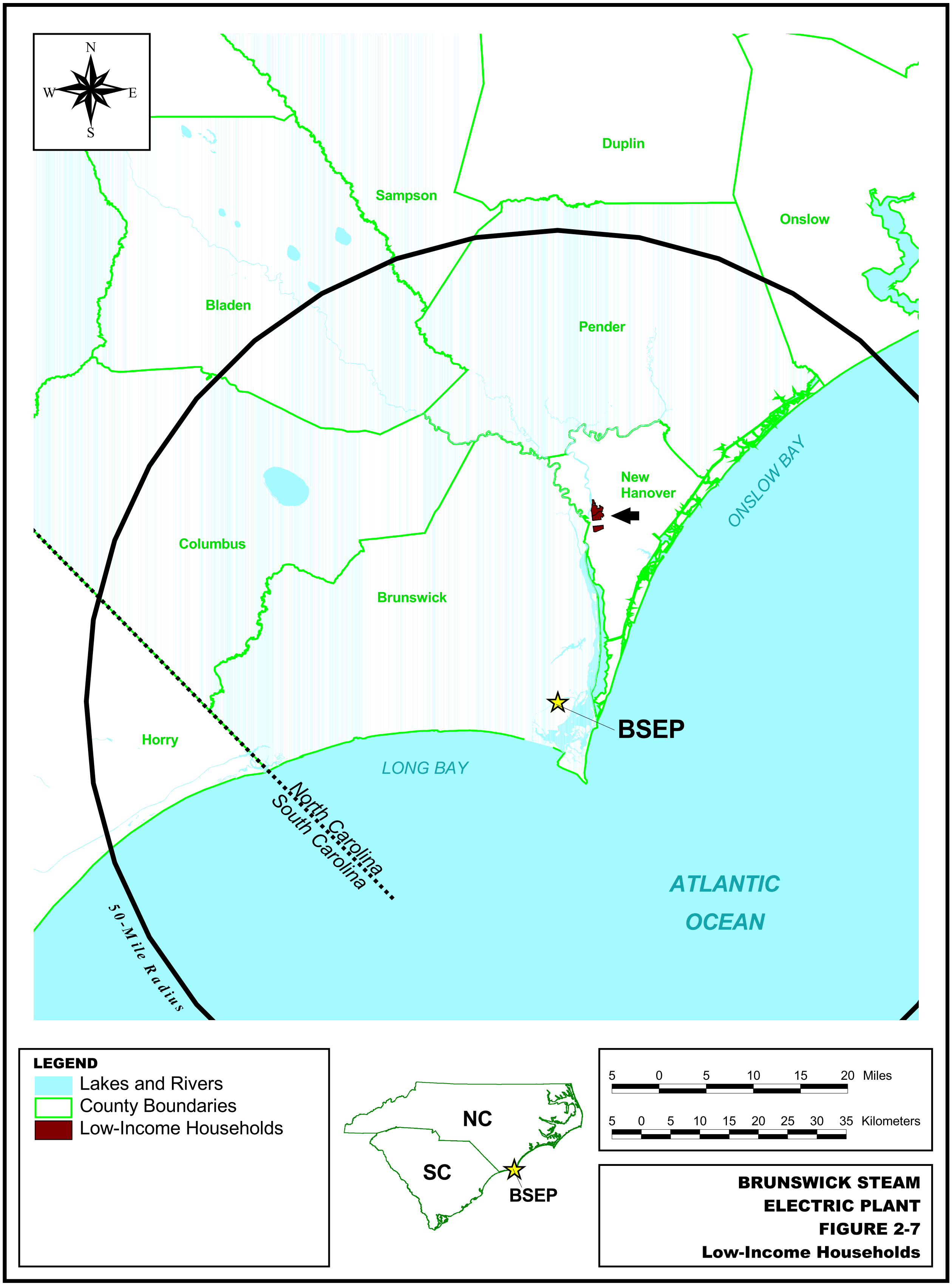
BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2-4
American Indian and Alaskan Native Minority Populations



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2-5
Black Races Minority Populations



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2-6
Aggregate Minority Populations



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2-7
Low-Income Households

2.13 REFERENCES

Note to reader: Some web pages cited in this document are no longer available, or are no longer available through the original URL addresses. Hard copies of 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.

AEC (U.S. Atomic Energy Commission). 1974. Final Environmental Statement related to the continued construction and proposed issuance of an operating license for the Brunswick Steam Electric Plant Units 1 and 2, Carolina Power and Light Company. United States Atomic Energy Commission Directorate of Licensing. Washington, DC.

Ahern (Patricia Ahern). 2002. BSEP Employee Addresses by County. BSEP Human Resources Department, Progress Energy. Southport, NC. July.

Blanchard (Wyatt Blanchard). 2002. "New Hanover County Water Data" E-mail from Wyatt Blanchard (New Hanover County) to Gary Gunter (TTNUS). November 22.

Brunswick County. 1997. Brunswick County Land Use Plan. 1997 Update. Brunswick County Planning Board, Brunswick County, North Carolina. Adopted October 5 and, as revised, December 7, 1998.

Brunswick County (Brunswick County Government Public Utilities). 2001. Public Utilities. Available on-line at www.co.brunswick.nc.us/pu.asp.

BSEP (Brunswick Steam Electric Plant). 2002. Endangered and Threatened Species. EVC-SUBS-00011, Rev 0. October.

BSEP (Brunswick Steam Electric Plant). 2003. Environmental Training: Endangered Species. EVC-SUBS-00062, Rev 0. January.

Calhoun, T. 2002. "ADM suing county over water rates." *The State Port Pilot* (Southport, NC), on-line edition. July 3.

City of Southport. 2001. City of Southport, North Carolina, Comprehensive Plan. City of Southport Planning Board, Southport, North Carolina. December.

Claggett, Stephen R. 1996. "North Carolina's First Colonists: 12,000 Years Before Roanoke." Available on-line at http://www.arch.dcr.state.nc.us/1stcolo.htm (North Carolina Archaeology website).

Cogentrix (Cogentrix Energy, Inc). Undated. Southport Cogeneration Plant. Available on-line at http://www.cogentrix.com/plants/southport.html.

CP&L (Carolina Power and Light Company). 1971. Environmental Report, Brunswick Steam Electric Plant Units 1 and 2. Volume one.

CP&L (Carolina Power & Light Company). 1980. Brunswick Steam Electric Plant Cape Fear Studies: Interpretive Report. January 1980.

CP&L (Carolina Power & Light Company). 1985. Brunswick Steam Electric Plant Cape Fear Studies: Interpretive Report. August 1985.

CP&L (Carolina Power and Light Company). 1998. Threatened and Endangered Species Self-Assessment Report. Memo. August 12.

CP&L (Carolina Power and Light Company). 2001. Brunswick Nuclear Plant Updated FSAR. Chapter 1, Revision 17B, Introduction and Summary.

CP&L (Carolina Power and Light Company). 2002. Brunswick Steam Electric Plant – 2001 Environmental Monitoring Report. Environmental Services Section, New Hill. August.

EEI (Edison Electric Institute). 2002. “Electric Competition in the States, A Summary.” April.

Global Security. 2001. “Military Ocean Terminal Sunny Point (MOTSU) Southport, N.C.” Available on-line at http://www.globalsecurity.org/military/facility/sunny-point.htm.

Gunter. 2002a. Telephone conversation between Mr. George Baird of Progress Energy and Gary Gunter of Tetra Tech NUS concerning site water wells and resulting facsimile from George Baird to Gary Gunter. September 4.

Gunter. 2002b. Telephone conversation between Mr. George Baird of Progress Energy and Gary Gunter of Tetra Tech NUS concerning site water wells. November 25.

Hall, Delores. 1986. "The Cape Fear Shipwreck District." Newsletter of the Friends of North Carolina Archaeology, Volume 2, Number 2, Spring issue. Available on line at http://www.arch.dcr.state.nc.us/sites/capefear.htm. Accessed February 6, 2004.

Hensdale, D. 2002. E-mail from D. Hensdale, N.C. Department of Transportation to G. Gunter, Tetra Tech NUS. November 27.

LCFWSA (Lower Cape Fear Water and Sewer Authority). 2002a. Water Use by Customers (2000). Available at www.lcfwasa.org.

LCFWSA (Lower Cape Fear Water and Sewer Authority). 2002b. Water Use Forecast. Available at www.lcfwasa.org.

Lower Cape Fear River Program. 2003. Mission and Objectives. Available at http://www.uncwil.edu/cmsr/aquaticecology/lcfrp/.

Martof, B. S., W. M. Palmer, J. R. Bailey, and J. R. Harrison, III. 1980. *Amphibians and Reptiles of the Carolinas and Virginia*. The University of North Carolina Press, Chapel Hill, N.C.

Mid-Atlantic Technology and Environmental Research, Inc. 2001. A Cultural Resources Marine Remote Sensing Survey of the Proposed Realignment Corridor of a Power Cable Crossing the Cape Fear River to Bald Head Island, NC. Prepared for Carolina Power and Light Company by Mid-Atlantic Technology and Environmental Research, Castle Hayne, North Carolina.

Moser, M. L., and S. W. Ross. 1995. Habitat use and movements of shortnose and Atlantic sturgeons in the lower Cape Fear River, North Carolina. Transactions of the American Fisheries Society 124: 225-234.

NC (State of North Carolina). 2000. “State of North Carolina’s Recommendation on Boundaries for 8-Hour Ozone Nonattainment Areas.” Available at http://www.epa.gov/ ttn/naaqs/ozone/areas/recommend/nc_01.pdf. June 29, 2000.

NCCLT (North Carolina Coastal Land Trust). 2001. “Group Preserving Remnant of Wetland Studied by N. C. State Ecologist.” Press release dated October 22, 2001. Available at http://www.coastallandtrust.org. Accessed August 27, 2002.

NCDENR (North Carolina Department of Environment and Natural Resources). 2001. Natural Heritage Program List of the Rare Animal Species of North Carolina. North Carolina Natural Heritage Program.

NCDENR (North Carolina Department of Environment and Natural Resources). 2002a. Natural Heritage Program List of the Rare Plant Species of North Carolina. North Carolina Natural Heritage Program.

NCDENR (North Carolina Department of Environment and Natural Resources). 2002b. "Cape Fear River Basin Water Supply Plan Second Draft," Division of Water Resources, March.

NC State Treasurer (North Carolina Department of State Treasurer). 2003. North Carolina Department of State Treasurer, Financial Information, Brunswick County. Available online at http://ncdst-web2.treasurer.state.nc.us/lgc/units/D_09.htm.

NHC (New Hanover County). 2002. "Water Systems." New Hanover County Engineering Department. Available at http://www.nhcgov.com/ENG/ Mainwaterpage.asp. July 23.

NMFS (National Marine Fisheries Service). 1998. Recovery Plan for the Shortnose Sturgeon (Acipenser brevirostrum). Prepared by the Shortnose Sturgeon Recovery

Team for the National Marine Fisheries Service, Silver Spring, Maryland. December.

NMFS (National Marine Fisheries Service). 2000. Endangered Species Act – Section 7 Consultation Biological Opinion: Operation of the Cooling Water Intake System at the Brunswick Steam Electric Plant Carolina Power and Light Company. January 20.

North Carolina Commission of Indian Affairs. Undated. "North Carolina Indians." Available at http://www.doa.state.nc.us/doa/cia/facts.pdf.

North Carolina Division of Archives and History. 1985. The Ligature. A Link with the Past. North Carolina's Underwater Archaeology. Available online at http://www.arch.dcr.state.nc.us/UW-LIGIT.HTM. Accessed September 17, 2002.

North Carolina Office of State Budget and Management. 2002. Population Overview. Available at http://demog.state.nc.us/demog/pop0030.html.

NRC (U.S. Nuclear Regulatory Commission). 1996. Generic Environmental Impact Statement for License Renewal of Nuclear Plants. NUREG-1437, Office of Nuclear Regulatory Research. Washington DC. May.

NRC (U.S. Nuclear Regulatory Commission). 2001. "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues." NRR Office Instruction No. LIC-203, June 21.

Ogren, L. H. 1992. "Atlantic Ridley Turtle" *in* Rare and Endangered Biota of Florida, Vol III Amphibians and Reptiles, P. E. Moler, ed. University of Florida Press. Gainesville, Fl.

O'Keefe, C. 2003. Electronic mail to E. N. Hill (TtNUS, Inc.). Land Use Information. New Hanover County Planning Department. February 19.

Philadelphia Architects and Buildings. 2003. National Register Sites in North Carolina. Available on line at http://www.philadelphiabuildings.org. Accessed February 6, 2004.

Progress Energy. 2002. "Progress Energy 2001 Annual Report."

Radford, A. E., H. E. Ahles, and C. R. Bell. 1968. *Manual of the Vascular Flora of the Carolinas*. University of North Carolina Press. Chapel Hill, N.C.

Reed Business Information. 1998. "Availability keeps prices flat." Published in Purchasing.com, an on-line magazine, and available at http://www.manufacturing.net/pur. December 10.

Smith, L. 2002. "Water Use Data for BSEP," Email from Lee Smith (Brunswick County) to Gary Gunter (TTNUS). November 26.

Smith, J. 2002. "People of the Fallen Star: Waccamaw-Siouan Tribe." Columbus County Native American Resources. Columbus County (N.C.) GenWeb Site. Available at http://www.spiritdesign.net/columbus/nativeamerican.htm.

State Library of North Carolina. 1998. North Carolina Encyclopedia. Historical Highlights of North Carolina. Available online at http://statelibrary.dcr.state.nc.us/nc/history/history.htm. Accessed September 17, 2002.

Stewart, M. 2003. Personal communication with E. N. Hill (Tetra Tech NUS, Inc.). Land Use Information. Brunswick County Planning Department. February 19.

Tetra Tech NUS (TtNUS). 2002. Population projection for the year 2040. Aiken, S.C. November.

USACE (United States Army Corps of Engineers). 2000. "U.S. Army Corps of Engineers to dredge at MOTSU." Public Affairs Office, United States Army Corps of Engineers, Wilmington District. News Release, dated April 21.

USACE (United States Army Corps of Engineers). 2003. Wilmington Harbor Project web site. Available on-line at http://www.saw.usace.army.mil/wilmington-harbor/main.htm.

USAEC (United States Army Environmental Center). 1998. "Army Terminal Joins Natural Heritage Registry." From a Military Traffic Management Command, Eastern Area news release. Available at http://aec.army.mil/usaec/publicaffairs/update/spr98/registry.htm.

USCB (U.S. Census Bureau). 1990. Census 1990 Summary Tape File 1 (STF 1) – 100 percent data. Table GCT-Ha. General Housing Characteristics: 1990. Geographic Area: North Carolina – County. Available online at http://factfinder.census.gov/servlet/BasicFactsServlet.

USCB (U.S. Census Bureau). 1995. Population of Counties by Decennial Census: 1900-1990. Available at http://www.census.gov/population/cencounts/nc/190090.txt.

USCB (U.S. Census Bureau). 2000a. American FactFinder Quick Tables. Table QT-PL. Race, Hispanic or Latino, and Age: 2000. Geographic Area: North Carolina. Available at http://factfinder.census.gov/servlet/BasicFactsServlet.

USCB (U.S. Census Bureau). 2000b. American FactFinder Quick Tables. Table QT-PL. Race, Hispanic or Latino, and Age: 2000. Geographic Area: South Carolina. Available at http://factfinder.census.gov/servlet/BasicFactsServlet.

USCB (U.S. Census Bureau). 2000c. American FactFinder Detailed Tables. Table HCT24. Tenure by Poverty Status in 1999 by Age of Householder. Data set: Census 2000 Summary File 3 (SF 3) – Sample Data. Available at http://factfinder.census.gov/servlet/BasicFactsServlet.

USCB (U.S. Census Bureau). 2000d. Census 2000 Summary File 1 (SF 1) – 100 percent data. Table GCT-PH1. Population, Housing Units, Area, and Density: 2000. Geographic Area: North Carolina – County. Available online at http://factfinder.census.gov/servlet/BasicFactsServlet.

USCB (U.S. Census Bureau). 2000e. Census 2000 Summary File 3 (SF 3) – Sample Data. Quick Tables, Table DP-4. Profile of Selected Housing Characteristics: 2000. Geographic Area: Brunswick County, North Carolina. Available online at http://factfinder.census.gov/servlet/BasicFactsServlet.

USCB (U.S. Census Bureau). 2000f. Census 2000 Summary File 1 (SF 1) – 100 percent data. Table DP-1. Profile of General Demographic Characteristics: 2000. Geographic area: Charlotte city, North Carolina. Available online at http://factfinder.census.gov/servlet/BasicFactsServlet.

USCB (U.S. Census Bureau). 2001a. Census 2000 Summary File 1 (SF 1). Available at http://www.census.gov/Press-Release/www/2001/sumfile1.html.

USCB (U.S. Census Bureau). 2001b. Ranking Tables for Metropolitan Areas: Population in 2000 and Population Change from 1990 to 2000 (PHC-T-3). Available at http://www.census.gov/population/www/cen2000/phc-t3.html.

USCB (U.S. Census Bureau). 2001c. Ranking Tables for States: Population in 2000 and Population Change from 1990 to 2000 (PHC-T-2). Available at http://www.census.gov/population/www/cen2000/phc-t2.html.

USCB (U.S. Census Bureau). 2001d. Ranking Tables for Counties: Population in 2000 and Population Change from 1990 to 2000 (PHC-T-4). Available at http://www.census.gov/population/www/cen2000/phc-t4.html.

USCB (U.S. Census Bureau). 2002. Census 2000 Summary File 3 (SF 3). Available at http://www.census.gov/Press-Release/www/2002/sumfile3.html.

U.S. Department of the Interior. 2004. National Register Information System. Available online at http://www.nr.nps.gov/. Accessed February 9, 2004.

USFWS (U.S. Fish and Wildlife Service). 2002a. Endangered species in North Carolina. Available at http://nc-es.fws.gov/es/es.html. Updated 2/05/03. Accessed February 17, 2003.

USFWS (U.S. Fish and Wildlife Service). 2002b. Golden Sedge Provided Endangered Species Act Protection. Southeast Region (4) Press Release, dated January 23.

Wilmington (City of Wilmington). 2002. "Annual Wastewater Report for FY 2001-2002," City of Wilmington Public Utilities.

Wilmington-New Hanover County. 1999. Wilmington – New Hanover County CAMA Land Use Plan Update and Comprehensive Plan. 1997-2010. New Hanover

County Planning Department and Wilmington Planning Division. Adopted September 7, 1999.

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 Brunswick Steam Electric Plant Units 1 and 2 (BSEP) for an additional 20 years. Renewal would give Progress Energy and the state of North Carolina the option of relying on BSEP to meet future electricity needs. Section 3.1 discusses the plant in general. Sections 3.2 through 3.4 address potential changes that could occur as a result of license renewal.

3.1 GENERAL PLANT INFORMATION

General information about BSEP is available in several documents. In 1974, the U.S. Atomic Energy Commission, the predecessor agency of NRC, prepared the Final Environmental Statement for continued construction and proposed issuance of an operating license for the BSEP Units 1 and 2 (AEC 1974). The NRC *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996) describes BSEP features and, in accordance with NRC requirements, Progress Energy maintains the Updated Final Safety Analysis Report for BSEP (CP&L 2001). Progress Energy has referred to each of these documents while preparing this environmental report for license renewal.

3.1.1 REACTOR AND CONTAINMENT SYSTEMS

BSEP is a two-unit plant as shown in Figure 3-1. Each unit uses a boiling water reactor (BWR) and steam-driven turbine generator manufactured by General Electric (GE). The architect/engineer for the Brunswick project was United Engineers and Constructors, Inc. The construction contractor was Brown and Root, Inc.

Each reactor's primary containment is a pressure suppression system consisting of a drywell, a pressure-suppression chamber storing a large volume of water, a connecting vent system between the drywell and the suppression pool, a vacuum relief system, isolation valves, containment cooling systems, and other service equipment. Together with its engineered safety features, each containment is designed to provide adequate radiation protection for both normal operation and postulated design-basis accidents, such as earthquakes or loss of coolant CP&L 2001, Rev. 17B, pg. 1-8).

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

Construction permits for Units 1 and 2 were issued in February 1970 (Scientech 2003). The U.S. Atomic Energy Commission approved the Unit 2 operating license (DPR-62) in December 1974; commercial operation began on November 3, 1975. The Unit 1 operating license (DPR-71) was approved in September 1976; commercial operation began on March 18, 1977.

As originally built and operated, each of the BSEP units had a design rating of 2,436 megawatts-thermal (AEC 1974, p. III-7). Each electrical generator was rated at 847 megawatts-electrical, with a net output to the grid of 821 megawatts-electrical. Total plant output at the time the second unit became fully operational in March 1977 was therefore 4,872 megawatts-thermal and 1,694 megawatts electrical.

In November 1996, the NRC approved an increase in the licensed maximum core thermal level of BSEP Units 1 and 2 from 2,436 megawatts-thermal to 2,558 megawatts-thermal per unit, an increase of approximately 5 percent. The NRC determined in an Environmental Assessment (EA) prepared at that time that the uprate would not have a significant effect on human health and the environment and issued a Finding of No Significant Impact (Federal Register, Vol. 61, No. 209, pp. 55673-55675). The 5 percent power uprate for Unit 1 was carried out during the spring 1997 refueling outage, and the 5 percent power uprate for Unit 2 was carried out during the fall 1997 refueling outage.

In an application and supplements submitted to the NRC in the fall of 2001, Progress Energy sought approval to amend the BSEP facility operating licenses to allow an increase of approximately 15 percent in the licensed core thermal level of the two BSEP reactors, taking them to approximately 20 percent over the original licensed core thermal level of 2,436 megawatts-thermal. The NRC prepared an Environmental Assessment for this action that concluded that the issuance of the amendment would not have a significant effect on the quality of the human environment (Federal Register, Vol. 67, No. 99, pp. 36040-36046) and resulted in a Finding of No Significant Impact. The NRC issued Amendments Numbers 222 and 247 to Facility Operating License Numbers DPR-71 and DPR-62, respectively, revising the facility operating licenses and technical specifications for operation of BSEP on May 31, 2002 (Federal Register, Volume 67, No. 110, pg. 39445).

Progress Energy completed Phase One of the extended power uprate in April 2003, during a scheduled refueling outage for Unit 2 (Progress Energy 2003a). At the completion of Phase One of the uprate, Unit 1 was rated at approximately 2,755 megawatts-thermal and capable of generating 893 megawatts-electrical while Unit 2 was rated slightly higher than 2,755 megawatts-thermal and capable of generating 885 megawatts-electrical. Upon completion of the extended power uprate in the spring of 2005, each reactor will have a licensed core thermal level of approximately 2,923 megawatts-thermal and will be capable of generating 958 megawatts-electrical

(Unit 1) and 951 megawatts-electrical (Unit 2), respectively (Federal Register, Volume 67, No. 99, pg. 36040).

This is considered an Extended Power Uprate (EPU) because it follows the 5 percent “stretch” uprate, completed in 1997, that took both reactors to 2,558 megawatts-thermal from the original licensing basis of 2,436 megawatts-thermal. The operational goal of the EPU is a corresponding (approximately 14 percent) increase in each nuclear unit’s electrical output, increasing Unit 1 from 841 to 958 megawatts-electric and increasing Unit 2 from 835 to 951 megawatts-electric.

Progress Energy has concluded that the fuel enrichment at BSEP will increase to approximately 4.4 percent as a result of the extended power uprate with burnup remaining at approximately 45,000 megawatt days per metric ton uranium. NRC has found that BSEP operation within these constraints would have no significant environmental impact (Federal Register, Volume 67, No. 99, pg. 36045).

Fuel removed from the reactors is placed in an onsite spent fuel storage pool and certain fuel elements that meet burnup and cooling criteria are shipped offsite for storage. The shipping is performed in Progress Energy-owned, NRC-licensed casks on dedicated railroad trains. The shipping routes are NRC-approved and Progress Energy provides 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 2003b). 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 in 2010. 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.

3.1.2 COOLING AND AUXILIARY WATER SYSTEMS

3.1.2.1 Surface Water

Under full power operation, as much as 1.05 million gallons per minute (2,335 cubic feet per second) of water are withdrawn from the Cape Fear River for condenser cooling. After passing through the plant’s condensers, the heated water travels through a 6-mile-long discharge canal to Caswell Beach before being pumped 2,000 feet offshore through a pair of (13-foot diameter) underwater pipes that extend into the Atlantic Ocean along the bottom (Figure 2-3). Although some of the waste heat is radiated to the atmosphere from the surface of the discharge canal, the bulk of the heat is dissipated by mixing with cooler Atlantic Ocean water.

Circulating Water System Description

The BSEP circulating water system is a once-through heat dissipation system designed to remove waste heat from the two main condensers when both reactors are operating at full power. The circulating water system includes the intake canal, intake structure, condensers, discharge canal, Caswell Beach pumping station, and the discharge pipes that move the heated effluent into the Atlantic Ocean.

Cooling water is drawn from the Cape Fear River by way of a three-mile long intake canal. The intake canal consists of a cut through Snows Marsh and a more clearly-defined canal that runs across the mainland (high ground) to the plant. A fish diversion structure was built across the intake canal in 1982 at the mouth of the canal proper, the point at which Snows Marsh meets high ground. The fish diversion structure minimizes the number of fish entering the intake canal, and as a consequence reduces impingement of fish and shellfish on the plant's traveling screens (CP&L 2001, Rev. 17C, pg. 2-26).

The intake canal is subject to the same tidal fluctuations as the Cape Fear estuary. Consequently, water movements in the canal are complex and current velocities vary with circulating water pump rates, tides (both daily and seasonal variation), and location in the canal (CP&L 1980, pg. 3-4). Current velocities in the intake canal are generally around 0.6 feet per second (CP&L 2002).

The circulating water intake structure consists of eight separate intake bays (four bays per unit), each with a trash rack, vertical traveling screen, and vertical intake pump. Two of the four intake screens for each unit are fitted with 1-mm fine mesh. The other two are fitted with half fine mesh and half coarse mesh (3/8-in) screens. Each unit typically operates with three bays in service using two of the full fine mesh screens and one of the half fine mesh/half coarse mesh screens. As the screens rotate, they are pressure-washed, forcing fish and debris impinged on the screens into a collection trough leading to the nekton return system (also referred to as the fish return system). The screen wash water, carrying marine life and other materials, flows by gravity via the nekton return system to a holding pond (also referred to as the return basin). From this return basin, the organisms can move into Walden Creek and then the Cape Fear River.

A vertical circulating water pump is located behind the traveling screen in each intake bay. Each pump has a capacity of 156,000 gallons per minute, making the design system capacity approximately 1.25 million gallons per minute if all eight circulating water pumps were in operation (CP&L 2002).

However, the BSEP NPDES permit (NC0007064) limits cooling water flows to 922 cubic feet per second per unit (cfs/unit) over the December – March period and 1,105 cfs/unit over the April – November period, with the stipulation that one unit may increase its flow to 1,230 cfs during the months of July, August, and September. These NPDES permit limits translate into two-unit flows of 1,844 cfs (827,690 gallons per minute), 2,210 cfs

(991,848 gallons per minute), and 2,335 cfs (1,048,017 gallons per minute), respectively.

Chlorine gas is injected into the circulating water inlet piping to minimize fouling in the circulating water piping and condensers. When the chlorine gas system is being serviced or maintained, liquid sodium hypochlorite is injected as a substitute to control bio-fouling. Chlorine concentrations are monitored to ensure that no chlorine is discharged at the Atlantic Ocean outfall. Total residual chlorine is measured at the Caswell Beach pump station as a condition of the BSEP NPDES permit. In addition, a non-toxic, silicon-based elastomer has been used to coat much of the circulating water inlet piping and has significantly reduced the settlement and accumulation of macrofouling organisms. Chlorine is intended to control growth of microfouling organisms (e.g., bacterial slime) in the condenser tubes and larger fouling organisms in parts of the circulating water system that have not been coated with the silicon-based compound.

From the intake structure, circulating water is carried through eight 6-foot diameter pipes (4 per unit) to the condensers. Each unit uses a condenser consisting of two shells, each arranged in a single-pass, divided-water-box configuration.

After passing through the condensers, the circulating water from each unit moves through a concrete discharge tunnel and into the common discharge canal. The discharge canal, which is approximately 6 miles long, extends to the southwest for roughly half of its length (see Figure 2-3), then moves south to Oak Island.

At a point near the Intracoastal Waterway, the heated effluent enters a stilling basin, then moves under the Intracoastal Waterway in two 13-foot diameter pipes by way of an inverted siphon (water is “pulled” by pumps at Caswell Beach) to a second stilling basin which lies adjacent to the Caswell Beach pumping station. Eight discharge pumps (each rated at 166,000 gallons per minute) at the Caswell Beach pumping station move water from the second stilling basin via two discharge headers to a pair of 13-foot diameter pipes that extend 2,000 feet offshore from Caswell Beach along the ocean floor (CP&L 1980; CP&L 2002). At the point at which the two discharge pipes terminate, the tops of the pipes lie under approximately 10 feet of water (CP&L 1980; pg. 3-8). This configuration, in association with a high-momentum jet discharge, is intended to facilitate rapid mixing with ambient waters.

3.1.2.2 Groundwater

BSEP currently has four water wells (Wells 2, 4, 5 and a well that serves the biology laboratory) in the Castle Hayne aquifer (see Section 2.3, “Groundwater Resources”). Wells 2, 4, 5 were used until the early 1980s when they were capped and removed from service after the plant began receiving treated water from Brunswick County Public Utilities. The well used to supply water to the biology laboratory is still in use. The well has a pumping capacity of 30 gallons per minute (see Section 2.3). Due to the intermittent use of the biology laboratory by a limited number of people, the actual production of this well is known to be less than the pump capacity.

Since the early 1980s, BSEP has received treated water for potable/process use from the Brunswick County. From 1996 through 2001, BSEP's water use ranged from approximately 0.22 million gallons per day (MGD) to approximately 0.25 MGD with an average consumption of 0.23 MGD (Smith 2002).

3.1.3 TRANSMISSION FACILITIES

The Final Environmental Statement (FES) (AEC 1974) identifies eight 230-kilovolt transmission lines that were built to connect BSEP to the electric grid. Four lines connect to Unit 1, and four lines connect to Unit 2. The lines are grouped in common corridors to the extent practicable, with the first 1.3 miles of corridor containing all eight lines. The transmission line towers are generally of H-frame construction, with occasional steel towers as needed.

Subsequent to the publication of the FES, several changes were made to the transmission system.

- The 103-mile line to Fayetteville now terminates at the Whiteville Substation, approximately 49 miles from BSEP.

- The Barnard Creek East line has been renamed to indicate that the termination point is actually at the Castle Hayne Substation. No substantive physical changes have taken place. Although there is a substation at Barnard Creek, its connection to the grid is insufficient to represent a termination of this BSEP line.

- The Barnard Creek West line, which originally terminated at the Castle Hayne Substation, was connected in 2002 to the Wilmington Corning Switching Station approximately 25 miles from BSEP.

As a result of these system changes, the transmission lines of interest for this report are somewhat different than those described in the FES, as indicated below. Figure 3-2 is a map of the current transmission system of interest.

- <u>Whiteville</u> – Approximately four miles from BSEP, this line diverges from the common right-of-way for 45 miles in a 100-foot corridor. The line traverses northwest to complete the total 49-mile run to the Whiteville Substation near Whiteville, about 40 miles west of Wilmington, North Carolina.

- <u>Weatherspoon</u> – This circuit runs northwest with the two Delco lines to ultimately connect just west of the Delco Substation to an existing 230 kilovolt line to the Weatherspoon plant. Only the 31 miles of new transmission line from BSEP to the tap is under evaluation in this Environmental Report. The corridor width ranges from 170 feet to 240 feet wide, depending on the number of lines in the corridor.

- <u>Delco East</u> – Traversing a total of 31 miles, this line connects to the Delco Substation, approximately 15 miles west of Wilmington. Initially, the line runs with

the Delco West and Weatherspoon lines in a 240-foot wide corridor, but diverges 6.6 miles from the substation to enter from the east.

- Delco West – Traversing a total of 31 miles, this line connects to the Delco Substation, approximately 15 miles west of Wilmington. Initially, the line runs with the Delco East and Weatherspoon lines in a 240-foot wide corridor. It then runs with the Weatherspoon line to enter the Delco Substation from the west.

- Wallace – Connecting to the Wallace Substation 35 miles north of Wilmington and 35 miles west of Jacksonville, this line runs for 55 miles in a corridor ranging from 170 to 310 feet wide. The line shares the corridor with the Jacksonville line for much of the way.

- Jacksonville – The line to Jacksonville is 76 miles long, but 35 of those miles are in an existing corridor. The corridor width ranges from 100 to 310 feet wide.

- Castle Hayne East – Approximately 14 circuit-miles from BSEP, this line diverges from the common right-of-way for 3 miles in a 170-foot corridor shared with the Castle Hayne West line. After passing through the Barnard Creek Substation, the line continues through the City of Wilmington to a point where it diverges from the Castle Hayne West Line, taking an eastern route to Castle Hayne Substation just north of Wilmington.

- Wilmington Corning – Formerly known as the Castle Hayne West line, this transmission line shares the right-of-way with the Castle Hayne East line until just past the Barnard Creek Substation at which point it traverses through the City of Wilmington another 9 miles to the new Wilmington Corning Switching Station.

As currently configured, the transmission corridors of interest are approximately 220 miles long and occupy approximately 4,000 acres. The corridors pass through low population areas that are primarily forest, farm, and swamp lands. The lines cross numerous state and U.S. highways, the Cape Fear River, and Interstate 40. Four lines in a single 310-foot corridor make a short crossing of the Orton Plantation Waterfowl Impoundment, and the Jacksonville line makes a short crossing of the Holly Shelter Game Land. Corridors that pass through farm lands generally continue to be used as farm land. 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 after BSEP is decommissioned.

Progress Energy designed and constructed all BSEP transmission lines in accordance with the National Electrical Safety Code (for example, IEEE 1997) and industry guidance that was current when the lines were built. Ongoing right-of-way surveillance and maintenance of BSEP transmission facilities ensure continued conformance to design standards. These maintenance practices are described in Section 4.13.

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. 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 resprouts 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, because low-volume foliar application of herbicides begins in May in some transmission corridors (Progress Energy 2004). A point of contact at Progress Energy is also named, 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 phone number for customers with questions about the herbicide program (Progress Energy 2004).

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, the reactor vessel, 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 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 BSEP 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 BSEP license renewal period. 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 BSEP. These programs are described in the *Brunswick Steam Electric Plant License Renewal Application, Appendix B, Aging Management Programs.*

3.4 EMPLOYMENT

Current Workforce

Progress Energy employs approximately 760 permanent employees and 300 long-term contract employees at BSEP, a two-unit facility (Ahern 2002a,b). The permanent staff at a nuclear plant with multiple reactors normally ranges between 800 and 2,400 employees, depending on the number of operating reactors at the site (NRC 1996, pg. 2-26). Approximately 90 percent of the employees live in Brunswick and New Hanover Counties. The remaining employees are distributed across 13 counties in North and South Carolina, with numbers ranging from 1 to 26 employees per county.

BSEP is on a 24-month refueling cycle (Trimble 1998). During refueling outages, the number of workers onsite increases substantially. In a recent (March 2002) outage, approximately 1,000 contractors and 190 “shared resources” (technical specialists from other Progress Energy power plants) were on site (Ahern 2002b). This falls within the range (200 to 900 workers per reactor unit) reported in the GEIS for additional maintenance workers (NRC 1996, pg. 2-27).

License Renewal Increment

Performing the license renewal activities described in Sections 3.2 and 3.3 would necessitate increasing BSEP 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 BSEP incremental license renewal workload scheduling. Many BSEP license renewal SMITTR activities would have to be performed during outages. Although some BSEP 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 BSEP staff. Therefore, Progress Energy has no plans to add non-outage employees to support BSEP operations during the license renewal term. In recent years, refueling and maintenance outages have typically lasted around 30 days and, as described above, result in a large temporary increase in employment at BSEP. 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.

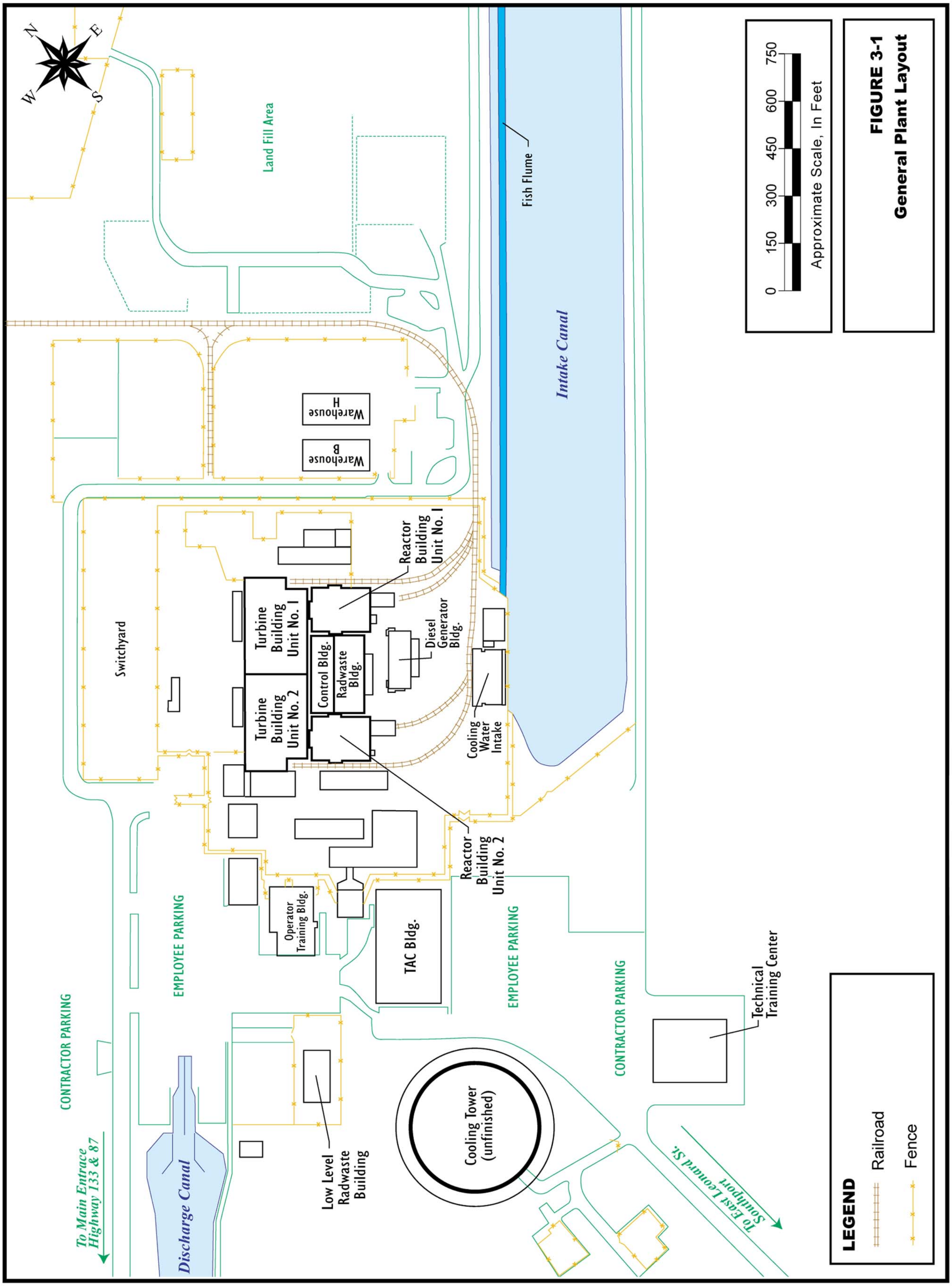
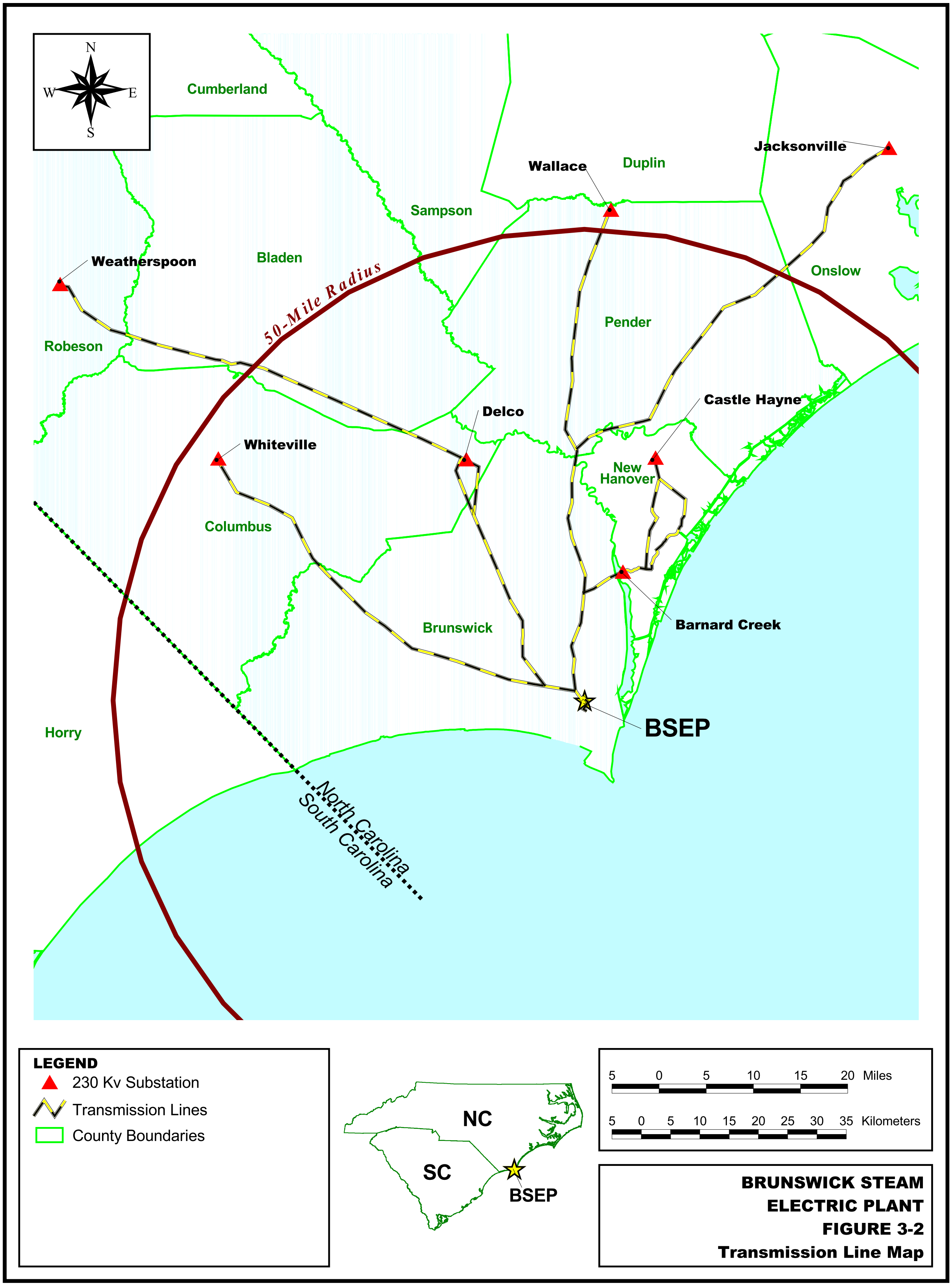


FIGURE 3-1
General Plant Layout



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 3-2
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.

AEC (U. S. Atomic Energy Commission). 1974. Final Environmental Statement related to the continued construction and proposed issuance of an operating license for the Brunswick Steam Electric Plant, Units 1 and 2, Carolina Power and Light Company, Docket Nos. 50-324 and 50-325, Directorate of Licensing, Washington, DC. January.

Ahern, P. 2002a. BSEP Employee Addresses by County. BSEP Human Resources Dept., Progress Energy, Southport, NC. July 29.

Ahern, P. 2002b. Outage Workers. BSEP Human Resources Dept., Southport, NC. November 20.

CP&L (Carolina Power & Light). 1980. Brunswick Steam Electric Plant Cape Fear Studies: Interpretive Report. January 1980.

CP&L (Carolina Power and Light). 1998. Memorandum of Agreement, June 8.

CP&L (Carolina Power & Light). 2001. Brunswick Nuclear Plant Updated FSAR. Chapter 2, Revision 17C. Site Characteristics.

CP&L (Carolina Power & Light). 2002. Circulating Water System Description. System Description (SD-29), Rev. 2. BSEP Training Department.

NRC (U.S. Nuclear Regulatory Commission). 1996. Generic Environmental Impact Statement for License Renewal of Nuclear Plants. NUREG-1437, Office of Nuclear Regulatory Research. Washington DC. May.

Progress Energy. 2003a. "Progress Energy Brunswick Plant successfully completes refueling outage; Unit 2 now able to generate more electricity." News release dated April 7, 2003. Available on line at http://www.progress-energy.com/aboutus/news/article.asp?id=5902.

Progress Energy. 2003b. "Progress Energy exploring dry nuclear fuel storage facilities at Robinson, Brunswick nuclear plants." News release dated April 30.

Progress Energy. 2004. “Herbicide Usage --- Progress Energy Carolinas, Inc.” Available on line at http://www.progress-energy.com/environment/vegetation/herbicide.asp.

Scientech. 2003. Commercial Nuclear Power Plants. Edition No. 22, January. Gaithersburg, MD.

Smith, L. 2002. "Water Use Data for BSEP," Email from Lee Smith (Brunswick County) to Gary Gunter (TTNUS). November 26.

Trimble, D.C. 1998. Letter from D.C. Trimble, Project Manager, NRC Office of Nuclear Reactor Regulation, to C.S. Hinnant, Vice President, Carolina Power & Light Company, regarding changes in Technical Specifications for BSEP Units 1 and 2 that included extension of 18-month refueling interval surveillance requirements to 24 months.

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 Brunswick Steam Electric Plant (BSEP) 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.

NRC rules do not require analyses of Category 1 issues that NRC resolved using generic findings (10 CFR 51) as described in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996a). 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 11 of the 69 Category 1 issues do not apply to BSEP 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 BSEP, 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 BSEP. 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, six Category 2 issues apply to operational features that BSEP does not have. In addition, four Category 2 issues apply only to refurbishment activities. If the issue does not apply to BSEP, the section explains the basis for inapplicability.

For the 11 Category 2 issues that Progress Energy has determined to be applicable to BSEP, 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 BSEP 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 1996a, Section 4.3.2.1).

The issue of surface water use conflicts does not apply to BSEP because the plant does not use cooling towers or cooling ponds. As Section 3.1.2 describes, BSEP uses a once-through cooling system that withdraws water from the Cape Fear estuary by way of an intake canal and returns discharge water via a discharge canal to the Atlantic Ocean.

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

NRC made impacts on fish and shellfish resources resulting from entrainment a Category 2 issue, because it could not assign a single significance level to the issue. The impacts of entrainment are small at many plants, but they may be moderate or large at others. Also, ongoing restoration efforts may increase the number of fish susceptible to intake effects during the license renewal period (NRC 1996a, Section 4.2.2.1.2). Information needing to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond), and (2) status of Clean Water Act (CWA) Section 316(b) determination or equivalent state documentation.

As Section 3.1.2 describes, BSEP has a once-through heat dissipation system that withdraws water from the Cape Fear River estuary for condenser cooling and discharges offshore of Caswell Beach, in the Atlantic Ocean.

Section 316(b) of the CWA requires that any standard established pursuant to Sections 301 or 306 of the CWA shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts (33 USC 1326). Entrainment through the condenser cooling system of fish and shellfish in early life stages is a potential adverse environmental impact that can be minimized by the best available technology. Progress Energy has monitored entrainment of fish and shellfish at BSEP since 1974 and has made a number of material and operational changes during that time to reduce entrainment, including the installation of 1-mm fine mesh screens and a fish return system at the plant's cooling water intake structure (see Section 3.1.2).

The 316(b) Demonstration for BSEP concluded that “operation of the plant has not adversely affected the fisheries in the estuary in any measurable way” (CP&L 1985, pg. 28). With respect to entrainment, the report acknowledged that “some entrainment of larvae still occurs” despite the mitigation measures but noted that “populations in the estuarine nurseries have not been affected” (CP&L 1985, pg. 30).

NPDES permits issued to BSEP after the 316(b) Demonstration was submitted in 1985 contained a requirement that a diversion structure be operated and maintained at the mouth of the intake canal and fine mesh screens be employed on the plant cooling water intake structure. These permits also required that:

> “a biological monitoring program shall be continued which will provide sufficient information to allow for a continuing assessment of the impact of the Brunswick Steam Electric Plant on the Cape Fear Estuary, with particular emphasis on the marine fisheries. Data shall be reported annually and shall include an interpretive summary report assessing the effectiveness of the diversion fence, and the effectiveness of flow minimization and fine mesh screens to curtail organism impingement and entrainment.”

Thus the current BSEP NPDES permit, issued June 30, 2003, constitutes the current CWA Section 316(b) determination for BSEP. This permit became effective on August 1, 2003 and will expire on November 30, 2006. Appendix B contains portions of the permit, including the material quoted in the preceding paragraph. For this reason, and because of the mitigation measures already in place, Progress Energy concludes that impacts of entrainment of fish and shellfish at BSEP are SMALL and warrant no additional mitigation.

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

NRC made impacts on fish and shellfish resources resulting from impingement a Category 2 issue because it could not assign a single significance level to the issue. The impacts of impingement are small at many plants, but they may be moderate or large at others (NRC 1996a, Section 4.2.2.1.3). Information needing to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond), and (2) status of CWA Section 316(b) determination or equivalent state documentation.

As Section 3.1.2 describes, BSEP has a once-through heat dissipation system that uses water from the Cape Fear River for condenser cooling. Section 4.2 discusses the 1985 Cape Fear Interpretive Studies Report [i.e., the plant's 316(b) Demonstration] and on-going biological monitoring programs at BSEP.

As noted in Section 4.2, the 1985 Cape Fear Interpretive Studies Report concluded "operation of the plant has not adversely affected the fisheries in the estuary in any measurable way" (CP&L 1985, pg. 28). With respect to impingement, the report noted that the fish diversion structure completed in 1982 had been successful in preventing larger fish from entering the intake canal, thus had substantially reduced impingement of these fish (CP&L 1985, pg. 22 and pg. 30).

When CP&L installed the fine mesh (1 millimeter) screens in 1983, it also built a fish return system to return fish and other organisms washed from the screens to the Cape Fear River estuary via the Walden Creek system (CP&L 1985, pg. 5). Previously, CP&L transported impinged organisms to the Cape Fear estuary by boat (CP&L 1980, pg. 3-6). The 1985 Cape Fear Interpretive Studies Report evaluated survival of organisms washed from the intake screens and returned to the estuary via the fish return system. Survival rates of several commercially and recreationally important fish species, most notably striped mullet and flounder, were high (CP&L 1985, pg. 28). Survival of three species of Penaeid shrimp (pink, white, and brown) and blue crabs

was also high, depending on age, species, and screen speed (CP&L 1985, Table 18). Survival of fragile, schooling fish species such as menhaden and anchovy was low, however.

Appendix B contains relevant portions of the current NPDES permit. Because BSEP has a valid NPDES permit (NC0007064) which constitutes a Section 316(b) determination, Progress Energy concludes that impacts due to the impingement of fish and shellfish are SMALL and do not require mitigation measures beyond those already in place.

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

NRC made impacts on fish and shellfish resources resulting from heat shock a Category 2 issue, because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions (NRC 1996a). Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond), and (2) evidence of a CWA Section 316(a) variance or equivalent state documentation.

As Section 3.1.2 describes, BSEP has a once-through heat dissipation system that withdraws from the Cape Fear River and discharges to the Atlantic Ocean. The original NPDES permit for BSEP, issued in November 1974 by EPA Region IV, contained summer and winter limits on the temperature rise across the condenser during once-through operation but assumed cooling towers (then under construction) would be completed and operated (Cooke 2001). CP&L subsequently appealed the conditions of the 1974 permit and was granted approval to continue operating in a once-through mode providing the thermal plume was monitored and aquatic populations were not harmed. CP&L was ultimately able to show in a Clean Water Act Section 316(a) Demonstration that once-through operation of BSEP would not have a significant impact on the discharge area and would "assure the protection of a balanced, indigenous population of fish and shellfish…in the nearshore area" (CP&L 1979).

In the transmittal letter accompanying the 1981 NPDES permit, the EPA Administrator acknowledged that "the thermal plume does not cause significant harm to the aquatic community and the proposed effluent limitations…do protect the population" (Cooke 2001). The Administrator noted further that "the provisions of Section 316(a) for alternative thermal limitations are not applicable," meaning that the Plant's discharge

was in compliance with applicable water quality standards and the Plant could operate in the once-through mode without a thermal variance. The 1981 NPDES permit contained summer and winter limitations on the temperature rise across the condensers and required quarterly thermal plume monitoring (Cooke 2001). Subsequent NPDES permits were issued with reduced thermal plume monitoring requirements (twice annually rather than quarterly) and no limitation on temperature rise across the condensers (Cooke 2001).

Cooling water flow (withdrawal) rates and heat rejection rates (defined by water temperatures in the area of the ocean discharge) are currently limited by the provisions of NPDES permit number NC0007064, issued to Progress Energy on June 30, 2003 by the North Carolina Department of Environment and Natural Resources, Division of Water Quality. The permit became effective August 1, 2003 and will expire on November 30, 2006.

As noted earlier in this section, the NPDES permit for BSEP contains a requirement for semi-annual monitoring of water temperatures at the ocean discharge. Temperature monitoring is to be conducted once during the months of April – November and once during the months of December – March when both reactor power levels are 85 percent or greater.

BSEP is able to operate at or near full power in the once-through mode while still meeting State water temperature standards. Therefore, it has not sought a 316(a) variance in accordance with 40 CFR 125. Because it has an approved 316(a) Demonstration and an NPDES permit that requires conformance with State water temperature standards, Progress Energy concludes that heat shock impacts are SMALL and no further mitigation is necessary.

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 groundwater use conflicts a Category 2 issue because, at a withdrawal rate of more than 100 gpm, a cone of depression could extend offsite. This could deplete the groundwater supply available to offsite users, an impact that could warrant mitigation. Information to be ascertained includes: (1) BSEP groundwater withdrawal rate (whether greater than 100 gpm), (2) drawdown at offsite locations, and (3) impact on neighboring wells.

The issue of groundwater use conflicts at plants that pump more than 100 gallons per minute of groundwater does not apply to BSEP. BSEP, since the early 1980s, has used groundwater from only one site well. That well, as described in Section 2.3, is located at the Biology Laboratory, has a pumping capacity of 30 gpm, and is only intermittently used. BSEP obtains the remainder of its domestic water from Brunswick County Public Utilities. As Section 3.1.2 describes, the plant obtains all its cooling water from the Cape Fear River (estuary) by way of a three-mile long intake canal.

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 tower and cooling ponds lose flow due to evaporation, which is necessary to cool the heated water before it is discharged to the environment.

The issue of groundwater use conflicts does not apply to BSEP because the plant does not use cooling towers or cooling ponds and does not withdraw water from a small river. As Section 3.1.2 describes, BSEP uses a once-through cooling system that withdraws water from the Cape Fear estuary by way of an intake canal and discharges water to the Atlantic Ocean.

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 BSEP because the plant does not use Ranney wells. As Section 3.1.2 describes, BSEP uses a once-through cooling system that removes water from the Cape Fear estuary by way of an intake canal and discharges to the Atlantic Ocean.

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 BSEP because the plant is not located at an inland site and does not use cooling ponds. As Section 3.1.2 describes, BSEP uses a once-through cooling system that withdraws water from the Cape Fear estuary by way of an intake canal and discharges to the Atlantic Ocean.

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 1996a

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 1996a). 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 BSEP because, as discussed in Section 3.2, Progress Energy has no plans for refurbishment or other license-renewal-related construction activities at BSEP.

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 1996a, Sections 3.9 and 4.1).

Section 2.2 of this Environmental Report describes the ocean and estuarine communities at BSEP and discusses population trends in recreationally and commercially important populations. Section 2.4 describes important terrestrial habitats at BSEP and along the associated transmission corridors. Section 2.5 discusses threatened or endangered species that occur or may occur at BSEP and along associated transmission corridors, or in the Cape Fear River (estuary) in the vicinity of the plant's intake canal.

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 BSEP or along the associated transmission corridors. Current operations of BSEP 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.

As noted in Section 2.5, two federally-threatened and one federally-endangered species of sea turtles have occasionally been found in the intake canal after passing through breaches in the fish diversion structure. The NRC consulted with National Marine Fisheries Service under Section 7 of the Endangered Species Act regarding the effect of BSEP operations on sea turtle populations. NMFS concluded that incidental takes at

BSEP are not likely to jeopardize the continued existence of these turtle species (NMFS 2000).

Progress Energy wrote to the North Carolina Department of Environment and Natural Resources, the U.S. Fish and Wildlife Service, and the National Marine Fisheries Service requesting information on any listed species or critical habitats that might occur on the BSEP 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, which benefit a number of rare plants, are followed.

As discussed in Section 3.2, Progress Energy has no plans to conduct refurbishment or construction activities at BSEP 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.

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 1996a). 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 BSEP because, as discussed in Section 3.2, Progress Energy has no plans for refurbishment at BSEP.

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 $3.15 \times 10^{12} ft^3$/year ($9 \times 10^{10} m^3$/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

Due to the lack of sufficient data for facilities using cooling ponds, lakes, or canals that discharge to small rivers, NRC designated impacts on public health from thermophilic organisms a Category 2 issue. Information to be ascertained is: (1) whether the plant discharges to a small river, and (2) whether discharge characteristics (particularly temperature) are favorable to the survival of thermophilic organisms.

This issue does not apply to BSEP because, as indicated in Section 3.1.2, BSEP 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.

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 BSEP, 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 eight 230-kilovolt lines that were specifically constructed to distribute power from BSEP 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, produced by the Electric Power Research Institute (EPRI 1991). 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 BSEP 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 Connor (2002).

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

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.

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 BSEP transmission lines. Due to the small significance of the issue, mitigation measures, such as installing warning signs at road crossings or increasing clearances, are not warranted.

4.14 HOUSING IMPACTS

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 1996a)

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 1996a). 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 result in housing impacts due to increased staffing. As described in Section 3.2, BSEP 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 BSEP operations on local housing availability.

Sections 2.6 and 2.8 indicate that BSEP is located in a medium population area that is not subject to growth control measures that limit housing development. Using the NRC regulatory criteria, BSEP 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 BSEP operations during the license renewal term (Section 3.4). Progress Energy concludes that since there is no increase in staffing, no housing impacts would be experienced and, therefore, the appropriate characterization of BSEP 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 1996a)

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 1996a). 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. At this time, BSEP uses approximately one percent of the total treated water production capacity of Brunswick County Public Utilities and two percent of actual production. Usage does not stress system capacity (Section 2.9.1 describes the public water supply systems in the area, their production capacities, and current demands) and is not currently an issue. As discussed in Section 4.14, Progress Energy has no plans to increase BSEP staffing due to refurbishment or plant aging management activities. Progress Energy has identified no operational changes during the BSEP license renewal term that would increase plant water use.

Because Progress Energy has no plans to increase plant municipal water usage or increase employment for license renewal purposes, Progress Energy concludes that impacts on public water supply would be SMALL and not require mitigation.

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 1996a)

NRC made refurbishment-related impacts to education a Category 2 issue because site- and project-specific factors determine the significance of impacts (NRC 1996a). 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 BSEP because, as discussed in Section 3.2, Progress Energy has no plans for refurbishment or other license-renewal-related construction activities at BSEP.

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 1996a)

NRC made impacts to offsite land use as a result of refurbishment activities a Category 2 issue because land-use changes could be considered beneficial by some community members and adverse by others. Local conditions to be ascertained include: (1) plant-related population growth, (2) patterns of residential and commercial development, and (3) proximity to an urban area with a population of at least 100,000.

This issue is not applicable to BSEP because, as discussed in Section 3.2, Progress Energy has no plans for refurbishment due to license renewal at BSEP.

4.17.2 OFFSITE LAND USE - LICENSE RENEWAL TERM

NRC

The environmental report must contain "…[a]n assessment of the impact of the proposed action on…land-use…." 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 1996a, Section 3.7.5)

"…[I]f 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 preestablished patterns of development and has provided adequate public services to support and guide development." (NRC 1996a, 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 detrimental by others. Therefore, NRC could not assess the potential significance of site-specific offsite land-use impacts (NRC 1996a, Section 4.7.4.2). Site-specific factors to consider in an assessment of 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 1996a, 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 percent change represented by operations-related growth (NRC 1996a, Section 3.7.3). Progress Energy agrees with the NRC conclusion that population-driven land use impacts would be SMALL. Mitigation would not be warranted.

Tax-Revenue-Related Impacts

NRC defined the magnitude of land-use changes as follows (NRC 1996a, Section 4.7.4):

- Small - very little new development and minimal changes to an area's land-use pattern
- Moderate - considerable new development and some changes to land-use pattern
- Large - large-scale new development and major changes in land-use pattern.

Table 2-5 provides a comparison of tax payments made by BSEP to Brunswick County and the County's annual property tax revenues. NRC has determined that the significance of tax payments as a source of local government revenue would be small, if the payments are less than 10 percent of revenue (NRC 1996a, Section 4.7.2.1). For the six-year period from 1997 through 2002, BSEP's property tax payments represented approximately 9 percent of the County's annual property tax revenues. In 2002, BSEP's property tax payments represented 7.5 percent of the County's annual property tax revenues and 4.0 percent of the County's total annual tax revenues.

As described in Section 3.2, Progress Energy does not anticipate refurbishment or construction during the license renewal period. Therefore, Progress Energy does not anticipate any increase in the assessed value of BSEP due to refurbishment-related improvements, nor any related tax-increase-driven changes to offsite land-use and development patterns. Using the NRC methodology would lead to the conclusion that BSEP operations has, and license renewal would have, SMALL tax-driven land use impacts.

From 1990 to 2000, Brunswick County's population growth rate averaged 4.4 percent per year, while the population of the state of North Carolina grew an average of 2.1 percent per year (USCB 2001 a,b). Over the same period, the number of housing units in Brunswick County increased by 38.6 percent, while the total number of units in the state increased by 25.0 percent (USCB 1990; USCB 2000).

The Brunswick County Land Use Plan (1997) acknowledges that growth and development have increased in recent years, and continued growth is inevitable, "predominantly in the form of a growing tourism economy, rapidly rising seasonal and permanent populations, and related residential and commercial development." The Land Use Plan notes (pg. 8-28) that the County's overall land use policy "calls for continued efforts to diversify the local economy, protect area resources, and improve the quality of life. A particular point of emphasis for this plan is the desire to foster…a distinct 'town and county' development pattern." The intent of the County's land use policy is to allow for the preservation of open space and productive farm and timber land, to minimize costs of extending infrastructure and services, to avoid higher taxes, and minimize traffic congestion associated with urban sprawl (Brunswick County 1997, pg. 8-30).

Conclusion

Progress Energy views the continued operation of BSEP as a significant benefit to Brunswick County through direct and indirect salaries and tax contributions to the County's economy. Because population growth related to the license renewal of BSEP is expected to be small and there would be no new tax impacts to Brunswick County land use, the renewal of BSEP's license would have a continued beneficial impact on Brunswick County.

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 1996a)

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 1996a). 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 and believes no mitigation would be necessary.

4.19 HISTORIC AND ARCHAEOLOGICAL RESOURCES

NRC

The environmental report must "…assess whether any historic or archeological 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 archeological 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, Table B-1, Issue 71

"…Sites are considered to have small impacts to historic and archeological 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 1996a)

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 1996a).

The Final Environmental Statement (FES) for the construction and operation of BSEP Units 1 and 2 (AEC 1974) listed 7 properties on the National Historic Register within the "vicinity" of BSEP. In the FES for BSEP, the AEC concluded that BSEP's construction and operation activities would not have unacceptable impacts on National Register properties (AEC 1974, pg. XII-5). This conclusion was supported in letters from Stuart C. Schwartz, Archaeologist, Janet K. Seapker, Survey Specialist, and H. G. Jones, State Historian/Administrator, dated August 18, 1972, July 21, 1972, and November 17, 1972, respectively (AEC 1974). Similarly, the North Carolina Department of Art, Culture, and History voiced no objections to the project (AEC 1974).

As of February 2004, the National Register of Historic Places listed 12 locations in Brunswick County and 28 locations in New Hanover County, North Carolina (U.S. Department of the Interior 2004). Of these 40 locations, 13 fall within a 6-mile radius of BSEP.

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 BSEP operations, including operation and maintenance of transmission lines. Progress Energy has no plans to change transmission line inspection and maintenance practices or right-of-way vegetation management practices over the license renewal term. Based on the fact that current practices are not expected to change significantly (there may well be minor changes in inspection and surveillance procedures, vegetation management procedures, etc.), Progress Energy concludes that operation of these same 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 F 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 (PSA) model to use in evaluating the most significant risks of radiological release from BSEP fuel into the reactor and from the reactor into the containment structure. For the SAMA analysis, Progress Energy used the PRA 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 BSEP

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 BSEP-specific information to create a list of approximately 43 SAMAs for consideration. Progress Energy analyzed this list and screened out SAMAs that would not apply to the BSEP design, that Progress Energy had already implemented at BSEP, or that would achieve results that Progress Energy had already achieved at BSEP by other means. Progress Energy prepared preliminary 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 candidate SAMA (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 prepared more detailed cost estimates for implementing each SAMA and repeated the cost/benefit comparison.

Progress Energy performed two 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 F.

Based on the results of the BSEP SAMA analysis, Progress Energy concludes that several cost-beneficial options exist to reduce plant risk that could be examined further, but none are related to plant aging.

TABLE 4-1
RESULTS OF INDUCED CURRENT ANALYSIS

Transmission Line	Voltage (kilovolts)	Limiting Case Induced Current[a] (milliamperes)
Castle Hayne East	230	<2.8
Delco East	230	<3.2
Delco West	230	<3.1
Jacksonville	230	<3.0
Wallace	230	<3.7
Weatherspoon	230	<2.9
Whiteville	230	<2.9
Wilmington Corning	230	<3.3

a. "Less-than" values are reported because the calculation was performed for a 200-degree Fahrenheit sag instead of the prescribed 120-degree sag. The limiting case for each line was the lowest point on the line without regard to whether a road existed at that location, adding more conservatism to the calculation. Evaluations at road locations had lower values.

4.21 REFERENCES

Note to reader: 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.

AEC (U.S. Atomic Energy Commission). 1974. Final Environmental Statement related to continued construction and proposed issuance of an operating license for the Brunswick Steam Electric Plant Units 1 and 2. Carolina Power and Light Company. Docket Nos. 50-324 and 50-325, January.

Brunswick County. 1997. Brunswick County Land Use Plan. 1997 Update. Brunswick County Planning Board, Brunswick County, North Carolina. Adopted October 5 and, as revised, December 7, 1998.

Connor, Steven J. 2002. "Calculation Package for Brunswick Transmission Lines – Induced Current Analysis." Tetra Tech NUS, Aiken, South Carolina, December 13.

Cooke, J. 2001. "Brunswick NPDES Permit (Thermal Discharge) Historical Background." Environmental Services, CP&L. New Hill, NC.

CP&L (Carolina Power & Light Company). 1979. Section 316(a) Demonstration, Brunswick Steam Electric Plant, Southport, North Carolina. Brunswick Steam Electric Plant Cape Fear Studies, Volume XIX. Prepared by Environmental Technology Section. December.

CP&L (Carolina Power & Light Company). 1980. Brunswick Steam Electric Plant Cape Fear Studies: Interpretive Report. January.

CP&L (Carolina Power & Light Company). 1985. Brunswick Steam Electric Plant Cape Fear Studies: Interpretive Report. August.

EPRI (Electric Power Research Institute). 1991. TL Workstation Code, Version 2.3, Volume 7: ACDCLINE Manual. Palo Alto, California. June.

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

NMFS (National Marine Fisheries Service). 2000. Endangered Species Act – Section 7 Consultation Biological Opinion: Operation of the Cooling Water Intake System at the Brunswick Steam Electric Plant Carolina Power and Light Company. January 20.

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

NRC (U.S. Nuclear Regulatory Commission). 1996b. Environmental Review for Renewal of Nuclear Power Plant Operating Licenses. Federal Register, Volume 61, Number 109. June 5.

USCB (U.S. Census Bureau). 1990. Census 1990 Summary Tape File 1 (STF 1) – 100 percent data. Table GCT-Ha. General Housing Characteristics: 1990. Geographic Area: North Carolina – County. Available online at http://factfinder.census.gov/servlet/BasicFactsServlet.

USCB (U.S. Census Bureau). 2000. Census 2000 Summary File 1 (SF 1) – 100 percent data. Table GCT-PH1. Population, Housing Units, Area, and Density: 2000. Geographic Area: North Carolina – County. Available online at http://factfinder.census.gov/servlet/BasicFactsServlet.

USCB (U.S. Census Bureau). 2001a. Ranking Tables for Counties: Population in 2000 and Population Change from 1990 to 2000 (PHC-T-4). Available at http://www.census.gov/population/www/cen2000/phc-t4.html.

USCB (U.S. Census Bureau). 2001b. Ranking Tables for States: Population in 2000 and Population Change from 1990 to 2000 (PHC-T-2). Available at http://www.census.gov/population/www/cen2000/phc-t2.html.

U. S. Department of the Interior. 2004. National Register Information System. Available at http://www.nr.nps.gov.

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 process that Progress Energy used 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 Brunswick Steam Electric Plant (BSEP), (2) an extensive review of documents related to environmental issues at BSEP, (3) correspondence with state and federal agencies to determine if the agencies had concerns not addressed in the GEIS, (4) a review of internal procedures for reporting to the NRC events that could have environmental impacts, and (5) credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies.

Progress Energy is aware of no new and significant information regarding the environmental impacts of BSEP 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 Brunswick Steam Electric Plant Units 1 and 2 (BSEP) operating licenses 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 52 Category 1 issues that apply to BSEP, 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 BSEP 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, continuous emissions 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:

- Waste heat from plant operations is discharged to the Atlantic Ocean.
- Because the land surrounding the plant is flat, some structures (most notably the off-gas stack) are visible from offsite. This visual impact will continue during the license renewal term.
- Procedures for the disposal of sanitary, 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 BSEP 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 BSEP also establishes a very low probability risk of accidental radiation exposure to inhabitants of the area.
- Some adult and juvenile fish and shellfish are impinged on the traveling screens at the circulating water intake structure.
- Some larval fish and shellfish are entrained at the circulating water intake structure.

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 BSEP 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 BSEP site was established when the plant began operating in 1974. The Final Environmental Statement (AEC 1974) evaluated the impacts of constructing and operating BSEP in rural Brunswick County, North Carolina. Short-term use of natural resources would include land and water. The area surrounding the plant site is chiefly rural, with much undeveloped land. Approximately 130 acres of the 962-acre site are devoted to the production of electrical energy. This includes the area occupied by BSEP facilities (buildings, parking lots, roadways) and landscaped areas around the BSEP facilities. Approximately 117 acres of marsh were required for the intake and discharge canals, and an additional approximately 1,000 acres of marsh were modified by dredging and spoil piles, loss of freshwater inflow, sedimentation, and other reasons. The loss of marsh resulted in loss of wildlife habitat, and may have produced local changes in salinity, tidal patterns, sedimentation, and nutrient flux patterns. Most of the upland areas of the BSEP site not required for plant operations are pine forests, managed for timber production and wildlife habitat. Transmission line construction required over 3,500 acres of new land that resulted in the alteration of natural wildlife habitats (AEC 1974). An estimated 4 to 5 cubic feet per second of fresh water from the Castle Hayne aquifer is lost through upwelling into the unlined canal system. One cubic foot per second of brackish water may enter the Yorktown – Castle Hayne aquifer from the discharge canal (AEC 1974).

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. However, the lost marshland and any saltwater intrusion into the freshwater aquifer can not be restored easily.

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 BSEP

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. BSEP 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.** Progress Energy has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best technology available to minimize entrainment.
26	Impingement of fish and shellfish	**Small.** Progress Energy has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best technology available to minimize impingement.
27	Heat shock	**Small.** The BSEP discharge meets state WQ standards and has very little effect on local marine life.
	Groundwater Use and Quality	
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	**None.** BSEP uses less than 100 gpm of groundwater per minute.
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 BSEP 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 BSEP does not use Ranney wells.
39	Groundwater quality degradation (cooling ponds at inland sites)	**None**. This issue does not apply because BSEP is not located at an inland site and does not use cooling ponds.
	Terrestrial Resources	
40	Refurbishment impacts	**None.** No impacts are expected because BSEP will not undertake refurbishment.
	Threatened or Endangered Species	
49	Threatened or endangered species	**Small.** NMFS has concluded that incidental takes of sea turtles at the BSEP intake have not jeopardized the continued existence of these species.
	Air Quality	
50	Air quality during refurbishment (non-attainment and maintenance areas)	**None.** No impacts are expected because BSEP will not undertake refurbishment.

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

No.	Issue	Environmental Impact
		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.** BSEP 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 BSEP lines is substantially less than the 5-milliampere limit. Therefore, the BSEP transmission lines conform to the National Electrical Safety Code provisions for preventing electric shock from induced current.
		Socioeconomics
63	Housing impacts	**Small.** BSEP anticipates no additional employment, thus negligible housing impacts.
65	Public services: public utilities	**Small.** BSEP 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 BSEP will not undertake refurbishment.
68	Offsite land use (refurbishment)	**None.** No impacts are expected because BSEP 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.** BSEP anticipates no additional employment, thus no increase in traffic.
71	Historic and archeological resources	**Small.** Continued operation of BSEP 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. Final Environmental Statement related to the continued construction and proposed issuance of an operating license for the Brunswick Steam Electric Plant Units 1 and 2. Carolina Power and Light Company. Docket No. 50-324 and 50-325. Directorate of Licensing. January. 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 evaluates alternatives to Brunswick Steam Electric Plant (BSEP) license renewal. The chapter 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 licenses. 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 BSEP operating licenses. Components of this alternative include replacing the generating capacity of BSEP and decommissioning the facility, as described below.

Progress Energy supplies as much as 57.5 terawatt hours of electricity to its 1.3-million customer base in North and South Carolina (Progress Energy 2003). A terawatt hour is one billion kilowatt hours. BSEP provides approximately 14.2 terawatt hours or about 24 percent of the electricity Progress Energy provides to its customers in the Carolinas (EIA 2003a). 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 BSEP 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” boiling-water reactor is the 1,155-megawatt electric [MWe] Energy Northwest’s Columbia Plant). This description is comparable to decommissioning activities that Progress Energy would conduct at BSEP for each unit.

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 2002, 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 BSEP 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 2002). 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 BSEP is in North Carolina, about 11 percent of Progress Energy's electrical energy generation is in South Carolina (EIA 2003a). 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 utility industry had a total generating capacity of 23,652 MWe in 2002. As Figure 7-1 indicates, this capacity includes units fueled by coal (52.6 percent); nuclear (20.0 percent); dual-fired (9.2 percent); hydroelectric (6.9 percent); gas (9.6 percent); and petroleum (1.7 percent). Approximately 3,023 MWe (11.3 percent of the State's generating capacity) was from non-utility sources in 2002 (EIA 2004). North Carolina's non-utility generators also use a variety of energy sources.

In 2002, South Carolina's electric utility industry had a total generating capacity of 19,101 MWe. As Figure 7-2 indicates, this capacity includes units fueled by nuclear (34.0 percent); coal (31.0 percent); hydroelectric (18.7 percent); dual-fired (8.8 percent); gas (4.0 percent) and petroleum (3.5 percent). Approximately 1,262 MWe (6.2 percent of the State's generating capacity) was from non-utility sources (EIA 2004). South Carolina's non-utility generators also use a variety of energy sources.

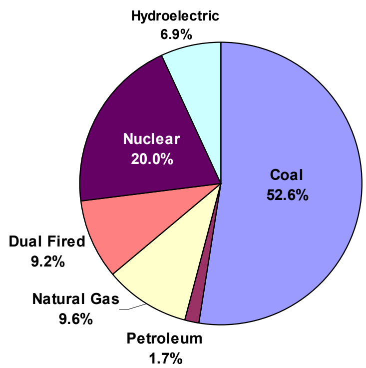


FIGURE 7-1. NORTH CAROLINA UTILITY GENERATING CAPACITY, 2002

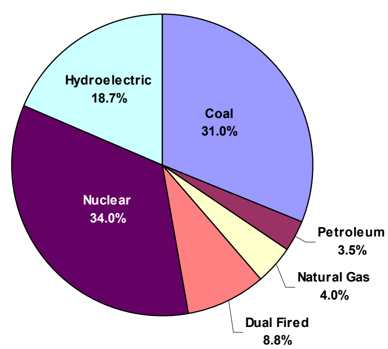


FIGURE 7-2. SOUTH CAROLINA UTILITY GENERATING CAPACITY, 2002

Based on 2002 generation data, North Carolina utility companies produced about 116 terawatt hours of electricity. As shown in Figure 7-3, utilities' generation by fuel type in North Carolina was dominated by coal (61.6 percent), followed by nuclear

(34.3 percent), hydroelectric (2.1 percent), gas (1.7 percent), and petroleum (0.3 percent) (EIA 2004).

Based on 2002 generation data, utility companies in South Carolina produced about 94 terawatt hours of electricity. As Figure 7-4 depicts, utilities' generation by fuel type in South Carolina was dominated by nuclear (56.9 percent), followed by coal (38.9 percent), gas (3.7 percent), hydroelectric (0.2 percent) and petroleum (0.2 percent) (EIA 2004).

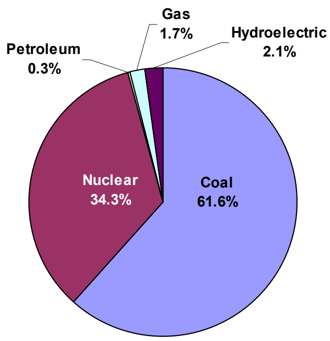


FIGURE 7-3. NORTH CAROLINA UTILITY GENERATION BY FUEL TYPE, 2002

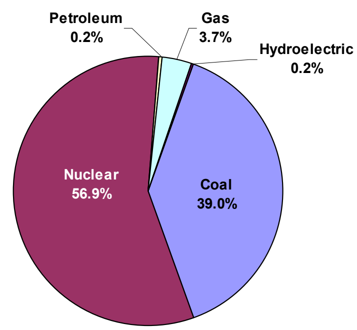


FIGURE 7-4. SOUTH CAROLINA UTILITY GENERATION BY FUEL TYPE, 2002

The difference between capacity and utilization is the result of optimal usage. For example, in North Carolina, nuclear energy represented 20.0 percent of utilities' installed capacity, but produced 34.3 percent of the electricity generated by utilities (EIA 2004). This reflects North Carolina's reliance on nuclear energy as a base-load generating source. South Carolina also shows a preference for reliance on nuclear energy as a base-load generating source, with nuclear energy representing 33.9 percent of utilities' installed capacity and 56.9 percent of the electricity generated by utilities (EIA 2004).

Progress Energy summer generation capability (in North and South Carolina), including jointly owned capacity, was 12,248 MWe in 2002. Figure 7-5 illustrates the Progress Energy summer capacity mix in the Carolinas. Forty-three (43) percent of Progress Energy's capacity was from coal, 26 percent from nuclear, 29 percent from combustion turbines, and 2 percent from hydroelectric (NCUC 2003). The Progress Energy share of energy supplied by these units in 2002 was 57.5 terawatt hours. Figure 7-6 illustrates the Progress Energy generation by fuel type in the Carolinas. Coal power generated

49.4 percent of the total electricity produced, nuclear 46.4 percent, combustion turbines generated 3.4 percent, and hydroelectric generated 0.8 percent (EIA 2003a).

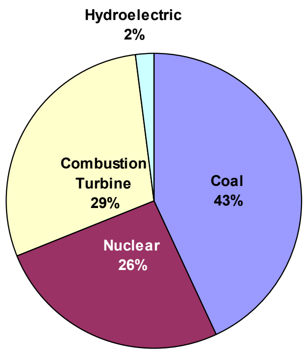


FIGURE 7-5. PROGRESS ENERGY GENERATING CAPACITY IN NORTH AND SOUTH CAROLINA, 2002

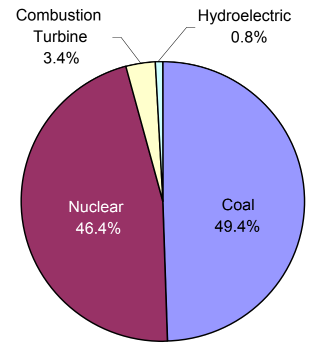


FIGURE 7-6. PROGRESS ENERGY GENERATION BY FUEL TYPE IN NORTH AND SOUTH CAROLINA, 2002

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 2002 installed capacity in the Carolinas, but produced 46.4 percent of the electricity generated (NCUC 2003 and EIA 2003a).

7.2.1 ALTERNATIVES CONSIDERED

Technology Choices

Progress Energy routinely conducts evaluations of alternative generating technologies. The most recent study evaluated 16 technologies: of these, 12 are commercially available and 8 are mature, proven technologies (CP&L 2002a). Based on this review, Progress Energy identified candidate technologies that would be capable of replacing the net base-load capacity (1,909 MWe) of the nuclear units at BSEP. BSEP is undergoing an extended power uprate that will increase the original capacity of 1,676 MWe to 1,909 MWe, which is planned for completion in the year 2005 (CP&L 2001).

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 BSEP), the most economical commercially available technology is combined-cycle combustion turbines, followed by units fired by pulverized coal (CP&L 2002a). Based on these evaluations, Progress Energy has concluded that feasible new plant systems that could replace the capacity of the BSEP nuclear units are limited to pulverized coal and combined-cycle units. Progress Energy would use gas as the primary fuel in its combined-cycle turbines because of its economical and

environmental advantages over petroleum. Approximately 92 percent of Progress Energy combustion turbine capacity is fired primarily by gas (CP&L 2000 and CP&L 2002a). Manufacturers now produce large standard-size combined-cycle gas turbines that are economically attractive and suitable for high-capacity base-load operation.

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 coal- and gas-fired generation presented in this chapter would bound the impacts from any generation mixture of the two 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).

Over the past few years, deregulation of the electric utility industry has received considerable attention in the Carolinas. The legislatures of both North and South Carolina have been studying the issue of electric power industry restructuring, or deregulation, but are taking a cautious approach to deregulation in light of the recent energy crisis in California (CP&L 2002b and EEI 2002).

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 BSEP 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 those at BSEP, if its licenses 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 BSEP 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) and purchased power (Section 7.2.1.2) as reasonable alternatives to license renewal. Section 7.2.1.3 discusses reduced demand and presents the basis for concluding that it is not a reasonable alternative to license renewal. Section 7.2.1.4 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 BSEP site and at an undetermined greenfield site. Progress Energy concluded that BSEP 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 1,909 MWe could be assumed to replace the 1,909-MWe BSEP net 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 365-MWe net capacity (Siemens 2002). Five 365-MWe plants would provide 1825-MWe net capacity. For comparability, Progress Energy set the net power of the coal-fired unit equal to the gas-fired plants (1,825 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 BSEP.

Coal-Fired Generation

NRC evaluated coal-fired generation alternatives for the Calvert Cliffs Nuclear Power Plant (NRC 1999a) and for the Oconee Nuclear Station (NRC 1999b). For Oconee, NRC analyzed 2,500 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 1,825 MWe discussed in this analysis. In defining the BSEP 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.

Gas-Fired Generation

Progress Energy's current emphasis on combined-cycle units fueled primarily by gas for base- and intermediate-load operation is evidenced by its bringing online more than 620 MWe of gas-fired combined-cycle capacity in Richmond County, North Carolina (CP&L 2002c). 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 (365 MWe net) is available and economical. Therefore, Progress Energy has analyzed 1,825 MW of net power, consisting of five 365-MWe net capacity gas-fired combined cycle plants, to be located on BSEP property. Table 7-2 presents the basic gas-fired alternative characteristics.

7.2.1.2 Purchase Power

Progress Energy has evaluated conventional and prospective power supply options that could be reasonably implemented before the current BSEP licenses expire in 2014 and 2016. 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 2014 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 2000, South Carolina exported 61.8 terawatt-hours of electricity (EIA 2003b). North Carolina, on the other hand, exported 9.5 terawatt-hours of electricity in 2000 (EIA 2003b). Therefore, approximately 71.3 terawatt-hours of electricity were exported from the Carolinas in 2000. Some of the exported power may be the result of purchase contracts, which would prevent Progress Energy from using this power to replace BSEP generation. However, Progress Energy cannot rule out the possibility that power would be available for purchase as an alternative to BSEP 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 BSEP, Progress Energy believes that it is reasonable to assume that new capacity would have to be built for the purchased-power alternative.

7.2.1.3 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 (CP&L 2002d):

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 MW) 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 BSEP.

7.2.1.4 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 BSEP is a base-load generator and that any feasible

alternative to BSEP 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 BSEP generating capacity (1,909 MWe net) with wind power, even assuming ideal wind conditions, would require dedication of about 450 square miles. Based on the lack of sufficient wind speeds and the amount of land needed to replace BSEP, 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 450 square miles), wind power is not a reasonable alternative to BSEP 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 BSEP generating capacity with solar power would require dedication of about 100 square miles for photovoltaic and 42 square miles for solar thermal systems. Neither type of solar electric system would fit at the BSEP 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 42 to 100 square miles), solar power is not a reasonable alternative to BSEP license renewal.

Hydropower

A portion (about 5,000 MW) of utility generating capacity in the Carolinas is hydroelectric (EIA 2004). 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. From 1993 to 2002, utilities reduced hydroelectric production by about 8.1 percent annually in North Carolina and 25.6 percent annually in South Carolina (EIA 2004). According to the *U.S. Hydropower Resource Assessment for North Carolina* (INEEL 1997a), 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 1997b), 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 BSEP generating capacity would require flooding more than 3,050 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 3,050 square miles), hydropower is not a reasonable alternative to BSEP 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 BSEP 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 MW 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 BSEP 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, particularly with electricity prices declining.

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 BSEP 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 BSEP 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 BSEP.

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 BSEP 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 2004). 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 BSEP 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 MW in 2001 (Hemberger 2001). Recent estimates suggest that a company would have to produce about 100 MW 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 MW per year (CSFCC 2002). Progress Energy believes that this technology has not matured sufficiently to support production for a facility the size of BSEP. Progress Energy has concluded that, due to cost and production limitations, fuel cell technology is not a reasonable alternative to BSEP 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. Therefore, there are no unit retirements that could be delayed as an alternative to BSEP license renewal.

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 BSEP license renewal: coal-fired generation, gas-fired generation, and purchased power.

7.2.2.1 Coal-Fired Generation

NRC evaluated environmental impacts from 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 BSEP.

Air Quality

A coal-fired plant would emit oxides of sulfur (SO_x) and nitrogen (NO_x), 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 = 4,778 tons per year

NO_x = 1,479 tons per year

Carbon monoxide = 1,479 tons per year

Particulates:

Total suspended particulates = 308 tons per year

PM_{10} (particulates having a diameter of less than 10 microns) = 71 tons per year

Table 7-3 shows how Progress Energy calculated these emissions.

In 2002, emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) from North Carolina's generators ranked 9th and 11th nationally, respectively (EIA 2004). In 1998, the EPA promulgated the NO_x SIP (State Implementation Plan) Call regulation that required 22 states, including North Carolina, to reduce their NO_x emissions by over 30 percent to address regional transport of ground-level ozone across state lines (EPA 1998b). The NO_x SIP Call imposes a NO_x "budget" to limit the NO_x emissions from each state. Implementation of the NO_x 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 NO_x SIP Call (ATA 2002). To operate a fossil-fuel-fired plant at the BSEP site, Progress Energy would need to obtain enough NO_x credits to cover annual emissions either from the set-aside pool or by buying NO_x 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, NO_x emission offsets, low NO_x 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 5,920,000 tons of coal having an ash content of 10.4 percent (Tables 7-3 and 7-1, respectively). After combustion, most (99.9 percent) of this ash, approximately 615,000 tons per year, would be collected and disposed of onsite. In addition,

approximately 261,000 tons of scrubber sludge would be disposed of onsite each year (based on annual calcium hydroxide usage of nearly 88,000 tons). Progress Energy estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 487 acres (a square area with sides of approximately 4,600 feet). Table 7-4 shows how Progress Energy calculated ash and scrubber waste volumes. The BSEP site is approximately 1,200 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 BSEP 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 520 acres of land and associated terrestrial habitat. Because most of this construction would require the clearing of several hundred acres of woodlands, impacts at the BSEP site would be moderate to large, 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 Wilmington, North Carolina, 15 miles from the site. Progress Energy estimates an operational workforce of only 150 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 BSEP’s proximity to Wilmington.

Impacts to aquatic resources and water quality would be similar to impacts of BSEP, due to the plant’s use of the existing cooling water system that withdraws from the Cape Fear River and discharges to the Atlantic Ocean, and would be offset by the concurrent shutdown of BSEP. 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 notes the EPA has revised requirements (EPA 2003) that could affect the design of cooling water intake structures for new facilities. This could require constructing a natural draft cooling tower or mechanical cooling towers. Recirculation would reduce cooling water intake volume by approximately 90 percent.

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 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 BSEP site. Land-use impacts from gas-fired units on BSEP would be less than those from the coal-fired alternative. 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 four 440-MW combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal (NRC 1999a). This analysis is for a generating capacity approximately the same as the BSEP gas-fired alternatives analysis, because Progress Energy would install 1825 MW of net power. Progress Energy has adopted the rest of 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 NO_x emissions. Progress Energy estimates the gas-fired alternative emissions to be as follows:

SO_x = 149 tons per year

NO_x = 478 tons per year

Carbon monoxide = 99 tons per year

Filterable Particulates = 83 tons per year (all particulates are PM_{10})

Table 7-5 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. NO_x effects on ozone levels, SO_2 allowances, and NO_x emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are

less stringent, the emissions are still substantial. Progress Energy concludes that emissions from the gas-fired alternative at BSEP 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 coal-fired alternative, the ability to construct the gas-fired alternative on the existing BSEP site would reduce construction-related impacts. A new gas pipeline would be required for the five 365-MW 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 114 miles of new pipeline construction would be required to connect BSEP to the existing pipeline network. A 30-inch diameter pipeline would necessitate a 100-foot-wide corridor, resulting in the disturbance of as much as 1,382 acres. This new construction may also necessitate an upgrade of the State-wide pipeline network. Progress Energy estimates that 122 acres would be needed for a plant site; this much previously disturbed acreage is available at BSEP, reducing loss of terrestrial habitat. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be similar to the 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 66 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 Wilmington.

7.2.2.3 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 more than 200 miles of high-voltage (i.e., 500-kilovolt) transmission lines to get power from the remote locations in the Carolinas to the Progress Energy network. Progress Energy believes most of the transmission lines could be routed along existing rights-of-way. Progress Energy assumes that the environmental impacts of 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 BSEP site.

TABLE 7-1
COAL-FIRED ALTERNATIVE

Characteristic	Basis
Unit size = 913 MW ISO rating net[a]	Calculated to be ≤ BSEP net capacity – 1909 MW
Unit size = 967 MW ISO rating gross[a]	Calculated based on 6 percent onsite power
Number of units = 2	
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 NO_x 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
NO_x control = low NO_x burners, overfire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NO_x emissions (EPA 1998a)
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions (EPA 1998a)
SO_x control = Wet scrubber – lime (95 percent removal efficiency)	Best available for minimizing SO_x emissions (EPA 1998a)

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

Btu = British thermal unit

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

NSPS = New Source Performance Standard

Lb = pound

MW = megawatt

NO_x = nitrogen oxides

SO_x = oxides of sulfur

≤ = less than or equal to

TABLE 7-2
GAS-FIRED ALTERNATIVE

Characteristic	Basis
Unit size = 365 MW ISO rating net:[a] One 365-MW combustion turbine	Manufacturer's standard size gas-fired combined-cycle plant that is ≤ BSEP net capacity - 1909 MW
Unit size = 380 MW ISO rating gross:[a] One 380-MW combustion turbine	Calculated based on 4 percent onsite power
Number of units = 5	
Fuel type = natural gas	Assumed
Fuel heating value = 1,032 Btu/ft^3	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)
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_x emissions (EPA 2000)
Fuel NO_x 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 = 6,204 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
ft^3 = 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
MW = megawatt
NO_x = nitrogen oxides
≤ = less than or equal to

TABLE 7-3
AIR EMISSIONS FROM COAL-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual coal consumption	$2\text{ units} \times \frac{967\text{ MW}}{\text{unit}} \times \frac{10{,}200\text{ Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\text{ kW}}{\text{MW}} \times \frac{\text{lb}}{12{,}415\text{ Btu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times 0.85 \times \frac{24\text{ hr}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}}$	5,917,186 tons of coal per year
SO_x[a,c]	$\frac{38 \times 0.85\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times (100 - 95/100) \times \frac{5{,}917{,}186\text{ tons}}{\text{yr}}$	4,778 tons SO_x per year
NO_x[b, c]	$\frac{10\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times (100 - 95/100) \times \frac{5{,}917{,}186\text{ tons}}{\text{yr}}$	1,479 tons NO_x per year
CO[c]	$\frac{0.5\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{5{,}917{,}186\text{ tons}}{\text{yr}}$	1,479 tons CO per year
TSP[d]	$\frac{10 \times 10.4\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times (100 - 99.9/100) \times \frac{5{,}917{,}186\text{ tons}}{\text{yr}}$	308 tons TSP per year
PM_{10}[d]	$\frac{2.3 \times 10.4\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times (100 - 99.9/100) \times \frac{5{,}917{,}186\text{ tons}}{\text{yr}}$	71 tons PM_{10} 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
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_x = oxides of sulfur
TSP = total suspended particulates

TABLE 7-4
SOLID WASTE FROM COAL-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual SO_x generated[a]	$\frac{5{,}917{,}186 \text{ ton coal}}{\text{yr}} \times \frac{0.85 \text{ ton S}}{100 \text{ ton coal}} \times \frac{64.1 \text{ ton } SO_2}{32.1 \text{ ton S}}$	100,542 tons of SO_x per year
Annual SO_x removed	$\frac{100{,}542 \text{ ton } SO_2}{\text{yr}} \times (95/100)$	95,515 tons of SO_x per year
Annual ash generated	$\frac{5{,}917{,}186 \text{ ton coal}}{\text{yr}} \times \frac{10.4 \text{ ton ash}}{100 \text{ ton coal}} \times (99.9/100)$	614,772 tons of ash per year
Annual lime consumption[b]	$\frac{100{,}542 \text{ ton } SO_2}{\text{yr}} \times \frac{56.1 \text{ ton CaO}}{64.1 \text{ ton } SO_2}$	87,994 tons of CaO per year
Calcium sulfate[c]	$\frac{95{,}515 \text{ ton } SO_2}{\text{yr}} \times \frac{172 \text{ ton } CaSO_4 \bullet 2H_2O}{64.1 \text{ ton } SO_2}$	256,296 tons of $CaSO_4 \cdot 2H_2O$ per year
Annual scrubber waste[d]	$\frac{87{,}994 \text{ ton CaO}}{\text{yr}} \times \frac{(100-95)}{100} + 256{,}296 \text{ ton } CaSO_4 \bullet 2H_2O$	260,695 tons of scrubber waste per year
Total volume of scrubber waste[e]	$\frac{260{,}695 \text{ ton}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{144.8 \text{ lb}}$	144,062,469 ft^3 of scrubber waste
Total volume of ash[f]	$\frac{614{,}772 \text{ ton}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	491,817,562 ft^3 of ash
Total volume of solid waste	144,062,469 ft^3 + 491,817,562 ft^3	635,880,031 ft^3 of solid waste
Waste pile area (acres)	$\frac{635{,}880{,}031 \, ft^3}{30 \text{ ft}} \times \frac{\text{acre}}{43{,}560 \, ft^2}$	487 acres of solid waste
Waste pile area (ft x ft square)	$\sqrt{(635{,}880{,}031 \, ft^3/30 ft)}$	4,604 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 SO_2 generated.

c. Calcium sulfate generation is based on total SO_2 removed.

d. Total scrubber waste includes scrubbing media carryover.

e. Density of $CaSO_4 \cdot 2H_2O$ is 144.8 lb/ft^3.

f. Density of coal bottom ash is 100 lb/ft^3 (FHA 2000).

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

TABLE 7-5
AIR EMISSIONS FROM GAS-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual gas consumption	$5\text{ units} \times \frac{380\text{ MW}}{\text{unit}} \times \frac{6{,}204\text{ Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\text{ kW}}{\text{MW}} \times 0.85 \times \frac{\text{ft}^3}{1{,}032\text{ Btu}} \times \frac{24\text{ hr}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}}$	84,959,379,488 ft^3 per year
Annual Btu input	$\frac{84{,}959{,}379{,}488\ \text{ft}^3}{\text{yr}} \times \frac{1{,}032\ \text{Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\text{ Btu}}$	87,678,080 MMBtu per year
SO_x[a]	$\frac{0.0034\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{87{,}678{,}080\ \text{MMBtu}}{\text{yr}}$	149 tons SO_x per year
NO_x[b]	$\frac{0.0109\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{87{,}678{,}080\ \text{MMBtu}}{\text{yr}}$	478 tons NO_x per year
CO[b]	$\frac{0.00226\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{87{,}678{,}080\ \text{MMBtu}}{\text{yr}}$	99 tons CO per year
TSP[a]	$\frac{0.0019\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{87{,}678{,}080\ \text{MMBtu}}{\text{yr}}$	83 tons filterable TSP per year
PM_{10}[a]	$\frac{83\text{ tons TSP}}{\text{yr}}$	83 tons filterable PM_{10} per year

a. EPA 2000, Table 3.1-1.
b. EPA 2000, Table 3.1-2.
CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_x = oxides of sulfur
TSP = total suspended particulates

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.

ATA (American Trucking Associations) v. Environmental Protection Agency. 2002. District of Columbia Circuit Court. Available at http://www.pacer.cadc.uscourts.gov/common/opinions/200203/97-1440c.txt. Accessed February 19, 2003.

CP&L (Carolina Power and Light Company). 2000. CP&L Integrated Resource Plan. September 1.

CP&L (Carolina Power and Light Company). 2001. Supplemental Environmental Report: Brunswick Steam Electric Plant Extended Power Uprate. Prepared for CP&L by Tetra Tech NUS, Inc. June.

CP&L (Carolina Power and Light Company). 2002a. CP&L Resource Plan. September.

CP&L (Carolina Power and Light Company). 2002b. "About Deregulation." Available at http://www.cpl.com/learning/deregulation.html. Accessed December 11, 2002.

CP&L (Carolina Power and Light Company). 2002c. "CP&L adds second phase at Richmond County power plant." News release dated June 4, 2002. Available at http://www.cpl.com/cfusion/news/article.cmf?id=3142. Accessed December 6, 2002.

CP&L (Carolina Power and Light Company). 2002d. "Site Map." Available at http://www.cpl.com/sitemap.html. Accessed December 9, 2002.

CSFCC (California Stationary Fuel Cell Collaborative). 2002. White Paper Summary of Interviews with Stationary Fuel Cell Manufacturers. Available at http://stationaryfuelcells.org/Index.htm. Accessed December 23, 2003.

EEI (Edison Electric Institute). 2002. Electric Competition in the States, A Summary. April.

EIA (Energy Information Administration). 2002. *Electric Power Annual 2000, Volume II*. DOE/EIA-0348(00)/2. November. Available at http://www.eia.doe.gov/cneaf/electricity/epav2/epav2.pdf. Accessed December 2, 2002.

EIA (Energy Information Administration). 2003a. Electric Power Monthly – Back Issues, April 2002 to March 2003, with Data for January 2002 to December 2002. Table 56, U.S. Electric Utility Net Generation and Fuel Consumption, by Company and Plant. Available at http://www.eia.doe.gov/cneaf/electricity/epm/matrix96_2000.html. Accessed on December 23, 2003.

EIA (Energy Information Administration). 2003b. "State Consumption Data." Available at http://www.eia.doe.gov/emeu/ states/_use_multistate.html. Accessed December 23, 2003.

EIA (Energy Information Administration). 2004. State Electricity Profiles 2002. DOE/EIA-0348(01)/2. January. Available at http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html. Accessed February 4, 2002.

EPA (U.S. Environmental Protection Agency). 1998a. Air Pollutant Emission Factors. Vol. 1, Stationary Point Sources and Area Sources. Section 1.1, "Bituminous and Subbituminous Coal Combustion." AP-42. September. Available at http://www.epa.gov/ttn/chief/ap42c1.html. Accessed December 3, 2002.

EPA (U.S. Environmental Protection Agency). 1998b. *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone. Federal Register*. Vol. 63, No. 207. October 27.

EPA (U.S. Environmental Protection Agency). 2000. *Air Pollutant Emission Factors.* Vol. 1, *Stationary Point Sources and Area Sources.* Section 3.1, "Stationary Gas Turbines." AP-42. April. Available at http://www.epa.gov/ttn/chief/ap42c3.html. Accessed December 3, 2002.

EPA (U.S. Environmental Protection Agency). 2003. Regulation 40 CFR 125, Subpart I, Requirements Applicable to Cooling Water Intake Structures for New Facilities under Section 316(b) of the Act.

FHA (Federal Highway Administration). 2000. *User Guidelines for Waste and Byproduct Materials in Pavement Construction*. Available at http://tfhrc.gov/hnr20/recycle/waste/pubs.htm. Accessed December 3, 2002.

Hemberger, Peter. 2001. "Fuel Cells: FAQs." Available at http://www.crest.org/articles/static/1/995303594_1008081206.html. Accessed on February 21, 2003

INEEL (Idaho National Engineering and Environmental Laboratory). 1997a. U.S. Hydropower Resource Assessment for North Carolina. DOE/ID-10430(NC). Available at http://hydropower.id.doe.gov/resourceassessment/nc/nc.pdf. Accessed December 3, 2002.

INEEL (Idaho National Engineering and Environmental Laboratory). 1997b. U.S. Hydropower Resource Assessment for South Carolina. DOE/ID-10430(SC). Available at http://hydropower.id.doe.gov/resourceassessment/sc/sc.pdf. Accessed December 3, 2002.

Kenergy Corporation. 2000. "Fuel Cell Technology – Its Role in the 21st Century." From Commercial & Industrial News 4th Quarter 2000. Available at http://www.kenergycorp.com/ci/cinews/qtr4ci2000/technology.htm. Accessed on June 19, 2002.

NCUC (North Carolina Utilities Commission). 2003. Annual Report Regarding Long Range Needs for Expansion of Electric Generating Facilities for Service in North Carolina. July 2003.

NEI (Nuclear Energy Institute). 2000. "Restructuring the U.S. Electric Power Industry." Available at http://www.nei.org/doc.asp?catnum=3&catid=277. Accessed December 3, 2002.

NRC (U.S. Nuclear Regulatory Commission). 1996a. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG 1437. Washington, DC. May.

NRC (U.S. Nuclear Regulatory Commission). 1996b. Supplementary Information to Final Rule. *Federal Register*. Vol. 61, No. 244. December 18.

NRC (U.S. Nuclear Regulatory Commission). 1999a. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Calvert Cliffs Nuclear Power Plant*. NUREG-1437, Supplement 1, Final. Office of Nuclear Reactor Regulation. Washington, DC. October.

NRC (U.S. Nuclear Regulatory Commission). 1999b. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Oconee Nuclear Station*. NUREG-1437, Supplement 2, Final. Office of Nuclear Reactor Regulations. Washington, DC. December.

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

NREL (National Renewable Energy Laboratory). 1986. "Wind Energy Resource Atlas of the United States." DOE/CH 10093-4. Available at http://rredc.nrel.gov/wind/pubs/atlas/chp3.html. Accessed December 3, 2002.

Progress Energy. 2003. Progress Energy 2002 Annual Report. Available at http://www.progress-energy.com/investors/financials/annuals/annreport-02.pdf.

Siemens. 2002. "Combined Cycle Plant Ratings." Available at http://www.pg.siemens.com/en/plantrating/index.cfm. Accessed December 10, 2002.

Walsh M. E., R. L. Perlack, A. Turhollow, D. de la Torre Ugarte, D. A. Becker, R. L. Graham, S. E. Slinsky, and D. E. Ray. 2000. Biomass Feedstock Availability in the United States: 1999 State Level Analysis. Oak Ridge National Laboratory. Oak Ridge, TN. April 30, 1999. Updated January, 2000. Available at http://bioenergy.ornl.gov/resourcedata/index.html. Accessed December 3, 2002.

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 Brunswick Steam Electric Plant, Units 1 and 2 (BSEP) 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 Gas-Fired Generation	With Purchased Power
Land Use	SMALL	SMALL	MODERATE	SMALL to MODERATE	MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Air Quality	SMALL	SMALL	MODERATE	MODERATE	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	MODERATE	SMALL to MODERATE	SMALL to MODERATE
Threatened or Endangered Species	SMALL	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	SMALL	MODERATE	SMALL to MODERATE
Waste Management	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	MODERATE	SMALL to MODERATE	SMALL to MODERATE
Cultural Resources	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

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Alternative Descriptions				
BSEP license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current BSEP license. Adopting by reference, as bounding BSEP decommissioning, GEIS description (NRC 1996, Section 7.1)	New construction at the BSEP site.	New construction at the BSEP site.	Would involve construction of new generation capacity in the state. Adopting by reference GEIS description of alternate technologies (Section 7.2.1.2)
		Use existing rail spur	Construct 114 miles of gas pipeline in a 100-foot-wide corridor. May require upgrades to existing pipelines.	
		Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Construct more than 200 miles of transmission lines
		Two 913-MW (net) tangentially-fired, dry bottom unit; capacity factor 0.85	Five 365 MW of net power (Combined-cycle turbines to be used)	
		Existing BSEP intake/ discharge canal system	Existing BSEP 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; 5,917,186 tons coal/yr	Natural gas, 1,032 Btu/ft^3; 6,204 Btu/kWh; 0.0034 lb sulfur/MMBtu; 0.0109 lb NO_x/MMBtu; 84,959,379,488 ft^3 gas/yr	

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
		Low NO_x burners, overfire air and selective catalytic reduction (95% NO_x reduction efficiency). Wet scrubber – lime/limestone desulfurization system (95% SO_x removal efficiency); 87,994 tons limestone/yr Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency)	Selective catalytic reduction with steam/water injection	
760 permanent and 300 long term contract workers		150 workers (Section 7.2.2.1)	66 workers (Section 7.2.2.2)	
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)	MODERATE – 520 acres required for the powerblock and associated facilities. (Section 7.2.2.1)	SMALL to MODERATE – 122 acres for facility at BSEP location; 1,382 acres for pipeline (Section 7.2.2.2). New gas pipeline would be built to connect with existing gas pipeline corridor.	MODERATE – most transmission facilities could be constructed along existing transmission corridors (Section 7.2.2.3) Adopting by reference GEIS description of land use impacts from alternate technologies (NRC 1996)

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative		
		With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Water Quality Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 4, 7, 9-12, 32, and 37). Five Category 2 groundwater issues not applicable (Section 4.1, Issue 13; 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 Cape Fear River and discharges to ocean. (Section 7.2.2.1)	SMALL – Reduced cooling water demands, inherent in combined-cycle design (Section 7.2.2.2)	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 – 4,778 tons SO_x/yr 1,479 tons NO_x/yr 1,479 tons CO/yr 308 tons TSP/yr 71 tons PM_{10}/yr (Section 7.2.2.1)	MODERATE – 149 tons SO_x/yr 478 tons NO_x/yr 99 tons CO/yr 83 tons PM_{10}/yr[a] (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (NRC 1996)

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Ecological Resource Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 15-24, 45-48). One Category 2 issue not applicable (Section 4.9, Issue 40). BSEP holds a current NPDES permit, which constitutes compliance with Clean Water Act Section 316(b) (Section 4.2, Issue 25; Section 4.3, Issue 26).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 90)	MODERATE – 243 acres of forested land could be required for ash/sludge disposal over 20-year license renewal term. (Section 7.2.2.1)	SMALL to MODERATE – Construction of the pipeline could alter habitat. (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of ecological resource impacts from alternate technologies (NRC 1996)
Threatened or Endangered Species Impacts				
SMALL – With the exception of occasional sea turtle sightings, no threatened or endangered species are known at the site or along the transmission corridors. (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

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: 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)	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (NRC 1996)	SMALL to MODERATE – Adopting by reference GEIS description of human health impacts from alternate technologies (NRC 1996)
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 medium population area with limited growth controls minimizes potential for housing impacts. Section 4.14, Issue 63). Plant property tax payment represents 4 percent of county's total tax revenues (Section 4.17.2, Issue 69).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 91)	SMALL – Reduction in permanent work force at BSEP could adversely affect surrounding counties, but would be mitigated by BSEP's proximity to Wilmington (Section 7.2.2.1).	SMALL to MODERATE – Reduction in permanent work force at BSEP could adversely affect surrounding counties, but would be mitigated by BSEP's proximity to Wilmington (Section 7.2.2.2)	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 Gas-Fired Generation**	**With Purchased Power**
Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65 and Section 4.18, Issue 70)				
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 – 614,772 tons of coal ash and 260,695 tons of scrubber sludge would require 243 acres over 20-year license renewal term. Industrial waste generated annually (Section 7.2.2.1)	SMALL – Almost no waste generation (Section 7.2.2.2)	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 to MODERATE – Steam turbines and stacks would create visual impacts comparable to those from existing BSEP facilities (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (NRC 1996)

TABLE 8-2
IMPACTS COMPARISON DETAIL (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative With Coal-Fired Generation	No-Action Alternative With Gas-Fired Generation	No-Action Alternative 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 – 114 miles of pipeline construction in southeastern NC could affect some cultural resources (Section 7.2.2.2)	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 Brunswick Steam Electric Power (BSEP) 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 BSEP 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 BSEP environmental documentation, and communication with state and federal environmental protection agencies. Based on this assessment, Progress Energy concludes that BSEP is in compliance with applicable environmental standards and requirements.

Table 9-2 lists additional environmental authorizations and consultations related to NRC renewal of the BSEP 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 BSEP 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) and a letter to NMFS, which has jurisdiction over marine species. The FWS response noted that license renewal was unlikely to adversely affect any federally listed species or its habitat as long as Progress Energy continues to be an active participant in a 1993 Memorandum of Understanding between Carolina Power and Light and the North Carolina Natural Heritage Program that addresses the management of federally protected plants in transmission line rights-of-way in southeastern North Carolina. The NCDENR response also noted the importance of these transmission corridors to rare plants and recommended that Progress Energy continue to employ vegetation management practices (e.g., mowing during the non-growing season on a three-year cycle) that benefit rare species and habitats.

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 2001). BSEP, located in Brunswick County, is within the North Carolina Coastal Management Area (NCDENR 2002). Therefore, certification from the North Carolina Coastal Resource Commission is necessary. The certification prepared by Progress Energy is in Appendix E.

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 (35 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 State Historic Preservation Office.

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). NRC has indicated in its

Generic Environmental Impact Statement for License Renewal (NRC 1996) that issuance of a National Pollutant Discharge Elimination System (NPDES) permit implies certification by the state. Progress Energy is applying to NRC for license renewal to continue BSEP operations. Appendix B contains excerpts from the BSEP NPDES permit. Consistent with the GEIS, Progress Energy is providing BSEP's NPDES permit as evidence of state water quality (401) certification.

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, 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 the coal- and gas-fired alternatives if surface water were used for cooling.

TABLE 9-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BSEP UNITS 1 AND 2 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	Unit 1: DPR-71 Unit 2: DPR-62	Issued 11/12/1976 Expires 9/8/2016 Issued 12/27/74 Expires 12/27/2014	Operation of Units 1 and 2
U.S. Fish and Wildlife Service	16 USC 703-712	Federal Fish and Wildlife Permit, Depredation	MB789112-0	Issued 04/01/03; Expires 03/31/04	Removal and relocation of migratory bird nests
U.S. Department of Transportation	49 USC 5108	Registration	050603550001L	Issued 5/6/03; Expires 6/30/04	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	NC0007064	Issued 06/30/03; Expires 11/30/06	Wastewater discharges to Atlantic Ocean (Part I) and stormwater discharges to waters of the State (Part II).

TABLE 9-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BSEP UNITS 1 AND 2 OPERATIONS (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
North Carolina Department of Environment and Natural Resources	NC General Statutes 143-215.95 et. Seq., Part 3 of the NC Oil Pollution and Hazardous Substances Control Act	Certificate of Registration of Oil Terminal Facility	104021005	Issued 2/29/00 updated as necessary to reflect changes in facilities/operations /organizations	PE operation of an oil terminal supplying fuel to emergency diesel generator and lubrication oils
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	5556R13	Issued 12/17/03; Expires 12/01/08	Air emissions for boilers and emergency generators source operation
North Carolina Department of Environment and Natural Resources and Coastal Commission	Federal Coastal Zone Management Act (16 USC 1451 et seq; NC General Statutes 113-229	Dredging Permit	293	Issued 10/20/03; Expires 12/31/06	Maintenance dredging of existing cooling water intake canal
North Carolina Wildlife Resources Commission	Endangered Species act of 1973 (16 USC 1531-1544)	Endangered Species Permit - Sea Turtles	04ST49	Issued 1/15/04; Expires 12/31/04	Tagging, Possession and Disposition of Entrained or Stranded Sea Turtles
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	No Number	Issued 1/30/03; Expires 12/31/03	Removal and relocation of migratory bird nests

TABLE 9-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT BSEP UNITS 1 AND 2 OPERATIONS (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
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	0041-32-04	Issued 11/20/03; Expires 12/31/04	Transportation of radioactive waste into the State of South Carolina
Utah Department of Environmental Quality Division of Radiation Control	Utah Division of Radiation Control Rule R313-26	Utah Radiation Control Generator Site Access Permit	0109000007	Issued 9/30/01; Expires 6/30/04	Transportation of radioactive waste into the State of Utah
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-NC001-L04	Issued 1/1/04; Expires 12/31/04	Transportation of radioactive waste into the State of Tennessee

**TABLE 9-2
ENVIRONMENTAL AUTHORIZATIONS FOR
BSEP UNITS 1 AND 2 LICENSE 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 Division of Coastal Management	Federal Coastal Zone Management Act (16 USC 1452 et seq.)	Certification	Requires applicant to prove certification to Federal agency issuing the license that license renewal would be consistent with the Federally approved State Coastal Zone Management program. Based on its review of the proposed activity, the State must concur with or object to the applicant's certification (Appendix E).
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, Coastal Area Management Act. Available at http://dcm2.enr.state.nc.us/cama_counties.htm. Accessed October 29, 2002.

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). 2001. *Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issue*s. NRR Office Instruction No. LIC-203. June 21.

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 BSEP addressed each applicable issue in this environmental report. For organization and clarity, BSEP has assigned a number to each issue and uses the issue numbers throughout the environmental report.

TABLE A-1
BSEP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

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 BSEP will not undertake.
2. Impacts of refurbishment on surface water use	1	NA	Issue applies to an activity, refurbishment, that BSEP will not 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	4.0	4.2.1.2.2/4-4
5. Altered thermal stratification of lakes	1	NA	Issue applies to a plant feature, discharge to a lake, that BSEP does not have.
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	NA	Issue applies to a plant feature, discharge to a lake, that BSEP does not have.
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	4.0	4.2.1.3/4-13
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	
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	NA	Issue applies to an activity, refurbishment, that BSEP will not 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

TABLE A-1
BSEP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
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
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	4.2	4.2.2.1.2/4-16
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	4.3	4.2.2.1.3/4-16
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	4.4	4.2.2.1.4/4-17
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	NA	Issue applies to a heat dissipation system, cooling towers, that BSEP does not have
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	NA	Issue applies to a heat dissipation system, cooling towers, that BSEP does not have
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	NA	Issue applies to a heat dissipation system, cooling towers, that BSEP does not have

TABLE A-1
BSEP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Ground-water Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	NA	Issue applies to an activity, refurbishment, that BSEP will not undertake.
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	4.0	4.8.1.1/4-116
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	NA, and discussed in Section 4.5	
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	NA, and discussed in Section 4.6	
35. Groundwater use conflicts (Ranney wells)	2	NA, and discussed in Section 4.7	
36. Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney Wells, that BSEP does not have.
37. Groundwater quality degradation (saltwater intrusion)	1	4.0	4.8.2.1/4-119
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Issue applies to a feature, cooling ponds, that BSEP does not have.
39. Groundwater quality degradation (cooling ponds at inland sites)	2	NA, and discussed in Section 4.8	
Terrestrial Resources			
40. Refurbishment impacts to terrestrial resources	2	NA, and discussed in Section 4.9	
41. Cooling tower impacts on crops and ornamental vegetation	1	NA	Issue applies to a feature, cooling towers, that BSEP does not have.
42. Cooling tower impacts on native plants	1	NA	Issue applies to a feature, cooling towers, that BSEP does not have.
43. Bird collisions with cooling towers	1	NA	Issue applies to a feature, cooling towers, that BSEP does not have.

TABLE A-1
BSEP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
44. Cooling pond impacts on terrestrial resources	1	NA	Issue applies to a feature, cooling ponds, that BSEP 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	4.5.6.3/4-77
48. Floodplains and wetlands on power line right-of-way	1	4.0	4.5.7/4-81
Threatened or Endangered Species (for all plants)			
49. Threatened or endangered species	2	4.10	4.1/4-1
Air Quality			
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	NA, and discussed in Section 4.11	
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 BSEP will not undertake.
55. Occupational radiation exposures during refurbishment	1	NA	Issue applies to an activity, refurbishment, that BSEP will not 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	
58. Noise	1	4.0	4.3.7/4-49

TABLE A-1
BSEP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
59. Electromagnetic fields, acute effects (electric shock)	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) 4.7.1/4-101 (renewal term)
64. Public services: public safety, social services, and tourism and recreation	1	4.0	<u>Refurbishment</u> 3.7.4/3-14 (public services) 3.7.4.3/3-18 (safety) 3.7.4.4/3-19 (social) 3.7.4.6/3-20 (tour, rec) <u>Renewal Term</u> 4.7.3/4-104 (public services) 4.7.3.3/4-106 (safety) 4.7.3.4/4-107 (social) 4.7.3.6/4-107 (tour, rec)
65. Public services: public utilities	2	4.15	3.7.4.5/3-19 (refurbishment) 4.7.3.5/4-107 (renewal term)
66. Public services: education (refurbishment)	2	NA , and discussed in Section 4.16	
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	
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) 4.7.3.2/4-106 (renewal term)
71. Historic and archaeological resources	2	4.19	3.7.7/3-23 (refurbishment) 4.7.7/4-114 (renewal term)
72. Aesthetic impacts (refurbishment)	1	NA	Issue applies to an activity, refurbishment, that BSEP will not undertake.
73. Aesthetic impacts (license renewal term)	1	4.0	4.7.6/4-111

TABLE A-1
BSEP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
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)
76. Severe accidents	2	4.20	5.3.3/5-12 (probablistic 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 (conclusion)

TABLE A-1
BSEP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
89. Water quality (decommissioning)	1	4.0	7.3.4/7-21 (water) 7.4/7-25 (conclusion)
90. Ecological resources (decommissioning)	1	4.0	7.3.5/7-21 (ecological) 7.4/7-25 (conclusion)
91. Socioeconomic impacts (decommissioning)	1	4.0	7.3.7/7-24 (socioeconomic) 7.4/7-25 (conclusion)
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).

c. NRC findings are not applicable because Progress Energy has no plans for major refurbishment.

d. Not applicable because BSEP discharges to the ocean and not a [small] lake or river.

e. Not applicable because BSEP does not use cooling ponds or cooling towers using make-up water from a small river with low flow.

f. Not applicable because BSEP uses less than 100 gpm of groundwater.

g. Not applicable because BSEP does not use Ranney wells.

NEPA = National Environmental Policy Act.

APPENDIX B
NPDES PERMIT

This Appendix contains selected pages of Brunswick Steam Electric Plant's National Pollutant Discharge Elimination System permit, including the cover page, which authorizes the Plant to discharge wastewater to the Atlantic Ocean in the Cape Fear River Basin, and pages pertinent to the Chapter 4 discussions of entrainment, impingement, and heat shock.

Permit NC0007064

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
(NPDES)

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,

Progress Energy Carolinas, Inc.

is hereby authorized to discharge wastewater from outfalls located at the

Brunswick Steam Electric Plant
NC Highway 87, Southport
Brunswick County

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

This permit shall become effective **August 1, 2003.**

This permit and authorization to discharge shall expire at midnight on **November 30, 2006.**

Signed this day **June 30, 2003.**

Alan Klimek, P.E., Director
Division of Water Quality
By Authority of the Environmental Management Commission

SUPPLEMENT TO PERMIT COVER SHEET

Progress Energy Carolinas, Inc.

is hereby authorized:

1. to continue operating a 1,900 MGD cooling water system consisting of an intake structure, 9.6 miles of intake and effluent canals connected via internal Outfalls 001and 002, circulation pumps, siphons under the intra-coastal waterway, a discharge pump station at Oak Island, and final discharge conduits terminating 2,000 feet off shore; all necessary appurtenances to withdraw cooling water from the Cape Fear River near Snow Marsh, and thereby to discharge cooling water into the Atlantic Ocean; and

2. to continue operating and discharging via internal Outfall 004 (see attached map), a 0.055 MGD domestic wastewater treatment plant (WWTP) consisting of influent pumps, bar screen, flow measuring device, aeration tank, secondary clarifier and chlorination chamber; and

3. to continue discharging via internal Outfall 010 (see attached map), and continue operating the existing 0.036 MGD Support Services domestic WWTP (previously permitted under NC0083895) consisting of an influent duplex pump station, manually cleaned bar screen, flow EQ basin, flow splitter box, two (2) aeration basins, two (2) clarifiers, two (2) tertiary filters, aerobic sludge digestor with airlift sludge pump, baffled chlorine contact chamber with two (2) tablet chlorinators, and an effluent flow v-notch weir measuring device; and

4. to begin operating additional "helper' cooling facilities and begin discharging 0.187 MGD of cooling tower blowdown (if installed) to Outfall 011, then to Outfall 005 to the Intake Canal (see attached map); and

5. to continue to discharge treated metal cleaning wastes (Outfall 006), treated low-volume wastes and stormwater (Outfall 005) to the Intake Canal; and

6. to continue operating a diversion fence located at the mouth of the intake canal; and

7. to continue operating fine-mesh screens, as described under Part I, A.(1.) Outfalls 001and 002 at intake pump bays; and

8. to continue to operate an intake pump system to minimize intake flow rate; and

9. to discharge stormwater from Outfalls 007, 008, and 009 (see attached map) into Nancy's Creek, classified as Class SC-Sw-HQW waters within the Cape Fear River Basin; and

10. to discharge stormwater, wastewater, and cooling water via internal outfalls from said treatment works, Intake Canal, and Discharge Canal (see **Attachment 1**) into the Atlantic Ocean, Class SB waters;

located at the **Brunswick Steam Electric Plant** on NC Highway 87, Southport, Brunswick County.

All discharges shall conform to the attached schedules:

Part I: **Wastewater Monitoring, Controls and Limitations for Permitted Discharges**
Part II: **Stormwater Monitoring, Controls and Limitations for Permitted Discharges**
Part III: **Standard Conditions for NPDES Permits**
Part IV: **Other Requirements**
Part V: **Annual Administering and Compliance Monitoring Fee Requirements**

This permit does not relieve the permittee from responsibility to comply with any other applicable federal, state or local law, rule, standard, ordinance, order, judgement or decree.

Permit No. NC0007064

A. (1.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of the permit and lasting until expiration, the Permittee is authorized to discharge once-through cooling and non-contact service water through **Outfalls 001 and 002**. Such discharges shall be limited and monitored by the Permittee as specified below:

Effluent Characteristics	Discharge Limitations			Monitoring Requirements		
	Monthly Average	Weekly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location [1]
Cooling Water Flow [2]				Continuous	Pump Logs / Recording	
For April - November			1105 cfs / unit [3,4]			
For December - March			922 cfs / unit			

1. Unless otherwise specified, the permittee shall sample the effluent of each individual generating unit prior to mixing with other waste streams. During periods of refueling and other outages at zero reactor power, the Permittee shall maintain minimum unit flows required for the safe and efficient operation & maintenance of plant systems.

2. During a generating-unit outage (one unit not in operation), the Permittee may increase flow to the remaining operating unit as needed, provided that the total cooling water flow does not exceed the maximum flow limit for two-unit operation.

3. During the months of July, August and September, **one unit only** may increase its flow to 1230 cfs. At times when the system demand is within 200 MW of available system reserves, the Permittee may suspend flow limitations upon notice to the Regional Supervisor. Notice shall include anticipated flow rates and an estimate of the duration of flow rates in excess of those otherwise allowed. Excursions up to eight hours per week are allowed to clean debris from filters. Three hours per week are allowed for testing of backup pumps and related equipment.

4. cfs/unit = cubic feet per second per generating unit

NOTE: Part III A.7.a. identifying flow limits as Monthly Averages is not applicable to flow requirements for 001 and 002.

A. (1.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS -- Continued

FINE MESH SCREENS – Two and a half (2½) fine mesh screens shall be maintained on the plant intake structure such that intake cooling water flowing into three (3) pump bays per generating unit will continuously pass through the two and a half (2½) fine mesh screens. The fourth bay will be maintained with one half (½) fine mesh screens such that, if this fourth pump bay is put in service, cooling water will pass through one half (½) fine mesh screen in this bay only. If the Circulating Water Intake Pumps are in jeopardy of tripping as a result of high differential pressure across the traveling screens, the fine mesh screens may be temporarily removed to prevent or mitigate unplanned decreases in power or plant trips. The fine mesh screens will be reinstalled when conditions permit the Circulating Water Intake Pumps to sustain continuous operation. Should the use of at least two and a half (2½) fine-mesh pumped bays be impossible as a result of screen failure or other malfunction, the Permittee shall provide explanation in the monthly report stating the cause(s) of the malfunction, duration and corrective action(s) taken by the plant. For testing purposes, pumps may be operated when not in compliance with the fine mesh screen requirements.

Preventative maintenance of the fine mesh screens is allowed during periods when the generating unit is operating, if such work is accomplished in the time between one hour after sunrise and one hour before sunset. Preventative maintenance as required at other times is allowed; however, the Permittee shall report monthly the total time that screens are out of service for such maintenance. CP&L shall maintain a record of fine-mesh screen total maintenance outages.

DIVERSION FENCE - A diversion fence located at the mouth of the intake canal shall be continuously operated and maintained in such a manner as to minimize impingement. A biological monitoring program shall be continued which will provide sufficient information to allow for a continuing assessment of the impact of the Brunswick Steam Electric Plant on the Cape Fear estuary, with particular emphasis on the marine fisheries. Data shall be reported annually and shall include an interpretive summary report assessing the effectiveness of the diversion fence, and the effectiveness of flow minimization and fine mesh screens to curtail organism **impingement** and **entrainment**. The Director of the Division of Water Quality shall approve any major changes in the biological monitoring program.

CHLORINE - There shall be no discharge of Total Residual Chlorine (total residual oxidants) at the ocean outfall. Total Residual Chlorine or total residual oxidants are to be measured weekly at the Caswell Beach Pump Station by multiple grab samples.

Permit No. NC0007064

A. (1.) **EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS -- Continued**

TEMPERATURE – Cooling-water system facilities shall be effectively maintained and operated so as to meet the temperature standards assigned to the Atlantic Ocean: 0.8°C (1.44°F) increase above ambient water temperature during the months June through August; 2.2°C (3.96°F) increase above ambient water temperature during the months September through May. In no case should the temperature exceed 32°C (89.6°F) due to the discharge of heated liquid measured three (3) feet below the water surface except within the following defined mixing zones:

(a). The temperature increase above ambient water temperature shall not exceed 7°F outside an area of **120 acres** included within the plume extending from the point of discharge.

(b). The temperature increase above ambient water temperature shall not exceed 0.8°C (1.44°F) increase above ambient water temperature during the months of June through August; 2.2°C (3.96°F) increase above ambient water temperature during the months of September through May. In no case should the temperature exceed 32°C (89.6°F) outside an area of **2000 acres.**

(c). The temperature increase above ambient water temperature at the bottom (defined as one foot above the ocean floor) shall not exceed 7°F for more than **1000 feet** from the point of discharge, nor for an area of more than **four (4) acres.**

Temperature monitoring at the ocean discharge shall be conducted **semiannually**, once during the months of **April - November** and once during the months of **December - March**. Reactor power levels should be at least 85% for each unit on the date of monitoring. If it is determined by this Division that the water quality standards or conditions of this permit are being violated or being threatened (within 90% of the limitations or standards), additional monitoring may be required.

Temperature shall be monitored within a 2320-acre rectangular mixing zone defined by two (2) sampling grids; one near the ocean surface (three feet below the water surface) and the second near the bottom (one foot above the ocean floor). Temperatures shall be recorded at locations sufficient in number to establish compliance with Water Quality Standards. If sufficient temperature variation exists, the permittee shall plot 1°F isotherms to report surface and bottom conditions. The permittee shall likewise establish and report ambient temperatures beyond each grid by averaging four (4) temperature measurements -- each measurement to be taken approximately 1500 feet beyond a different mixing-zone corner on a baring approximately 135° relative to each sampling grid.

The Permittee shall discharge no polychlorinated biphenyl compounds such as those used for transformer fluid.

Discharge at the ocean outfall shall contain no floating solids or foam visible in other than trace amounts.

DENR / DWQ / NPDES Unit
SUPPLEMENTAL FACT SHEET FOR 2003 FINAL PERMIT
NPDES Permit No. NC0007064

FACILITY DESCRIPTION

Brunswick Steam Electric Plant (BSEP) is a two-unit, 1642 megawatts (MWe) power-generating facility intending to uprate 10 to 15% during this permit cycle (to ~1806 MWe). The facility utilizes cooling water captured from the Cape Fear River via an intake canal with diversion fence. For this renewal, this facility is permitted to utilize eleven (11) internal outfalls including two on-site domestic wastewater treatment plants (WWTP), one previously permitted under NC0083895. At the permittee's request, the latter permit will be rescinded and its discharge included under this renewal at the issuance of NC0007064 as Outfall 010.

PERMIT DRAFT REVIEW SUMMARY

During the permit renewal interim, the parent company, Carolina Power and Light (CP&L), requested a company name change to **Progress Energy Carolinas, Inc.** Therefore the final permit for the Brunswick Steam Electric Plant (BSEP) shall be issued under this new company name.

The Division submitted the Draft Permit to public notice and to the EPA Region 4 for review on March 23, 2002. EPA Region 4 requested clarification and justification for permittee-proposed new mixing zone parameters and monitoring schedules. Following EPA's review of supporting documentation for the proposed power up-rate and related doubling of the Atlantic Ocean discharge mixing zone, no significant permit changes were deemed necessary by EPA. Therefore, the Division did not re-notice the Draft Final permit. For Division and permittee responses to EPA requests for additional information, see the Division's transmittal to EPA Region 4 and accompanying attachments dated May 6, 2003.

The permittee has requested minor permit revisions and corrections to the Draft Final, all of which have been documented and explained in the final issuance cover letter. For a record of changes to the Draft permit, see the **Fact Sheet for Draft Final Permit** (signed March 31, 2003).

PROPOSED SCHEDULE OF ISSUANCE

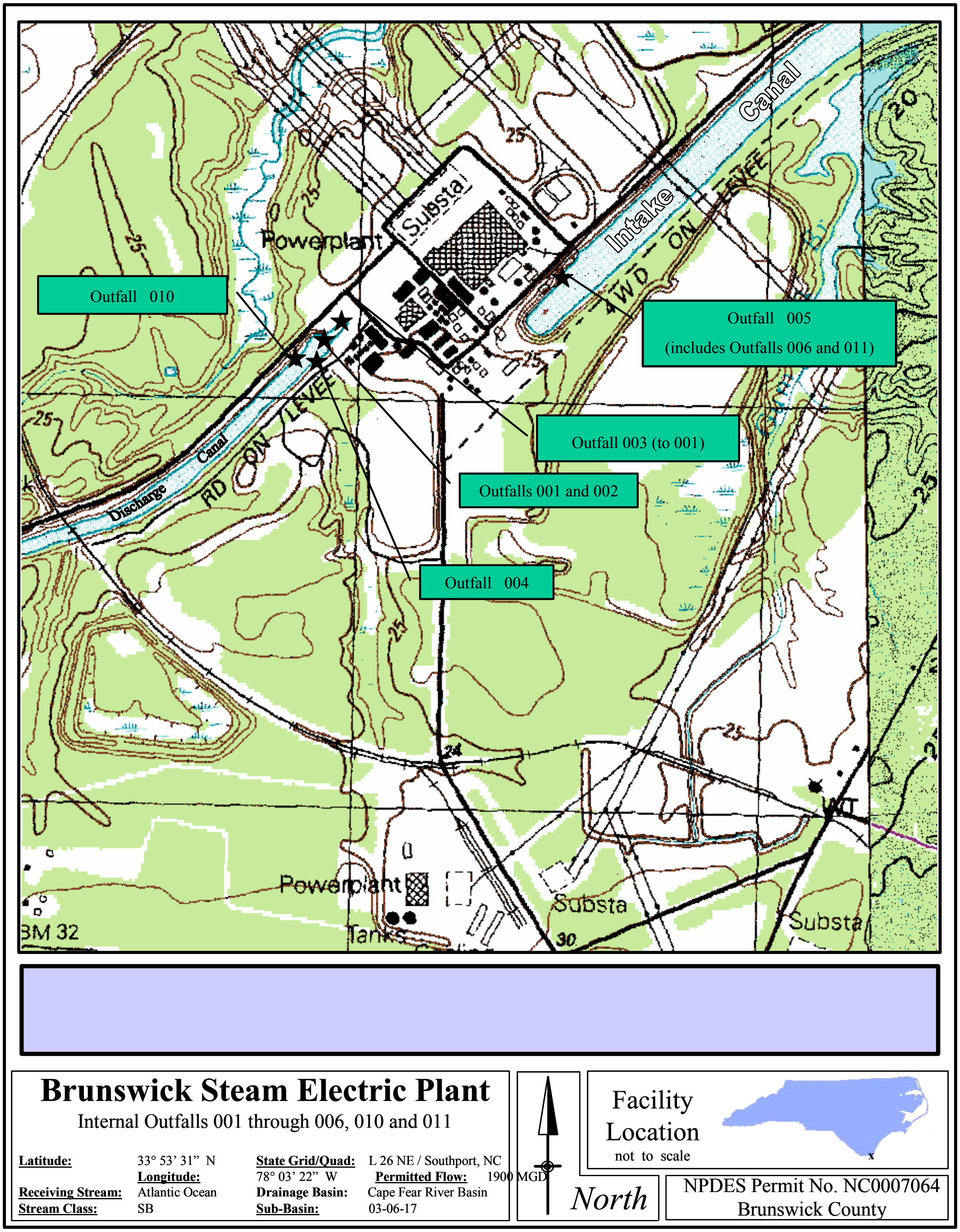
Draft Permit to Public Notice:	March 20, 2002.
Permit Scheduled to Issue:	August 1, 2003

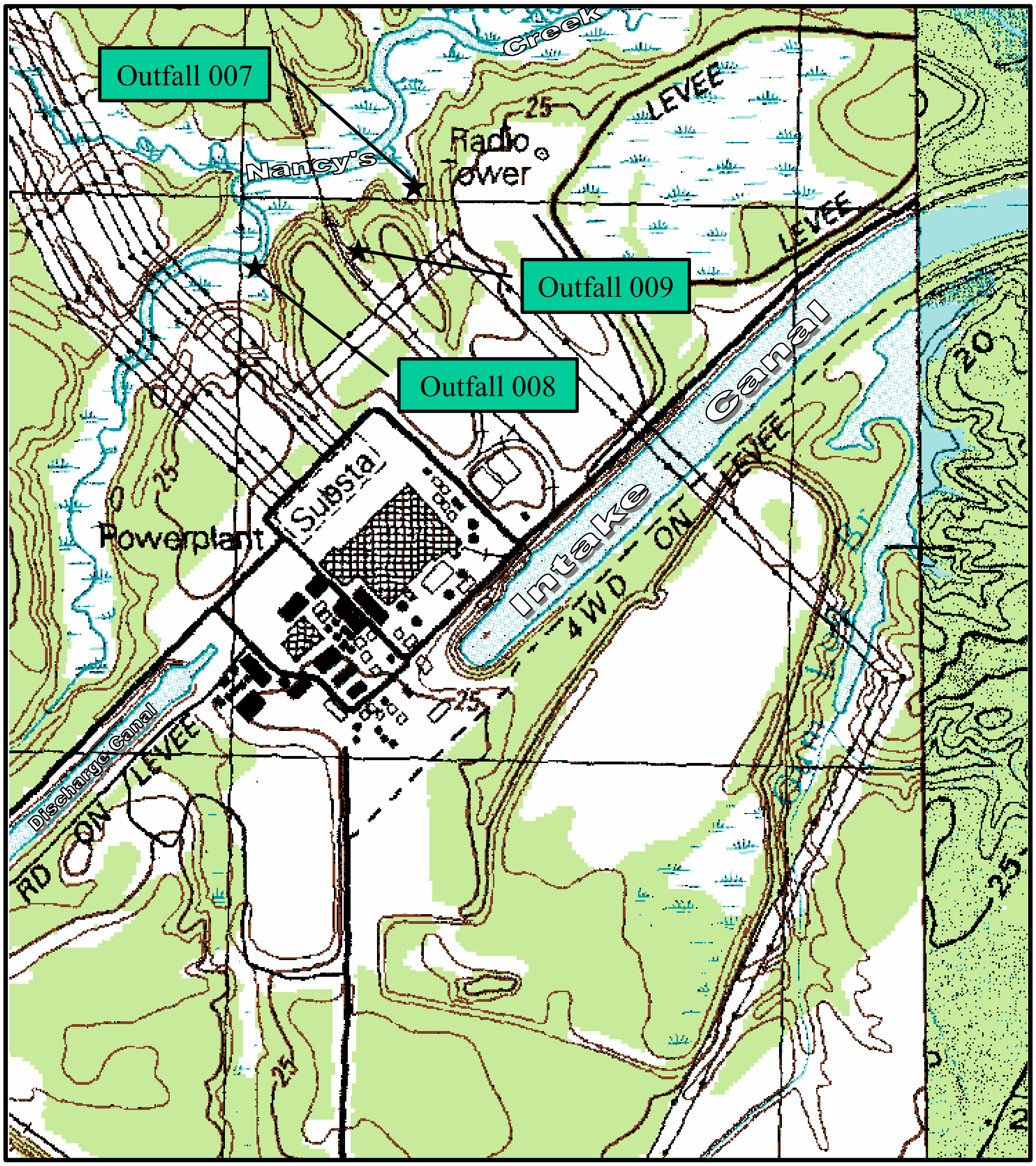
NPDES UNIT CONTACT

If you have questions regarding any of the above information or the final permit, please contact Joe Corporon at (919) 733-5083 ext. 597.

NAME:____ **DATE:**________________________

Supplemental Fact Sheet to Final
Renewal -- NPDES Permit NC0007064
Page 1


Outfall 010
Outfall 005
(includes Outfalls 006 and 011)
Outfall 003 (to 001)
Outfalls 001 and 002
Outfall 004
Powerplant
Substa
Intake Canal
Discharge Canal
Tanks
BM 32
Brunswick Steam Electric Plant
Internal Outfalls 001 through 006, 010 and 011
Latitude: 33° 53' 31" N
Longitude: 78° 03' 22" W
State Grid/Quad: L 26 NE / Southport, NC
Permitted Flow: 1900 MGD
Receiving Stream: Atlantic Ocean
Drainage Basin: Cape Fear River Basin
Stream Class: SB
Sub-Basin: 03-06-17
North
Facility Location
not to scale
NPDES Permit No. NC0007064
Brunswick County



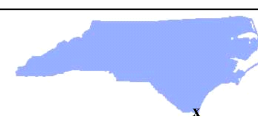
Brunswick Steam Electric Plant

Stormwater Outfalls 007, 008 and 009

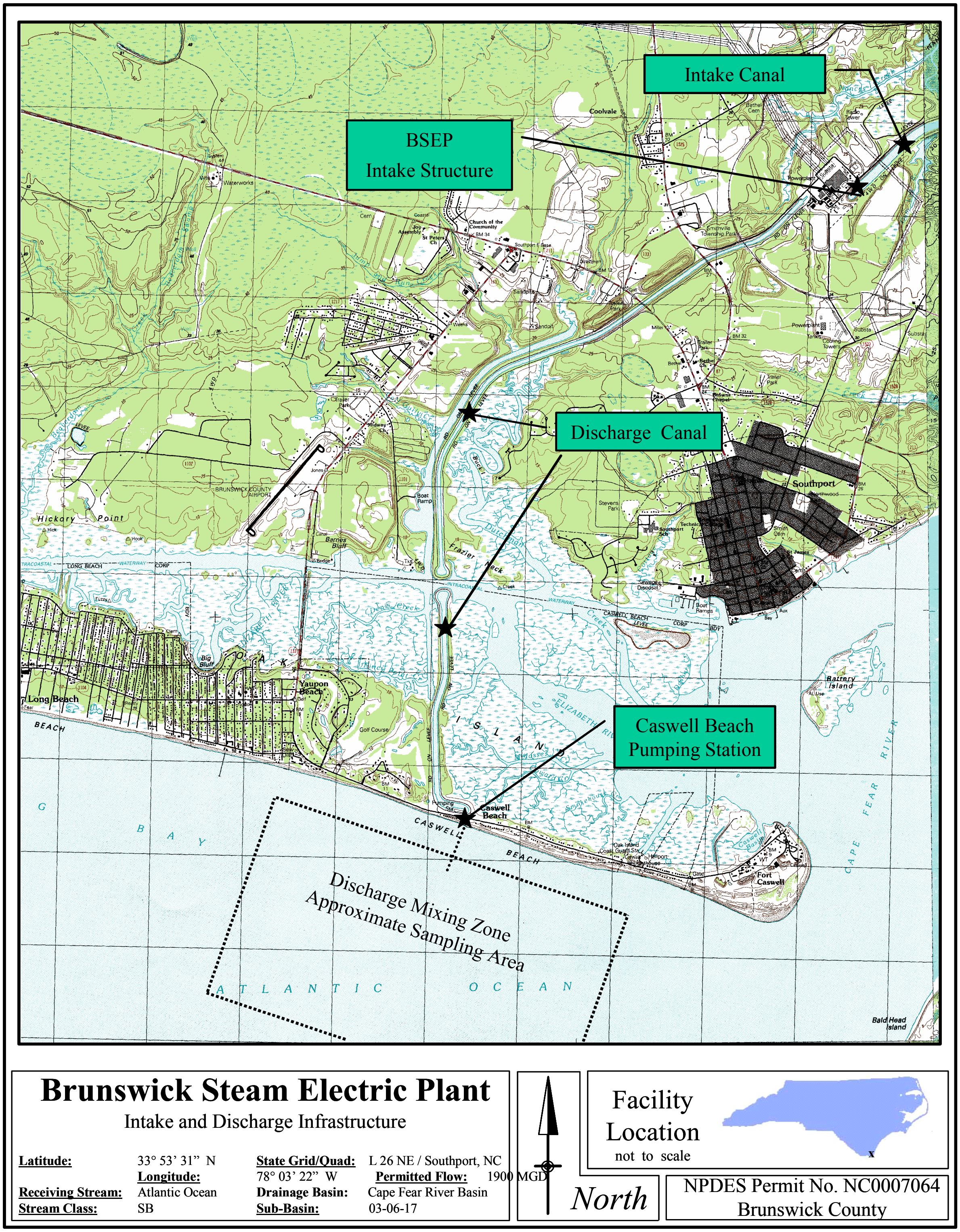
Latitude:	33° 53' 31" N	**State Grid/Quad:**	L 26 NE / Southport, NC
Longitude:	78° 03' 22" W	**Permitted Flow:**	1900 MGD
Receiving Stream:	Atlantic Ocean	**Drainage Basin:**	Cape Fear River Basin
Stream Class:	SB	**Sub-Basin:**	03-06-17

North

Facility Location
not to scale



NPDES Permit No. NC0007064
Brunswick County


Intake Canal
BSEP
Intake Structure
Discharge Canal
Caswell Beach
Pumping Station
Discharge Mixing Zone
Approximate Sampling Area
Brunswick Steam Electric Plant
Intake and Discharge Infrastructure
Latitude: 33° 53' 31" N
Longitude: 78° 03' 22" W
Receiving Stream: Atlantic Ocean
Stream Class: SB
State Grid/Quad: L 26 NE / Southport, NC
Permitted Flow: 1900 MGD
Drainage Basin: Cape Fear River Basin
Sub-Basin: 03-06-17
North
Facility
Location
not to scale
NPDES Permit No. NC0007064
Brunswick County

APPENDIX C
SPECIAL-STATUS SPECIES CORRESPONDENCE

Letter — Page

Edward T. O’Neil, Progress Energy, to Garland Pardue, USFWS (NC) C-2

Garland Pardue, USFWS, to Edward T. O'Neil, Progress Energy............................... C-7

Edward T. O'Neil, Progress Energy, to Robert Hoffman, NOAA-NMFS (FL) C-12

Edward T. O'Neil, Progress Energy, to Harry Legrand, NC Dept of Environment & Nat Resources (NCDENR)... C-17

Harry Legrand, NCDENR, to Edward T. O'Neil, Progress Energy............................. C-22

CP&L
A Progress Energy Company

MAY 1 2 2003

SERIAL: BSEP 03-0084

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

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
LICENSE RENEWAL - REQUEST FOR INFORMATION
LISTED SPECIES AND IMPORTANT HABITATS

Dear Mr. Pardue:

Progress Energy Carolinas, Inc. (PEC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for the Brunswick Steam Electric Plant (BSEP), which expire in 2016, for Unit 1 and 2014, for Unit 2. PEC intends to submit this application for license renewal in December 2004. 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 BSEP and associated transmission lines since 1975, when Unit 2 began commercial operation. Unit 1 began operating in 1976. BSEP is located in Brunswick County in southeastern North Carolina, near the mouth of the Cape Fear River. The plant is situated on approximately 1,200 acres of land. The facility includes the powerblock area and support facilities, the nuclear exclusion zone, a buffer zone, a three-mile long intake canal that is used to withdraw cooling water from the Cape Fear River, and a six-mile long discharge canal that conveys heated effluent to the Atlantic Ocean (i.e., see Figure 1).

PEC, previously known as Carolina Power & Light, Company built eight transmission lines to connect BSEP to the regional transmission system. All eight lines share the first 1.3 miles of corridor. At that point, the Whiteville, Delco East, Delco West, and Weatherspoon lines veer to the northwest, and divide again with the Whiteville line traveling parallel to and south of the Weatherspoon and Delco lines which share a

Brunswick Nuclear Plant
P.O. Box 10429
Southport, NC 28461

Mr. Garland Pardue
BSEP 03-0084 / Page 2

corridor to the Delco Substation and then the Weatherspoon lines continues to the Weatherspoon Substation (i.e., see Figure 2). The Whiteville line crosses several pocosins and the Green Swamp; which has been designated a National Natural Landmark by the Department of the Interior. It passes approximately two miles west of Lake Waccamaw, and approximately one mile west of Lake Wacamaw State Park. The Weatherspoon and Delco lines both cross the Little Green Swamp.

The Wallace, Jacksonville, Castle Hayne East, and Wilmington Corning lines travel north from the split near BSEP. Approximately 15 miles north of BSEP, the Castle Hayne line moves east and then north to the Castle Hayne Substation. The other lines continue north, and then split after they cross into Pender County, with one line proceeding north to the Wallace Substation and the other line moving northeast to Jacksonville. The Jacksonville line crosses the northwest portion of the Holly Shelter Game Land in the Holly Shelter Swamp. The Wallace line crosses the B. W. Wells Savannah, a 117-acre remnant of wetland savannah, in northwest Pender County. This tract supports 170 native plant species, several of which are rare. PEC has entered into a partnership with the N. C. Coastal Land Trust, the Conservation Trust for North Carolina, and the N. C. Wild Flower Preservation Society to preserve this unique property.

PEC has no plans to significantly alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously-disturbed areas. No expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. As a consequence, 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 June 15, 2003, providing any information you may have concerning listed species or ecologically-significant habitats that may occur on the 1,200-acre BSEP 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.

Mr. Garland Pardue
BSEP 03-0084 / Page 3

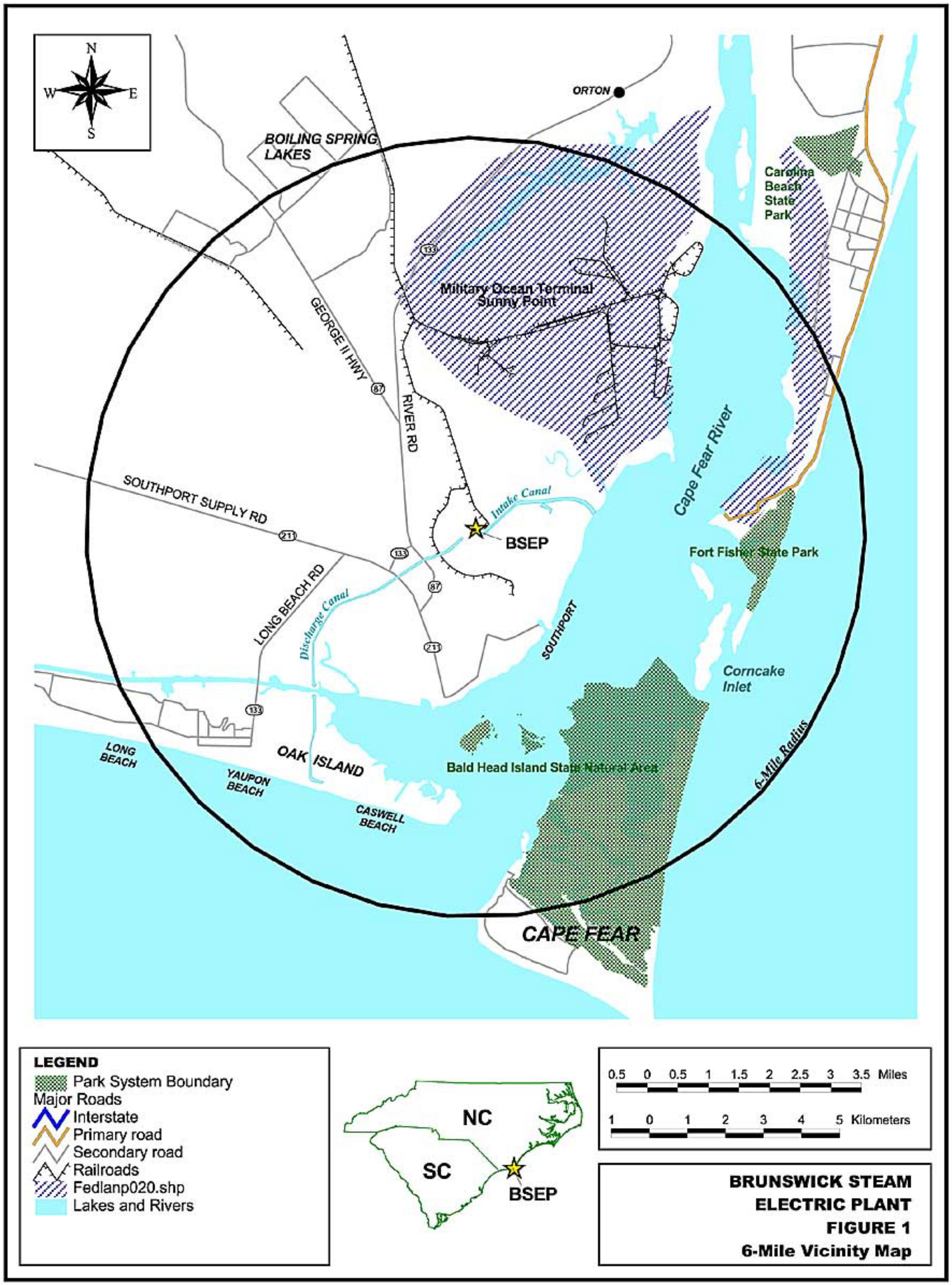
Please refer any questions regarding this submittal to Mr. Jan Kozyra, Lead Engineer - License Renewal, at (843) 857-1872.

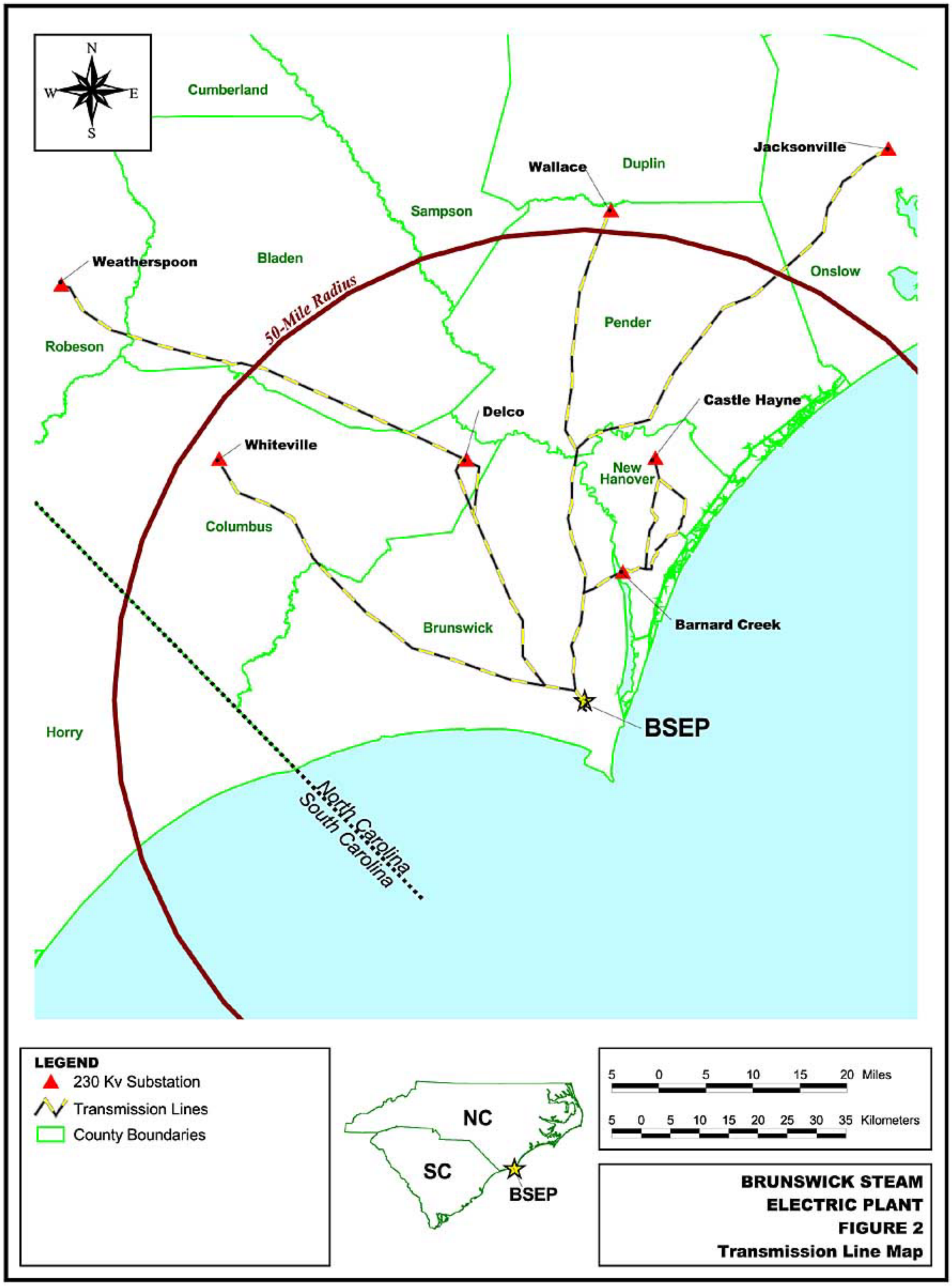
Sincerely,

Edward T. O'Neil
Manager - Support Services
Brunswick Steam Electric Plant

MAT/mat

Enclosures:
Figure 1 - Brunswick Steam Electric Plant 6-Mile Vicinity Map
Figure 2 - Brunswick Steam Electric Plant Transmission Line Map


N
W
E
S
ORTON
BOILING SPRING LAKES
Carolina Beach State Park
Military Ocean Terminal Sunny Point
GEORGE II HWY
RIVER RD
SOUTHPORT SUPPLY RD
Intake Canal
BSEP
Cape Fear River
Fort Fisher State Park
LONG BEACH RD
Discharge Canal
SOUTHPORT
Corncake Inlet
LONG BEACH
OAK ISLAND
YAUPON BEACH
CASWELL BEACH
Bald Head Island State Natural Area
6-Mile Radius
CAPE FEAR
LEGEND
Park System Boundary
Major Roads
Interstate
Primary road
Secondary road
Railroads
Fedlanp020.shp
Lakes and Rivers
NC
SC
BSEP
0.5 0 0.5 1 1.5 2 2.5 3 3.5 Miles
1 0 1 2 3 4 5 Kilometers
BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 1
6-Mile Vicinity Map



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2
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

July 15, 2003

Edward T. O'Neil
Carolina Power and Light
Brunswick Nuclear Plant
P.O. Box 10429
Southport, NC 28461

Dear Mr. O'Neil:

Thank you for your May 12, 2003 letter requesting information from the U.S. Fish and Wildlife Service (Service) concerning the proposed license renewal for the Brunswick Steam Electric Plant (Unit Numbers 1 and 2). The Brunswick Steam Electric Plant is located near Southport in Brunswick County, North Carolina. Transmission lines radiate from the plant in Southport to various points in Columbus, Robeson, Pender, New Hanover and Onslow Counties. Our comments are provided pursuant to, and in accordance with, provisions of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 et seq.) (Act).

The Service is aware of various populations of federally protected plant species that occur in transmission line rights-of-way in southeastern North Carolina. Specifically, populations of rough-leaved loosestrife (*Lysimachia asperulaefolia*), Cooley's meadowrue (*Thalictrum cooleyi*), and golden sedge (*Carex lutea*) are known to occur in various CP&L power line rights-of-way in the counties mentioned above and specifically in the Jacksonville transmission line. Currently, there is a Memorandum of Understanding (MOU) (dated March 19, 1993) between Carolina Power and Light and the North Carolina Natural Heritage Program that addresses the management of these sites in order to protect the rare species that occur in them. In this MOU, CP&L agreed to "preserve and protect the special elements of natural diversity and natural areas which best exemplify the state's natural heritage which occur on their power line rights-of-way" by mowing only during the non-growing season and avoiding impact to the soil and hydrologic components of the natural area. The MOU states that herbicides will only be used selectively to supplement mechanical maintenance when woody or invasive species threaten the rare species or natural communities. In addition, CP&L agreed to notify the Natural Heritage Program when an emergency or operation has occurred which impacts a site. CP&L also agreed to notify the Natural Heritage Program if the right-of-way is sold or transferred, if threats to the natural area are observed by CP&L staff, or if management changes are anticipated.

Based on the information provided in your letter and the existing MOU, the Service believes that as long as CP&L continues to be an active participant in this MOU, the renewal of the license for

the Brunswick Steam Electric Plant (Unit Numbers 1 and 2) 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. We remind you 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 about our comments on this project, please contact Mr. Dales Suiter at (919) 856-4520, extension 18, or via email at Dale_Suiter@fws.gov.

Sincerely,

Garland B. Pardue

Dr. Garland Pardue
Ecological Services Supervisor

enclosure: Memorandum of Understanding

cc: North Carolina Natural Heritage Program (Jame Amoroso)

Post-it® Fax Note 7671	Date 7-15-03 # of pages ▸ 3
To Dale Suiter	From Jame Amoroso
Co./Dept. US FWS	Co. NC NHP
Phone #	Phone # 715-8700
Fax # 919 856 4556	Fax #

:RSTANDING

between the

CAROLINA POWER AND LIGHT COMPANY

and the

N.C. DEPARTMENT OF ENVIRONMENT, HEALTH, & NATURAL RESOURCES

This agreement is made and entered into this 19th day of March, 1993, by and between the Carolina Power and Light Company (hereinafter referred to as CP&L) and the North Carolina Department of Environment, Health, and Natural Resources (hereinafter referred to as the Department).

Objectives:

WHEREAS CP&L, a public utility required to generate, transmit and distribute electric power, is strongly committed to the preservation of rare species and natural communities, and the hydrologic and disturbance regimes, such as flooding or fire, that maintain them; and

WHEREAS CP&L recognizes that:

1) the artificial disturbance, such as periodic mowing or hand-cutting, employed in powerline right-of-way maintenance can mimic natural disturbance regimes, such as flooding or fire, required by rare species and natural communities for survival,

2) certain rare species and natural communities are especially vulnerable to soil disturbance and to disruption of their hydrologic regime,

3) indiscriminate application of herbicides is harmful to most rare species and natural communities; and

WHEREAS the Department's Natural Heritage Program was created by the General Assembly of North Carolina to inventory and protect the special elements of natural diversity and natural areas which best exemplify the state's natural heritage; and

WHEREAS the protection strategies used by the Natural Heritage Program are threefold, as follows:

1) establishing a statewide system of registered natural areas and dedicated nature preserves,

2) promoting the awareness and involvement of the general public, private corporations, and agencies, in natural areas protection,

3) providing input to the private and public sector to assist them in land use planning that optimally has no impact on the special elements of natural diversity and natural areas which best exemplify the state's natural heritage; and

WHEREAS, under existing provisions of law, the Department is authorized to enter into Agreements with public utilities;

WHEREAS, both parties recognize that the successful management of rare, threatened and endangered species, sensitive or exemplary natural communities and other significant natural features on public utility powerlines depends on close cooperation between said public utility and the Department's Natural Heritage Program.

NOW THEREFORE, in consideration of the above premises and in the interest of the mutual advantage in attainment of common objectives, the parties hereto desire to cooperate and mutually agree as follows:

Statements of Work:

A. To the best of its knowledge and ability, CP&L agrees to:

1. Preserve and protect the special elements of natural diversity and natural areas which best exemplify the state's natural heritage which occur on their powerline rights of way. "Preserve and protect" can be defined as managing each site according to the Natural Heritage Program's recommendations which usually include mowing only during the non-growing season and avoiding impact to the soil and hydrologic components of the natural area. Herbicide use in the vicinity of a rare species or unique natural area will be carefully managed in consultation with the Natural Heritage Program. Selective and specific herbicide applications may be needed to supplement mechanical maintenance when woody or invasive species threaten the rare species or natural communities.

2. Notify the Natural Heritage Program when an emergency or operational situation has occurred which impacts a site.

3. Notify the Natural Heritage Program if the right of way is sold or transferred, if threats to the natural area are observed by CP&L staff, or if management changes are anticipated. Ideally, notification should be well in advance of any anticipated change, to allow time for negotiation or other protection planning.

B. To the best of its knowledge and ability, the Department agrees to:

1. Provide CP&L with location and management information for the special elements of natural diversity and natural areas which best exemplify the state's natural heritage which occur on CP&L rights of way.

2. Provide CP&L with continued management information and information on rare species and natural communities, through periodic consultation and survey forms.

3. Include the natural areas identified as occurring on CP&L rights of way and protected under this Memorandum of Understanding in the North Carolina Natural Heritage Program Registry of Natural Areas.

C. It is further mutually agreed between the parties that:

1. Nothing in thi.: agreement shall be construed as obligating either the Department or CP&L to expend funds specifically for fulfillment of the statements of work.

2. Nothing herein contained shall be construed as limiting or affecting in any way the delegated authority of the Department or of CP&L in any way.

Key Contacts:

CP&L:

Ms. Brenda Brickhouse, Transmission Forester
Carolina Power & Light Company
6C3 Center Plaza Building
P.O. Box 1551
Raleigh, NC 27602 919/546-6782

Natural Heritage Program:

Ms. Ann Prince, Protection Specialist
North Carolina Natural Heritage Program
Division of Parks and Recreation
P.O. Box 27687
Raleigh, NC 27611-7687 919/733-7701

Conditions of Agreement:

This Memorandum of Understanding shall become effective when signed by both agencies and shall continue in force until terminated by either agency.

This Memorandum of Understanding may be terminated thirty (30) days after written notification by either party, or for due cause at any time.

Nothing in this Memorandum of Understanding shall be construed to place a financial commitment upon either of the parties.

SIGNATURES

CAROLINA POWER AND LIGHT COMPANY

APPROVED:

LW Eury

Lynn W. Eury, Executive Vice President-Power Supply

DEPARTMENT OF ENVIRONMENT, HEALTH, AND NATURAL RESOURCES

APPROVED:

Jonathan B. Howes

Jonathan B. Howes, Secretary

CP&L
A Progress Energy Company

MAY 1 2 2003

SERIAL: BSEP 03-0086

Mr. Robert Hoffman
Fishery Biologist
Endangered Species Team
Southeast Regional Office
National Marine Fisheries Service
9721 Executive Center Drive North
St. Petersburg, FL 33702

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
LICENSE RENEWAL - REQUEST FOR INFORMATION
THREATENED OR ENDANGERED MARINE SPECIES

Dear Mr. Hoffman:

Progress Energy Carolinas, Inc. (PEC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for the Brunswick Steam Electric Plant (BSEP), which expire in 2016, for Unit 1 and 2014, for Unit 2. PEC intends to submit this application for license renewal in December 2004. 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 request an informal consultation with your office, at a later date, under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that need to be addressed or information required to expedite the NRC's consultation.

PEC has operated BSEP and associated transmission lines since 1975, when Unit 2 began commercial operation. Unit 1 began operating in 1976. BSEP is located in Brunswick County in southeastern North Carolina, near the mouth of the Cape Fear River (i.e., see Figure 1). The plant is situated on approximately 1,200 acres of land. PEC, previously known as Carolina Power & Light Company, built eight, 230 kV transmission lines to connect BSEP to the regional transmission system (i.e., see Figure 2).

Under full power operation, as much as 1.05 million gallons per minute (i.e., 2,335 cubic feet per second) of water is withdrawn from the Cape Fear River via a three-mile long intake canal for condenser cooling. After passing through the plant's condensers, the heated water travels through a six-mile long discharge canal to Caswell Beach before being pumped 2,000 feet offshore through a pair of 13-foot diameter underwater pipes that extend into the

Brunswick Nuclear Plant
P.O. Box 10429
Southport, NC 28461

Mr. Robert Hoffman
BSEP 03-0086 / Page 2

Atlantic Ocean along the ocean floor. Although some of the waste heat is radiated to the atmosphere from the surface of the discharge canal, the bulk of the heat is dissipated by mixing with cooler Atlantic Ocean water. Cooling water flow (i.e., withdrawal) rates and heat rejection rates, defined by water temperatures in the area of the ocean discharge, are limited by the provisions of National Pollutant Discharge Elimination System (NPDES) Permit Number NC0007064, issued on September 19, 2000, by the North Carolina Department of Environment and Natural Resources, Division of Water Quality.

One federally listed anadromous fish species and five federally listed sea turtle species are known to occur off the North Carolina coast. Once plentiful, the Cape Fear River population of shortnose sturgeons (*Acipenser brevirostrum*) has been reduced to perhaps 50 individuals. No shortnose sturgeons have been captured by PEC biologists in more than 25 years of monitoring fish populations in the area of BSEP.

Although five sea turtle species may be found in the Cape Fear area, only three (i.e., the loggerhead turtle, *Caretta caretta*; the green turtle, *Chelonias mydas*; and the Kemp's ridley turtle, *Lepidochelys kempi*) are observed in the vicinity of BSEP on a regular basis. These are also the only sea turtle species that have been taken at BSEP. The hawksbill turtle, *Eretmochelys imbricata*, is uncommon along the Atlantic coast, preferring coral reef areas of the Caribbean and Central America. The leatherback turtle, *Dermochelys coriacea*, is more pelagic in its habits than other sea turtles, and is rarely seen inshore in the Carolinas.

The National Marine Fisheries Service (NMFS) reviewed data on incidental takes of sea turtles at BSEP and the operation of the cooling water intake system and issued a final Biological Opinion, with an incidental take statement, in January 2000, that concluded:

> …operation of the water intake system of the Brunswick Steam Electric Plant…is not likely to jeopardize the continued existence of the loggerhead, leatherback, green, hawksbill, or Kemp's ridley sea turtles. No critical habitat has been designated for these species in the action area; therefore, none will be affected. This conclusion is based on the proposed action's {operation of the cooling water intake system} anticipated effects on each of these species being limited to the incidental take, through death or injury, on a small number of immature sea turtles per year over the next 20 years.

In accordance with the terms and conditions of the January 2000, Biological Opinion, PEC continues to: (1) conduct daily sea turtle patrols in the intake canal area, including the diversion structure and trash racks, over the April-August period, and maintain a logbook with observations, (2) inspect and maintain the diversion structure to ensure it is working as designed, (3) capture, photograph, treat (i.e., as appropriate), and relocate any turtles found in the canal in consultation with the North Carolina Sea Turtle Coordinator, (4) maintain detailed records on disposition of turtles found dead or alive, and (5) submit an annual report

Mr. Robert Hoffman
BSEP 03-0086 / Page 3

to NMFS with particulars on each sea turtle taking, including species, size, date, and disposition of each individual.

PEC is committed to the conservation of natural habitats and protected species, and expects that operation of the plant through the license renewal period (i.e., an additional 20 years) would not jeopardize the population of any listed marine species. PEC has no plans to significantly alter current operations over the license renewal period. No expansion of existing facilities is planned, and no additional disturbance is anticipated in support of license renewal, beyond some limited dredging that might be necessary in the area of the plant intake. PEC would obtain the necessary approvals and permits, if required, from the agencies that regulate these activities before dredging.

Please provide a letter detailing any concerns you may have about any listed species in the area or confirming PEC's conclusion that operation of BSEP over the license renewal term would not jeopardize the population of any threatened or endangered species, including candidate species and species proposed for listing, under the jurisdiction of the NMFS. PEC will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the BSEP license renewal application.

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

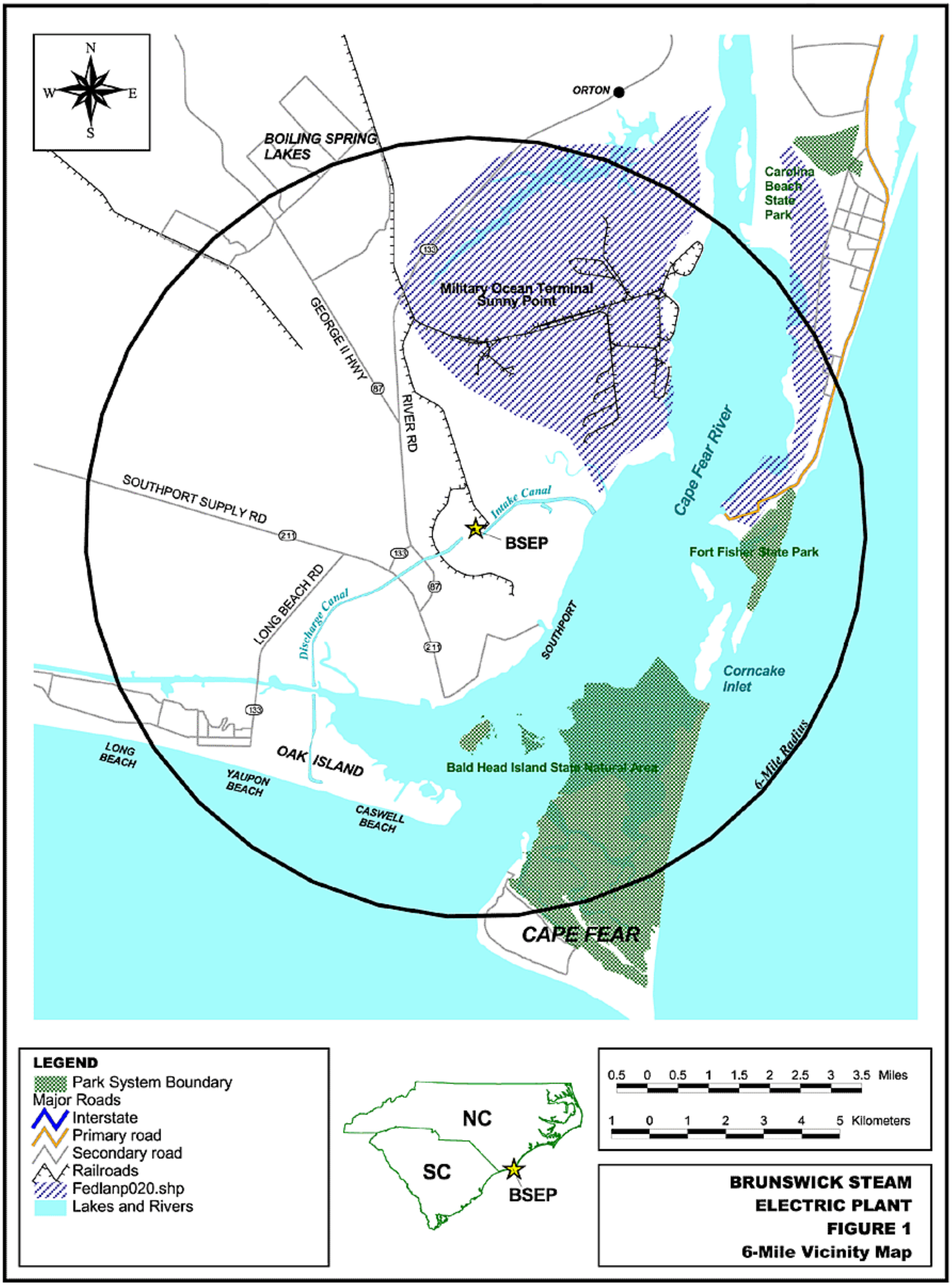
Sincerely,

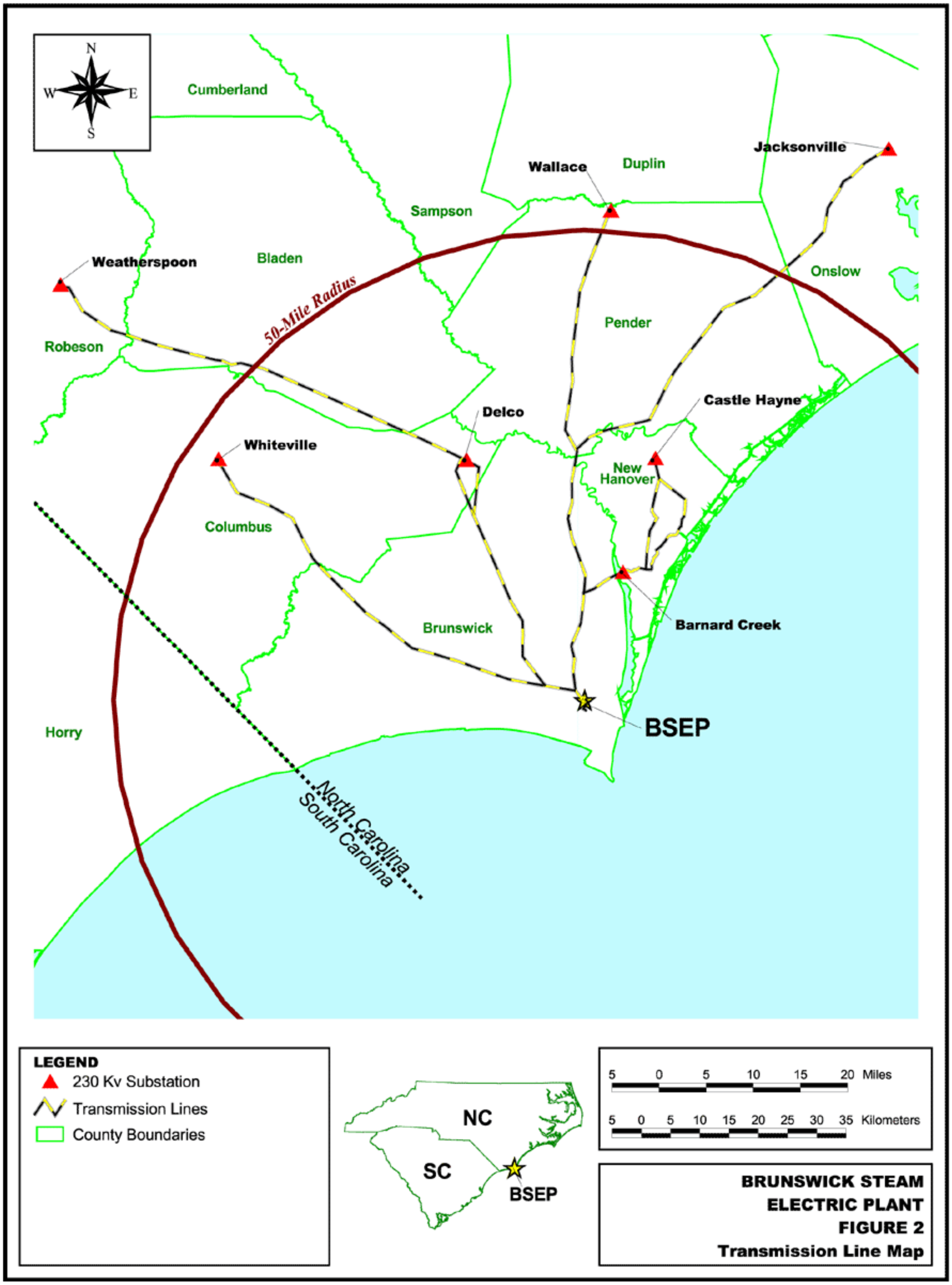
ET O'Neil

Edward T. O'Neil
Manager - Support Services
Brunswick Steam Electric Plant

MAT/mat

Enclosures:
Figure 1 - Brunswick Steam Electric Plant 6-Mile Vicinity Map
Figure 2 - Brunswick Steam Electric Plant Transmission Line Map


N
S
E
W
ORTON
BOILING SPRING LAKES
Carolina Beach State Park
Military Ocean Terminal Sunny Point
GEORGE II HWY
RIVER RD
SOUTHPORT SUPPLY RD
Intake Canal
BSEP
Cape Fear River
Fort Fisher State Park
LONG BEACH RD
Discharge Canal
SOUTHPORT
Corncake Inlet
LONG BEACH
YAUPON BEACH
OAK ISLAND
CASWELL BEACH
Bald Head Island State Natural Area
6-Mile Radius
CAPE FEAR
LEGEND
Park System Boundary
Major Roads
Interstate
Primary road
Secondary road
Railroads
Fedlanp020.shp
Lakes and Rivers
NC
SC
BSEP
0.5 0 0.5 1 1.5 2 2.5 3 3.5 Miles
1 0 1 2 3 4 5 Kilometers
BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 1
6-Mile Vicinity Map



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2
Transmission Line Map

CP&L
A Progress Energy Company

MAY 1 2 2003

SERIAL: BSEP 03-0085

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

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
LICENSE RENEWAL - REQUEST FOR INFORMATION
LISTED SPECIES AND IMPORTANT HABITATS

Dear Mr. LeGrand:

Progress Energy Carolinas, Inc. (PEC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for the Brunswick Steam Electric Plant (BSEP), which expire in 2016, for Unit 1 and 2014, for Unit 2. PEC intends to submit this application for license renewal in December 2004. 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 BSEP and associated transmission lines since 1975, when Unit 2 began commercial operation. Unit 1 began operating in 1976. BSEP is located in Brunswick County in southeastern North Carolina, near the mouth of the Cape Fear River. The plant is situated on approximately 1,200 acres of land. The facility includes the powerblock area and support facilities, the nuclear exclusion zone, a buffer zone, a three-mile long intake canal that is used to withdraw cooling water from the Cape Fear River, and a six-mile long discharge canal that conveys heated effluent to the Atlantic Ocean (i.e., see Figure 1).

PEC, previously known as Carolina Power & Light Company, built eight transmission lines to connect BSEP to the regional transmission system. All eight lines share the first 1.3 miles of corridor. At that point, the Whiteville, Delco East, Delco West, and

Brunswick Nuclear Plant
P.O. Box 10429
Southport, NC 28461

Mr. Harry LeGrand
BSEP 03-0085 / Page 2

Weatherspoon lines veer to the northwest, and divide again with the Whiteville line traveling parallel to and south of the Weatherspoon and Delco lines which share a corridor to the Delco Substation and then the Weatherspoon lines continues to the Weatherspoon Substation (i.e., see Figure 2). The Whiteville line crosses several pocosins and the Green Swamp; which has been designated a National Natural Landmark by the Department of the Interior. It passes approximately two miles west of Lake Waccamaw, and approximately one mile west of Lake Wacamaw State Park. The Weatherspoon and Delco lines both cross the Little Green Swamp.

The Wallace, Jacksonville, Castle Hayne East, and Wilmington Corning lines travel north from the split near BSEP. Approximately 15 miles north of BSEP, the Castle Hayne line moves east and then north to the Castle Hayne Substation. The other lines continue north, and then split after they cross into Pender County, with one line proceeding north to the Wallace Substation and the other line moving northeast to Jacksonville. The Jacksonville line crosses the northwest portion of the Holly Shelter Game Land in the Holly Shelter Swamp. The Wallace line crosses the B. W. Wells Savannah, a 117-acre remnant of wetland savannah, in northwest Pender County. This tract supports 170 native plant species, several of which are rare. PEC has entered into a partnership with the N. C. Coastal Land Trust, the Conservation Trust for North Carolina, and the N. C. Wild Flower Preservation Society to preserve this unique property.

PEC has no plans to significantly alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously-disturbed areas. No expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. As a consequence, 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 June 15, 2003, providing any information you may have concerning listed species or ecologically-significant habitats that may occur on the 1,200-acre BSEP 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.

Mr. Harry LeGrand
BSEP 03-0085 / Page 3

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

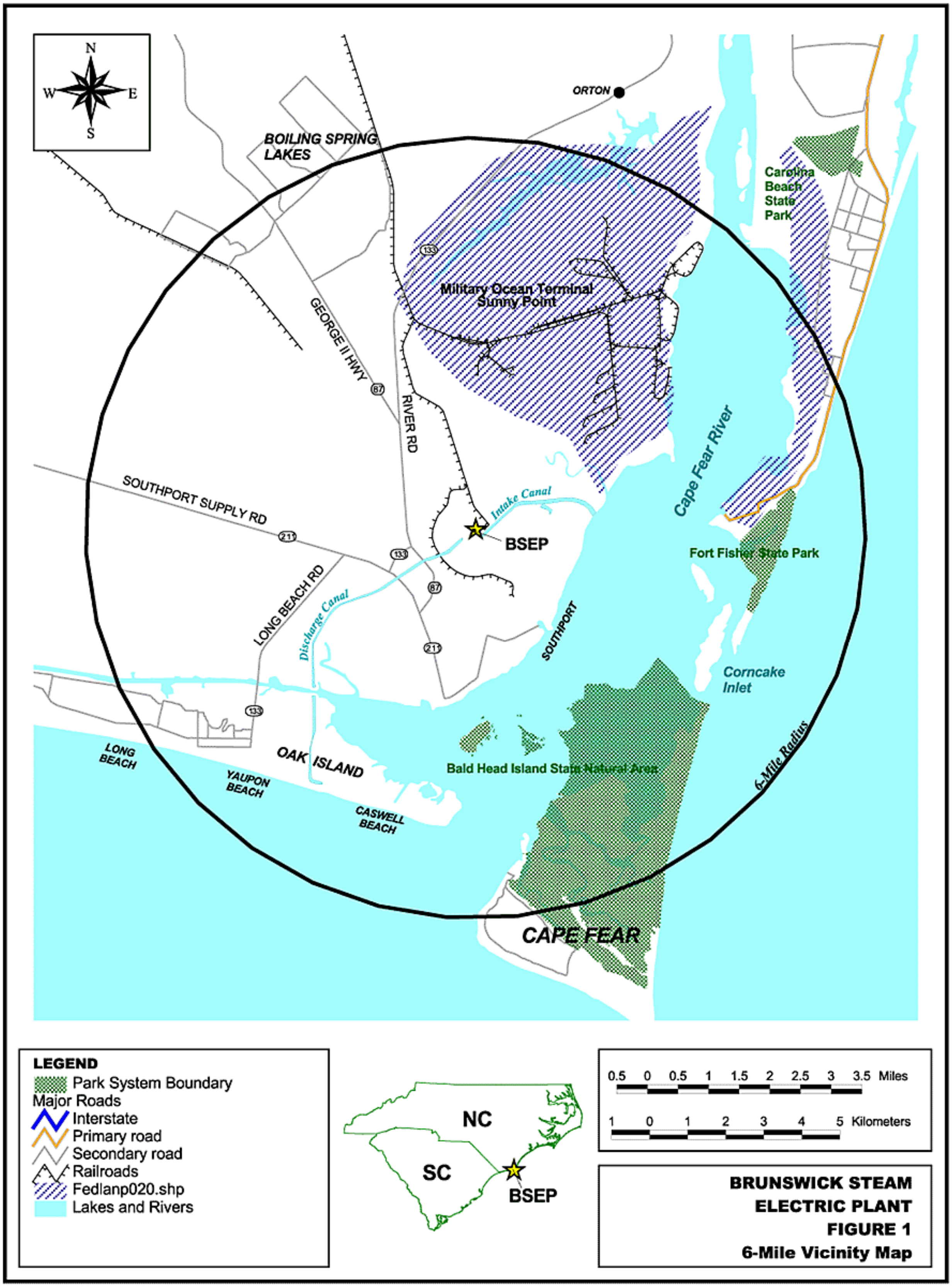
Sincerely,

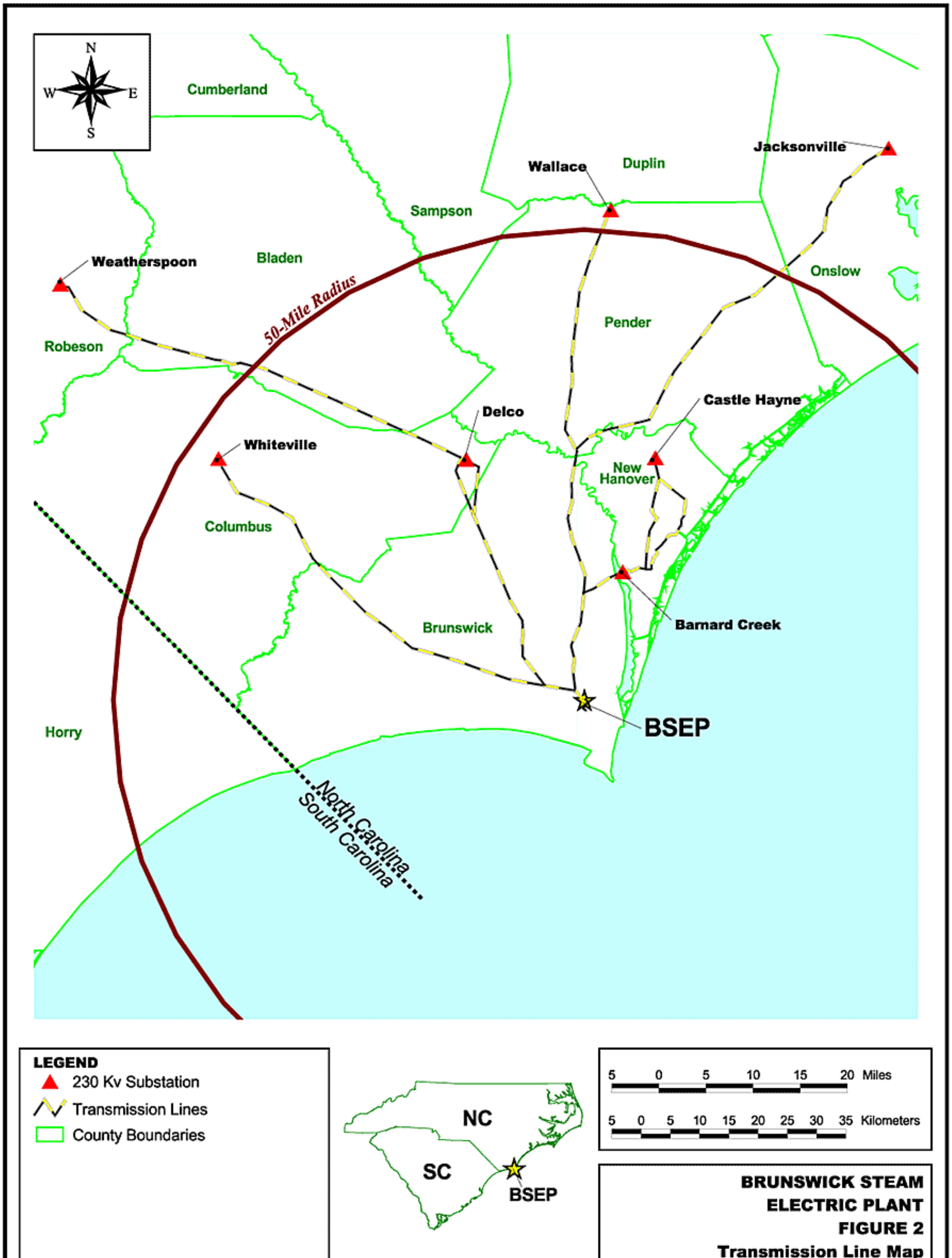
Edward T. O'Neil
Manager - Support Services
Brunswick Steam Electric Plant

MAT/mat

Enclosures:

Figure 1 - Brunswick Steam Electric Plant 6-Mile Vicinity Map
Figure 2 - Brunswick Steam Electric Plant Transmission Line Map


N
W
E
S
ORTON
BOILING SPRING LAKES
Carolina Beach State Park
Military Ocean Terminal Sunny Point
GEORGE II HWY
RIVER RD
SOUTHPORT SUPPLY RD
Intake Canal
BSEP
Cape Fear River
Fort Fisher State Park
LONG BEACH RD
Discharge Canal
SOUTHPORT
Corncake Inlet
LONG BEACH
YAUPON BEACH
OAK ISLAND
CASWELL BEACH
Bald Head Island State Natural Area
6-Mile Radius
CAPE FEAR
LEGEND
Park System Boundary
Major Roads
Interstate
Primary road
Secondary road
Railroads
Fedlanp020.shp
Lakes and Rivers
NC
SC
BSEP
0.5 0 0.5 1 1.5 2 2.5 3 3.5 Miles
1 0 1 2 3 4 5 Kilometers
BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 1
6-Mile Vicinity Map



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2
Transmission Line Map

NCDENR

North Carolina Department of Environment and Natural Resources
Division of Parks and Recreation

Michael F. Easley, Governor   William G. Ross, Jr., Secretary   Philip K. McKnelly, Director

May 21, 2003

Mr. Edward T. O'Neil
Progress Energy Carolinas, Inc.
P.O. Box 10429
Southport, NC 28461

Subject: License Renewal for the Brunswick Steam Electric Plant; Southport, Brunswick County

Dear Mr. O'Neil:

The Natural Heritage Program has only one record of rare species on the Brunswick Plant site at Southport. The Carolina diamondback terrapin (*Malaclemys terrapin centrata*), a Federal Species of Concern, has been reported from the canal near the plant. This species is typically found along estuarine shores, however.

Although our maps do not show records of other natural heritage elements in the electric plant project area, it does not necessarily mean that they are not present. It may simply mean that the area has not been surveyed. The use of Natural Heritage Program data should not be substituted for actual field surveys, particularly if the project area contains suitable habitat for rare species, significant natural communities, or priority natural areas.

On the other hand, our Program has many dozens of rare species locations, mostly plants, within the powerline corridors in the overall project area, which extends in a 50-mile radius from the electric plant. Getting that material to Progress Energy is beyond the capabilities of our Program. The State's Center for Geographic Information and Analysis is best suited for such a large-area information request, and CGIA <www.cgia.state.nc.us> has the Natural Heritage data layer on rare species locations. They also have a data layer on protected or other Natural Heritage sites.

Your letter mentions several natural areas along PEC powerline corridors in the study area. It is also worth mentioning that in summer 2002, a biologist for a consulting firm, perhaps hired by PEC, found several new populations of the Federally Endangered golden sedge (*Carex lutea*) and rough-leaf loosestrife (*Lysimachia asperulifolia*) and numerous new populations of the Federal Species of Concern Venus flytrap (*Dionaea muscipula*) in the powerline on lands owned by The Nature Conservancy, north and east of Holly Shelter Game Land. Some of these lands are being inspected for potential acquisition by the Division of Parks and Recreation for a future state park

1615 Mail Service Center, Raleigh, North Carolina 27699-1615
Phone: 919-733-4181 \ Fax: 919-715-3085 \ Internet: www.ncsparks.net

unit. Thus, it is important the PEC continue its level and type of powerline maintenance, such as mowing/bush-hogging during the non-growing season on a roughly 3-year cycle, and avoid usage of herbicides or other chemicals to kill or retard vegetation in such sensitive biological areas.

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 919-715-8687 if you have questions or need further information.

Sincerely,

Harry E. LeGrand, Jr.

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

HEL/hel

APPENDIX D
STATE HISTORIC PRESERVATION OFFICER CORRESPONDENCE

Letter | Page

Edward T. O'Neil, Progress Energy Carolinas, Inc., to Dr. Jeffrey Crow, SHPO (NC) D-2

CP&L
A Progress Energy Company

MAY 1 2 2003

SERIAL: BSEP 03-0083

Dr. Jeffrey Crow
Deputy Secretary of Archives and History and
State Historic Preservation Officer
North Carolina Department of Cultural Resources
4610 Mail Service Center
Raleigh NC 27699-4610

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
LICENSE RENEWAL - REQUEST FOR INFORMATION
HISTORIC AND ARCHAEOLOGICAL RESOURCES

Dear Dr. Crow:

Progress Energy Carolinas, Inc. (PEC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for the Brunswick Steam Electric Plant (BSEP), which expire in 2016, for Unit 1 and 2014, for Unit 2. PEC intends to submit this application for license renewal in December 2004. 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 (16 USC 470), and Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

PEC has operated BSEP and associated transmission lines since 1975, when Unit 2 began commercial operation. Unit 1 began operating in 1976. BSEP is located in Brunswick County in southeastern North Carolina, near the mouth of the Cape Fear River. The plant is situated on approximately 1,200 acres of land. The facility includes the powerblock area and support facilities, the nuclear exclusion zone, a buffer zone, a three-mile long intake canal that is used to withdraw cooling water from the Cape Fear River, and a six-mile long discharge canal that conveys heated effluent to the Atlantic Ocean (i.e., see Figure 1).

PEC, previously known as Carolina Power & Light Company built eight transmission lines to connect BSEP to the regional transmission system. All eight lines share the first 1.3 miles of corridor. At that point, the Whiteville, Delco East, Delco West, and Weatherspoon lines veer to the northwest, and divide again with the Whiteville line traveling parallel to and south of the Weatherspoon and Delco lines which share a

Brunswick Nuclear Plant
P.O. Box 10429
Southport, NC 28461

Dr. Jeffrey Crow
BSEP 03-0083 / Page 2

corridor to the Delco Substation and then the Weatherspoon lines continues to the Weatherspoon Substation. The Wallace, Jacksonville, Castle Hayne East and Wilmington Corning lines travel northeast from the split near BSEP (i.e., see Figure 2). Approximately 15 miles north of BSEP, the Castle Hayne line moves east and then north to the Castle Hayne Substation. The other lines continue north, and then split after they cross into Pender County, with one line proceeding north to the Wallace Substation and the other line moving northeast to Jacksonville.

The Final Environmental Statement (FES) for the construction and operation of BSEP Units 1 and 2, prepared by the U.S. Atomic Energy Commission (AEC) in 1974, listed seven properties on the National Historic Register within the vicinity of BSEP. After evaluating the project, the AEC concluded that the plant will not impose unacceptable impact upon National Register properties.

Using the National Register Information System (NRIS) online database, PEC compiled a list of sites on the National Register of Historic Places within a six-mile radius of the BSEP property. As of December 2002, the Register listed 12 locations in Brunswick County and 26 locations in New Hanover County, North Carolina. Of these 38 locations, 14 fall within a six-mile radius of BSEP. This information will be provided to the NRC to aid in the evaluation of the license application.

PEC does not expect BSEP operation, through the license renewal term (i.e., an additional 20 years), to adversely affect cultural or historical resources in the area because PEC has no plans to significantly alter current operations over the license renewal period. No expansion of existing facilities is planned, and no major structural modifications have been identified for the purpose of supporting license renewal. No land-disturbing activities are anticipated beyond those required for routine maintenance and repairs.

PEC would appreciate a response to this letter, by June 15, 2003, detailing any concerns regarding historic or archaeological properties in the area of BSEP or confirming PEC's conclusion that operation of BSEP, 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.

Dr. Jeffrey Crow
BSEP 03-0083 / Page 3

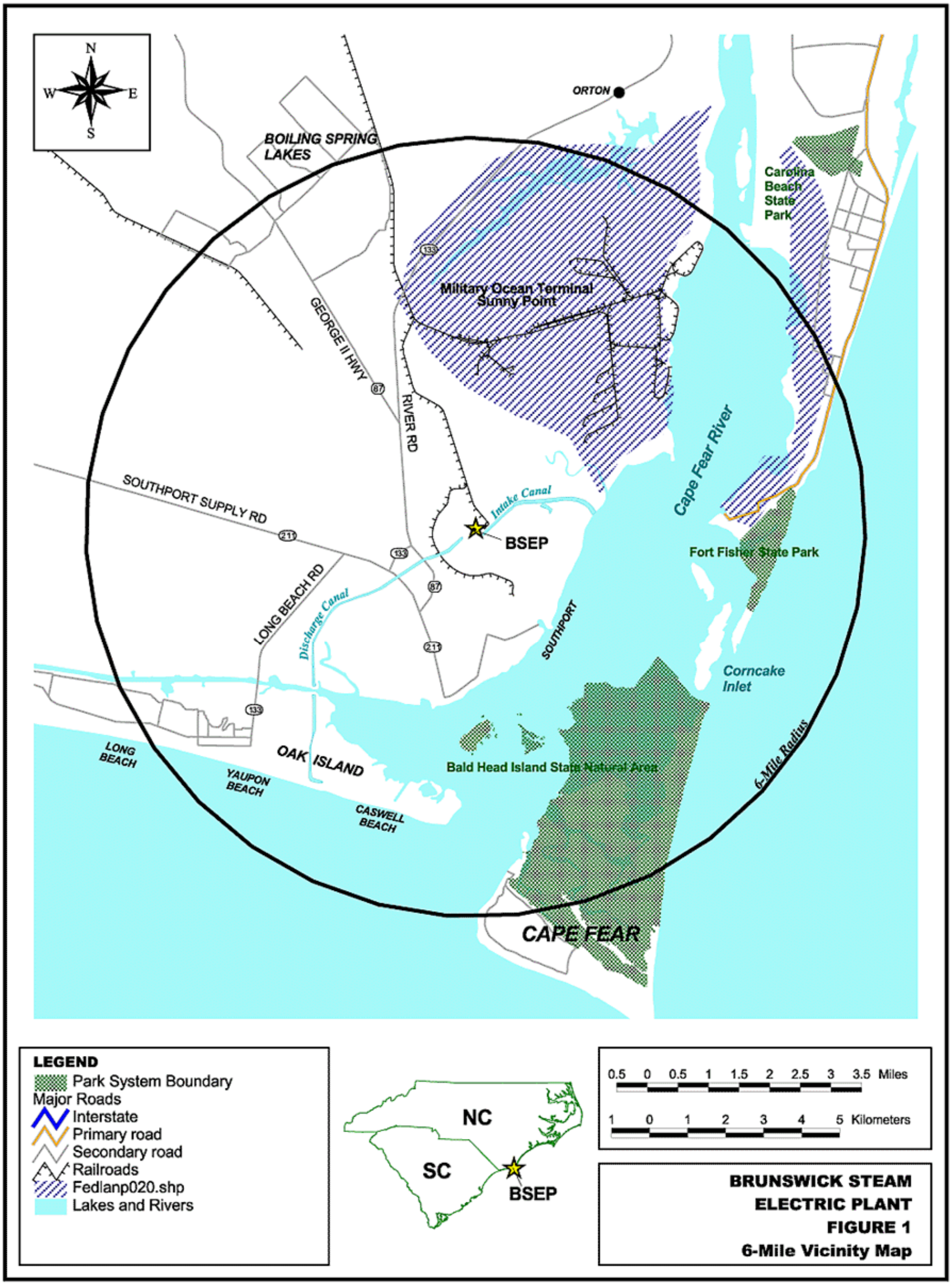
Please refer any questions regarding this submittal to Mr. Jan Kozyra, Lead Engineer - License Renewal, at (843) 857-1872.

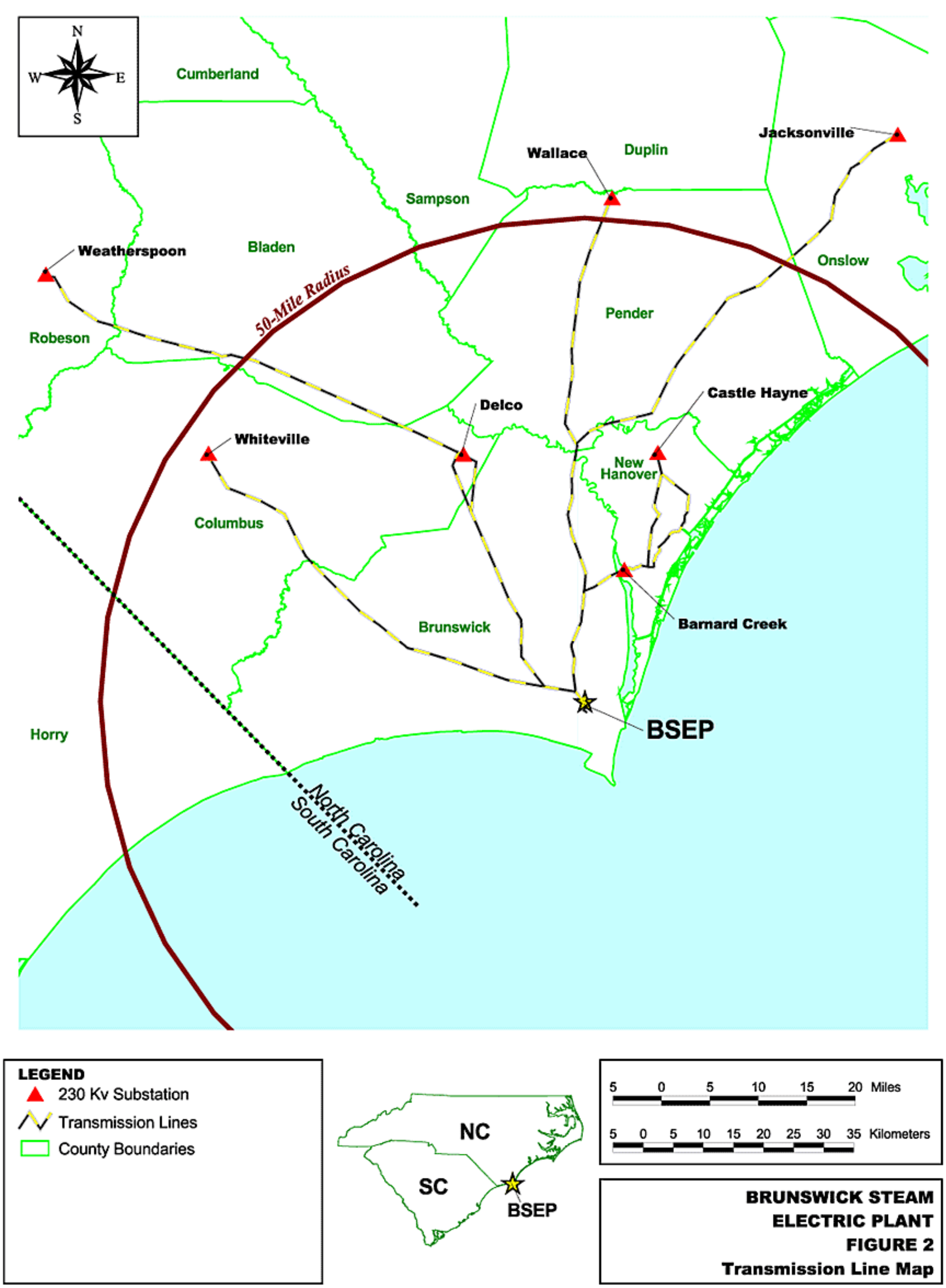
Sincerely,

Edward T. O'Neil
Manager - Support Services
Brunswick Steam Electric Plant

MAT/mat

Enclosures:
Figure 1 - Brunswick Steam Electric Plant 6-Mile Vicinity Map
Figure 2 - Brunswick Steam Electric Plant Transmission Line Map


N
W
E
S
ORTON
BOILING SPRING LAKES
Carolina Beach State Park
Military Ocean Terminal Sunny Point
GEORGE II HWY
RIVER RD
SOUTHPORT SUPPLY RD
Intake Canal
BSEP
Cape Fear River
Fort Fisher State Park
LONG BEACH RD
Discharge Canal
SOUTHPORT
Corncake Inlet
LONG BEACH
OAK ISLAND
YAUPON BEACH
CASWELL BEACH
Bald Head Island State Natural Area
6-Mile Radius
CAPE FEAR
LEGEND
Park System Boundary
Major Roads
Interstate
Primary road
Secondary road
Railroads
Fedlanp020.shp
Lakes and Rivers
NC
SC
BSEP
0.5 0 0.5 1 1.5 2 2.5 3 3.5 Miles
1 0 1 2 3 4 5 Kilometers
BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 1
6-Mile Vicinity Map



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2
Transmission Line Map

APPENDIX E
COASTAL ZONE CONSISTENCY CERTIFICATION

FEDERAL CONSISTENCY CERTIFICATION FOR FEDERAL PERMIT AND LICENSE APPLICANTS[1]

This is the Progress Energy certification to the U. S. Nuclear Regulatory Commission (NRC) that renewal of the Brunswick Steam Electric Plant Unit 1 and Unit 2 (BSEP) operating licenses would be consistent with enforceable policies of the federally approved state coastal zone management program. The certification describes background requirements, the proposed action (i.e., license renewal), anticipated environmental impacts, North Carolina enforceable coastal resource protection policies and BSEP's compliance status, and summary findings.

CONSISTENCY CERTIFICATION

Progress Energy certifies to the NRC that renewal of the BSEP operating licenses would be consistent with the federally approved North Carolina coastal management program. Progress Energy expects BSEP operations during the license renewal term to be a continuation of current operations as described below, with no station structural or operational modifications related to license renewal that would change effects on North Carolina's coastal zone.

NECESSARY DATA AND INFORMATION

Statutory Background

The federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on an applicant for a federal license to conduct an activity that could affect a state's coastal zone. The Act requires an applicant to certify to the licensing agency that the proposed action would be consistent with the state's federally approved coastal zone management program The Act also requires the applicant to provide to the state a copy of the certification statement and requires the state, at the earliest practicable time, to notify the federal agency and the applicant whether the state concurs with, or objects to, the consistency certification. See 16 USC 1456(c)(3)(A).

The National Oceanic and Atmospheric Administration (NOAA) has promulgated implementing regulations that indicate that the certification requirement is applicable to renewal of federal licenses for activities not previously reviewed by the state [15 CFR 930.51(b)(1)]. The Administration approved the North Carolina coastal management program September 1978 (Ref. 2). In North Carolina, the approved program is the Coastal Area Management Act, North Carolina General Statutes (NCGS) 113-100, with regulations at 15A North Carolina Administrative Code (NCAC) 7. NRC licensing of BSEP Unit 2, in 1974, and BSEP Unit 1 in 1976, pre-dated state program approval.

Proposed Action

NRC operating licenses for BSEP will expire in 2014 for Unit 2 and in 2016 for Unit 1. NRC regulations provide for license renewal, and Progress Energy is applying for renewal of the Unit 2 license to 2034 and the Unit 1 license to 2036.

BSEP is an electric generating plant located within the North Carolina coastal zone, in Brunswick County, near the mouth of the Cape Fear River. The plant withdraws water from the Cape Fear River via a 3-mile long intake canal for non-contact cooling, and returns the heated discharge to the Atlantic Ocean via a 6-mile long discharge canal. Approximately 60 percent of the area within a 50-mile radius of BSEP is the water of the Atlantic Ocean. Figures E-1 and E-2 are BSEP 50- and 6-mile vicinity maps, respectively.

[1] This certification is patterned after the example certification included as Appendix E of the NRC Office of Nuclear Reactor Regulation's "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues" (LIC-203, 6-21-01).

BSEP Units 1 and 2 are boiling water reactors with an expected total output of 5,846 MW thermal and an expected electric output of 1,909 MW electric after completion of an NRC-approved Extended Power Uprate in 2005 (67 FR 39445; June 7, 2002). Each unit has a separate intake structure with four circulating water pumps per intake structure. The eight pumps provide a continuous supply (maximum of 1.25 million gallons per minute [gpm]) of condenser cooling water. After moving through the condensers (and service water systems) water is discharged into a 6-mile discharge canal to Caswell Beach where the heated water enters two 13-foot diameter underwater pipes that move it 2,000 feet offshore where it is ultimately discharged at the bottom of the ocean.

The BSEP workforce consists of approximately 760 Progress Energy employees and 300 long-term contract employees. Approximately 90 percent reside in Brunswick or New Hanover counties. The BSEP reactors are on a 24-month refueling cycle. During refueling outages, site employment increases by approximately 1,000 workers for temporary (approximately 30 days) duty. Progress Energy has no plans to add additional employees due to license renewal.

NRC and Progress Energy have identified no refurbishment activities necessary to allow operation for an additional 20 years, and have identified no significant environmental impacts from programs and activities for managing the effects of aging. As such, renewal would result in a continuation of environmental impacts currently regulated by the state. Table E-1 lists state and federal licenses, permits, and other environmental authorizations for current BSEP operations and Table E-2 identifies compliance activities associated specifically with NRC license renewal.

Eight transmission lines were built to connect BSEP to the regional electric grid. These lines are co-located in common corridors to the extent practical with all eight lines in a single corridor for the first 1.3 miles. In all, approximately 220 miles of transmission corridor are associated with BSEP; and approximately 140 miles traverse the coastal counties of Brunswick, New Hanover, Pender and Onslow (Figure E-3). The proposed action, renewing the license of BSEP for an additional 20 years, would not require additional transmission lines, nor is Progress Energy anticipating that it would change any corridor maintenance practices.

Environmental Impacts

NRC has prepared a generic environmental impact statement (GEIS; Ref. 3) on impacts that nuclear power plant operations could have on the environment and has codified its findings (10 CFR 51, Subpart A, Appendix B, Table B-1). The regulation identified 92 potential environmental issues, 69 of which the NRC identified as having small impacts and termed “Category 1 issues.” NRC defines “small” as:

> Small – For the issue, environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purpose of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission’s regulations are considered small as the term is used in this table (10 CFR 51, Subpart A, Appendix B, Table B-1)

The NRC regulation and the GEIS discuss the following types of Category 1 environmental issues:

- Surface water quality, hydrology, and use
- Aquatic ecology
- Groundwater use and quality
- Terrestrial resources
- Air quality

- Land use
- Human health
- Postulated accidents
- Socioeconomics
- Uranium fuel cycle and waste management
- Decommissioning

In its decision-making for plant-specific license renewal applications, absent new and significant information to the contrary, NRC relies on its codified findings, as amplified by supporting information in the GEIS, for assessment of environmental impacts from Category 1 issues [10 CFR 51.9(c)(4)]. For plants such as BSEP that are located in coastal areas, many of these issues involve impacts to the coastal zone. Progress Energy has adopted by reference the NRC findings and GEIS analyses for all 58[2] applicable Category 1 issues.

The NRC regulation identified 21 issues as "Category 2," for which license renewal applicants must submit additional site-specific information.[3] Of these, 11 apply to BSEP[4], and like the Category 1 issues, could involve impacts to the coastal zone. The applicable issues and Progress Energy's impact conclusions are listed below.

- <u>Entrainment of fish and shellfish in early life stages</u> – This issue addresses mortality of organisms small enough to pass through the plant's circulating cooling water system. Progress Energy has monitored the fishery in the Cape Fear Estuary since 1968 (since 1974 as a condition of the NPDES permit) to identify impacts of plant operations, and has implemented several design and operational changes to ensure that best available technology is in place to minimize entrainment. Operational changes involve seasonal reductions in water flow. Design changes include installing fine-mesh screens on two and a half of the four traveling screens of each unit. Progress Energy concludes that impacts of entrainment during current operations are small and it has no plans that would change this conclusion for the license renewal term.
- <u>Impingement of fish and shellfish</u> – This issue addresses mortality of organisms large enough to be caught by intake screens before passing through the plant's circulating cooling water system. The monitoring program and permit discussed above also address impingement. Since 1982, a permanent fish diversion structure has been maintained at the mouth of the intake canal and, since 1983, a fish return system has been maintained at the intake screens. These design modifications have reduced the number of large fish impinged and impingement mortality. Progress Energy concludes that impacts of impingement during current operations are small and it has no plans that would change this conclusion for the license renewal term.

---

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

[3] 10 CFR 51, Subpart A, Appendix B, Table B-1 also identifies 2 issues as "NA" for which NRC could not come to a conclusion regarding categorization. Progress Energy believes that these issues, chronic effects of electromagnetic fields and environmental justice, do not affect the "coastal zone" as that phrase is defined by the Coastal Zone Management Act [16 USC 1453(1)].

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

- Heat shock – This issue addresses mortality of aquatic organisms by exposure to heated plant effluent. Cooling water flow rates and heat rejection rates are limited by provisions of NPDES permit number NC0007064.

- Threatened or endangered species -- This issue addresses effects that BSEP operations could have on species that are listed under federal law as threatened or endangered. In analyzing this issue, Progress Energy has also considered species that are protected under North Carolina law (Table E-3).

  Three federally-listed sea turtle species (loggerhead [*Caretta caretta*], green [*Chelonia mydas*], and Kemp's Ridley [*Lepidochelys kempi*]) could potentially be affected by BSEP operations. In 1998, in compliance with the Endangered Species Act, the U.S. Nuclear Regulatory Commission initiated a formal Section 7 consultation with the National Marine Fisheries Service regarding the effect of BSEP operations on the sea turtles. The NMFS reviewed the data on the incidental take of sea turtles at BSEP and the operation of the cooling water intake system and, in January 2000, issued a final Biological Opinion (with an incidental take statement) that concluded that "operation of the water intake system of the Brunswick Steam Electric Plant…is not likely to jeopardize the continued existence of the loggerhead, leatherback, green, hawksbill, or Kemp's ridley sea turtles. No critical habitat has been designated for these species in the action area; therefore, none will be affected. This conclusion is based on the proposed action's (operation of the cooling water intake system) anticipated effects on each of these species being limited to incidental take, through death or injury, of a small number of immature sea turtles per year over the next 20 years" (Ref. 4). No hawksbill or leatherback turtles have ever been observed in the vicinity of BSEP.

  Progress Energy has installed and maintains blocker panels in the diversion structure to curtail the entrance of sea turtles and patrols the intake canal daily to find and return to the ocean any turtles that do get past the diversion structure. Progress Energy has a permit from North Carolina Wildlife Resources Commission to capture, tag, and relocate these turtles to the open ocean.

  Four federally-listed terrestrial species could potentially be affected by BSEP operations: the red-cockaded woodpecker *(Picoides borealis*), Cooley's meadowrue (*Thalictrum cooleyi*), rough-leaved loosestrife (*Lysimachia asperulaefolia*), and golden sedge (*Carex lutea*). Red-cockaded woodpecker nesting habitat is not found on the BSEP site; however, birds may forage in the area. Cooley's meadowrue, rough-leaved loosestrife, and golden sedge populations are known on the transmission line corridors. Progress Energy has a Memorandum of Understanding with the North Carolina Department of Environment and Natural Resources to protect endangered, threatened or special concern species along the rights-of-way. The company also maintains best management practices for management of rare plants on Progress Energy rights-of-way (Ref. 5).

  Progress Energy correspondence with cognizant federal and state agencies has identified no impacts of concern. Progress Energy concludes that BSEP impacts to these protected species are small during current operations and has no plans that would change this conclusion for the license renewal term.

- Electromagnetic fields, acute effects (electric shock) – This issue addresses the potential for shock from induced currents, similar to static electricity effects, in the vicinity of transmission lines. Because this human-health issue does not directly or indirectly affect natural resources of concern within the Coastal Zone Management Act definition of "coastal zone" [16 USC 1453(1)], Progress Energy concludes that the issue is not subject to the certification requirement.

- Housing – This issue addresses impacts that additional Progress Energy employees required to support license renewal and the additional resulting indirect jobs could have on local

housing availability. NRC concluded, and Progress Energy concurs, that impacts would be small for plants located in medium population areas that do not have growth control measures which limit housing development. Using the NRC definitions and categorization methodology, BSEP is located in a medium population area without restrictive growth controls. Progress Energy expects no additional employees would be required to support license renewal. Progress Energy concludes that impacts during the BSEP license renewal term would be small.

- Public services; public utilities – This issue address impacts that adding license renewal workers could have on public utilities, particularly public water supply. Progress Energy has analyzed the availability of public water supplies in the area and has found no limitations that would suggest that additional BSEP workers would cause impacts. Progress Energy expects no additional employees to support license renewal. Therefore, Progress Energy has concluded that impacts during the BSEP license renewal term would be small.
- Offsite land use – This issue addresses impacts that local government spending of plant property tax dollars can have on land use patterns. BSEP property taxes comprised 4 percent of Brunswick County's total tax revenues in 2002. Progress Energy projects that BSEP taxes will remain relatively constant during the license renewal term. At some time in the future deregulation could affect utilities' tax payments, however, changes to BSEP tax rates due to deregulation would be independent of license renewal. Progress Energy concludes that impacts during the BSEP license renewal term would be small and not warrant mitigation.
- Public services; transportation – This issue addresses impacts that adding license renewal workers could have on local traffic patterns. Progress Energy expects no additional employees would be required to support license renewal. Therefore, Progress Energy has concluded that impacts during the BSEP license renewal term would be small.
- Historic and archaeological resources – This issue address impacts that license renewal activities could have on resources of historic or archaeological significance. Although a number of archaeological or historic sites have been identified within 6 miles of BSEP, Progress Energy is not aware of any adverse or detrimental impacts to these sites from current operations and Progress Energy has no plans for license renewal activities that would disturb these historic and archaeological resources.
- Severe accidents – Preliminary results from the Progress Energy severe accident mitigation alternatives (SAMA) analysis identify cost-beneficial ways to mitigate risk to public health and the economy in the area of the plant, including the coastal zone, due to potential severe accidents at BSEP. The SAMAs, however, are unrelated to aging management issues that are the subject of the license renewal analysis and, therefore, are not related to the consistency certification for license renewal.

State Program

The North Carolina Coastal Management Program is administered by the Division of Coastal Management within the Department of Environment and Natural Resources. The Department maintains a website that describes the program in general terms (Ref. 6). The North Carolina Coastal Management Statutes (Ref. 7) contain guidelines for preservation and management of the coastal area that are set forth in policy statements, standards, and management objectives. Attachment E-1 lists these objectives and discusses for each the applicability to BSEP. Attachment E-2 lists Brunswick County Land Use policies and discusses for each the applicability of BSEP and its associated transmission corridors. Attachment E-3 lists New Hanover County Land Use policies and discusses for each the applicability of BSEP transmission corridors. Attachment E-4 lists Onslow County Land Use policies and discusses for each the applicability of BSEP transmission corridors. Attachment E-5 lists Pender County Land Use policies and discusses for each the applicability of BSEP transmission corridors.

In addition, CAMA charges the Division of Coastal Management with managing "development" in "areas of environmental concern" (definitions within the regulatory context are provided in the authorizing legislation) within the 20 coastal counties through a well-structured permitting program. BSEP plans no development during the license renewal period.

Findings:

1. NRC has determined that the impacts of certain license renewal environmental issues (i.e., Category 1 issues) are small. Progress Energy has adopted by reference NRC findings for these issues as they are applicable to BSEP.

2. For other license renewal issues (i.e., Category 2 and "NA" issues) that are applicable to BSEP, Progress Energy has determined that the environmental impacts are small.

3. To the best of Progress Energy's knowledge, BSEP and its transmission corridors are in compliance with all North Carolina's licensing and permitting requirements and are in compliance with its state-issued licenses and permits.

4. Progress Energy's license renewal and continued operation of BSEP would be consistent with the enforceable policies of the North Carolina coastal zone management program.

STATE NOTIFICATION

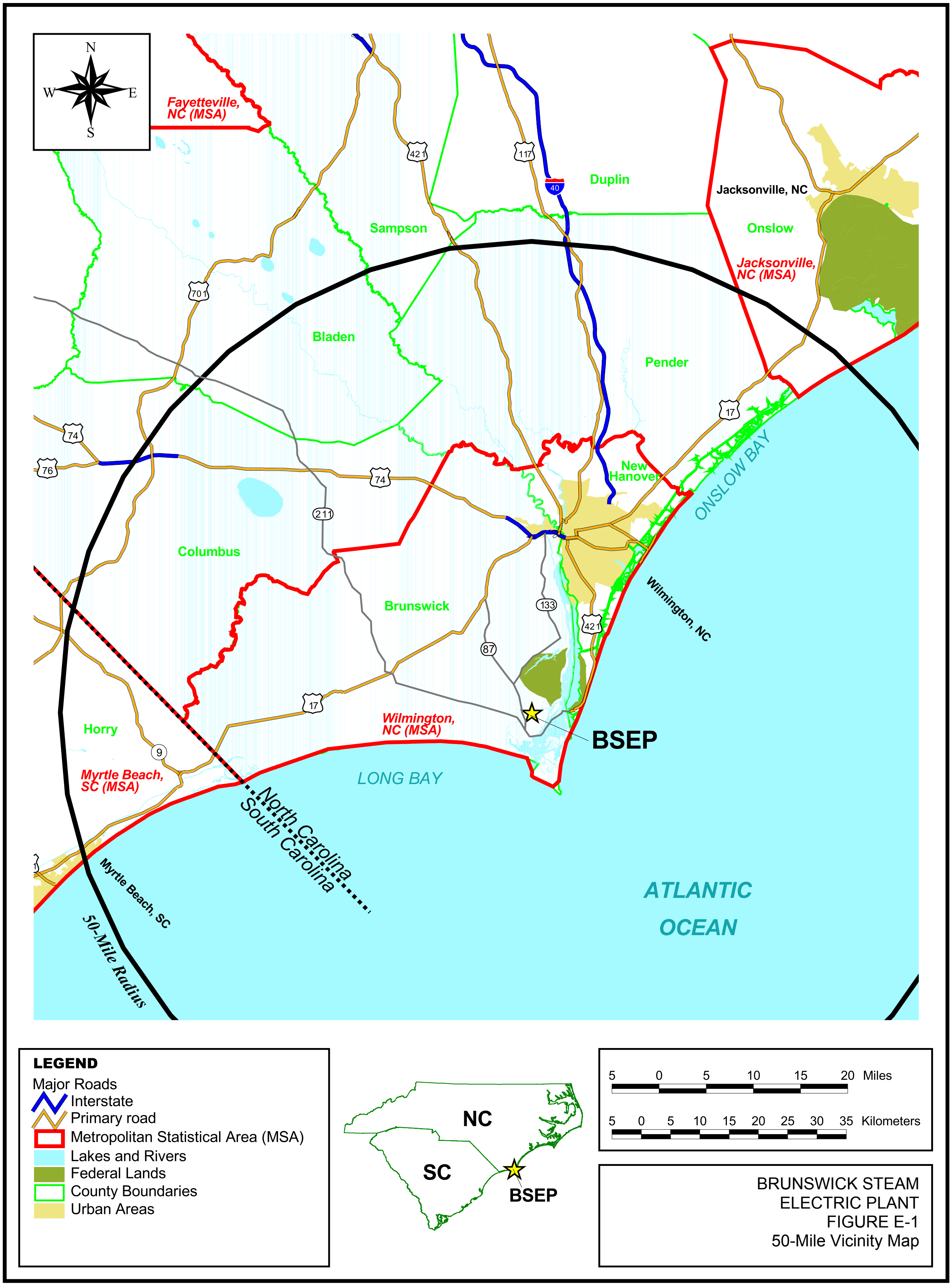
By this certification that BSEP license renewal is consistent with North Carolina's coastal zone management program, North Carolina is notified that it has six months from receipt of this letter and accompanying information in which to concur with or object to Progress Energy's certification. However, pursuant to 301 CMR 21.08(3)(b), if North Carolina has not issued a decision within three months following the commencement of state agency review, it shall notify the contacts listed below of the status of the matter and the basis for further delay. North Carolina's concurrence, objection, or notification of review status shall be sent to:

Mr. Richard L. Emch
Senior Project Manager
United States Nuclear Regulatory Commission
One White Flint North
11555 Rockville Pike
Rockville, MD 20852-2738

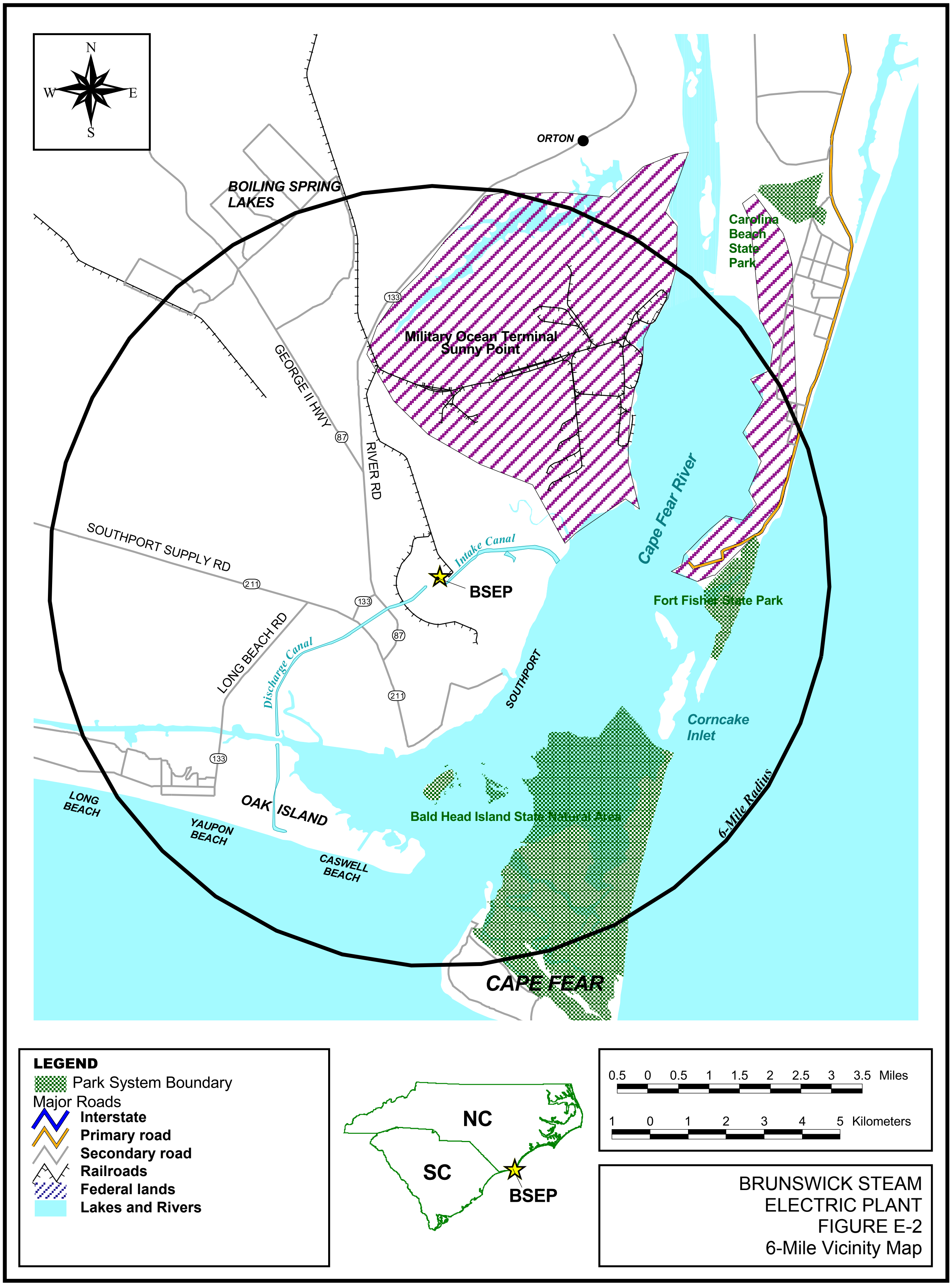
Mr. C. J. Gannon
Vice President
Brunswick Steam Electric Plant
Carolina Power & Light Company
Post Office Box 10429
Southport, North Carolina 28461

REFERENCES

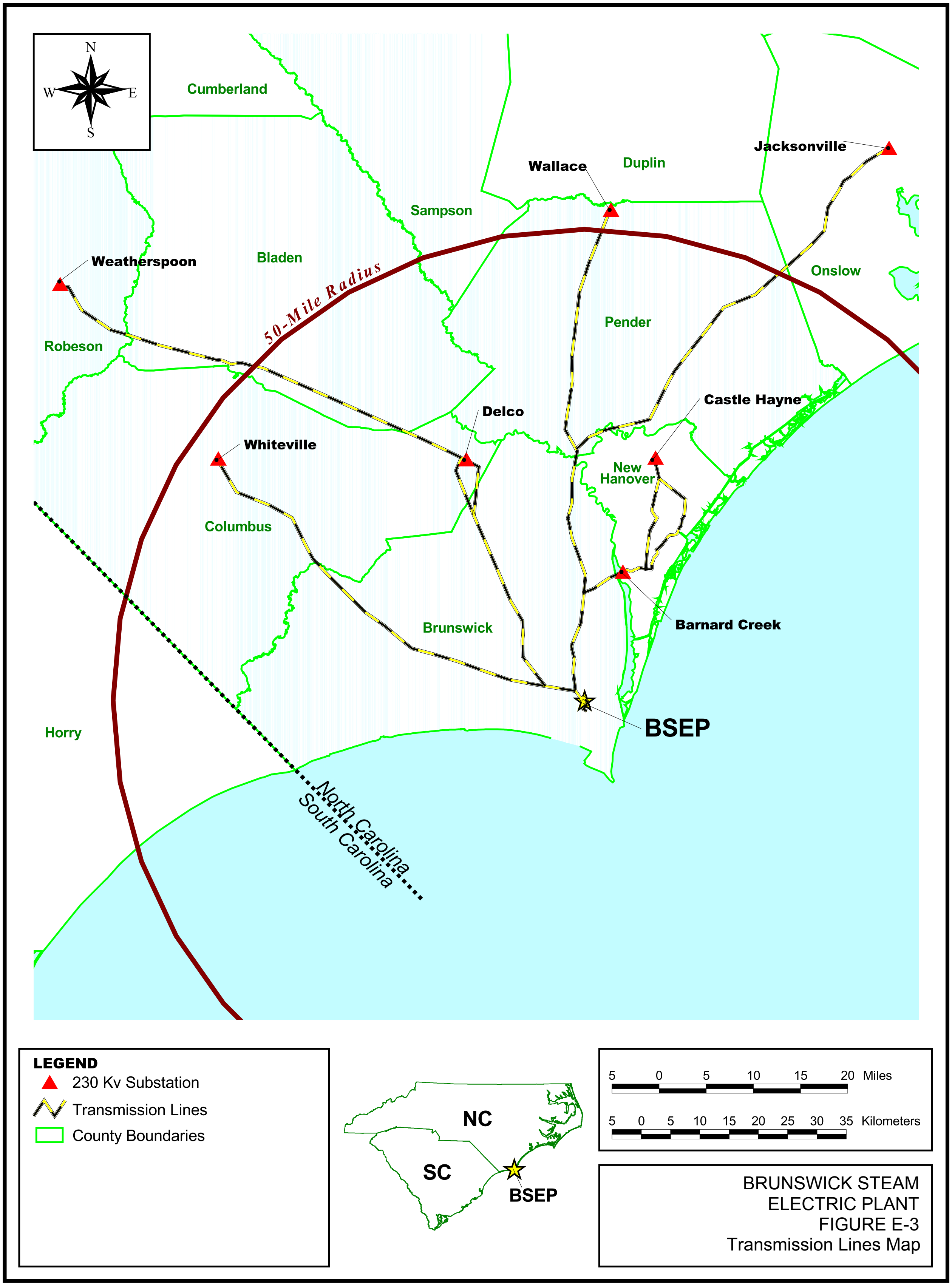
1. *NRR Office Instruction No. LIC-203, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues."* U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation. June 21, 2001.
2. *State and Territory Coastal Management Program Summaries*, National Oceanic and Atmospheric Administration. Available on line at http://www.ocrm.nos.noaa.gov/czm/czmsitelist.html (accessed April 23, 2003).
3. *Generic Environmental Impact statement for License Renewal Nuclear Plants*, U. S. Nuclear Regulatory Commission, NUREG-1437, May 1996. Available on line at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1437. Accessed 12-23-03.
4. NMFS (National Marine Fisheries Service). 2000. Endangered Species Act – Section 7 Consultation Biological Opinion: Operation of the Cooling Water Intake System at the Brunswick Steam Electric Plant Carolina Power and Light Company. January 20.
5. BSEP (Brunswick Steam Electric Plant). 2002. Endangered and Threatened Species. EVC-SUBS-00011, Rev 0. October.
6. North Carolina Department of Environment and Natural Resources. No Date. Division of Coastal Management. Available at http://dcm2.enr.state.nc.us/index.htm. Accessed April 23, 2003.
7. North Carolina Administrative Code, Title 15A Department of Environment, Health, and Natural Resources, Chapter 7, Coastal Management.



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE E-1
50-Mile Vicinity Map



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE E-2
6-Mile Vicinity Map



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE E-3
Transmission Lines Map

Table E-1
Environmental Authorizations for Current
BSEP Units 1 and 2 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	Unit 1: DPR-71 Unit 2: DPR-62	Issued 11/12/1976 Expires 9/8/2016 Issued 12/27/74 Expires 12/27/2014	Operation of Units 1 and 2
U.S. Fish and Wildlife Service	16 USC 703-712	Federal Fish and Wildlife Permit, Depredation	MB789112-0	Issued 4/01/03; Expires 3/31/04	Removal and relocation of migratory bird nests
U.S. Department of Transportation	49 USC 5108	Registration	050603550001L	Issued 5/06/03; Expires 6/30/04	Hazardous materials shipments
North Carolina Department of Environment and Natural Resources, Division of Water Quality	Clean Water Act (33 USC 1251 et seq.), NC General Statute 143-215.1	National Pollutant Discharge Elimination System Permit	NC0007064	Issued 6/30/03 Expires 11/30/06	Wastewater discharges to Atlantic Ocean (Part I) and stormwater discharges to waters of the State (Part II).

Table E-1
Environmental Authorizations for Current BSEP Units 1 and 2 Operations (continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
North Carolina Department of Environment and Natural Resources, Division of Waste Management	NC General Statutes 143-215.95 et. Seq., Part 3 of the NC Oil Pollution and Hazardous Substances Control Act	Certificate of Registration of Oil Terminal Facility	104021005	Issued 2/29/00 updated as necessary to reflect changes of facilities/operation s/organization	PE operation of an oil terminal supplying fuel to emergency diesel generator and lubrication oils
North Carolina Department of Environment and Natural Resources, Division of Air Quality	Clean Air Act Construction and Operating Permit (42 USC 7661 et seq.); NC General Statutes Article 21B of Chapter 143	Air Permit	5556R13	Issued 12/17/03; Expires 12/01/08	Air emissions for boilers and emergency generators source operation
North Carolina Department of Environment and Natural Resources, Division of Coastal Management	Federal Coastal Zone Management Act (16 USC 1451 et seq); State Dredge and Fill Permit (NC General Statutes 113-229)	Dredging Permit	293	Issued 10/20/03; Expires 12/31/06	Maintenance dredging of existing cooling water intake canal
North Carolina Wildlife Resources Commission	Endangered Species Act of 1973 (16 USC 1531-1544)	Endangered Species Permit - Sea Turtles	04ST49	Issued 1/15/04; Expires 12/31/04	Tagging, Possession and Disposition of Entrained or Stranded Sea Turtles

Table E-1
Environmental Authorizations for Current
BSEP Units 1 and 2 Operations (continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
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	No Number	Issued 1/30/03; Expires 12/31/03	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	0041-32-04	Issued 11/20/03; Expires 12/31/04	Transportation of radioactive waste into the State of South Carolina
Utah Department of Environmental Quality, Division of Radiation Control	Utah Division of Radiation Control Rule R313-26	Utah Radiation Control Generator Site Access Permit	0109000007	Issued 9/30/01; Expires 6/30/04	Transportation of radioactive waste into the State of Utah
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-NC001-L04	Issued 1/01/04; Expires 12/31/04	Transportation of radioactive waste into the State of Tennessee

Table E-2
Environmental Authorizations for
BSEP Units 1 and 2 License 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
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
North Carolina Division of Coastal Management	Coastal Zone Management Act (16 USC 1452 et seq.)	Certification	Requires applicant to prove certification to federal agency issuing the license that license renewal would be consistent with the federally approved State Coastal Zone Management program. Based on its review of the proposed activity, the State must concur with or object to the applicant's certification
North Carolina Department of Cultural Resources	National Historic Preservation Act Section 106 (16 USC 470f)	Certification	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

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

Table E-3
Endangered and Threatened Species Known to Occur in Brunswick County or in Counties Crossed by BSEP-Associated Transmission Lines[a]

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Mammals			
Neotoma floridana haematoreia	Eastern woodrat – Coastal Plain population	-	T
Puma concolor couguar	Eastern cougar	E	E
Trichechus manatus	Manatee	E	E
Birds			
Charadrius melodus	Piping plover	T	T
Falco peregrinus	Peregrine falcon	-	E
Haliaeetus leucocephalus	Bald eagle	T	E
Mycteria americana	Wood stork	E	E
Picoides borealis	Red-cockaded woodpecker	E	E
Sterna nilotica	Gull-billed tern	-	T
Reptiles and Amphibians			
Alligator mississippiensis	American alligator	T(S/A)	T
Ambystoma tigrinum	Tiger salamander	-	T
Caretta caretta	Loggerhead sea turtle	T	T
Chelonia mydas	Green sea turtle	T	T
Dermochelys coriacea	Leatherback sea turtle	E	E
Eretmochelys imbricate	Hawksbill sea turtle	E	E
Lepidochelys kempii	Kemp's ridley sea turtle	E	E
Rana capito	Carolina gopher frog	-	T
Fish			
Acipenser brevirostrum	Shortnose sturgeon	E	E
Elassoma boehlkei	Carolina pygmy sunfish	-	T
Etheostoma perlongum	Waccamaw darter	-	T
Menidia extensa	Waccamaw silverside	T	T
Invertebrates			
Anodonta couperiana	Barrel floater (mussel)	-	E
Catinella vermata	Suboval ambersnail	-	T
Elliptio marsupiobesa	Cape Fear spike (mussel)	-	T
E. roanokensis	Roanoke slabshell (mussel)	-	T
E. waccamawensis	Waccamaw spike (mussel)	-	T

Table E-3
Endangered and Threatened Species Known to Occur in Brunswick County or in Counties Crossed by BSEP-Associated Transmission Lines[a] (continued)

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Fusconaia masoni	Atlantic pigtoe (mussel)	-	T
Lampsilis cariosa	Yellow lampmussel	-	T
L. fullerkati	Waccamaw fatmucket (mussel)		
Planorbella magnifica	Magnificent rams-horn (snail)	-	E
Toxolasma pullus	Savannah lilliput (mussel)	-	T
Triodopsis soelneri	Cape Fear threetooth (snail)	-	T
Plants			
Adiantum capillus-veneris	Venus hair fern	-	E
Amaranthus pumilus	Seabeach amaranth	T	T
Amorpha georgiana var *confusa*	Savanna indigo-bush	-	T
A. g. var *georgiana*	Georgia indigo-bush	-	E
Asplenium heteroresiliens	Carolina spleenwort	-	E
Astragalus michauxii	Sandhills milk-vetch	-	T
Calopogom multiflorus	Many-flowered grass-pink	-	E
Carex lutea	Golden sedge	E	E
Carya myristiciformis	Nutmeg hickory	-	T
Chrysoma pauciflosculosa	Woody goldenrod	-	E
Fimbristylis perpusilla	Harper's fimbry	-	T
Helenium brevifolium	Littleleaf sneezeweed	-	E
H. vernale	Dissected sneezeweed		E
Lindera melissifolia	Southern spicebush	E	E
L. subcoriacea	Bog spicebush	-	E
Lilaeopsis carolinensis	Carolina grasswort	-	T
Lophiola aurea	Golden crest	-	E
Lysimachia asperulaefolia	Rough-leaved loosestrife	E	E
Macbridea caroliniana	Carolina bogmint	-	T
Muhlenbergia torreyana	Pinebarren smokegrass	-	E
Myriophyllum laxum	Loose watermilfoil	-	T
Panicum hirstii	Hirsts' panic grass	C	E
Parnassia caroliniana	Carolina grass-of-parnassus	-	E
P. grandifolia	Large-leaved grass-of-parnassus	-	T
Plantago sparsiflora	Pineland plantain	-	E

Table E-3
Endangered and Threatened Species Known to Occur in Brunswick County or in Counties Crossed by BSEP-Associated Transmission Lines[a] (continued)

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Plantanthera integra	Yellow fringeless orchid	-	T
P. nivea	Snowy orchid		T
Pteroglossapsis ecristata	Spiked medusa	-	E
Rhexia aristosa	Awned meadow-beauty	-	T
Rhus michauxii	Michaux's sumac	E	E
Rhynchospora thornei	Thorne's beaksedge	-	E
Schwalbea americana	American chaffseed	E	E
Solidago pulchra	Carolina goldenrod	-	E
Sporobolus teretifolius	Wireleaf dropseed	-	T
Stylisma pickeringii var *pickeringii*	Pickering's dawnflower	-	E
Thalictrum cooleyi	Cooley's meadowrue	E	E
Trillium pusillum var *pusillum*	Carolina least trillium	-	E
Utricularia olivacea	Dwarf bladderwort	-	T

Source: USFWS 2002a, CP&L 1998, NC DENR 2001, NC DENR 2002

a. Bladen, Brunswick, Columbus, New Hanover, Pender, Onslow, and Robeson counties.

b. E = Endangered; T = Threatened; T(S/A) = Threatened due to similarity of appearance; a species which is protected because it is very similar in appearance to a listed species; - = Not listed.

Attachment E-1

North Carolina Coastal Regulations Passed by the CRC

The North Carolina Coastal Area Management Act (the Act) establishes a Coastal Resources Commission (CRC) within the Department of Environment and Natural Resources[5] which is responsible for administering the Act.

The purpose of the Act is found in Section 113-102(b) of the statute:

(1) To provide a management system capable of preserving and managing the natural ecological conditions of the estuarine system, the barrier dune system, and the beaches, so as to safeguard and perpetuate their natural productivity and their biological, economic and esthetic values;

(2) To insure that the development or preservation of the land and water resources of the coastal area proceeds in a manner consistent with the capability of the land and water for development, use, or preservation based on ecological considerations;

The Act is codified in the North Carolina Administrative Code (NCAC)[6] and requires that "[S]tate guidelines for the coastal area shall consist of statements of objectives, policies and standards to be followed in public and private use of land and water areas within the coastal area."[7] The Act further states that "[S]uch guidelines shall be used … for review of and comment on proposed … federal agency activities that are subject to review for consistency with state guidelines for the coastal area."[8] Finally, the Act stipulates that each county shall prepare a land use plan that "consist[s] of objectives, policies and standards to be followed in public and private use of land within the county…."[9] Therefore entities seeking approval for coastal activities must demonstrate that the activity is consistent with all policies passed by the CRC, regulations administered under the authority of the CRC by the Division of Coastal Management, and local land-use plans certified by the CRC.

Progress Energy is seeking NRC renewal of operating licenses for Brunswick Steam Electric Plant Units 1 and 2. The following paragraphs enumerate provisions of NCAC Subchapter 7M, General Policy Guidelines for the Coastal Area, and provide the Progress Energy demonstration that BSEP license renewal would be consistent with these guidelines. Attachments E-2 through E-5 enumerate land use policies of the coastal counties in which BSEP and its associated transmission lines are located and demonstrate that BSEP license renewal would be consistent with those policies.

Because Progress Energy has no plans for further development of the BSEP during the license renewal term, those provisions of the CAMA dealing with "development" do not apply and are not addressed here.

Subchapter 7M – General Policy Guidelines for the Coastal Area

15A NCAC 07M. 0102 Purpose – The purpose of these rules is to establish generally applicable objectives and policies to be followed in the public and private use of land and water areas within the coastal area of North Carolina.

> Progress Energy Response - GS 113A-103(2) defines the coastal area and directs the Governor to designate the counties that constitute the "coastal area." Twenty counties comprise the North Carolina coastal area, including Brunswick County, where BSEP is located, and New Hanover, Pender and Onslow counties, which are crossed by transmission lines associated with BSEP.

---

[5] North Carolina General Statute 113A-104.
[6] North Carolina Administrative Code (NCAC) Title 15A, Department of Environment and Natural Resources, Chapter 7, Coastal Management
[7] NC General Statutes. Article 7, Coastal Area Management, Part 1, Organization and Goals, § 113A-107(a), State guidelines for the coastal area.
[8] GS §113A-107(a).
[9] GS §113A-110(a).

BSEP Units 1 and 2 operations, begun in 1976 and 1974, respectively, pre-dated federal approval of the North Carolina Coastal Area Management Act in 1978. Since operations began, the state has issued a number of licenses, permits, and other authorizations for construction and operations at BSEP. The state also reviews required reports on BSEP operations (e.g., NPDES discharge monitoring reports) and routinely inspects the BSEP site and facilities. Through review of permit applications and required monitoring, together with routine inspections, the state assures itself and Progress Energy that BSEP is in compliance with state environmental protection policies, including those for coastal zone management.

Section .0200 – Shoreline Erosion Policies
15A NCAC 07M .0202 Policy statements–

(a) Pursuant to Section 5, Article 14 of the North Carolina Constitution, proposals for shoreline erosion response projects shall avoid losses to North Carolina's natural heritage.

(b) Erosion response measures designed to minimize the loss of private and public resources to erosion should be economically, socially, and environmentally justified. Preferred response measures for shoreline erosion shall include but not be limited to Areas of Environmental Concern (AEC) rules, land use planning and land classification, establishment of building setback lines, building relocation, subdivision regulations and management of vegetation.

(c) The replenishment of sand on ocean beaches can provide storm protection and a viable alternative to allowing the ocean shoreline to migrate landward threatening to degrade public beaches and cause the loss of public facilities and private property.

(d) The following are required with state involvement (funding or sponsorship) in beach restoration and sand renourishment projects:

1. the entire restored portion of the beach shall be in permanent public ownership;
2. it shall be a local government responsibility to provide adequate parking, public access, and services for public recreational use of the restored beach.

(e) Temporary measures to counteract erosion, such as the use of sandbags and beach pushing, should be allowed, but only to the extent necessary to protect property for a short period of time until threatened structures may be relocated, or until effects of a short-term erosion event are reversed.

(f) Efforts to permanently stabilize the location of the ocean shoreline with seawalls, groins, shoreline hardening, sand trapping or similar protection devices should not be allowed except when the project meets one of the specific exceptions set out in 15A NCAC 7H .0308 [ocean hazard areas].

(g) The state of North Carolina will consider innovative institutional programs and scientific research that will provide for effective management of coastal shorelines.

(h) The planning, development and implementation of erosion control projects will be coordinated with appropriated planning agencies, affected governments, and interested public.

(i) The state will promote education of the public on the dynamics of nature of the coastal zone and on effective measure to cope with our ever changing shorelines.

Progress Energy Response – Brunswick County land use maps indicate the area in the immediate vicinity of BSEP is dry, sloping upland. The manmade intake and discharge canals are not considered estuarine shoreline, though both pass through floodplains and salt marshes. Transmission corridors cross streams and run through swamps, but do not occur along Atlantic beaches. Transmission corridor maintenance involves mowing, handcutting, and herbicide

applications and is governed by procedures, including MNT-TRMX-00176, Transmission line right of way. Routine maintenance is consistent with, and in most cases exempt from, CAMA regulations.

The pumping station at Caswell Beach is within the ocean hazard Area of Environmental Concern. Progress Energy owns approximately 3 acres of beachfront land between the Caswell Beach pumping station and the Atlantic Ocean. In the event of serious erosion, Progress Energy would cooperate with appropriate state and federal agencies to renourish the beach. Progress Energy has no plans for license renewal that would affect the ocean shoreline or its potential to erode.

Section .0300 – Shorefront Access Policies
15A NCAC 07M .0301 Declaration of General Policy

(a) The public has traditionally and customarily had access to enjoy and freely use the ocean beaches and estuarine and public trust waters of the coastal region for recreational purposes and the state has a responsibility to provide continuous access to these resources.

(b) The state has created an access program for the purpose of acquiring, improving and maintaining waterfront recreational property at frequent intervals throughout the coastal region for pedestrian access to the important public resources.

(c) In addition, some properties, due to their location, are subject to severe erosion so that development here is not possible or feasible. In these cases, a valid public purpose may be served by the donation, acquisition and improvement of these properties for public access.

Progress Energy Response – The public has access to Caswell Beach via a parking lot on Progress Energy property and to a freshwater canal near the discharge canal via a public boat ramp on Progress Energy property**.** Progress Energy has no license renewal plans that would limit public use of the Caswell Beach parking lot or he adjacent beachfront.

Section .0400 – Coastal Energy Policies
15A NCAC 07M .0401 Declaration of General Policy

(a) It is hereby declared that the general welfare and public interest require that reliable sources of energy be made available to the citizens of North Carolina. It is further declared that the development of energy facilities and energy resources within the state and in offshore waters can serve important regional and national interests. However, unwise development of energy facilities or energy resources can conflict with the recognized and equally important public interest that rests in conserving and protecting the valuable land and water resources of the state and nation, particularly coastal lands and waters. Therefore, in order to balance the public benefits attached to necessary energy development against the need to protect valuable coastal resources, the planning of future land uses, the exercise of regulatory authority, and determinations of consistency with the North Carolina Coastal Management Program shall assure that the development of energy facilities and energy resources shall avoid significant adverse impact upon vital coastal resources or uses, public trust areas and public access rights.

(b) Exploration for the development of offshore and Outer Continental Shelf (OCS) energy resources has the potential to affect coastal resources. The federal Coastal Zone Management Act of 1972, as amended, requires that federal oil and gas leasing actions of the US Department of the Interior be consistent to the maximum extent practicable with the enforceable policies of the federally approved North Carolina Coastal Management Program, and that exploration, development and production activities associated with such leases comply with those enforceable policies. Enforceable policies applicable to OCS activities include all the provisions and policies of this Rule, as well as any other applicable federally approved components of the North Carolina Coastal Management Program. All permit applications, plans and assessments related to exploration or development of OCS resources and other relevant energy facilities must contain sufficient information to allow adequate analysis of the consistency of all proposed activities with these Rules and policies.

Progress Energy Response – Progress Energy operates BSEP, a power-generating facility, in compliance with all applicable state and federal permits and authorizations. Progress Energy has no plans to conduct refurbishment or construction activities, or to change current operations during the license renewal term. Therefore, policies relating to the development of energy facilities are not applicable to the BSEP license renewal term. Progress Energy has no plans for offshore exploration for the development of energy sources. Therefore, no specific coastal energy policies are relevant to BSEP operations during the license renewal term.

SECTION .0500 - POST-DISASTER POLICIES
15A NCAC 07M .0501 DECLARATION OF GENERAL POLICY

It is hereby declared that the general welfare and public interest require that all state agencies coordinate their activities to reduce the damage from coastal disasters. As predisaster planning can lay the groundwork for better disaster recovery, it is the policy of the state of North Carolina that adequate plans for post-disaster reconstruction should be prepared by and coordinated between all levels of government prior to the advent of a disaster.

Progress Energy Response - Progress Energy believes that this policy applies to the state and for natural disasters, and not to private entities.

SECTION .0600 - FLOATING STRUCTURE POLICIES
15A NCAC 07M .0601 DECLARATION OF GENERAL POLICY

It is hereby declared that the general welfare and public interest require that floating structures to be used for residential or commercial purposes not infringe upon the public trust rights nor discharge into the public trust waters of the coastal area of North Carolina.

Progress Energy Response - 15A NCAC 07M .0602 defines a floating structure as "any structure, not a boat, supported by a means of flotation, designed to be used without a permanent foundation, which is used or intended for human habitation or commerce. A structure will be considered a floating structure when it is inhabited or used for commercial purposes for more than thirty days in any one location. A boat may be deemed a floating structure when its means of propulsion has been removed or rendered inoperative and it contains at least 200 square feet of living space area."

Progress Energy has no floating structures associated with BSEP, nor any plans to construct or purchase any such floating structure during the license renewal term. Therefore, this policy is not relevant to BSEP license renewal and no specific policy statements on floating structures are included in this certification document.

SECTION .0700 - MITIGATION POLICY
15A NCAC 07M .0701 DECLARATION OF GENERAL POLICY

(a) It is the policy of the state of North Carolina to require that adverse impacts to coastal lands and waters be mitigated or minimized through proper planning, site selection, compliance with standards for development, and creation or restoration of coastal resources. Coastal ecosystems shall be protected and maintained as complete and functional systems by mitigating the adverse impacts of development as much as feasible by enhancing, creating, or restoring areas with the goal of improving or maintaining ecosystem function and areal proportion.
(b) The CRC shall apply mitigation requirements as defined in this Section consistent with the goals, policies and objectives set forth in the Coastal Area Management Act for coastal resource management and development. Mitigation shall be used to enhance coastal resources and offset any potential losses occurring from approved and unauthorized development. Proposals to mitigate losses of coastal resources shall be considered only for those projects shown to be in the public interest, as defined by the standards in 15A NCAC 7M .0703, and only after all other reasonable means of avoiding or minimizing such losses have been exhausted.

Progress Energy Response - Progress Energy believes this policy is relevant to new development in coastal counties. Progress Energy plans no refurbishment or major construction at BSEP or along associated transmission lines associated with the license renewal term. Therefore, this policy is not relevant to license renewal and no specific mitigation policy statements are included in this certification document.

SECTION .0800 - COASTAL WATER QUALITY POLICIES
15A NCAC 07M .0801 DECLARATION OF GENERAL POLICIES

(a) The waters of the coastal area are a valuable natural and economic resource of statewide significance. Traditionally these waters have been used for such activities as commercial and recreational fishing, swimming, hunting, recreational boating, and commerce. These activities depend upon the quality of the waters. Due to the importance of these activities to the quality of life and the economic well-being of the coastal area, it is important to ensure a level of water quality which will allow these activities to continue and prevent further deterioration of water quality. It is hereby declared that no land or water use shall cause the degradation of water quality so as to impair traditional uses of the coastal waters. To the extent that statutory authority permits, the Coastal Resources Commission will take a lead role in coordinating these activities.
(b) It is further recognized that the preservation and enhancement of water quality is a complex issue. The deterioration of water quality in the coastal area has many causes. The inadequate treatment of human wastes, the improper operation of boats and their sanitation devices, the creation of increased runoff by covering the land with buildings and pavement and removing natural vegetation, the use of outdated practices on fields and woodlots and many other activities impact the water quality. Activities outside the coastal area also impact water quality in the coastal area. Increases in population will continue to add to the water quality problems if care is not taken in the development of the land and use of the public trust waters.
(c) Protection of water quality and the management of development within the coastal area is the responsibility of many agencies. It is hereby declared that the general welfare and public interest require that all state, federal and local agencies coordinate their activities to ensure optimal water quality.

15A NCAC 07M .0802 POLICY STATEMENTS

(a) All of the waters of the state within the coastal area have a potential for uses which require optimal water quality. Therefore, at every possible opportunity, existing development adjacent to these waters shall be upgraded to reduce discharge of pollutants.
(b) Basin wide management to control sources of pollution both within and outside of the coastal area which will impact waters flowing into the rivers and sounds of the coastal area is necessary to preserve the quality of coastal waters.
(c) The adoption of methods to control development so as to eliminate harmful runoff which may impact the sounds and rivers of the coastal area and the adoption of best management practices to control runoff from undeveloped lands is necessary to prevent the deterioration of coastal waters.

Progress Energy Response – BSEP currently holds an NPDES permit that allows the plant to discharge storm water into Nancy's Creek and storm water, wastewater, and cooling water into the Atlantic Ocean. BSEP's NPDES permit conditions and permit limits (effluent limitations) are periodically reevaluated by NCDENR to ensure that the best available technology is in place to prevent water quality degradation. In addition, other on-going activities at BSEP, such as periodic maintenance dredging of intake and discharge canals, are conducted under and in accordance with permits issued by the Division of Coastal Management. Prior to issuance, those permits are reviewed and approved by other state and federal agencies to ensure consistency with water quality, land use, and other environmental regulatory programs. Policies (b) and (c) do not apply to BSEP.

SECTION .0900 - POLICIES ON USE OF COASTAL AIRSPACE
15A NCAC 07M .0901 DECLARATION OF GENERAL POLICY

It is hereby declared that the use of aircraft by state, federal and local government agencies for purposes of managing and protecting coastal resources, detecting violations of environmental laws and rules and performing other functions related to the public health, safety and welfare serves a vital public interest. The Commission further finds that future economic development in the coastal area and orderly management of such development requires air access to and among coastal communities.

Progress Energy Response - Progress Energy does routinely not use aircraft at BSEP. Because BSEP is a nuclear facility, security requirements may restrict the airspace for some distance around the facility, however. Progress Energy believes that any limited restricted airspace in the vicinity of the plant would not inhibit the development of the coastal area in the vicinity of BSEP, nor would it prevent state, federal or local governments from carrying out their assigned functions.

SECTION .1000 - POLICIES ON WATER AND WETLAND BASED TARGET AREAS FOR MILITARY TRAINING ACTIVITIES
15A NCAC 07M .1001 DECLARATION OF GENERAL POLICY

The use of water and wetland-based target areas for military training purposes may result in adverse impacts on coastal resources and on the exercise of public trust rights. The public interest requires that, to the maximum extent practicable, use of such targets not infringe on public trust rights, cause damage to public trust resources, violate existing water quality standards or result in public safety hazards.

Progress Energy Response - The U.S. Government does not use waters or wetlands at BSEP as target areas for military training.

SECTION .1100 - POLICIES ON BENEFICIAL USE AND AVAILABILITY OF MATERIALS RESULTING FROM THE EXCAVATION OR MAINTENANCE OF NAVIGATIONAL CHANNELS

15A NCAC 07M .1101 DECLARATION OF GENERAL POLICY

Certain dredged material disposal practices may result in removal of material important to the sediment budget of ocean and inlet beaches. This may, particularly over time, adversely impact important natural beach functions especially during storm events and may increase long term erosion rates. Ongoing channel maintenance requirements throughout the coastal area also lead to the need to construct new or expanded disposal sites as existing sites fill. This is a financially and environmentally costly undertaking. In addition, new sites for disposal are increasingly harder to find because of competition from development interests for suitable sites. Therefore, it is the policy of the state of North Carolina that material resulting from the excavation or maintenance of navigation channels be used in a beneficial way wherever practicable.

15A NCAC 07M .1102 POLICY STATEMENTS

(a) Clean, beach quality material dredged from navigation channels within the active nearshore, beach, or inlet shoal systems must not be removed permanently from the active nearshore, beach or inlet shoal system unless no practicable alternative exists. Preferably, this dredged material will be disposed of on the ocean beach or shallow active nearshore area where environmentally acceptable and compatible with other uses of the beach.
(b) Research on the beneficial use of dredged material, particularly poorly sorted or fine grained materials, and on innovative ways to dispose of this material so that it is more readily accessible for beneficial use is encouraged.
(c) Material in disposal sites not privately owned shall be available to anyone proposing a beneficial use not inconsistent with Paragraph (a) of this Rule.
(d) Restoration of estuarine waters and public trust areas adversely impacted by existing disposal sites or practices is in the public interest and shall be encouraged at every opportunity.

Progress Energy Response – Progress Energy periodically dredges deposited material from the intake canal and, less frequently, from the discharge canal. This material is generally not of “beach quality,” nor is it suitable for structural use, and has thus been placed in on-site, permitted spoil ponds. Progress Energy would support innovative disposal and beneficial use of this material where possible.

SECTION .1200 - POLICIES ON OCEAN MINING
15A NCAC 07M .1201 DECLARATION OF GENERAL POLICY

(a) The Atlantic Ocean is designated a Public Trust Area of Environmental Concern (AEC) out to the three-mile state jurisdictional boundary; however, the ocean environment does not end at the state/federal jurisdictional boundary. Mining activities impacting the federal jurisdiction ocean and its resources can, and probably would, also impact the state jurisdictional ocean and estuarine systems and vice-versa. Therefore, it is state policy that every avenue and opportunity to protect the physical ocean environment and its resources as an integrated and interrelated system will be utilized.

(b) The usefulness, productivity, scenic, historic and cultural values of the state's ocean waters will receive the greatest practical degree of protection and restoration. No ocean mining shall be conducted unless plans for such mining include reasonable provisions for protection of the physical environment, its resources, and appropriate reclamation or mitigation of the affected area as set forth and implemented under authority of the Mining Act (G.S. 74-48) and Coastal Area Management Act (G.S. 113A-100).

(c) Mining activities in state waters, or in federal waters insofar as the activities affect any land, water use or natural or historic resource of the state waters, shall be done in a manner that provides for protection of those resources and uses. The siting and timing of such activities shall be consistent with established state standards and regulations and shall comply with applicable local land use plan policies, and AEC use standards.

Progress Energy Response - Progress Energy does not mine the ocean. This policy is not relevant to BSEP operations, therefore, no additional specific policy statements are included in this certification document.

Attachment E-2

Brunswick County Land Use Plan Policies

The Coastal Area Management Act passed by the North Carolina General Assembly in 1974 and approved by the federal government in 1978 requires that each of the 20 counties in the coastal area develop a land use plan and update it every five years, or the CRC will prepare and adopt a land use plan for that county[10]. The most recent Brunswick County Land Use Plan (Ref. 1) available is the 1997 plan. BSEP activities were reviewed for consistency with the policies in the 1997 plan.

BSEP is in the Cape Fear River Watershed and, in the 1997 Brunswick County Land Use Plan, has a land use classification of Industrial. Several transmission lines leave BSEP and traverse Brunswick County in four transmission corridors. Maintenance practices in the transmission corridors were reviewed for consistency with the policies in the land use plan.

The following discussion presents the six major land use policies of Brunswick County, and, if BSEP operations could affect the resource protected by the policy, a discussion of BSEP operations as they relate to the policy.

<u>Policy 8.1.1(a)</u>. Development is encouraged to locate in areas without soil suitability problems and where infrastructure is available. In areas where suitability problems exist, engineering solutions are supported to the extent that the natural environment is not compromised.

<u>Policy 8.1.1(b)</u>. In the absence of sewer facilities, the County shall work cooperatively with property owners to evaluate site suitability for septic tank use. When soil conditions are such that, in the opinion of County sanitarians, health or environmental standards would be compromised, full explanation of the reasons for denial shall be given, and alternatives for possible solutions provided.

<u>Policy 8.1.1(c)</u>. Brunswick County supports the administration and enforcement of applicable flood plain management regulations and the national flood insurance program.

<u>Progress Energy Response</u> – These policies are directed at overcoming the limitations on growth due to the lack of a centralized sewage treatment system and the tendency of many areas of the county to flood or be unsuitable for septic systems. Progress Energy has no plans to perform refurbishment or construction on BSEP during the license renewal term, so policies related to development are not relevant to the license renewal application. BSEP has modern sewage treatment facilities and does not plan to increase the number of employees during the license renewal term. Therefore, the current sewage treatment facilities at BSEP are adequate to support the plant through the license renewal term, including planned outages that require additional staff. According to Brunswick County land use maps, BSEP is located on dry uplands, not prone to flooding.

<u>Policy 8.1.2.0.</u> Brunswick County will support and enforce, through its local CAMA permitting capacity, the state policies and permitted uses in the Areas of Environmental Concern (AEC's). Such uses shall be in accord with the general use standards for coastal wetlands, estuarine waters, public trust areas and ocean hazard areas as stated in 15A NCAC Subchapter H.

<u>Progress Energy Response</u> – Attachment E-1 provides information on how BSEP complies with state guidelines found in 15A NCAC Subchapter M for protecting coastal areas, estuarine waters, public trust areas and ocean hazard areas. BSEP is located on dry uplands in an area zoned industrial by the county. The intake and discharge canals traverse estuarine waters, the pumping station at Caswell Beach is in an ocean hazard area, and the transmission lines cross tidal creeks throughout the county. Progress Energy complies with its own procedures and state and federal permitting requirements when performing maintenance work on the plant or associated infrastructure. Progress Energy is in compliance with this policy.

<u>Policy 8.1.2(a).</u> …Brunswick County strongly supports the efforts of the state and federal agencies to properly designate and preserve coastal wetlands…

[10] NCGS § 103A-109.

Progress Energy Response – Progress Energy does not anticipate any further development of the BSEP site. However, Progress Energy does support and comply with the state and federal regulatory programs that ensure protection and orderly development of the coastal area.

Policy 8.1.2(b). Developments and mitigation activities which support and enhance the natural function, cleanliness, salinity, and circulation of estuarine water resources shall be supported.

Progress Energy Response – The greatest potential impact of BSEP operations on the Cape Fear Estuary is on the biological community. BSEP operations have been scrutinized by state and federal resource agencies since Unit 2 came on line in 1974, focusing on potential impacts of the plant's cooling water systems on the Cape Fear Estuary. BSEP has not been found to have adverse impacts on the aquatic communities of the Cape Fear Estuary (as verified by biological monitoring programs required by the state).

Progress Energy holds an NPDES permit for BSEP cooling water withdrawals and discharges. For this reason, and because of mitigation measures in place, Progress Energy concludes that operations at BSEP are in compliance with this policy.

Policy 81.2.(c). …Efforts of state and federal agencies to limit the length of docks and piers as they project into estuarine waters are especially supported.

Progress Energy Response – BSEP has docks and piers in the intake and discharge canals. Progress Energy is not anticipating that license renewal will change any current operations; therefore, BSEP will not require larger or additional docks or piers during the license renewal term.

Policy 8.1.2(d). Brunswick County supports the protection and preservation of its estuarine shorelines, as enforced through the application of CAMA use standards.

Progress Energy Response – Progress Energy has a long history of support of the environment, through corporate contributions, direct employee involvement and other activities. For instance, the Progress Energy Foundation has established a goal of providing direct financial support to non-profit groups and projects that directly benefit buffers, riparian areas and similar areas, including estuarine shorelines.

Policy 8.1.2(e). Brunswick County supports state and federal standards for the management of development in the ocean hazard AEC's under the county planning jurisdiction: the Baptist assembly grounds and part of Bird Island.

Progress Energy Response – Progress Energy has no plans to develop the area around the Caswell Pumping Station due to license renewal. This is the only part of the plant that is near an Ocean Hazard AEC.

Policy 8.1.2(f). Brunswick County supports the designation of Public Water Supply AECs when such designation meets state prerequisites and when such action is deemed necessary to ensure the long term viability of the County's public water supplies.

Progress Energy Response – Currently there are no small surface water supply watersheds or public water supply well fields identified in Brunswick County. BSEP is not located near a Public Water Supply AEC. This policy is not relevant to BSEP or its license renewal application.

Policy 8.1.2(g). Brunswick County supports the selective designation of appropriate areas as natural and cultural resource AEC's.

Progress Energy Response – The designation of areas as AECs lies with the CRC and not with Progress Energy.

Policy 8.1.2(h). The abundance and diversity of wildlife in Brunswick County shall be preserved and enhanced through protection of the unique coastal ecosystem, including marshes, woodlands, open fields, and other areas upon which they depend.

Progress Energy Response – Undeveloped portions of the BSEP site provide habitat for a variety of amphibians, reptiles, songbirds, wading birds, waterfowl, and small mammals. Transmission corridors associated with BSEP transmission lines also provide important wildlife habitat. Progress Energy uses an integrated vegetation management approach to controlling vegetation under its transmission lines. Mowing, hand-cutting and small amounts of EPA-approved herbicides are used to maintain the rights-of-way under the lines. One benefit of this program is that the plant communities that develop under the power lines provide good habitat for species such as songbirds, deer, quail, rabbit, and turkeys. Progress Energy also supports the maintenance of food plots in some rights-of ways, further enhancing the diversity of wildlife that use the corridors as habitat. Progress Energy is in compliance with this policy. Further, Progress Energy has developed a cooperative agreement with NCDENR's Natural Heritage Program under which we identify and protect state and federally listed plant species on our rights-of-way. In many cases, these species are sun-loving, and flourish only in the ROWs, as fire suppression has reduced their normally open, prairie-like habitat.

Policy 8.1.3 There are none at this time.

Policy 8.1.4(a). Brunswick County will continue to support the efforts of the CAMA program and the U.S. Army Corps of Engineers 404 permitting program to preserve and protect sensitive freshwater swamps and marsh areas.

Progress Energy Response –Progress Energy has a corporate goal to fully comply with all applicable environmental regulatory programs.

Policy 8.1.4(b). Maritime forests in Brunswick County shall receive a high level of environmental protection when considering public and private sector use.

Progress Energy Response – Progress Energy has no plans to perform refurbishment or construction during the license renewal term. Therefore, this policy is not relevant to the license renewal application.

Policy 8.1.4(c). Brunswick County supports … efforts to restore the water quality of …estuarine waters in the county to a water quality level deserving of O[utstanding] R[esource] W[aters] designation.

Progress Energy Response – There are currently no ORW identified within Brunswick County. All of the county's estuarine waters have been classified as SA (high quality), but many are closed to shellfishing due to unacceptable fecal coliform counts. BSEP has a permitted sewage treatment facility with effluent limits that prescribe discharge limits below state and federal regulatory limits. Progress Energy is in compliance with this policy.

Policy 8.4.1(d). The County supports and encourages the activities of the state's shellfish management program. The County shall continue to promote estuarine water quality through its stormwater management planning and stormwater runoff policies.

Progress Energy Response – In addition to reducing point source contamination, the county recognizes the need to control nonpoint source runoff. BSEP has an NPDES permit for stormwater discharges that limits contaminant concentrations in the effluent such that the discharge is protective of the receiving waters. Progress Energy is in compliance with this policy.

Policy 8.1.4(e). The county's groundwater resources, including but not limited to the Castle Hayne aquifer, shall be recognized as an invaluable source of public and private potable water and shall receive the highest level of protection when considering County policies, standards and actions, including the possible creation of an overlay district.

Progress Energy Response – BSEP receives its potable water from the Brunswick County Public Utilities (which gets approximately 70 percent of its water from the Lower Cape Fear River and the rest from the Castle Hayne Aquifer). BSEP has one well in the Castle Hayne aquifer that pumps less than 30 gallons

per minute. The well serves an intermittently occupied facility. Progress Energy has no plans to change its mode of operations during the license renewal term. Progress Energy is in compliance with this policy.

Policy 8.1.4(f). Brunswick County encourages efforts to protect cultural and historic resources to preserve their cultural, educational and aesthetic values.

Progress Energy Response -- No cultural or natural resources AECs are known on the BSEP site or along the transmission lines. The Natural Historic Preservation Act (NHPA) requires that any proposed activity requiring a federal permit include a consideration of cultural resource impacts prior to initiation of the activity. Progress Energy is in compliance with this Brunswick County policy.

Policy 8.1.4(g). Brunswick County will seek to minimize potential land use conflicts and hazards related to development in areas near existing potentially hazardous facilities.

Progress Energy Response -- BSEP is recognized by Brunswick County as a manmade hazard. Progress Energy's emergency preparedness group works with county emergency planners to ensure that plans are in place to protect life and property in the unlikely event of an emergency at the site. Progress Energy is in compliance with this policy.

Policy 8.1.4(h). Plans for the safe transportation of hazardous materials, for the prevention of cleanup of spills of toxic materials, and for the evacuation of area residents in response to hazardous events shall be supported.

Progress Energy Response -- Progress Energy transports hazardous materials to and from the site. All transportation of hazardous materials follows established Department of Transportation regulations for notification and transport. In addition, Progress Energy's emergency preparedness personnel are trained to clean up hazardous material spills or protect the area in the unlikely event of an accident involving radioactive materials. In conjunction with county emergency response personnel, Progress Energy maintains emergency evacuation plans as part of its license requirements. Progress Energy is in compliance with this policy.

Policy 8.1.5(a). Brunswick County supports federal, state, and local efforts to protect the quantity and quality of water in the Cape Fear River whether such protection involved controls over point sources discharges, surface runoff, interbasin water transfers, or other appropriate means, including upstream activities.

Policy 8.1.5(b). Brunswick County supports federal, state, and local efforts to protect the quantity and quality of water in the region's groundwater system whether such protection involves control over location and management of activities involving hazardous substances, restrictions on groundwater drawdowns, or any other activity which would jeopardize the short and long term viability of groundwater resources.

Progress Energy Response – As stated earlier, BSEP has state-issued NPDES permits which regulate cooling water, wastewater, and stormwater discharges into waters of the state. BSEP gets its potable water from the Brunswick County Public Utilities, and has only one small well withdrawing from the Castle Hayne aquifer. BSEP has no plans to change facility operations during the license renewal term. Progress Energy is in compliance with these policies.

Policy 8.1.5(c). Brunswick County will continue improvements to and expansion of the County's potable, piped water supply system, with emphasis on the development of a self supporting operation, where costs are assigned in relative proportion to benefits conveyed.

Policy 8.5.1 (d). So as to facilitate the orderly development of the County water system, Brunswick County shall establish and maintain utility extension and tap-on policies designed to address the timing, location, priorities and sequence, etc., for system expansion.

Progress Energy Response – These policies apply to County activities and are not relevant to BSEP or Progress Energy.

Policy 8.1.6. Brunswick County advocates the development and use of regional sewage treatment plants over smaller, privately operated package sewage treatment plants. When package treatment plants are employed, they should be designed to allow for future connections to a larger regional system.

Progress Energy Response – Progress Energy operates two package sewage treatment plants at BSEP, one inside and one outside of the protected area. Both are permitted under the NPDES permit. Although these plants could be connected to a regional sewage treatment plant or plants, Progress has no plans for doing so.

Policy 8.1.7(a). Brunswick County shall take a proactive role in the development of storm water management and design standards intended to protect the quality of the county's streams, rivers, marshes, and estuarine systems.

Policy 8.1.7(b). Brunswick County shall support a program of vegetated buffers adjacent to all streams, rivers, marshes, and estuarine waters in the county, with the intent of reducing the flow of nutrients and other contaminants into area surface waters.

Policy 8.1.7(c). Brunswick County shall advocate a policy of stormwater runoff management in which post-development runoff has a rate of flow and volume which approximates, as closely as practical, pre-development conditions.

Progress Energy Response – Progress Energy conducts all land-disturbing activities using policy EVC-SUBS-00022 Land Disturbing Activities which include procedures for minimizing stormwater discharges, maintaining sediment and erosion control measures, and protecting river buffers, wetlands and waters of the U.S. This policy includes full compliance with applicable state and federal stormwater and water quality regulatory programs.

Policy 8.1.8. This policy deals with marinas and commercial fishing operations. Because BSEP is not a marina and Progress Energy owns no marinas nor participates in any commercial fishing, this policy does not apply and is not presented here.

Policy 8.1.9. Industries shall be encouraged to locate in suitable, non-fragile areas. Environmental impacts on air, land, and water resources, as well as compatibility with surrounding land uses and the availability of required services, shall be factors employed in evaluating the merits of any particular industrial development proposal.

Progress Energy Response – BSEP became operational in the 1970s, after thorough regulatory review under the existing environmental protection programs. The site and surrounding land are zoned industrial. Progress Energy holds all appropriate permits for discharges to water and air. Progress Energy has no plans for refurbishment or major construction, or to change the plant operations during the license renewal term. Progress Energy is in compliance with this policy.

Policy 8.1.10. Development of sound and estuarine islands, while not encouraged, is permitted, providing the impacts on the natural environment are properly mitigated….

Progress Energy Response – BSEP is not on an island nor does Progress Energy own any islands in the vicinity of the site. This policy is not applicable to Progress Energy and BSEP.

Policy 8.1.11. Development within areas susceptible to sea level rise, shoreline erosion, and/or wetland loss, should take into consideration such conditions upon initial development.…The County will not permit efforts to harden the shoreline in an attempt to counteract such conditions; however, this policy shall not preclude the use of innovative shoreline preservation techniques as approved by the CRC.

Progress Energy Response – This policy deals with the possibility of sea level rise and shoreline erosion. BSEP is constructed on land not prone to flooding, according to Brunswick County land use maps. The Caswell Beach pumping station could be affected by a rise in sea level, but Progress Energy would modify the facility before rising sea levels caused erosion around the facility. All activities would be in compliance with existing regulations.

Policy 8.1.12. This policy deals with marina basins. The policy is not applicable to Progress Energy or BSEP and is not included here.

Policy 8.1.13. Brunswick County supports state and federal standards which seek to prevent or minimize marsh damage from bulkheads or riprap installation. The County recognizes, however, that some limited marsh damage may be necessary to provide for otherwise environmentally sound development.

Progress Energy Response – When BSEP was constructed, the native marsh grass (*Spartina*) was planted to control erosion of the intake and discharge canals' banks. Progress Energy supports alternative means of controlling erosion rather than riprap or other hardened structures.

Policy 8.1.14. Brunswick County shall encourage and support state and federal standards which seek to prevent or minimize adverse water quality impacts. The county shall work proactively with the state on measures to reduce stormwater runoff rates, soil erosion, and sedimentation, and point source discharges into area waters.

Progress Energy Response – Progress Energy conducts all land-disturbing activities using policy EVC-SUBS-00022 Land Disturbing Activities which include procedures for minimizing stormwater discharges, maintaining sediment and erosion control measures, and protecting river buffers, wetlands and waters of the U.S.

Policy 8.1.15. Brunswick County shall encourage and support state and federal standards which seek to prevent or minimize adverse air quality impacts. The County shall work constructively with state and federal agencies and local industries on measures to reduce or eliminate air quality problems, including odor problems that may not fall under prescribed environmental standards.

Progress Energy Response – Progress Energy operates several emergency diesel generators and boilers on an intermittent basis at BSEP. These sources are permitted under CAA Title V. There are no other sources of air pollutants at BSEP. The plant is not a source of noxious odors. Progress Energy is in compliance with this policy.

8.2. Resource Production and Management Policies

Progress Energy Response – This group of policies relates to the use and protection of natural resources, including agricultural land, mines, commercial forest lands, gamelands, and hunt clubs. Progress Energy manages pine plantations around BSEP for timber production and wildlife. All thinning, harvesting, and associated land preparation and maintenance are done under the direction of a registered forester, and follow best management practices and standard operating procedures. As previously mentioned, Progress Energy cooperates with the DENR Natural Heritage Program to identify and protect areas on transmission and distribution line rights-of-way that contain state- or federally-listed plants.

8.3. Economic and Community Development Policies

Progress Energy Response – This group of policies relates to economic and community development. BSEP is an established facility, with no plans to expand during the license renewal term, therefore, the policies are not relevant to the continued operation of BSEP and are not included here.

8.4. Public Participation Policies

Progress Energy Response – This group of policies relates to public participation in developing the land use plan, therefore, the policies are not relevant to the continued operation of BSEP and are not included here.

8.5. Storm Hazard Mitigation/Post-Disaster Recovery and Evacuation Policies and Plans

Progress Energy Response – This group of policies relate to the county's preparations for and response to a natural disaster, most likely a hurricane, therefore, the policies are not relevant to the continued operation of BSEP and are not included here. It can be noted that Progress Energy, as a provider of electricity in the region, and with a licensed nuclear facility, maintains extensive disaster and disaster recovery plans designed to ensure that the nuclear facility is maintained in a safe condition and that electricity is restored to the service area as quickly and efficiently as possible, in the event of a natural disaster. These plans are prepared in close cooperation with local governments, including Brunswick County.

Attachment E-3

Wilmington and New Hanover County Land Use Plan Policies

The Coastal Area Management Act passed by the North Carolina General Assembly in 1974 and approved by the federal government in 1978 requires that each county in the coastal area develop a land use plan and update it every five years, or the CRC will prepare and adopt a land use plan for that county. The most recent City of Wilmington and New Hanover County Land Use Plan (Ref. 2) available is the 1999 plan. Two transmission lines from Brunswick Steam Electric Plant run through New Hanover County. Maintenance practices in the transmission corridors were reviewed for consistency with the policies in the land use plan.

Natural Resource Policies

A. Resource Protection

<u>Water Quality</u> The City of Wilmington and New Hanover County will:

1.1. Prevent further deterioration of estuarine water quality and loss of public trust uses in the creeks and sounds and bring all coastal water quality up to its use designation….

1.2. Ensure the protection of water quality throughout the Cape Fear River Basin within New Hanover County and the management and maintenance of drainage within our coastal watersheds through participation in the development of regional water quality/stormwater management programs.

1.3. Ensure the protection, preservation and wise use of our natural resources by careful review and consideration of the anticipated impacts of development through the creation and implementation of and Environmental Review Program.

1.4. It is the intent of this plan to further provide for the protection and improvement of out water quality through our Unified Development Ordinance. ….

<u>Progress Energy Response</u> – Transmission corridors from BSEP cross tidal streams and wetlands in New Hanover County. Progress Energy performs all transmission corridor maintenance according to established procedures and best management practices, and in accordance with applicable state and federal regulations. These procedures and best management practices are intended to be protective of water quality in streams and wetlands crossed by Progress Energy transmission lines. The Progress Energy integrated vegetation management program specifically identifies that cut brush must be removed from water bodies so as not to impede flow, and that when cuts occur through existing canals, the canal must be restored to its original condition.

<u>Open Space</u> The City of Wilmington and New Hanover County will:

2.1 Ensure the preservation of adequate open space for its continued enjoyment and contribution to our community today and for generations to come, to protect our natural environment and wildlife habitats and to provide educational and recreational opportunities.

<u>Progress Energy Response</u> – Progress Energy manages the vegetation along the transmission corridors to enhance habitat for certain kinds of wildlife. Progress Energy is in compliance with this policy. As previously mentioned, Progress Energy cooperates with the DENR Natural Heritage Program to identify and protect areas on transmission and distribution line rights-of-way that contain state- or federally-listed plants.

2.2 Identify and protect wildlife corridors as a part of the greenway system and require their protection or mitigation with all new development.

2.3 Preserve Airlie Gardens…

2.4 Ensure the protection of our community's significant trees and the provision of adequate landscaping….

2.5 Provide for the protection, acquisition, and development of public shorefront and boat access areas.

Progress Energy Response – Policies 2.2 – 2.5 are not relevant to Progress Energy.

Natural Resource Constraints The City of Wilmington and New Hanover County will:

3.1 Preserve and restore shell fishing to all SA waters and bring all coastal waters designated or formerly SA up to their use designation.

3.2 Provide for the continued protection of the Cape Fear River from the cumulative impacts of development by ensuring that Industrial permitting does not exceed the River's carrying capacity and land disturbing activities are carefully reviewed and considered for their potential sedimentation/turbidity and nutrient impacts.

Progress Energy Response – Progress Energy has no plans to construct additional transmission lines during the BSEP license renewal term, so no land disturbing activities will occur. This policy is not relevant to the BSEP license renewal application.

3.3 Minimize dense development activities in ocean erodable areas, high hazard flood areas, inlet hazard areas, and coastal and federally regulated wetlands…

3.4 Ensure the protection of coastal and federally regulated wetlands that have important functional significance through early identification in the development process…

3.5 Ensure the protection of our undeveloped barrier and estuarine islands…

3.6 Carefully control development activities within the 100-year floodplain….

3.7 Require that the cumulative and secondary impacts of land use and development, and the limited carrying capacity of our coastal ecosystems be considered in all land use decisions…

3.8 Allow channel maintenance projects only where the public interest is preserved or enhanced, significant economic or recreational benefits will occur for planning area residents and no significant adverse impacts will occur on shoreline dynamics. Support state and federal channel and inlet maintenance projects, including the continued use and development of the Wilmington Harbor and the state Ports, maintenance of the Atlantic Intracoastal Waterway, and beach renourishment projects.

Progress Energy Response – Progress Energy periodically maintains the portion of the BSEP intake canal that crosses Snows Marsh. All maintenance is permitted by the Army Corps of Engineers and NCDENR and done to the requirements of the permit. Progress Energy is in compliance with this policy.

3.9 Allow estuarine shoreline erosion control only when the public trust interest is not adversely impacted and the public shoreline will be the primary beneficiary….

3.10 Carefully control development activities within the estuarine watersheds to prevent the degradation of water quality in the creeks and sounds, to protect public health, and to ensure the protection of these vital natural resources…

3.11 To preserve, protect, and where possible, restore water quality and vital estuarine resources, a naturally vegetated buffer … shall be established or maintained within established setback areas defined as Conservation Overlay Districts. The determination and management of buffers must balance the above stated goals with the property owner's right to develop and use the property….

3.12 Limit density in hydric soils and Areas of Environmental Concern (AECs) and encourage Planned Residential Development and Planned Unit Development to allow greater design flexibility to save trees and natural buffers.

3.13 Clearcutting or mowing of coastal wetland vegetation within any coastal wetland AEC shall not be allowed.

Progress Energy Response – Note that only two of the 13 policies under Natural Resource Constraints, policies 3.2 and 3.8, relate to the maintenance of infrastructure associated with the continued operation of BSEP and therefore are relevant to the BSEP license renewal application.

Areas of Environmental Concern The City of Wilmington and New Hanover County shall:

4.1 Prohibit use of estuarine waters, estuarine shorelines and public trust areas for development activity which would result in significant adverse impact to the natural function of these areas.

4.2 Carefully control development activities within AECs to prevent the degradation of water quality and to ensure the protection of these vital natural resources by reducing nutrient, pesticide, sediment, and other harmful loadings through the use of density control, setbacks, buffers, impervious surface limits, and other means….

4.3 Support the preservation, protection, and acquisition of the Masonboro Island Estuarine Research Reserve.

4.4 Discourage the development of undeveloped barrier and estuarine system islands

4.5 Continue the phased development and extension of the County sewer system …

4.6 Allow only tertiary sewage treatment plants….

4.7 Seek to provide additional boat access facilities

4.8 Allow the development of marinas…

4.9 Allow use of estuarine and public trust waters that provide benefits to the public and which satisfy riparian access needs of private property owners….

4.10 Not allow dredging activities in Primary Nursery Areas (PNA), Outstanding Resource Waters (ORW), or Shellfishing Waters (SA), except for the purpose of scientific research….

4.11 Clearcutting or mowing of coastal wetland vegetation within any coastal wetland AEC shall not be allowed.

Progress Energy Response – Progress Energy controls vegetation in transmission corridors according to established procedures and best management practices and in accordance with applicable state and federal regulations. Site-specific and terrain-appropriate methods to are used to control vegetation under transmission lines in wetland areas. These include mechanical (pruning, felling, and hand-clearing) and chemical control of unwanted vegetation. Heavy mowing equipment is not used in wetlands. EPA-registered herbicides approved for use in wetlands are sometimes used in small amounts when other methods of vegetation control are not feasible. Progress Energy has signed a Memorandum of Understanding with the N.C. Department of Environment and Natural Resources to cooperate in the management of rare plants, including wetland plants along power line corridors. Progress Energy is in compliance with this policy.

4.12 Prohibit floating home development….

4.13 Pursue a policy of "retreat" along our estuarine shorelines in order to accommodate future sea level rise and wetland migration.

4.14 Allow shoreline erosion control and stabilization above our marsh wetlands only where the public trust interest is not impacted and the public shoreline will be the primary beneficiary….

Progress Energy Response – Note that only one of the 14 policies under Areas of Environmental Concern, policy 4.11, relates to the maintenance of transmission corridors associated with continued operation of BSEP and is therefore relevant to the BSEP license renewal application.

Potable Water Supply – The City of Wilmington and New Hanover County shall:

5.1 Ensure that all land use and development decisions protect our groundwater aquifers

5.2 Not allow the development of mining operations…

5.3 Conserve and protect the best sources of potable surface and groundwater

5.4 Preserve the Castle Hayne and Pee Dee aquifers….

Progress Energy Response – These policies are not related to the maintenance of transmission corridors associated with the continued operation of BSEP.

Other Fragile or Hazardous Areas – The City of Wilmington and New Hanover County shall:

6.1 Continue to support plans for the safe transportation of hazardous materials, for the prevention and clean-up of spills of toxic materials, and the evacuation of area residents in response to natural or man-made hazardous events.

Progress Energy Response – Progress Energy transports hazardous materials to and from BSEP in Brunswick County. Some of these materials could pass through the Port of Wilmington or on roads through New Hanover County. All transportation of hazardous materials follows established Department of Transportation regulations for notification and transport. In addition, Progress Energy's emergency preparedness personnel are trained to clean up any hazardous material spills or protect the area in the unlikely event of an accident involving radioactive materials. In conjunction with county emergency response personnel, Progress Energy maintains emergency evacuation plans as part of its license requirements. Progress Energy is in compliance with this policy.

6.2 Carefully review the siting of all industries, including energy facilities and high voltage utilities, to ensure the protection of area residents and natural resources. Development of all offshore mineral, oil, and gas resources should be discouraged.

Progress Energy Response – Progress Energy has no plans to expand the operations at BSEP during the license renewal term. No construction activities are planned on any transmission corridor associated with BSEP, nor are new transmission corridors planned. This policy is not relevant to the BSEP license renewal application.

6.3 Ensure that industrial permitting on the Cape Fear River does not exceed the river's carrying capacity and that land disturbing activities are carefully reviewed and considered for their potential cumulative impacts.

6.4 Ensure the continued protection of the Masonboro Island Estuarine Research Preserve….

Progress Energy Response – Policies 6.3 and 6.4 are not related to the maintenance of transmission corridors associated with the continued operation of BSEP.

Air Quality -- The City of Wilmington and New Hanover County shall

7.1 Ensure the protection and enhancement of air quality in our community through continued commitment and actions to meet or exceed the Cape Fear Region's National Air Quality Standards.

Progress Energy Response – Progress Energy transmission lines cross New Hanover County. The NRC has determined that transmission lines do not contribute measurably to ambient levels of ozone and oxides of nitrogen and do not affect air quality; therefore, this policy is not relevant to BSEP license renewal.

B. Resource Production and Management

Progress Energy Response – These policies relate to the use and protection of natural resources, including agricultural land, mines, commercial forest lands, gamelands, and hunt clubs. The policies are not relevant to BSEP operations, including maintenance of transmission corridors, and are not included here.

Land Use and Urban Design Policies

Progress Energy Response – These policies relate to various types of land use designations in the county. The policies are not relevant to transmission lines location or maintenance and are not included here.

Transportation

Progress Energy Response – These policies relate to traffic and transportation issues in the county. The policies are not relevant to transmission lines location or maintenance and are not included here.

Community Infrastructure Policies

Progress Energy Response – These policies relate to municipal services and infrastructure in the county. The policies are not relevant to transmission lines location or maintenance and are not included here.

Housing Policies

Progress Energy Response – These policies relate to providing adequate housing for county residents. The policies are not relevant to transmission lines location or maintenance and are not included here.

Economic Development Policies

Progress Energy Response – These policies relate to ensuring a diverse economy in the county. The policies are not relevant to transmission lines location or maintenance and are not included here.

Historic Preservation Policies

Progress Energy Response – These policies relate to the preservation of historic resources in the county. Progress Energy has no plans to perform construction or maintenance activities below the surface on any transmission lines as a condition of license renewal. The policies are not relevant to license renewal and are not included here.

Storm and Natural Hazards Policies

Progress Energy Response – These policies relate to the county's preparations for and response to a natural disaster, most likely a hurricane. The policies are not relevant to transmission lines location or maintenance and are not included here.

Attachment E-4

Onslow County Land Use Plan Policies

The Coastal Area Management Act passed by the North Carolina General Assembly in 1974 and approved by the federal government in 1978 requires that each county in the coastal area develop a land use plan and update it every five years, or the CRC will prepare and adopt a land use plan for that county. The most recent Onslow County Land Use Plan (Ref. 3) available is the 1997 plan. One transmission line from Brunswick Steam Electric Plant runs to Jacksonville in Onslow County. Progress Energy has no plans to add additional lines in the existing transmission corridor as a result of BSEP license renewal. Maintenance practices in the transmission corridors were reviewed for consistency with the policies in the land use plan.

Resource Protection Policy Statements

Soils

(a) Onslow County opposes the installation of package treatment plants and septic tanks or discharge of wastes in any area classified as coastal wetlands, freshwater wetlands (404) or natural heritage areas.

(b) ….The county supports the protection of splashable wetlands as defined by Section 404…

<u>Progress Energy Response</u> – These policies relate to development in the county. Because license renewal will not require ay operational changes at BSEP, Progress Energy has no plans to change the way it operates and maintains the existing BSEP transmission lines. Likewise, Progress Energy has no plans to construct any additional lines in support of license renewal. Consequently, these policies are not relevant to the BSEP license renewal application. To the extent CWA is applicable, maintenance of lines are performed under Corps of Engineers' Nationwide Permit 12

Flood Hazard Areas

Onslow County desires to minimize the hazards to life, health, public safety, and development within flood hazard areas.

<u>Progress Energy Response</u> – This policy relates to minimizing flood hazards in the county. It is not relevant to maintenance procedures for BSEP-associated transmission lines in Onslow County and therefore is not relevant to the BSEP license renewal application.

Groundwater/Protection of Potable Water Supplies

It is the policy of Onslow County to conserve its surficial groundwater resources.

<u>Progress Energy Response</u> – This policy relates to groundwater protection. It is not relevant to maintenance procedures for BSEP-associated transmission lines in Onslow County and therefore is not relevant to the BSEP license renewal application.

Manmade Hazards

(a) Onslow County supports plans for expansion of the Albert Ellis Airport…

(b) With the exception of bulk fuel storage tanks used for retail and wholesale sales, and individual heating fuel storage tanks, Onslow County opposes the bulk storage of man-made hazardous materials….

(c) Onslow County is opposed to the establishment of toxic waste dump sites within the county including dump sites on military reservations.

(d) Onslow County opposed the disposal of any toxic wastes….within its planning jurisdiction.

<u>Progress Energy Response</u> – These policies relates to waste sites and fuel storage tanks. They are not relevant to maintenance procedures for BSEP-associated transmission lines in Onslow County and therefore not relevant to the BSEP license renewal application.

Stormwater Runoff

(a) Onslow County recognizes the value of water quality maintenance to the protection of fragile areas and to the provision of clean water for recreational purposes and supports the control of stormwater runoff to aid in the preservation of water quality.

(b) It is county policy to recognize shellfishing waters as a valuable resource and provide protection to this fragile resource…..

Progress Energy Response – These policies are related to reducing stormwater runoff. Progress Energy uses an integrated vegetation management program that protects vegetation and waterways the transmission corridors traverse. Any maintenance procedures that require earth moving are done according to best management practices and established corporate procedures for sedimentation and erosion control. Progress Energy is in compliance with this policy.

Cultural/Historic Resources

It is policy to preserve and protect the county's significant architectural, archaeological, and cultural resources.

Progress Energy Response – Progress Energy has no plans to perform construction or maintenance activities below the surface on any transmission lines during the license renewal term. This policy is not relevant to the BSEP license renewal application.

Industrial Impacts on Fragile Areas

Onslow County deems industrial development within fragile areas acceptable only if the following conditions are met:

(a) CAMA minor or major permits can be obtained.

(b) Applicable zoning ordinance provisions are met in zoned areas.

(c) Within coastal wetlands, estuarine waters, and public trust waters, no industrial use will be permitted unless such use is water related.

Progress Energy Response – Progress Energy has no plans to expand the transmission corridors or transmission lines as a result of BSEP license renewal. This policy is not relevant to any potential impacts from BSEP license renewal on Onslow County.

Miscellaneous Resource Protection

These policies relate to package treatment plants, marinas, mooring fields, off-road vehicles, development of islands, bulkhead construction, sea level rise, maritime forests, estuarine systems, outstanding resource waters, and water quality management.

Progress Energy Response – These policies are not relevant to any potential impacts from BSEP license renewal on Onslow County.

Resource Production and Management Policies

Progress Energy Response – These policies relate to recreation resources, productive agricultural lands, aquaculture, productive forestlands, development, marine resource areas, and mining and are not relevant to any potential impacts from BSEP license renewal on Onslow County.

Economic and Community Development Policies

Progress Energy Response – These policies relate to water, sewer, and solid waste infrastructure; energy facility siting and development; redevelopment; urban growth patterns; estuarine access; types and locations of desired industry; commitment to state and federal programs; channel maintenance and interstate (sic) waterways; tourism; transportation; and land use trends and are not relevant to any potential impacts from BSEP license renewal on Onslow County.

Attachment E-5

Pender County Land Use Policies

The Coastal Area Management Act passed by the North Carolina General Assembly in 1974 and approved by the federal government in 1978 requires that each county in the coastal area develop a land use plan and update it every five years, or the CRC will prepare and adopt a land use plan for that county. The most recent Pender County Land Use Plan (Ref. 4) available is the 1991 plan, with amendments through 2001. Two transmission lines from Brunswick Steam Electric Plant cross Pender County. Maintenance practices in the transmission corridors were reviewed for consistency with the policies in the land use plan.

Resource Protection Policy Statements

1. Areas of Environmental Concern and Appropriate Land Use in AECs

   Pender County will permit those land uses which conform to the general use standards of the North Carolina Administrative Code for development within the estuarine system. Generally only those uses which are water-dependent will be permitted.

   <u>Progress Energy Response</u> -- The transmission lines in Pender County will be maintained according to established practices and procedures. No development will occur. These policies are not relevant to any potential impacts from BSEP license renewal on Pender County.

2. Constraints to Development Including Flood Prone Areas, Soil Suitability and Septic Tank Use

   County Policy will be to permit development which is proposed to be located outside hydric soil areas and meets all zoning, Health Department and flooding regulations and other State and federal regulations.

   <u>Progress Energy Response</u> – The transmission lines in Pender County will be maintained according to established practices and procedures. No development will occur. These policies are not relevant to any potential impacts from BSEP license renewal on Pender County.

3. Development Density in Proximity to Designated Outstanding Resource Waters

   Pender County policy shall be to protect the water quality in designated ORW waters and in waters within 1,000 feet of designated ORW waters. Development density in proximity to designated Outstanding Resource waters and within ORW buffer zones hall be only that allowed under applicable CAMA regulations or locally adopted regulations.

   <u>Progress Energy Response</u> – The transmission lines in Pender County will be maintained according to established practices and procedures. No development will occur. These policies are not relevant to any potential impacts from BSEP license renewal on Pender County.

4. Other Hazard or Fragile Land Areas

   (a) maritime forests – there are no known significant stands of maritime forest

   (b) freshwater swamps – Pender County policy shall be to continue to support the U.S. Army Corps of Engineers 404 program which has jurisdiction in regulating development in freshwater swamp and freshwater marsh areas and pocosins.

   (c) Other fragile areas – county policy on ORS is outlined in Section III.3 of this plan.

   <u>Progress Energy Response</u> – The transmission lines in Pender County will be maintained according to established practices and procedures. No development will occur. These policies are not relevant to any potential impacts from BSEP license renewal on Pender County.

5. Hurricane and Flood Evacuation Needs -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.

6. Protection of Potable Water Supply -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
7. Use of Package Treatment Plants -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
8. Stormwater Runoff – This policy refers to efforts the county is making to establish a conservation district in the zoning ordinance, and to establish better stormwater management controls in new developments. The policies are not relevant to the operation of BSEP transmission lines on Pender County.
9. Marinas and Floating Home Development and Dry Stack Facilities -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
10. Industrial Impact on Fragile Areas -- Pender County policy will be to continue to support applicable State and Federal regulations as they relate to the siting of new or expanded industry or impact of new or expanded industry on environmentally sensitive areas. This policy is not relevant to the maintenance of transmission lines in Pender County.
11. Development of Sound and Estuarine System Islands -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
12. Restriction of Development in Areas up to Five Feet Above Mean High Water -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
13. Upland Excavation for Marina Basins -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
14. Damaging of Existing Marshes by Bulkhead Installation -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.

Resource Production and Management Policies

Progress Energy Response – These policies relate to recreation resources, productive agricultural lands, aquaculture, productive forestlands, development, marine resource areas, and mining and are not relevant to any potential impacts from BSEP license renewal on Pender County.

Economic and Community Development Policies

Progress Energy Response – These policies relate to highway and port facility improvements; energy facility siting; redevelopment; urban growth patterns; estuarine access; types and locations of desired industry; commitment to state and federal programs; channel maintenance and dredging; tourism; recreation; transportation; and land use trends and are not relevant to any potential impacts from BSEP license renewal on Pender County.

Storm Hazard Mitigation and Post Disaster Reconstruction Policies

Progress Energy Response – These policies are related to planning before and recovery after a hurricane and are not relevant to any potential impacts from BSEP license renewal on Pender County.

References

1. Brunswick County Board of Commissioners. 1997. Brunswick County Land Use Plan. 1997 Update.
2. Wilmington City Council and New Hanover County Board of Commissioners. 1999. Wilmington – New Hanover County CAMA Land Use Plan Update and Comprehensive Plan.
3. Onslow County Board of Commissioners. 2000. Onslow County, North Carolina 1997 Land Use Plan Executive Summary.
4. Howard T. Capps and Associates. 2001. 1991 Pender County Land Use Plan Update.

APPENDIX F

SEVERE ACCIDENT MITIGATION ALTERNATIVES

TABLE OF CONTENTS

Section Page

F.1 METHODOLOGY ... 1
F.1.1 BSEP Specific SAMA ... 2
F.1.2 EXTERNAL EVENTS ... 2
F.1.2.1 Use of External Events in the BSEP SAMA Analysis ... 2
F.1.2.1.1 Fires ... 3
F.1.2.1.2 Seismic ... 8
F.1.2.1.3 High Winds ... 9
F.1.2.1.4 Transportation and Nearby Facility Accidents ... 10
F.1.2.1.5 Quantitative Strategy for External Events ... 12
F.2 BSEP PSA MODEL ... 13
F.2.1 PSA Model Changes Since IPE Submittal ... 13
F.2.1.1 1993 IPE Update ... 14
F.2.1.1.1 Initiating Events ... 14
F.2.1.1.2 Event Trees ... 15
F.2.1.1.3 Fault Trees ... 15
F.2.1.1.4 Human Reliability Analysis (HRA) ... 16
F.2.1.1.5 Component Performance Data ... 16
F.2.1.1.6 Industry Operating Experience ... 17
F.2.1.2 1994 IPE Update ... 17
F.2.1.3 1996 IPE Update ... 17
F.2.2 Current Level 1 BSEP PSA Model ... 18
F.2.3 Current Level 2 BSEP PSA Model ... 19
F.2.3.1 BSEP Level 2 PSA Release Categories ... 20
F.2.3.2 BSEP Level 2 PSA Source Terms ... 22
F.2.4 BSEP PSA Review Summary ... 22
F.2.4.1 Impact on the SAMA Analysis of Unresolved PSA Review Comments ... 23
F.3 Level 3 PSA Analysis ... 25
F.4 BASELINE RISK MONETIZATION ... 28
F.4.1 Off-Site Exposure Cost ... 28
F.4.2 Off-Site Exposure Cost ... 28
F.4.3 Off-Site Economic Cost Risk (OECR) ... 29
F.4.4 On-Site Exposure Cost Risk ... 29
F.4.5 On-Site Cleanup and Decontamination Cost ... 31
F.4.6 Replacement Power Cost ... 32
F.4.7 Total ... 32
F.5 PHASE I SAMA ANALYSIS ... 33
F.5.1 SAMA Identification ... 33
F.5.1.1 Level 1 BSEP Importance List Review ... 33
F.5.1.2 Level 2 BSEP Importance List Review ... 34
F.5.1.3 Industry Phase II SAMAs ... 34

F.5.1.4 BSEP IPE ... 35
F.5.1.5 BSEP IPEEE ... 35
F.5.2 Phase I Analysis ... 36
F.6 PHASE II SAMA ANALYSIS ... 37
F.6.1 Phase II SAMA Number 1: Portable DC Generator ... 37
F.6.1.1 PSA Model Results for Phase II SAMA Number 1 ... 39
F.6.2 Phase II SAMA Number 3: Provide the Main Control Room with the Capability to Align the UAT to the "E" Buses ... 40
F.6.2.1 PSA Model Results for Phase II SAMA Number 3 ... 40
F.6.3 Phase II SAMA Number 4: Direct Drive Diesel Injection Pump ... 41
F.6.3.1 PSA Model Results for Phase II SAMA Number 4 ... 42
F.6.4 Phase II SAMA Number 5: Enhanced CRD Flow ... 43
F.6.4.1 PSA Model Results for Phase II SAMA Number 5 ... 43
F.6.5 Phase II SAMA Number 6: Proceduralize All Potential 4KV AC Bus Cross-Tie Actions ... 44
F.6.5.1 PSA Model Results for Phase II SAMA Number 6 ... 45
F.6.6 Phase II SAMA Number 10: Improved Procedures/Equipment to Prevent Boron Dilution ... 46
F.6.6.1 PSA Model Results for Phase II SAMA Number 10 ... 47
F.6.7 Phase II SAMA Number 11: Enhance the Main Control Room (MRC) to Include Capability to Perform 480V AC Substation Cross-Tie ... 47
F.6.7.1 PSA Model Results for Phase II SAMA Number 11 ... 48
F.6.8 Phase II SAMA Number 12: Enhance the Main Control Room (MCR) to Include Capability to Align the Alternate DC Power Supply to Specific DC Panels ... 49
F.6.8.1 PSA Model Results for Phase II SAMA Number 12 ... 49
F.6.9 Phase II SAMA Number 13: Inter-Unit CRD Cross-Tie ... 50
F.6.9.1 PSA Model Results for Phase II SAMA Number 13 ... 51
F.6.10 Phase II SAMA Number 15: Diverse EDG Hvac Logic ... 52
F.6.10.1 PSA Model Results for Phase II SAMA Number 15 ... 53
F.6.11 Phase II SAMA Number 16: Diverse Swing DG Air Compressor ... 54
F.6.11.1 PSA Model Results for Phase II SAMA Number 16 ... 54
F.6.12 Phase II SAMA Number 17: Provide Alternate Feeds to Panels Supplied Only by DC Bus 2A-1 ... 55
F.6.12.1 PSA Model Results for Phase II SAMA Number 17 ... 56
F.6.13 Phase II SAMA Number 18: Provide Alternate Feeds to Essential Loads Directly from an Alternate "E" Bus ... 57
F.6.13.1 PSA Model Results for Phase II SAMA Number 18 ... 58
F.6.14 Phase II SAMA Number 19: Provide an Alternate Means of Supplying the Instrument Air Header ... 58
F.6.14.1 PSA Model Results for Phase II SAMA Number 19 ... 59
F.6.15 Phase II SAMA Number 20: Enhance the Main Control Room (MCR) to Include Capability to Swap AC Power Supplies to the Battery Chargers 60
F.6.15.1 PSA Model Results for Phase II SAMA Number 20 ... 61
F.6.16 Phase II SAMA Number 21: Enhance CRD logic ... 61
F.6.16.1 PSA Model Results for Phase II SAMA Number 21 ... 62

F.6.17 Phase II SAMA Number 22: Install Self Cooled CRD pumps.................. 63
F.6.17.1 PSA Model Results for Phase II SAMA Number 22................ 64
F.6.18 Phase II SAMA Number 29: Portable EDG Fuel Oil Transfer Pump....... 64
F.6.18.1 PSA Model Results for Phase II SAMA Number 29................ 65
F.6.19 Phase II SAMA Number 30: Improve Alternate Shutdown Panel............ 66
F.6.20 Phase II SAMA Number 31: Improved Alternate Shutdown Training and Equipment.. 68
F.6.21 Phase II SAMA Number 32: Add Automatic Fire Suppression System... 69
F.6.22 Phase II SAMA Number 33: Improve Fire Barriers Between Cabinets in the Cable Spreading Room.. 72
F.6.23 Phase II SAMA Number 35: Use Firewater as a Backup for EDG Cooling 74
F.6.23.1 PSA Model Results for Phase II SAMA Number 35................ 75
F.6.24 Phase II SAMA Number 36: Use Fire Water as a Backup for Containment Spray 75
F.6.24.1 PSA Model Results for Phase II SAMA Number 36................ 76
F.6.25 Phase II SAMA Number 37: Low Pressure RCIC Operation................... 77
F.6.25.1 PSA Model Results for Phase II SAMA Number 37................ 78
F.6.26 Phase II SAMA Number 25: Proceduralize Battery Charger High voltage Shutdown Circuit Inhibit 79
F.6.26.1 PSA Model Results for Phase II SAMA Number 25................ 80
F.6.27 Phase II SAMA Number 34: Supplemental Power Supplies for Offsite Power Recovery After Battery Depletion During SBO 81
F.6.27.1 PSA Model Results for Phase II SAMA Number 34................ 82
F.6.28 Phase II SAMA Analysis Summary... 83
F.7 UNCERTAINTY ANALYSIS.. 84
F.7.1 Real Discount Rate... 84
F.7.2 95th Percentile PSA Results.. 86
F.8 CONCLUSIONS 88
F.9 TABLES AND FIGURES.. 89
F.10 REFERENCES 181

ADDENDUM TO APPENDIX F SEVERE ACCIDENT MITIGATION ALTERNATIVES... 185

List of Tables

Table Page

Table F-1 Summary of the Core Damage Frequency by Accident Sequence Subclass for Brunswick Unit 2 90
Table F-2 Release Severity and Timing Classification Scheme (Severity, Timing) 92
Table F-3 Summary of Containment Evaluation 92
Table F-4 Summary of BSEP Unit 2 Level 2 Release Category Frequencies(1), (2) 93
Table F-5 BSEP Source Term Summary 94
Table F-6 Estimated Population Distribution within a 10-Mile Radius of BSEP, Year 2036 95
Table F-7 Estimated Population Distribution within a 50-Mile Radius of BSEP, Year 2036 96
Table F-8 Estimated Annual Population Growth Rate within a 10-Mile Radius of BSEP 97
Table F-9 Estimated Annual Population Growth Rate within a 10 to 50-Mile Radius of BSEP 98
Table F-10 Estimated BSEP Core Inventory 99
Table F-11 MACCS Release Categories vs. BSEP Release Categories 100
Table F-12 Results of BSEP Level 3 PSA analysis 101
Table F-13 Level 1 Importance List Review 102
Table F-14 Level 2 Importance List Review 113
Table F-15 Phase I SAMA 125
Table F-16 Phase II SAMA 148

List of Figures

Figure Page

Figure F-1 SAMA Screening Process 174
Figure F-2 Brunswick Unit 2 MOR03 Contribution to CDF by Initiator 175
Figure F-3 Contribution to CDF by System 176
Figure F-4 System RAW Ranking (CDF) 177
Figure F-5 Summary of Release Magnitudes 178
Figure F-6 Comparison of Contributors to the LERF Category 179
Figure F-7 Total CDF Distribution Relative to LERF 180

Acronyms Used in Appendix F

ADM	Archer Daniel Midland
ADS	Automatic Depressurization System
ATWS	Anticipated Transient Without Scram
BOP	Balance of Plant
BSEP	Brunswick Steam Electric Plant
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
CAC	Containment Atmospheric Control
CCF	Common Cause Failure
CDF	Core Damage Frequency
CET	Containment Event Tree
CRD	Control Rod Drive
CP&L	Carolina Power & Light
CST	Condensate Storage Tank
CSW	Conventional Service Water
DDDIP	Direct Drive Diesel Injection Pump
DG	Diesel Generator
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOPs	Emergency Operating Procedures
EPU	Extended Power Uprate
EPZ	Emergency Planning Zone
FIVE	Fire Induced Vulnerability Evaluation
GIS	Geographic Information System
HCTL	Heat Capacity Temperature Limit
HEP	Human Error Probability
HPCI	High Pressure Coolant Injection
HRA	Human Reliability Analysis
HVAC	Heating Ventilating Air Conditioning
IA	Instrument Air
IDCOR	Industry for Degraded Core Rulemaking
INEL	Idaho National Engineering Laboratory
INPO	Institute of Nuclear Power Operations
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination – External Events
ISLOCA	Interfacing System LOCA
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
MAAP	Modular Accident Analysis Program
MACCS2	MELCOR Accident Consequences Code System, Version 2
MCC	Motor Control Center

Acronyms Used in Appendix F

MCR	Main Control Room
MACR	Maximum Averted Cost-Risk
MMACR	Modified Maximum Averted Cost-Risk
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
MWe	Megawatts-electric
MWt	Megawatts-thermal
NEI	Nuclear Energy Institute
NPSH	Net Positive Suction Head
NRC	U.S. Nuclear Regulatory Commission
NSW	Nuclear Service Water
NUMARC	Nuclear Management and Resources Council
OCB	Oil Circuit Breaker
OECR	Off-site economic cost risk
PCB	Power Circuit Breaker
PCPL	Primary Containment Pressure Limit
PRA	Probabilistic Risk Analysis
PSA	Probabilistic Safety Assessment
PWR	Pressurized Water Reactor
RAI	Request for Additional Information
RAW	Risk Achievement Worth
RBCCW	Reactor Building Closed Cooling Water
RCIC	Reactor Core Isolation Cooling
RDR	Real Discount Rate
RHR	Residual Heat Removal
RFP	Reactor Feed Pump
RLE	Review Level Earthquake
RPV	Reactor Pressure Vessel
RRW	Risk Reduction Worth
RWCU	Reactor Water Cleanup
SAIC	Science Applications International Corporation
SAMA	Severe Accident Mitigation Alternative
SAMGs	Severe Accident Management Guidelines
SAT	Startup Auxiliary Transformer
SBO	Station Blackout
SER	Significant Event Report
SJAE	Steam Jet Air Ejector
SLC	Standby Liquid Control
SLOCA	Small Loss of Coolant Accident
SOER	Significant Operating Event Review
SP	Suppression Pool
SRV	Safety Relief Valve
SSE	Safe Shutdown Equipment
TE	Loss of Offsite Power Event Tree or Initiating Event

Acronyms Used in Appendix F

UAT	Unit Auxiliary Transformer
USI	Unresolved Safety Issue

Appendix F
Severe Accident Mitigation Alternatives

The severe accident mitigation alternatives (SAMA) analysis discussed in 4.20 is presented below.

F.1 METHODOLOGY

The methodology selected for this analysis involves identifying SAMA candidates that have the highest potential for reducing core damage frequency and person-rem and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. This process consists of the following steps:

- **BSEP Probabilistic Safety Assessment (PSA) Model** – Use the BSEP Internal Events PSA model as the basis for the analysis (Section F.2). Incorporate External Events contributions as described in Section F.1.2.

- **Level 3 PSA Analysis** – Use BSEP 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 probabilistic safety assessment (PSA) using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section F.3). Incorporate External Events contributions as described in Section F.1.2.

- **Baseline Risk Monetization** – Use NRC regulatory analysis techniques, calculate the monetary value of the unmitigated BSEP severe accident risk. This becomes the maximum averted cost-risk that is possible (Section F.4).

- **Phase I SAMA Analysis** – Identify potential SAMA candidates based on the BSEP PRA, IPEEE, and documentation from the industry and the NRC. Screen out Phase I SAMA candidates that are not applicable to the BSEP design or are of low benefit in boiling water reactors (BWRs) such as BSEP, candidates that have already been implemented at BSEP or whose benefits have been achieved at BSEP using other means, and candidates whose estimated cost exceeds the maximum possible averted cost-risk (Section F.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 any net cost benefit. Probabilistic safety assessment (PSA) insights are also used to screen SAMA candidates in this phase (Section F.6).

- **Uncertainty Analysis** – Evaluate how changes in the SAMA analysis assumptions might affect the cost/benefit evaluation (Section F.7).

- **Conclusions** – Summarize results and identify conclusions (Section F.8).

The steps outlined above are described in more detail in the subsections of this appendix and Figure F-1 provides a graphical representation of the SAMA process.

F.1.1 BSEP SPECIFIC SAMA

The initial list of SAMA candidates for BSEP was developed from a combination of resources. These include the following:

- BSEP PRA results
- Industry Phase II SAMAs [References 3, 4, 5, 6, 7, 8]
- BSEP IPE [Reference 9]
- BSEP IPEEE [Reference 10]

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 BSEP.

In addition, a generic SAMA list has been included in Addendum (see Table A-1). This list was compiled as part of the development of several industry SAMA analyses. It has been used in the BSEP SAMA analysis as a reference source to identify the types of plant changes that could be suggested to improve selected functions of the plant. Specifically, the list was used to help correlate events in the BSEP importance listings with potential plant improvements. The details of the SAMA identification process are provided in Section F.5.1.

F.1.2 EXTERNAL EVENTS

External events have been identified by the nuclear industry as non-negligible contributors to plant risk. While the focus of nuclear PSA applications has typically been on internal events models, efforts have been made to expand the types of PSA insights used in the SAMA analysis to include external events issues.

The Brunswick External Events analysis has not been maintained as a “living” analysis. The documentation and results are limited to what was produced during the performance of the IPEEE. As a result, any qualitative insights or quantitative estimates related to external events used in the SAMA analysis must be extrapolated based on existing information. As a result, external events models are considered to be useful tools for identifying important accident sequences and mitigative equipment, but the quantitative results should not be directly combined with those from the internal events models.

F.1.2.1 USE OF EXTERNAL EVENTS IN THE BSEP SAMA ANALYSIS

The IPEEE was used in the BSEP SAMA analysis primarily to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences. The available results allowed review of the following types of initiators not addressed by the internal events model:

- Fires
- Seismic events
- High wind events
- Transportation and nearby facility accidents

The type of information available for these initiators varied due to the manner in which they were addressed in the IPEEE. For instance, the fire analysis was performed using a combination of standard PSA modeling techniques and the EPRI FIVE methodology, which produced results similar to those yielded by the internal events analysis. However, the seismic margins analysis does not produce a core damage frequency and is predicated on the ability to evaluate the seismic durability of the equipment required to safely shut the plant down. The results of this kind of analysis do not directly lend themselves to the type of frequency-based analysis implemented in the SAMA evaluation. 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 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.

F.1.2.1.1 Fires

<u>Overview of Fire PRA Development</u>

As discussed above, the techniques used to model external events vary according to the type of initiator being analyzed. The BSEP 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 associated figure of merit, CDF, may introduce different levels of modeling uncertainty than the internal events PRA.

The uncertainties generally reflect the following:

- lack of adequate data for initiating events
- lack of realistic fire modeling capabilities including mitigation
- lack of ability to track all cables (e.g., BOP cables)
- uncertainty in crew response, especially for control room fires, and their modeling
- limited peer reviews that examine the need for realism instead of conservatism

In many cases, analysts choose to address these uncertainties by incorporating margin into the analysis (i.e., conservative assumptions).

Elements of Fire PRA

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 calculated core damage frequency figure of merit between the internal events PRA and the fire PRA. These areas are identified as follows:

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 steps at utilities.
System Response:	Fire protection 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. Cable routings are typically characterized conservatively because of the lack of data regarding the routing of cables or the lack of the analytic modeling to represent the different routings. This leads to limited credit for balance of plant systems that are extremely important in CDF mitigation.
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.
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 and consequential system damage.

Quality of Model: The peer review process for fire PRAs is less well developed than for 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.

Fire PRA Modeling Summary

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 figure of merit 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.

BSEP Fire Model

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 BSEP. The fire risk at Brunswick has been shown to be dominated by control room fires (CB-21, CB-23) (53.3 percent of the fire CDF). Several other major contributors have also been identified and include the following fire compartments as documented in Reference 39:

- RB2-1g(NC): 20’ level of the reactor building north central (8.7 percent)
- RB2-1g(NW): 20’ level of the reactor building north west (4.4 percent)
- CB-06: Unit 2 cable spreading room (4.3 percent)
- DG-14: E4 switchgear room (3.0 percent)
- DG-9: E8 switchgear room (3.0 percent)

Detailed information about accident sequence progression for these fire compartments is not currently available. The core damage frequencies for the fire compartments are documented, but the relative importance of specific equipment is not typically contained in the available documentation. General descriptions of the fire compartments are available, however, and these have been used to identify potential plant improvements.

Control Room Fires

A major contributor to the core damage frequency for control room fires is the failure to operate the plant from outside the control room. The total failure probability assigned to this action is 0.1 and is considered to be comprised of failures to 1) coordinate actions between operators, 2) failures of communication between local operators due to technical difficulties with communications equipment, and 3) improper operation of equipment. The ex-control room hardware failure probability is 1.5E-2, but these failures are not addressed here. Based on this information, the following SAMAs have been identified that may reduce plant risk:

- Enhance the alternate shutdown panel such that at least one complete division of controls is available to all equipment that would normally be used to place the plant in a safe, stable state. This could further be improved by adding controls for both divisions of equipment.

- Enhance the training the operators receive on operating the plant from outside the control room and improve the ex-control room communications equipment.

- Automatic CO_2 suppression could be added to the control room cabinets to ensure rapid fire mitigation and avoid control room evacuation.

These SAMAs have been incorporated into the initial BSEP list. Other SAMAs related to equipment improvements/additions are possible, but the human error of operating the plant outside the control room dominates the results. In addition, given that the dominant contributor to control room fires are those fires which do not damage vital equipment and only require evacuation of the MCR, the equipment response is considered to be similar to what is modeled in the internal events PRA model. This indicates that the fire related benefit of a given SAMA may be proportional to the internal events results.

20’ Level of the Reactor Building North Central

The fire contributors for this area are comprised of cable fires originating in the cable tray located 20 feet above the floor and in the MCCs directly below the cable tray. The critical equipment damaged in these fires includes RHR train “A” and E7. RHR train “B” is assumed to be recoverable outside the control room.

No automatic fire suppression is available for this area. Addition of automatic fire suppression equipment may reduce the fire risk in this area. This change has been included in the BSEP SAMA list.

Control of E7 is failed by some fire scenarios, but it is assumed to be recoverable through local action. No additional SAMAs have been suggested to mitigate loss of E7.

While failure of the “A” RHR train is a significant impediment, no potentially cost effective SAMAs have been specifically included in the BSEP SAMA list to mitigate this damage. Independent injection pumps and alternate DHR methods may improve plant

response, but these types of SAMAs have already been included based on the review of the internal events importance list.

20’ Level of the Reactor Building North West

The consequences of a fire in this compartment are nearly identical to those described for the North area with the exception that no MCCs are identified as failed items or as ignition sources. The conclusions are considered to be the same as those made for the North Central area.

Unit 2 Cable Spreading Room

The Cable Spreading Room contains cables for both division 1 and division 2 equipment. Failure of these cables will result in the loss of equipment control in the main control room and will require evacuation for shutdown with the alternate shutdown panel.

The main contributors to Cable Spreading Room Fires are transient fires that are not suppressed prior to extensive cable damage. While automatic actuation of fire suppression is available, the Cable Spreading Room is not constantly manned, which limits the credit for early identification and suppression of fires. A potential means of reducing the fire risk for this area would be to post a fire watch; however, a more cost-effective means of reducing risk would be to limit the transient combustibles allowed into the cable spreading room. The transient fire initiating event frequency for cable spreading room fires is dominated by welding work. Prohibiting welding while the plant is at-power and/or requiring a fire suppression person to be present for any welding work may have the greatest impact on reducing fire risk in this area. This potential change has been included in the BSEP SAMA list.

It has also been noted that not all electrical cabinets contain vital cables; however, a fire in one of these cabinets is assumed to spread to any attached cabinet. As a result, vital cables are assumed to be damaged even if a fire starts in a non-vital cabinet. Improved fire barriers between cabinets is another potential means of reducing fire risk in the Cable Spreading Room. This change has been included in the BSEP SAMA list.

Improvements in alternate shutdown capabilities would also reduce risk in this area. These SAMAs have been addressed as described in the Control Room fire section above.

E4 Switchgear Room

Fire in this area is important due to its impact on the E8 substation. E8 supports equipment such as MSIVs, the division “B” battery chargers, some division “B” of RHR components, and two of three containment vent paths. Recovery from a fire in this area is possible and effectively mitigated by performing a cross-tie between E7 and E8 (the fire only fails the supply to E8, not E8 itself).

The following changes have been identified as potential means of reducing the fire risk in this area:

- Provide remote cross-tie capability to improve E7-E8 cross-tie reliability (Already included in the BSEP SAMA list based on PSA results)

- Install automatic fire suppression equipment in the Switchgear Rooms (included in BSEP SAMA list).

The initiating event frequency is based on the breaker cubicles in the bus and no potentially cost effective methods have been identified to reduce the ignition frequency.

E8 Switchgear Room

The E8 switchgear is the only fire initiator and the only component of interest in this room. A fire in the switchgear is assumed to fail the entire switchgear and precludes recovery by cross-tying to the E7 substation. Otherwise, the consequences and conclusions for this fire area are the same as those for the E4 Switchgear Room.

F.1.2.1.2 Seismic

The EPRI seismic margins methodology [Reference 12] 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 seismic induced core damage frequency, this was not performed as part of the Brunswick IPEEE. In addition, the pedigree of information is not equivalent to what is used in the internal events models and it is not considered appropriate to combine the internal events and seismic core damage frequencies.

The nature of the seismic model limits its use in the SAMA analysis compared with the internal events model. The results of the IPEEE seismic analysis were reviewed in order to identify either of the following:

- 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 pursued due to cost considerations

At the time the IPEEE was completed, the USI A-46 analysis was not completed and was identified as an open item. After the submittal of the BSEP IPEEE, this item was addressed to the satisfaction of the NRC and closed out as documented in Reference 13.

Based on review of the IPEEE seismic results, no plant enhancements were identified and then not pursued based on cost concerns for Brunswick.

F.1.2.1.3 High Winds

The high wind risk at BSEP was examined for tropical storms, non-tropical storms, and tornadoes. Given the equipment required for safe shut down of the plant is contained in buildings designed for 360 mph winds, the risk posed to the plant from these types of events was considered to be due to loss of additional support systems outside of the class 1 structures.

Based on the site's tornado frequency, corresponding wind speeds, and damage potential, tornado risk was judged to be bounded by hurricane winds. Further examination of hurricane winds showed that the BSEP switchyard was the most vulnerable to these types of events.

The potential damaging factors included both high wind and flooding due to storm surge. Switchyard damage due to storm surge flood was determined to be possible; however, the frequency was estimated to be a factor of 20 less than damage due to high winds. In addition, the wind conditions required to cause the postulated storm surge flood would fail the switchyard without the flood effects. More detailed flood analysis showed that the potential flood conditions at BSEP would not fail the Reactor Building, Control Building, Service Water Building, or the diesel generator/diesel generator fuel oil vaults. For these reasons, the loss of the switchyard due to high wind was determined to be the most critical component of the high wind analysis.

The conditional core damage frequency developed for the loss for the switchyard (extended LOOP) combined with the Probable Maximum Hurricane wind initiating event frequency was below the cutoff frequency for the IPEEE (1E-6/yr) and no further analysis was considered to be required.

Enhancements to the switchyard and offsite power connections to prevent damage from high winds are possible, but these kinds of improvements are highly resource intensive. For instance, the installation of underground offsite power lines would improve the reliability of offsite power at the plant given high winds, but the cost of this improvement has been estimated to exceed $25 million (Reference 3). In addition, the switchyard itself would have to be placed in a Class 1 structure (or some equivalent enhancement) in order to take advantage of the available power. This upgrade would inflate the cost of implementation beyond the original estimate. The installation of additional sources of emergency onsite power are also effective means of reducing the plant risk due to high winds. As a fifth diesel generator is already included in the BSEP SAMA list, no additional SAMA has been added. It should also be noted that because the estimated high wind core damage frequency is low, the high wind component of any SAMA's averted cost-risk would be minimal.

Given the low potential for identifying cost-beneficial SAMAs to mitigate the risk posed by high winds, no further effort was made in the SAMA analysis to develop high wind related SAMAs.

F.1.2.1.4 Transportation and Nearby Facility Accidents

Transportation and nearby facility accidents were included in the IPEEE to account for human errors outside the normal operation of BSEP. The types of hazards identified for analysis included:

- Aircraft Impact
- Industrial Accidents
- Military Accidents
- Pipeline Accidents
- Hydrogen Storage Failures
- Transportation Accidents

In general, these threats were analyzed and determined to be dominated by the fire and high wind events described above. A short summary of each of these reviews has been provided for completeness.

<u>Aircraft Impact</u>

At the time the IPEEE was performed, available information related to military, commercial, and general aviation traffic was used to estimate a core damage frequency caused by aircraft impact. Given the information and conditions present at the time of the analysis, the CDF was determined to be less than 1E-6/yr and further analysis was not considered warranted.

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. No SAMAs were developed to mitigate aircraft impact events.

<u>Industrial Accidents</u>

The BSEP IPEEE reviewed the types of industry present around the site in order to determine if any of the facilities posed a hazard to the safe operation of the plant. The following facilities were identified as potential hazards:

- Archer Daniel Midland (ADM) Company
- A natural gas pipeline
- Cogentrix Southport Cogeneration Plant

It was determined that ADM only produced citric acid and had no known explosive materials on-site. Any threat posed by ADM was considered to be bounded by Military Ocean Terminal Sunny Point (included in Military Accidents).

The natural gas pipeline is included below in the Pipeline Accidents subsection.

Southport Cogeneration Plant, owned and operated by Cogentrix Energy, Inc., is a coal-fired power plant that provides steam to ADM and electric power for sale to Progress Energy. The worst postulated accident based on the operation of the Cogentrix facility was a turbine missile ejection or a high energy steam line break. These events were considered to be less severe than the same events occurring at BSEP due to scale of size considerations and the space between the sites. As these are design base accidents at BSEP, further review of Southport Cogeneration Plant initiators was not considered warranted.

The assumptions made in the IPEEE are judged to be valid and no credible risk to the safe operation of BSEP is considered to be posed from the operation of nearby facilities. No SAMAs were developed related to industrial accidents.

Military Accidents

Military Ocean Terminal Sunny Point’s cargo load was analyzed during the performance of the IPEEE. The largest concentration of explosives at the site was identified as two fully loaded barges equivalent to 19.2 million pounds of TNT. The blast pressure resulting from the detonation of this explosive source was determined to be 0.5 psi overpressure and 1 psi reflected overpressure. It was noted that this pressure load is less than the tornado loads, which the Class 1 buildings were designed to withstand. No further analysis was performed in the IPEEE and no SAMAs were determined to be required to address military accidents at Brunswick Steam Electric Plant.

Pipeline Accidents

A 12 inch natural gas pipeline runs just outside the 3000 foot Brunswick exclusion zone. The worst case failure of the pipeline, which was assumed to be a guillotine rupture, was examined to identify the impact on the BSEP site. The resulting radiant heat from the fire at the nearest safety structure would be less than a flat surface receives in the midday sun. For an un-ignited gas leak, control room habitability analysis showed that the control room ventilation system still met the requirements set forth in Regulatory Guide 1.78.

No SAMAs were developed for the BSEP list based on the presence of this pipeline.

Hydrogen Storage Failures

Detonation of the BSEP hydrogen storage tankers was investigated to determine the impact of such an explosion. Industry guidance on the minimum separation distance between plant structures and hydrogen storage units was used as the basis of the analysis (Reference 14). The results indicated that the minimum safe distance for storage of the BSEP hydrogen tankers was 200 feet from any safety structure. As this

distance was less than the distance between the hydrogen tankers and the building containing safe shutdown equipment, no credible threat was determined to exist based on hydrogen detonation.

No SAMAs were developed for the BSEP list based on the hydrogen storage equipment at BSEP.

Transportation Accidents

Transportation accidents were judged to include accidents on the roadways around the plant (river traffic was addressed in “Military Accidents”). The highest concentration of explosives on Highway 87, which is one mile from the plant, was determined to be 50,000 pounds of TNT. The impact of an accident on Highway 87 with this explosive load was determined to be bounded by the worst case explosion at Military Ocean Terminal Sunny Point. All chemical and hazardous materials accidents that could occur on the highway were also considered to be bounded by the worst case explosion at Military Ocean Terminal Sunny Point.

No SAMAs were developed for the BSEP list based on the potential for transportation accidents near the site.

F.1.2.1.5 Quantitative Strategy for External Events

The quantitative methods available to evaluate external events risk at BSEP are limited, as discussed above. In order to account for the external events contributions in the SAMA analysis, a two stage process has been implemented to provide gross estimates of the averted cost-risk based on external events accidents.

The first stage is used in the Phase I analysis and is based on the assumption that the risk posed by external and internal events is approximately equivalent. Given that the risk is assumed to be equal, the maximum averted cost-risk calculated for the internal events model has been doubled to account for external events contributions. This total is referred to as the “modified maximum averted cost-risk” or MMACR. The MMACR is used in the Phase I screening process to identify and screen SAMAs that could not be cost beneficial even if all risk related to power operations was eliminated. These are the SAMAs with costs of implementation that are greater than the MMACR (refer to Section F.4 for information related to dual unit implementation).

The second stage of the strategy is used in the Phase II analysis and begins with the assumption that the external events component of the averted cost-risk for a given SAMA is equivalent to the averted cost-risk based on internal events. This would require that any averted cost-risk calculated for a SAMA be multiplied by two to account for the corresponding reduction in external events risk. Insights from the existing external events evaluations are used, where appropriate, to modify the initial factor of two multiplier for any SAMAs requiring detailed averted cost-risk calculations. Engineering judgment is used to determine how to quantitatively address the available external events insights. If no information is available to justify the modification of the

base multiplier of two, then the factor of two is retained. No adjustments have been made in the BSEP analysis to further alter the multiplier of two.

F.2 BSEP PSA MODEL

The SAMA analysis is based on the most recent version of the Brunswick Steam Electric Plant (BSEP) Probabilistic Safety Assessment (PSA) model for internal events (i.e., the MOR03 model for Brunswick Unit 2), which represents the latest update to the upgraded model completed in 2000 to the original Individual Plant Examination (IPE). The upgraded models for Unit 1 and 2 have been subsequently updated in 2001, 2002, and 2003 to maintain design fidelity with the operating plant. The Unit 2 PSA model is currently the more advanced of the two units in implementation of extended power uprate (EPU) modifications for 2923 MW_t operation as begun in 2002.

The following subsections provide more detailed information related to the evolution of the BSEP 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 F.1.2 provides a description of the process used to integrate external events contributions into the BSEP SAMA process; therefore, no additional discussions of the external events models are included here.

F.2.1 PSA MODEL CHANGES SINCE IPE SUBMITTAL

The original Level 1 IPE model was updated in 1993 (Section F.2.1.1), 1994 (Section F.2.1.2), and 1996 (Section F.2.1.3). The IPE models for Level 1 CDF and Level 2 analyses were completely upgraded and replaced in 1998-2001 with the contractual assistance of Ricky Summitt Consulting and ERIN Engineering, respectively. The PSA and Level 2 models were made more robust than the previous IPE models but still retain the principal elements of the previous IPE system modeling. The details of the original IPE model upgrade are documented and controlled through calculations BNP-PSA-001 and BNP-PSA-050, EC 44622 (Rev. 0) and EC 45913 (Rev. 1), “PSA Model Upgrade,” and EC 47888 (Rev. 0), “Level 2/LERF PSA Model Update 1998.” The Level 1 PSA was subsequently updated in 2002 and 2003 for the primary purpose of incorporating plant modifications due to extended power uprate (EPU), to resolve peer review findings, and to incorporate user identified modeling corrections and enhancements. The details of these changes are described in EC 47885 (Rev. 0), “PSA Model Update 2002”, and EC 49660 (Rev. 0), “PSA Model Update 2003,” respectively. The Level 2/LERF model based on Unit 2 for MOR03 was updated by ERIN Engineering during the preparation of the SAMA analysis and is being documented and owner-reviewed for the BSEP license renewal project.

The historical nominal Brunswick CDF and Level2/LERF results for Unit 2 are as follows:

BSEP Model	Truncation (per yr)	CDF (per yr)	LERF (per yr)	Level 2 (per yr)
MOR92	-	2.7E-5	NA	1.9E-5
MOR96	1.0E-9	9.1E-6	NA	NA
MOR98	2.0E-9	2.54E-5	4.27E-6	NA
MOR98R1	2.0E-9	5.49E-5/4.92E-5*	4.78E-6	NA
MOR02	2.0E-9	4.97E-5	NA	NA
MOR03	5.0E-10	4.19E-5	2.13E-6	2.38E-5

* The updated CDF result was modified by calculation BNP-PSA-052 to include modeling corrections prior to the LERF analysis.

Summary descriptions of the model changes that were made as part of the 1993, 1994, and 1996 updates are provided is subsections F.2.1.1 through F.2.1.3 for reference purposes. Descriptions of the 1998-2003 changes are maintained in plant controlled documents.

F.2.1.1 1993 IPE UPDATE

The Brunswick Steam Electric Plant PRA IPE was submitted in August, 1992. Since then, a PRA model update standard has been established that requires elements of CP&L/Progress Energy PRA models to be updated after every refueling cycle. The model update described below reflects the BSEP Unit 2 plant configuration after the ninth refueling outage and includes the forced shutdown from April 1992 through May 1993.

The update effort involved the examination of various information sources. These sources included the review of plant operating logs, trouble ticket and out of service time histories for selected components, industry data, plant modifications which were implemented, model review comments and suggested changes, and industry operating experience.

As a result of this examination the following areas of the PRA model were revised for this update:

- Initiating Events
- Event Trees
- Fault Trees
- Human Reliability Analysis
- Component Performance Data

F.2.1.1.1 Initiating Events

Since the IPE submittal, the Brunswick Plant operated for approximately 4 months after the ninth refueling outage until the forced outage which occurred in April of 1992. The plant remained shut down until May of 1993. During this time, one event occurred which required an initiating event update. The accumulation of salt on transformer insulators

caused by salt spray led to a loss of offsite power. The loss of offsite power initiating event frequency was updated using Bayesian techniques. The frequency increased from 0.074/reactor year to 0.10/reactor year. Additionally, the dual unit loss of offsite power probability was changed from 0.48 to 0.695. All other initiating event frequencies were unchanged from the IPE submittal.

F.2.1.1.2 Event Trees

A comprehensive review of the loss of offsite power event tree (TE) was performed for this model update. Additionally, a cursory review of the remaining event trees was performed. As part of the event tree update a top logic model conversion was performed for all event trees. This conversion resulted in many nomenclature changes to all event trees. The purpose of the conversion was to streamline the quantification process by maximizing the use of macros. The new quantification process is consistent with the one used for quantifying the Harris IPE.

The main reason for focusing on the TE tree was the results of the IPE. The IPE results indicated that station blackout contributed approximately 65 percent of the total core damage frequency. The IPE TE event tree, however, did not include the effects of guidance provided by the newly developed Station Blackout Procedure, AOP-36.2. The review of the TE event tree and the incorporation of AOP-36.2 resulted in the following significant changes:

- The timeframe for recovery of offsite power was increased due the operator's ability to manually close the 4160V breakers without DC power.
- In case of a unit blackout, the use of the LPCI pump that can be powered from the non-blacked out unit for low pressure injection on the blacked out unit was added.
- The deletion of the emergency bus crosstie event and use of firewater for low pressure injection for sequences involving the failure of high pressure injection. These events were deleted since there is inadequate time to perform these actions before core damage occurs.

F.2.1.1.3 Fault Trees

There were many changes made to the IPE fault trees. These changes were primarily the result of incorporating items from the PRA Change Log. The noteworthy changes are highlighted below:

- The automatic operation of the Automatic Depressurization System (ADS) was deleted from the ADS top logic because the automatic function may be inhibited by the operator in accordance with the Emergency Operating Procedures (EOPs).
- The Control Rod Drive (CRD) System was added as an injection source because it is a means to provide makeup for decay heat removal. CRD injection combined with RPV head seal venting make up a new process named in the model as the W6-Process.

- The success criteria for emergency bus crosstie during a loss of offsite power was changed from an "OR" gate to an "AND" gate because one emergency diesel generator is capable of supplying the needed power for both units during a station blackout event. This success criteria is consistent with AOP-36.2.
- The W5-Process, which includes containment venting and injection from Core Spray or firewater, was modified to include the hardened wetwell vent.
- The failure probability of the operator action to crosstie emergency busses was updated to reflect the addition of the crosstie logic switches.
- A new operator action was added to the model to reflect the need to depressurize the reactor within 30 minutes following a loss of high pressure injection.

F.2.1.1.4 Human Reliability Analysis (HRA)

An improved HRA methodology developed since the IPE submittal has allowed the deletion of several pre-initiator events. This updated methodology added screening criteria and allowed removal of errors associated with components which:

- are independently verified by two or more people using a written verification procedure.
- are annunciated in the main control room.

Additionally, a selected number of post-initiator errors were evaluated and updated using an EPRI methodology (failure tree method) used by the Harris and Robinson plants in their IPE submittals. The failure tree method has the advantage of pointing out areas to be considered for improving accident mitigation. This method is considered an improvement over the EPRI time-reliability methodology used for the Brunswick IPE.

F.2.1.1.5 Component Performance Data

Component performance data for major pumps in the following systems plus the emergency diesel generators was collected for a time frame beginning in March of 1987 and ending in January of 1991:

- RHR
- Core Spray
- HPCI
- RCIC
- SLC
- Condensate (Condensate pumps only)
- Service Water
- CRD

- Fire Protection (Diesel-Driven Fire pump only)

These data include the failure rates for run failures, probabilities for start failures, and test and maintenance unavailabilities.

F.2.1.1.6 Industry Operating Experience

Operating experience reports were reviewed for applicability to the PRA model. The reports included NRC Information Notices, INPO reports (SOERs, SERs, etc.), Brunswick Adverse Condition Reports, and Licensee Event Reports for the period 1991 to 1993. A preliminary screening of the report titles produced about 70 reports that could have potential applicability. Each of these reports was reviewed for applicability to the model. Consideration was given to common cause failures, operator errors, precursors to larger failures, and specific component degradation or design problems. The problems identified in these reports appeared to be within the expected realm of failures. Although the review did not identify any reasons to change the PRA model, the review itself was valuable because of the insights it provided on how failures can occur at a nuclear plant.

F.2.1.2 1994 IPE UPDATE

A partial update to the PSA model was performed in August 1994 to support regulatory related work. The work required a more detailed and up-to-date model with respect to diesel generator failures and offsite power recovery options. The result of these changes was a new estimate of CDF of 1.1E-5 per reactor-year. The PSA model was used as the basis for a study of electrical distribution system proposed enhancements, and the study was presented to the NRC as part of Progress Energy's final position.

F.2.1.3 1996 IPE UPDATE

This model update had several objectives. The primary objectives were to (1) consolidate event trees where possible to speed up model quantification, (2) review selected system level fault tree logic to gain better familiarity and correct known discrepancies, and (3) incorporate plant-specific data from the efforts of the Maintenance Rule.

The previous model contained too many event trees, which dramatically slowed quantification due to the large number of plant sequences. The event tree transfers to Anticipated Transient Without SCRAM (ATWS), stuck open Safety Relief Valve (SRV), and internal plant flooding event trees were therefore consolidated. Model quantification time for accident sequences greater than 1E-9 was reduced to less than 1 hour.

Several system fault trees were selected for intensive review. These included Service Water, RHR, CRD, ADS, Instrument Air (including nitrogen backup), and Containment Atmospheric Control (CAC)(Venting Process). Multiple Change Log items had been identified for these systems during previous model reviews. This intensive review was considered necessary to prepare the model for increased application activity.

Changes to the database were made in conjunction with the implementation of the Maintenance Rule. This effort was very beneficial because of the technology transfer of PSA to the plant engineers. Additionally, a means to collect data for future model updates was developed.

The overall model results did not change significantly. The previous CDF was 1.1E-5 and the updated CDF was 9.1E-6 per year. System and human error importances shifted slightly, but the overall risk profile of BSEP remains the same. Station blackout, transients, and loss of decay heat removal remained the dominant accident types.

F.2.2 CURRENT LEVEL 1 BSEP PSA MODEL

The SAMA analysis is based on the most recent version of the Brunswick Steam Electric Plant Probabilistic Safety Assessment (PSA) model for internal events (MOR03, Unit 2). This model is used as it incorporates the changes that were required to support the BSEP extended power uprate project and includes the latest enhancements in model. The MOR03 baseline CDF is 4.19E-5 per reactor year. The results are summarized below.

The contribution to core damage frequency is dominated by two initiators at BSEP. Loss of Offsite Power (site) is the larger of the two with 35.1 percent of the total. This is followed closely by the turbine trip initiator at 27.2 percent.

For Loss of Offsite Power events, if AC power can be restored to the emergency buses by the diesel generators, then the plant response is similar to transient events. If more than one diesel generator is unavailable, the unit is considered to be in a station blackout sequence. These sequences involve:

- successful scram following a loss of offsite power
- failure of the unit emergency diesel generators to start and run
- failure to recover offsite power to Unit 2 in conjunction with either a failure of the Unit 1 crossties to restore power to the Unit 2 emergency buses or a failure of one of the Unit 1 diesels.

To prevent battery depletion, AC Power must be recovered. Depending on the equipment that is available and the outcome of battery load shed actions, the time to battery depletion could vary from 1 to 4 hours (30 minutes if no injection source is available). However, battery load shed is always assumed to fail in the BSEP model and no credit is taken for the potential additional coping time from load shed. Consideration is given to system failure timing, which does impact the available time to recover AC power.

Note that these are one-unit PSA models. The term "station blackout" is actually a unit blackout if only one unit is affected, but for the purposes of the PSA analyses, station blackout is used to describe the above conditions. The LOOP event may impact offsite

AC availability to the unit's switchyard or to both units' switchyards, which may in turn result in a dual unit Station Blackout (SBO).

The loss of AC E-buses and DC power panels have been modeled in considerably more detail in the current PSA models. The models are thus more indicative of the significance of these contributions to CDF compared to prior IPE evaluation.

Transients with Main Steam Isolation Valve (MSIV) closure and loss of condenser vacuum are also large contributors for BSEP. These initiators contribute about 11.4 percent to the CDF due to their relatively high frequency of occurrence combined with the need for the plant to respond from an isolated condition without the benefit of BOP systems. The ability to safely shut down during this type of transient is still very likely due to the redundant mitigating systems available.

Loss of CRD, loss of Reactor Building Closed Cooling Water (RBCCW), internal flooding events, and other transients contribute a smaller amount to the CDF.

Figure F-2 provides a more complete depiction of the BSEP CDF contributions grouped by initiating event category.

In addition, Figures F-3 and F-4 provide the contribution to CDF by system and the system based Risk Achievement Worth rankings, respectively.

It has been observed in past PSAs that the calculation of radionuclide releases are strongly linked to the results of the Level 1 accident sequences. More specifically, there is a high correlation between the types of accident sequences (e.g., Level 1 end states or Plant Damage States or Accident Classes) and the determination of the radionuclide release categories. This observation can be explained because the severe accident progression is strongly influenced by the systems available and the accident sequence timing as determined in Level 1. These features are directly correlated to the Plant Damage States or Accident Classes.

Table F-1 is a summary of the Brunswick Level 1 accident classes. Table F-1 also summarizes the core damage frequency (CDF) determined from the Brunswick Level 1 PSA. These CDF calculations are one of the inputs to the Level 2 calculational process. The Level 1 results including the cutsets are derived from the Brunswick Unit 2 PSA model (January 2003).

In addition, the Level 2 CETs are quantified using the cutset inputs from Level 1 that make up the CDF for each accident class, that is, a separate CET calculation has been performed for the cutsets transferred from Level 1 for each individual CET associated with an accident class.

F.2.3 CURRENT LEVEL 2 BSEP PSA MODEL

The BSEP Level 2 PRA analysis was developed consistent with the Extended Power Uprate (EPU) configuration of the Brunswick plants to be used as a basis for the assessment of PSA Applications, such as SAMA. It involved the development of a set of containment event trees (CETs) as a framework for examining severe accident

phenomena, including both active and passive mitigation functions of the Brunswick Mark I containment. This effort was based upon previous methods used in the Shoreham PSA, other BWR Level 2 PSAs, IDCOR Task 4.1, and the Vermont Yankee Containment Safety Study. In addition, this effort considered the BWROG effort on generic Mark I containment performance for NUMARC. The NRC sponsored research on simplification of the CET structure to address LERF issues only was acknowledged but not used in this full Level 2 analysis.

The principal technical advances that have been incorporated into the Brunswick containment evaluation effort include the following:

- Use of a containment event tree that includes sufficient detail to quantify effects of plant modifications and changes in procedures.
- Establishment of added success paths for recovery of degraded core conditions within the reactor vessel (e.g., TMI-2 events). These paths involved recovery actions during in-vessel core melt progression accidents.
- Incorporation of the Brunswick EOPs and Severe Accident Management Guidelines (SAMGs). This includes the latest BWR Owners Group (BWROG) containment flooding guidance, which is a major model perturbation from previous studies.
- Interface with the BWROG/NUMARC containment safety study to incorporate the latest input on severe accident issues as they affect containment response (e.g., direct containment heating, heat management, seal performance).
- Establishment of plant specific deterministic calculations to support the improved success criteria using MAAP (Modular Accident Analysis Program) calculations as the basis.
- Development of a traceable documentation path through the containment event tree so that both qualitative and quantitative insights can be developed. This facilitates both communication with the NRC and internal use within Progress Energy.
- Consideration of NRC sponsored insights for simplifying the CET process.

The results of the BSEP Level 2 analysis are summarized in sections F.2.3.1 and F.2.3.2.

F.2.3.1 BSEP LEVEL 2 PSA RELEASE CATEGORIES

The frequency of radionuclide release is characterized by the quantification of the Level 1 and Level 2 PSA models. The Level 2 containment event tree end states are delineated by the magnitude and timing of the calculated radionuclide release. Therefore, the containment event tree end states are characterized using a two-term matrix (severity, time) as shown in Table F-2.

Given this characterization strategy, the Level 2 quantification can be summarized in two complementary tables. These tables provide quantitative information that is useful in the interpretation of the current containment capability given the spectrum of core damage sequences calculated in the Level 1 PSA.

Table F-3 includes the following information:

Input:	Individual Level 1 accident sequences with their failure cutsets and frequencies are transferred into Level 2. However, only a summary of the Level 1 PRA total accident sequence frequency is presented here. This total frequency is not used directly as input to the containment event tree evaluation. Nevertheless, it represents a convenient summary of the total frequency of the sequences that are being transferred into the CET.
Radionuclide Release End States:	The release categories used to discriminate among the CET end states are identified.
Output:	The output frequencies of the CETs as a function of the end state bins are identified.

Table F-4 summarizes the radionuclide releases by accident class that contribute to each of the radionuclide release categories established for the Brunswick Level 2 evaluation. In addition to the radionuclide release categories, Table F-4 also identifies the intact containment conditions.

The quantification provides a yardstick with which to measure the best estimate of containment performance given that severe accidents could progress to beyond core damage. The quantification may include some conservatisms to account for the inability of current models and experiments to predict certain severe accident related phenomena.

A substantial fraction (43 percent) of the accidents transferred from Level 1 PRA are effectively mitigated such that releases are essentially contained within an intact containment (i.e., OK release bin). Approximately 95 percent of the postulated accidents do not have "large" releases occurring before protective action can be taken (i.e., approximately 95 percent of the accidents do not result in LERF).

Figure F-5 summarizes in graphical form a histogram comparing the total core damage frequency (i.e., the results of the Level 1 PRA) with the end state frequencies of the Level 2 analysis, i.e., High (H), Medium or Moderate (M), Low (L) and Low-Low (LL) release magnitudes plus those severe accident sequences that result in an intact containment (OK). A substantial fraction (approximately 57 percent) of the core damage end states lead to either low release or the containment remains intact and no substantial release occurs. These release categories have a minimal impact on the SAMA analysis.

Figure F-6 provides a graphical summary of LERF contributors by accident class. As can be seen from the figure, loss of reactivity control (Class IV) and unisolated LOCA outside containment (Class V) accidents are the dominant contributors to High-Early releases. While the LERF release category is a recognized risk metric and an important contributor to risk at BSEP, it is not the largest contributor to offsite consequences. Section F.3 provides additional information on the dose-risk and offsite economic cost-risk associated with the BSEP release categories.

Figure F-7 provides a graphical comparison of the percentage of plant CDF leading to a Large Early release (5.1 percent) and the percentage of plant CDF leading to no release (43.2 percent) or releases less severe than Large Early (51.7 percent).

F.2.3.2 BSEP LEVEL 2 PSA SOURCE TERMS

The input to the Level 3 BSEP model provided by the Level 2 model is a combination of radionuclide release fractions, the timing of the radionuclide releases relative to the declaration of a general emergency, and the frequencies at which the releases occur. This combination of information is used in conjunction with other BSEP site characteristics in the Level 3 model to evaluate the consequences of a core damage event.

Source terms were developed for 9 of the 13 release categories identified in Table F-3. The “OK”, “Low-Low/Early”, “Moderate/Late”, and “High/Late” release categories were excluded as they were minimal contributors. Table F-5 provides a summary of the Level 2 results that were used as Level 3 input for the BSEP SAMA analysis. This table includes the following information:

- Frequency
- BSEP Modular Accident Analysis Program (MAAP) case identifier (for reference)
- Airborne release percent at 48 hours for each of the fission product groups provided by MAAP
- Start time of the airborne release (measured from the time of accident initiation)
- End time of the airborne release (measured from the time of accident initiation)

The consequences corresponding to each of these source terms are provided in section F.3.

F.2.4 BSEP PSA REVIEW SUMMARY

The Brunswick Steam Electric Plant (BSEP) Unit Nos. 1 and 2 Individual Plant Examination (IPE), Individual Plant Examination for External Events (IPEEE), and the associated Probabilistic Safety Assessment (PSA) models have been subjected to a number of assessments and reviews. The following comprehensive peer reviews have been performed:

1988: The original Brunswick PRA which included a Level 1 PRA and external events PRA was docketed in May 1988. The PRA was reviewed by INEL under contract to NRC and the results documented in November 1989 through NUREG/CR-5465 (Reference 15). Many of the insights provided by this review were factored into the PRA for submittal to NRC under the IPE program.

1990-1992: As indicated in Section 5 of the IPE (Reference 9), inputs to and outputs from the IPE analysis were reviewed by Progress Energy's Nuclear Fuels Section; Brunswick plant personnel from operations, training, the plant simulator, and engineering; and other external organizations. Consultants from NUS Corporation provided review of PRA tasks performed by the CP&L staff. Ed Burns, PhD, from ERIN Engineering and Alan Kolaczkowski from SAIC performed a comprehensive external review of the major elements of the PRA. Chris Amos, PhD, from SAIC performed an independent review of the Level 2 analysis. CP&L also used multi-disciplined project teams (including plant and corporate engineering staff, plant operations and training staff, and PSA personnel) to determine possible actions to address the results and insights.

1994-1995: As indicated in Section 6 of the IPEEE (Reference 10), a variety of peer reviews were provided. Vectra Technologies, Inc performed a seismic peer review. CP&L engineers performed an in-depth review of each of the separate analyses that comprised the fire analysis and the analysis of external events. A multi-disciplined independent review team composed of corporate and Brunswick plant personnel in operations, training, fire protection, licensing, and nuclear engineering considered the final results of the IPEEE analysis. The results were evaluated using NEI 91-04 closure guidelines for potential plant vulnerabilities, identification of alternative solutions, and recommendation of actions to resolve severe accident issues. The results and conclusions were subsequently reviewed and accepted by Brunswick senior plant management.

2000: An independent peer review was performed by E.T. Burns, PhD, ERIN (Reference 38).

2001: BWROG Peer Certification Review. A comprehensive review of the BSEP Level 1 and Level 2 (LERF) models was performed Ed Burns, PhD, ERIN; Vincent Andersen, ERIN; Rashid Abbas, Browns Ferry Nuclear Plant; Gerry Kindred, Perry Nuclear Power Plant; Clement Littleton, Entergy Nuclear Northeast; and Vishu Visweswaran, GE. A description of this review is provided in Section F.2.4.1.

F.2.4.1 IMPACT ON THE SAMA ANALYSIS OF UNRESOLVED PSA REVIEW COMMENTS

The BWROG peer review of the Brunswick PSA was completed in December 2001. A final report summarizing the results of the review has been received (Reference 11). The results of peer review are characterized in the following table that provides the element grades assigned to the BSEP PSA.

PRA Element	Summary Grade
Initiating Events	3
Accident Sequences Evaluation	3
Thermal Hydraulic Analysis	2
Systems Analysis	3
Data Analysis	3
Human Reliability Analysis	3
Dependency Analysis	3
Structural Response	3
Quantification and Results Interpretation	3
Containment Performance Analysis	3
Maintenance and Update Process	3

A grade of “3” is defined in the report as follows: “This review grade extends the requirements to ensure that risk significance determinations made by the PRA are adequate to support regulatory applications, when combined with deterministic insights. Therefore, a PRA with elements certified at Grade 3 can support physical plant changes when it is used in conjunction with other deterministic approaches that ensure that defense-in-depth is preserved. Grade 3 is acceptable for Grade 1 and 2 applications, and also for assessing safety significance of equipment and operator actions. This assessment can be used in licensing submittals to NRC to support positions regarding absolute levels of safety significance if supported by deterministic evaluations.”

For the Brunswick PSA, the only element that received a summary grade lower than "3" from the certification team was "Thermal Hydraulic Analysis." This was an area in which the team believed that attention was merited to reduce identified conservatism in the existing success criteria and data of the BSEP PSA models. This was also a recognized area for improvement by Progress Energy. Measures have been taken during 2002-2003 to generate more Level 1 and Level 2 supporting thermal hydraulic analyses in support of the Brunswick PSA. These results are to be linked into the risk models in subsequent model updates.

The peer review team identified no findings of significance level “A” that needed to be evaluated and potentially addressed before the next regular PRA update. The team did identify 66 findings of significance level “B”. The primary focus of these findings was aimed at improving upon the conservative logic and data elements in the model identified by the team. These “B” level findings are considered important and necessary to address, but disposition may be deferred until the next PSA update. These “B” level findings have been entered into the Progress Energy corrective action process for evaluation and disposition. Six of the findings were resolved prior to the MOR03 model being used for the SAMA analysis. The large number of remaining findings and the need for thermal hydraulic analyses to validate the resolution of some findings has required that resolution of the remaining findings be spread over subsequent model updates. There were six areas of strength identified. The team acknowledged as strengths:

- The inclusion of initiator fault trees directly into the accident sequence logic.
- The use of state of technology approach for HRA dependency analysis based on explicit review and quantification of human error probabilities within a cutset.
- The comprehensiveness of the HRA documentation.
- The completeness and plant-specific nature of the primary containment capability evaluation.
- The thoroughness of the documentation for the quantification process.
- The explicit analysis of the BSEP Emergency Action Level declaration procedure and how it relates the characterization of the Level 2 release timing.

In general, the resolution of the open comments will remove conservative modeling assumptions in the BSEP PSA. Removal of these assumptions would result in a lower Maximum Averted Cost-Risk and lower SAMA specific averted cost-risk estimates, which would reduce the likelihood that SAMAs will be identified as cost beneficial. No open issues have been identified that would result in the retention of a SAMA for implementation that would be screened based on the current PSA model results.

F.3 LEVEL 3 PSA ANALYSIS

The MACCS2 code (Reference 28) was used to perform the level 3 probabilistic risk assessment (PRA) for the BSEP. The input parameters given with the MACCS2 “Sample Problem A,” which included the NUREG-1150 food model (Reference 29), formed the basis for the present analysis. These generic values were supplemented with parameters specific to BSEP and the surrounding area. Site-specific data included population distribution, economic parameters, and agricultural production. Plant-specific release data included the time-nuclide distribution of releases, release frequencies, and release locations. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points (i.e., declaration of a General Emergency) and the emergency planning zone (EPZ) evacuation times (Reference 30). These data were used in combination with site-specific meteorology to simulate the probability distribution of impact risks (exposure and economic) to the surrounding (within 50 miles) population from the representative accident sequences at BSEP.

Population

The population surrounding the plant site was estimated for the year 2036. The distribution was given in terms of population at distances to 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles from the plant and in the direction of each of the 16 compass points (i.e., N, NNE, NE……NNW). The total population for the 160 sectors (10 distances × 16 directions) in the region was estimated as 847,834, the distribution of which is given in Tables F-6 and F-7.

Population projections within 50 miles of BSEP were determined using a geographic information system (GIS), U.S. Census Bureau Block Group population data for 2000, and population growth rates based on 1990 and 2000 county-level census data. Population sectors were created for 16 sectors at an interval of 1 mile from 0 to 5 miles, the interval from 5 to 10 miles and at 10-mile intervals from 10 miles to 50 miles. The counties were combined with the sectors to determine what counties fell within each sector. The area of each county within a given sector was calculated to determine the area fraction of a county or counties that comprise each sector. The decennial growth rate for each county was converted to an equivalent annual growth rate. The annual growth rate in each sector was then calculated by the sum of the products of the annual growth rate of each county within a sector and the fraction of the area in that sector occupied by that county. This weighted-average annual growth rate for each sector is given in Tables F-8 and F-9. Zero values in Tables F-8 and F-9, as well as Table F-7, indicate a sector that totally encompasses water.

The U.S. Census Bureau Block Group population data for BSEP (Reference 31), was projected to the year 2036 using the county area-weighted-average annual growth rate in each sector. The county populations in 1990 and 2000 are provided in Reference 32. It was assumed that the annual population growth rate would remain the same as that reported between 1990 and year 2000. Using the sector specific population growth rates, projections were made for the year 2036 by multiplying the 2000 sector population data by 36 times the annual growth rate (expressed as an increment).

Economy

MACCS2 requires the spatial distribution of certain economic data (fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) in the same manner as the population. This was done by specifying the data for each of the 8 counties surrounding the plant, to a distance of 50 miles. The values used for each of the 160 sectors was then the data corresponding to that county which made up a vast majority of the land in that sector. For 8 sectors, no county encompassed more than 2/3rd of the area, so conglomerate data (weighted by the fraction of each county in that sector) was defined.

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. These revised parameters include value of farm and non-farm wealth and fraction of farm wealth from improvements (e.g., buildings, equipment).

Agriculture

Agricultural production information was taken from the 1997 Agricultural Census (Reference 33). Production within 50 miles of the site was estimated based on those counties within this radius. Production in those counties, which lie partially outside of this area, was multiplied by the fraction of the county within the area of interest. Of the food crops, grains and legumes (approximately 38 percent of total cropland each) were harvested from the largest areas; pasture made up 15 percent of this land.

The duration of the growing seasons for grains, legumes, and stored forage were obtained from Reference 34. The duration of the growing season for the remaining crop categories (pasture, roots, green leafy vegetables, and other food crops) were taken to be the same as those used previously at a site in the neighboring state of Georgia (Reference 35).

Nuclide Release

The core inventory at the time of the accident was based on the input supplied in the MACCS Users Guide (Reference 28). The core inventory corresponds to the end-of-cycle values for a 3578-MWth BWR plant. A scaling factor of 0.817 was used to provide a representative core inventory of 2923-MWth at BSEP. Table F-10 gives the estimated BSEP core inventory. Release frequencies (ranging from 5.09E-8/yr for Sequence L/I to 1.06E-5/yr for Sequence M/I) and nuclide release fractions (of the core inventory) were analyzed to determine the sum of the exposure (50-mile dose) and economic (50-mile economic costs) risks from 9 sequences representative of the suite of potential accident releases. BSEP nuclide release categories were related to the MACCS categories as shown in Table F-11.

Each BSEP category corresponded with a single release duration (either puff or continuous).

The reactor building has a width of 140 feet and a height of 160 feet. All releases were modeled as occurring at ground level. The affect of this assumption on the exposure risk was analyzed by varying the release height of all 9 sequences from ground level to the height of the reactor building; the risk increased by less than 4 percent with increased release height. The thermal content of each of the releases was conservatively assumed as to be the same as ambient, i.e., buoyant plume rise was not modeled. The affect of this assumption on the exposure risk was analyzed by varying the heat content of all of the modeled releases from 0 megawatts to 10 megawatts; the risk decreased with increasing plume heat by 3 percent over this range.

Evacuation

Scram for each sequence was taken as time 0 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; for example, a General Emergency will be declared when 2 of the 3 fission product barriers have been breached and the third is in jeopardy. General Emergency declarations would range from 5 minutes for sequence H/L to 60 minutes for Sequence M/L.

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 studies (e.g., Hatch, Calvert Cliffs, References 35 and 36) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the emergency planning zone (Reference 29). The evacuees are assumed to begin evacuation 30 minutes (Reference 30) after a general emergency has been declared

and are evacuated at a radial speed of 0.24 m/sec. This speed is taken from the minimum speed from any evacuation zone under adverse weather conditions.

Meteorology

Annual onsite meteorology data sets from 1997 through 2001 were investigated for use in MACCS2. The 2001 sequential hourly data set was found to result in the largest risk and was subsequently used in all MACCS2 risk calculations. Wind speed from the lower wind sensor (11.5-meter height) was reduced to equivalent 10-meter speed using the power law wind profile as applied in MACCS2. This wind speed and the direction from the lower sensor were combined with precipitation (hourly cumulative) and atmospheric stability (Pasquill-Gifford) class.

Atmospheric mixing heights were specified for AM and PM hours by season. These values ranged from 500 to 580 meters and from 900 to 1280 meters for AM and PM, respectively. (Reference 37)

MACCS2 Results

The resulting annual risks from the 9 BSEP release sequences are provided in Table F-12. The largest risks are from sequences M/I and H/I. The former is characterized by its high frequency (1.06×10^{-5}); the latter is also a relatively high frequency release (3.79×10^{-6}) combined with relatively large releases of Cs, I, Te and Sb. These two sequences contribute over 70 percent of the exposure risk and over 80 percent of the economic risk from BSEP.

F.4 BASELINE RISK MONETIZATION

F.4.1 OFF-SITE EXPOSURE COST

This section explains how Progress Energy calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). Progress Energy also used this analysis to establish the maximum benefit that a SAMA could achieve if it eliminated all BSEP risk.

F.4.2 OFF-SITE EXPOSURE COST

The baseline annual off-site exposure risk was converted to dollars using the NRC's conversion factor of $2,000 per person-rem (Reference 2), and discounting to present value using NRC standard formula (Reference 2):

$$W_{pha} = C \times Z_{pha}$$

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 (as fraction) = 0.07/year

Z_{pha} = monetary value of public health (accident) risk per year before discounting ($/year)

The Level 3 analysis showed an annual off-site population dose risk of 29.35 person-rem. The calculated value for C using 20 years and a 7 percent discount rate is approximately 10.76. Therefore, calculating the discounted monetary equivalent of accident risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (10.76). The calculated off-site exposure cost is $631,782.

F.4.3 OFF-SITE ECONOMIC COST RISK (OECR)

The Level 3 analysis showed an annual off-site economic risk of $48,492. 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 $521,915.

F.4.4 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using the NRC methodology in Reference 2, which involves separately evaluating “immediate” and long-term doses.

Immediate Dose - For the case where the plant is in operation, the equation that NRC recommends using (Reference 2) is:

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 ($/person-rem)

F = accident frequency (events/yr)

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

$_S$ = subscript denoting status quo (current conditions)

$_A$ = subscript denoting after implementation of proposed action

r = real discount rate

t_f = years remaining until end of facility life.

The values used in the BSEP analysis are:

R = \$2,000/person-rem

r = 0.07

D_{IO} = 3,300 person-rem/accident (best estimate, as documented in Reference 2)

t_f = 20 years (license extension period)

F = 4.19×10^{-5} (total core damage frequency)

For the basis discount rate, assuming F_A is zero, the best estimate of the immediate dose cost is:

$$W_{IO} = R\,(FD_{IO})_S\,\{[1 - \exp(-rt_f)]/r\}$$

$$= 2{,}000 * 4.19\times10^{-5} * 3{,}300 * \{[1 - \exp(-0.07 * 20)]/0.07\}$$

$$= \$2{,}976$$

Long-Term Dose - For the case where the plant is in operation, the NRC equation (Reference 2) is:

Equation 2:

$$W_{LTO} = R\{(FD_{LTO})_S - (FD_{LTO})_A\}\,\{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/rm\}$$

Where:

W_{IO} = monetary value of accident risk avoided long-term doses, after discounting, \$

m = years over which long-term doses accrue

The values used in the BSEP analysis are:

R = \$2,000/person-rem

r = 0.07

D_{LTO} = 20,000 person-rem/accident (best estimate, as documented in Reference 2)

m = “as long as 10 years”

t_f = 20 years (license extension period)

F = 4.19×10^{-5} (total core damage frequency)

For the basis discount rate, assuming F_A is zero, the best estimate of the long-term dose is:

W_{LTO} = $R\ (FD_{LTO})_S\ \{[1 - \exp(-rt_f)]/r\}\ \{[1 - \exp(-rm)]/rm\}$

= $2{,}000 * 4.19\times10^{-5} * 20{,}000 * \{[1 - \exp(-0.07*20)]/0.07\}\ \{[1 - \exp(-0.07*10)]/0.07*10\}$

= \$12,973

Total Occupational Exposure - Combining Equations 1 and 2 above and using the above numerical values, the total accident related on-site (occupational) exposure avoided (W_O) is:

W_O = $W_{IO} + W_{LTO}$ = (\$2,976 + \$12,973) = \$15,949

F.4.5 ON-SITE CLEANUP AND DECONTAMINATION COST

The net present value that NRC provides for cleanup and decontamination for a single event is \$1.1 billion, discounted over a 10-year cleanup period (Reference 2). NRC uses the following equation to integrate the net present value over the average number of remaining service years:

U_{CD} = $[PV_{CD}/r][1-\exp(-rt_f)]$

Where:

PV_{CD} = net present value of a single event

r = real discount rate

t_f = years remaining until end of facility life.

The values used in the BSEP analysis are:

PV_{CD} = $\$1.1\times10^9$

r = 0.07

t_f = 20

The resulting net present value of cleanup integrated over the license renewal term, $\$1.18\times10^{10}$, must be multiplied by the total core damage frequency of 4.19×10^{-5} to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is \$496,062.

F.4.6 REPLACEMENT POWER COST

Long-term replacement power costs was determined following the NRC methodology in Reference 2. 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 = 0.07

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 BSEP's size relative to the "generic" reactor described in NUREG/BR-0184 (Reference 2)(i.e., 1006 MWe/910 MWe) and multiplying by 2 to account for the assumption the remaining unit has to shutdown after a core damage event, the replacement power costs are determined to be 1.74×10^{10} ($-year). Multiplying this value by the CDF (4.19×10^{-5}) results in a replacement power cost of $730,963.

F.4.7 TOTAL

The sum of the baseline costs is as follows:

Off-site exposure cost	=	$631,782
Off-site economic cost	=	$521,915
On-site exposure cost	=	$15,949
On-site cleanup cost	=	$496,062
Replacement Power cost	=	$730,963
Total cost	=	$2,396,671

This is the single unit Maximum Averted Cost-Risk (MACR) based on internal events contributions (rounded to $2,397,000). As some SAMAs may be implemented on a site basis, all cost calculations for the BSEP SAMA analysis are also presented on a site basis. This convention maintains consistency between the averted cost-risk estimates and the costs of implementation. Thus, the single unit MACR is doubled to obtain the site MACR of $4,794,000. Use of a factor of two to account for both units is based on the assumption that the two units are symmetrical.

As described in section F.1.2, the internal events MACR is doubled to account for external events contributions. The resulting modified MACR (MMACR) is $9,588,000 and was used in the Phase I screening process to eliminate SAMAs that are not economically feasible. If the estimated cost of implementing a SAMA exceeded $9,588,000, it was excluded from further analysis.

Exceeding this threshold would mean that a SAMA would not have a positive net value even if it could eliminate all severe accident costs. On the other hand, if the cost of implementation is less than this value, then a more detailed examination of the potential fractional risk benefit that can be attributed to the SAMA is performed.

F.5 PHASE I SAMA ANALYSIS

F.5.1 SAMA IDENTIFICATION

The SAMA identification process for BSEP is primarily based on the PRA importance listings, the IPE, and the IPEEE. In addition to these plant specific sources, selected industry SAMA analyses were reviewed to identify any Phase II SAMAs that were determined to be cost beneficial at other plants. These SAMAs were further analyzed and included in the BSEP SAMA list if they were considered to be potentially cost beneficial for Brunswick. The following subsections provide a more detailed description of the identification process.

F.5.1.1 LEVEL 1 BSEP IMPORTANCE LIST REVIEW

The BSEP PRA 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 most reduce the BSEP CDF if the failure probability were set to 0.0. The events were reviewed down to the 1.01 level, which approximately corresponds to a 1 percent change in the CDF given 100 percent reliability of the event. If the dose-risk and offsite economic cost-risk were also assumed to be reduced by 1 percent, the corresponding averted cost-risk would be approximately $23,000. Applying a doubling factor to estimate the potential impact of External Events (refer to Section F.1.2), the result is less than $50,000 ($100,000 per site). This is considered to be the lower end of the implementation costs for potential plant changes, especially given that this estimate is based on complete reliability of the proposed change. No further review of the importance listing was performed below the 1.01 level. Table F-13 documents the disposition of each event in the Level 1 BSEP RRW list.

F.5.1.2 LEVEL 2 BSEP IMPORTANCE LIST REVIEW

A similar review was performed on the importance listing from the Level 2 results. A composite cutset file containing the High/Early, High/Intermediate, and Medium/Intermediate cutsets was used as the basis for the importance listing. This method was used to ensure the Risk Reduction Worth rankings were based on the largest contributors to dose-risk. These three release categories represent 90 percent of the BSEP person-rem/yr contributions. Inclusion of the remaining release categories may mask important events and they have been excluded for this reason.

The Level 2 RRW values were also reviewed down to the 1.01 level. As described for the Level 1 RRW list, events below the 1.01 cutoff value are estimated to yield an averted cost-risk less than $100,000/site and are not considered to be likely candidates for identifying cost effective SAMAs. As such, the events with RRW values below 1.01 were not reviewed. Table F-14 documents the disposition of each event in the Level 2 BSEP RRW list.

F.5.1.3 INDUSTRY PHASE II SAMAS

Phase II SAMAs are those plant changes that require more detailed analysis than what is performed in the Phase I screening process for proper disposition. While many of these SAMAs are shown not to be cost-beneficial, some are close contenders and a small number have been shown to be cost-beneficial at other plants. Use of the BSEP importance ranking should identify the types of changes that would most likely be cost beneficial for Brunswick, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for BSEP due to PRA modeling differences. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the BSEP SAMA identification process.

The Phase II SAMAs from the following U.S. nuclear sites have been reviewed:

- Calvert Cliffs [Reference 3]
- H.B. Robinson [Reference 4]
- Edwin I. Hatch [Reference 5]
- Peach Bottom [Reference 6]
- Dresden [Reference 7]
- Quad Cities [Reference 8]

Three PWR and three BWR sites were randomly chosen from available documentation to serve as the Phase II SAMA sources. Not all of the Phase II SAMAs from these sources were included in the initial Brunswick SAMA list. Many of the industry Phase II SAMAs were already represented by other SAMAs in the Brunswick list or it was judged that they would not be close contenders for BSEP. These SAMAs were not considered further. Based on engineering judgment, the SAMAs considered to be potentially cost

beneficial for BSEP were retained and included in the initial BSEP SAMA lists. These SAMAs include:

- Diverse EDG HVAC Logic
- Add Alternate/Manual Methods for Containment Venting
- Use Firewater as a Backup for EDG Cooling
- Auto Re-Fill of the CST
- Use Firewater as a Backup for Containment Spray
- Demonstrate RCIC Operation following Depressurization
- Enhance EOPs to Include Control Band for Containment Venting

F.5.1.4 BSEP IPE

Performance of the Brunswick IPE generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPE process are implemented and closed out for each of the sites; however, there are some items that are not completed due to high projected costs or other criteria. As the criteria for implementation of a SAMA may be different than what was used in the post IPE decision-making process, these SAMAs are re-examined in this analysis and include the following changes:

- 5^{th} Diesel Generator
- Dedicated DC Power Supply for Switchyard Breakers

F.5.1.5 BSEP IPEEE

Similar to the IPE, there may be a number of proposed plant changes that were previously rejected based on non-SAMA criteria that should be re-examined. In addition, there may be issues that are in the process of being resolved, which may be important to the disposition of some SAMAs. The IPEEE was used to identify these items.

An effort was also made to use the IPEEE to develop new SAMAs based on a review of the original results. However, the BSEP IPEEE was not maintained as a “living” analysis. This limits the qualitative insights and quantitative estimates that can be made with regard to external events contributors. The results of the review include the identification of the following SAMAs:

- Improve Alternate Shutdown Panel
- Improve Alternate Shutdown Training and Communications Equipment

- Add Automatic Fire Suppression System
- Prohibit Transient Combustibles in the Cable Spreading Room and/or Require Fire Suppression Personnel to be Present During Work that May Cause a Fire
- Improve Fire Barriers between Cabinets in the Cable Spreading Room
- Add Alternate/Manual Methods for Containment Venting

These SAMAs have been included in the initial BSEP SAMA list. This list contains all of the initial SAMAs identified for the Phase I analysis and are presented in Table F-15.

F.5.2 PHASE I ANALYSIS

The initial list of SAMA candidates is presented in Table F-15. This list was developed as described in Section F.5.1 and is used as the starting point for the BSEP SAMA review. The screening process used in this analysis is summarized in Figure F-1.

The purpose of the Phase I 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 criteria are used in the Phase I analysis to eliminate SAMAs from further consideration:

- Applicability to the Plant: If a proposed SAMA does not apply to the BSEP design, it is not retained. For example, inclusion of an automatic alternate refill system for an Isolation Condenser System would not require further analysis for a plant that does not have an Isolation Condenser System.
- Excessive Implementation Cost: If a SAMA requires extensive changes that are known to exceed any possible benefit, they are screened without developing an estimated cost of implementation. For example, the cost of installing an additional, buried offsite power source over a path of fifty miles is known to exceed any potential benefit and would be immediately disqualified.
- 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.

The potential for screening SAMA candidates using the first of these criteria is limited as the BSEP list was developed from plant specific insights and other industry SAMAs that were judged to be potentially cost beneficial at BSEP. The second and third criteria are also limited in there use as the BSEP MMACR is relatively high at $9,588,000. However, these criteria were applied to the initial SAMA list in order to identify the list of SAMAs to be passed to the Phase II analysis.

Table F-15 provides a description of how each SAMA was dispositioned in Phase I. Those SAMAs that required a more detailed cost-benefit analysis are evaluated in Section F.6. A list of these SAMAs is provided in Table F-16.

F.6 PHASE II SAMA ANALYSIS

It was possible to screen some of the remaining SAMA candidates from further analysis based on plant specific insights regarding the risk significance of the systems that would be affected by the proposed SAMAs. The SAMAs related to non-risk significant systems were screened from a detailed cost benefit analysis as any change in the reliability of these systems is known to have a negligible impact on the PSA evaluation. In addition, those SAMAs that can be shown to have a small averted cost-risk based on relevant importance rankings are excluded from further review. No detailed analysis is performed for these SAMAs and the bases for their dispositions are considered to be contained within Table F-16.

For each of the remaining SAMA candidates that could not be eliminated based on screening cost or PSA/application insights, 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 used to determine the desirability of implementing the SAMA is defined by the following equation:

Net Value = (baseline cost-risk of site operation (MMACR) – cost-risk of site operation with SAMA implemented) – cost of implementation

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 F.4. The cost-risk of plant operation with the SAMA implemented is determined in the same manner with the exception that the PSA results reflect the application of the SAMA to the plant (the baseline input is replaced by the results of a PSA sensitivity with the SAMA change in effect).

Subsections F.6.1 – F.6.27 describe the detailed cost benefit analysis that was used to determine how the remaining candidates were ultimately treated. Refer to Table F-16 for the cost of implementation bases for each SAMA candidate.

F.6.1 PHASE II SAMA NUMBER 1: PORTABLE DC GENERATOR

Description: Loss of DC power can be mitigated in some circumstances through the alignment of a portable DC generator. It is assumed that these generators can be aligned to any and all of the 125V DC switchboards (1A-1, 1A-2, 1B-1, 1B-2, 2A-1, 2A-2, 2B-1, 2B-2) and can at least provide the full DC load (no load shed required). This enhancement is not assumed to provide benefit when the DC bus/switchboard has failed or during accidents where the batteries are disconnected from the DC system.

The portable DC generator will provide benefit in several types of scenarios including the following:

- Loss of the AC power supply to the battery charger with on-site AC power available (and failure to align the alternate source for the "B" chargers)

- Failure of the DC charger(s)
- SBO conditions

The benefit of the portable charger is limited in SBO sequences due to the need to depressurize when HCTL is challenged. Given that a steam driven injection system is providing makeup to the RPV for these cases, injection is lost on vessel depressurization. Even if suction is maintained on the CST until high suppression pool level occurs, BSEP MAAP runs indicate HCTL is reached in about 4.5 hours given the unavailability of cooling coincident with accident initiation. Therefore, for SBO sequences, the primary benefit of the portable DC generator is realized in the increased time available for restoration of AC power. Non-LOOP, AC power failure sequences without containment heat removal face similar limitations depending on the availability of low pressure injection.

Sequences with loss of the DC chargers or the AC power supply to the chargers include a variety of circumstances in which the availability of alternate DC power may reduce plant risk. Providing motor/valve control power or instrumentation support to allow ECCS systems to operate are good examples of the types of potential benefits that could be gleaned from the portable DC generators.

The portable DC generators are assumed to require 1 hour to align and energize. No credit is taken for supporting components requiring alternate DC power prior to one hour after loss of the DC chargers.

The benefit of this SAMA is estimated through manipulation of the BSEP recovery files. This is a two step process involving the following: 1) Modification of the original recovery file to reflect the increase in available AC power recovery time due to prolonged RCIC/HPCI availability, and 2) Creation of a new recovery file to account for the availability of the portable DC generator. PORTGENREC is assigned a failure probability of $1x10^{-2}$ based on an industry example of an action to align an alternate 480V AC charger to the battery chargers. The changes that were made to the recovery file(s) to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 1 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
X-AC-18RNLS: RCIC depletes with no load shed - 3 run failures	Modified original recovery file to account for 4.5 hours of high pressure injection after loss of on-site AC and 0.5 hours of boildown time. New probability = $8.75x10^{-3}$.
X-AC-12RNLS: RCIC depletes with no load shed - 1 run failure	Modified original recovery file to account for 4.5 hours of high pressure injection after loss of on-site AC and 0.5 hours of boildown time. New probability = $2.08x10^{-2}$.
X-AC-18HPG: New recovery based on X-AC-18H, but only accounts for battery depletion cases.	New AC recovery failure based on 16 hours of EDG run time, 4.5 hours of RCIC/HPCI operation, and 0.5 hours of boildown for a total of 21 hours. New probability = $1.45x10^{-2}$.

Phase II SAMA Number 1 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
X-AC-2HPG: New recovery based on X-AC-2H, but only accounts for battery depletion cases.	New AC recovery failure based on 0 hours of EDG run time, 4.5 hours of RCIC/HPCI operation, and 0.5 hours of boildown for a total of 5 hours. New probability = 9.88×10^{-2}.
PORTGENREC: Portable generator credit adjustment	New recovery file to add on recovery for use of the portable generator. Any cutsets with the following event combinations are appended with an additional 1×10^{-2} recovery term (PORTGENREC): DCP1BAT-XXDEP1A DCP1BAT-XXDEP1B DCP2BAT-XXDEP2A DCP2BAT-XXDEP2B DCP1BAT-XXDEP1A DCP1BAT-XXDEP1B DCP2BAT-XXDEP2A DCP2BAT-XXDEP2B

F.6.1.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 1

The results from this case indicate a 20.5 percent reduction in CDF ($CDF_{new}=3.33\times10^{-05}$ per year), a 17.9 percent reduction in dose-risk (Dose-Risk_{new}=24.1 per year), and a 21.1 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$38,251 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 1 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.09E-06	2.77E-06	1.62E-06	8.30E-06	2.95E-06	1.49E-08	1.21E-06	4.96E-08	1.45E-07	**1.92E-05**
SAMA Dose-Risk	5.39	6.69	1.83	9.21	0.94	0.00	0.01	0.01	0.03	**24.11**
SAMA OECR	$4,557	$16,896	$1,896	$13,862	$1,028	$1	$1	$3	$9	**$38,251**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 1 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$7,675,443	$1,912,557	$489,277	**$1,423,280**

Given the relatively low cost of implementation for this SAMA, the net value is positive and is cost beneficial based on the SAMA methodology.

F.6.2 PHASE II SAMA NUMBER 3: PROVIDE THE MAIN CONTROL ROOM WITH THE CAPABILITY TO ALIGN THE UAT TO THE "E" BUSES

Description: Given a Loss of Off-site Power (LOOP) event with failure of the Startup Auxiliary Transformer (SAT), power can be aligned to the "E" buses by backfeeding through the Unit Auxiliary Transformer (UAT). This action would be desirable given the unavailability of the bus's EDG and failure of a cross-tie to an alternate 4kV bus. Providing controls within the main control room to perform this action reduces the time required to perform the manipulation and simplifies the human action required for successful execution of the alignment.

The human reliability analysis for this action was reviewed and modified based on the assumption that this main control room enhancement would reduce the manipulation time from 40 minutes to 20 minutes. The execution error contributors were also reviewed to determine if credit could be taken for improved operator interface; however, based on the available information, no further credit could be justified. In addition, the primary execution failure contributors are related to step omission. The probability of control manipulation failure is only 4.2×10^{-4} compared with the total execution failure probability of 1.8×10^{-1} and changes to those contributors would have a small impact on the results. Based on the assumed information related to the enhanced controls, the HEP for this action was recalculated to be 4.1×10^{-2}.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 3 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
OPER-GENDISC: Operators fail to backfeed through unit auxiliary transformer after failure of startup transformer	Failure probability changed from 1.8×10^{-1} to 4.1×10^{-2}.

F.6.2.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 3

The results from this case indicate a 0.5 percent reduction in CDF ($CDF_{new}=4.17\times10^{-05}$ per year), a 0.7 percent reduction in dose-risk ($Dose\text{-}Risk_{new}=29.1$ per year), and a 0.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$48,134 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 3 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.77E-06	1.62E-06	1.04E-05	3.30E-06	5.09E-08	2.00E-06	7.16E-08	2.30E-07	**2.36E-05**
SAMA Dose-Risk	5.49	9.10	1.83	11.59	1.05	0.01	0.01	0.01	0.04	**29.14**
SAMA OECR	$4,641	$22,987	$1,896	$17,441	$1,147	$3	$1	$4	$14	**$48,134**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 3 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,528,756	$59,244	$434,775	**-$375,531**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.3 PHASE II SAMA NUMBER 4: DIRECT DRIVE DIESEL INJECTION PUMP

Description: Given a failure of the existing BSEP high pressure injection systems, a direct drive diesel injection pump (DDDIP) could provide an alternate means of supplying make-up without depressurizing the RPV.

The DDDIP is assumed to be located outside of the reactor building for engine exhaust purposes, which requires the addition of a building to house the engine/pump. To reduce costs, the DDDIP is assumed to use the Feedwater injection lines rather than a new, independent high pressure line. The suction sources are assumed to be the CST or Service Water. This combination would provide the DDDIP with potential suction sources for both SBO sequences and those that require high flow makeup, such as LOCA and ATWS scenarios. Division “II” DC power is assumed to be required for valve control and operation.

It is also assumed that the DDDIP is available for injection after containment failure as the pump is located outside of containment. The lumped event representing the DDDIP hardware and operator failures was assigned a failure probability of 5×10^{-2} to approximate the potential reduction in risk (based on engineering judgement).

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 4 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
DD-DG-INJ: DIRECT DRIVE DIESEL INJECTION	New “OR” gate with the following inputs: • New basic event DG-INJ • Gate FWS2G-INJECT-A • Gate RC1-G250-XDB • New “AND” gate G002
DG-INJ: LUMPED EVENT FOR HARDWARE AND OPERATOR FAILURE TO START, ALIGN, AND INJECT	New basic event: $5x10^{-2}$
G002: WATER SUPPLY: CST OR SERVICE WATER	New “AND” gate with the following inputs: • HPC2G-CST-NOSPC • New “OR” gate G006
G006: SW SUPPLY FAILURE	New “OR” gate with the following inputs: • SWS-G2680 • SWS-G2901 • SWS-G2NSW-RHCOM
• #U • #U-ATWS • #V2	Added DD-DG-INJ
#XIU: FAILURE TO CONTROL LOWERED RCS WATER LEVEL	Added new “OR” gate #XIUDGINJ
#XIUDGINJ: FAILURE TO CONTROL LOWERED WATER LEVEL WITH DG INJECTION PUMP (COMPLETELY DEPENDENT ON HPCI)	New “OR” gate with the following inputs: • OPER-LLEVEL1 • DD-DG-INJ

F.6.3.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 4

The results from this case indicate a 14.6 percent reduction in CDF (CDF_{new}=$3.58X10^{-5}$ per year), a 12.2 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=25.8 per year), and a 12.9 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $42,256 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 4 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.04E-06	3.33E-06	1.56E-06	8.76E-06	3.00E-06	4.14E-08	1.31E-06	7.13E-08	1.54E-07	**2.03E-05**
SAMA Dose-Risk	5.25	8.03	1.76	9.73	0.96	0.01	0.01	0.01	0.03	**25.78**
SAMA OECR	$4,436	$20,300	$1,821	$14,637	$1,045	$2	$1	$4	$9	**$42,256**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 4 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,288,310	$1,299,690	$4,000,000	**-$2,700,310**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.4 PHASE II SAMA NUMBER 5: ENHANCED CRD FLOW

Description: The current CRD system was examined to determine if maximizing system flow would provide a viable, single source injection system for transient cases. The results indicated that the CRD in maximized flow configuration would not provide sufficient make-up in the early time frames. This SAMA examines the possibility of further increasing CRD injection to the RPV by installing larger pumps. It is assumed that larger pumps alone would enable CRD to function with the current piping to provide makeup for transient cases from accident initiation forward such that Feedwater is not initially required.

Enhancements to allow make-up flow for the high end of the SLOCA spectrum (up to a 4” diameter steam line or 1” diameter liquid line break) are judged to require installation of an alternate injection line and are not considered here.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 5 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
FWS2G-INJ: FEEDWATER FAILS TO CONTINUE FOLLOWING TRIP	Deleted from #U2.

F.6.4.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 5

The results from this case indicate a 13.1 percent reduction in CDF (CDF_{new}=3.62x10^{-5} per year), a 9.0 percent reduction in dose-risk (Dose-Risk_{new}=26.7 per year), and a 9.1 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $44,081 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 5 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.10E-06	3.57E-06	1.62E-06	8.86E-06	3.02E-06	5.09E-08	1.26E-06	7.16E-08	1.53E-07	**2.07E-05**
SAMA Dose-Risk	5.42	8.61	1.83	9.83	0.96	0.01	0.01	0.01	0.03	**26.71**
SAMA OECR	$4,581	$21,746	$1,896	$14,791	$1,051	$3	$1	$4	$9	**$44,081**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 5 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,518,151	$1,069,849	>> $1,000,000	**Large Negative**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.5 PHASE II SAMA NUMBER 6: PROCEDURALIZE ALL POTENTIAL 4KV AC BUS CROSS-TIE ACTIONS

Description: Currently, the Abnormal Operating Procedures (AOPs) exist to direct the following 4kV cross-tie actions:

- E1 to E3
- E2 to E4

In addition, Alternate Safe Shutdown (ASSD) procedures exist that direct these additional cross-ties:

- E4 to E1 to E2
- E3 to E1 to E2

The cross-tie between Bus E1 and E2 appears to be addressed by the ASSD procedures; however, the E3 to E4 cross-tie is not.

This SAMA assumes that the AOPs include provisions to explicitly address all of these cross-ties instead of only E1 to E3 and E2 to E4. Inclusion of these cross-tie actions in the plant Abnormal Operating Procedures increases the power alignment options available to the operators. This would reduce the risk in scenarios where two diesels in the same division have failed while the diesels from the opposite division are available.

The operator action for this cross-tie is assumed to be completely dependent on the divisional cross-tie (same action used in the model). The BSEP HRA documentation includes an assessment of the inter-divisional cross-tie action; however, it is not used for this sensitivity as it is not considered to reflect the plant conditions after SAMA implementation. Given implementation of the SAMA, conditions for performing the divisional or inter-divisional cross-tie are assumed to be equivalent. Implementation of this SAMA would require appropriate controls to preclude loss of the diesel generator due to overload which would tend to increase the cost estimate.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 6 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
FL-ASSD (FLAG)	Set to FALSE
• ACP-G326: LOSS OF POWER FROM ALTERNATIVE SUPPLY E3 • ACP-G226: LOSS OF POWER FROM ALTERNATIVE SUPPLY E4	• Deleted basic event OPER-ALTBUSXC2 • Added basic event OPER-ALTUNITXC
• ACP-G026: LOSS OF POWER FROM ALTERNATIVE SUPPLY E2 • ACP-G126: LOSS OF POWER FROM ALTERNATIVE SUPPLY E1	• Deleted basic event OPER-ALTBUSXC1 • Added basic event OPER-ALTUNITXC

F.6.5.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 6

The results from this case indicate a 0.7 percent reduction in CDF (CDF_{new}=4.16x10^{-5} per year), a 0.6 percent reduction in dose-risk (Dose-Risk$_{new}$=29.2 per year), and a 0.6 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,193 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 6 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.78E-06	1.62E-06	1.05E-05	3.31E-06	5.09E-08	2.01E-06	7.06E-08	2.33E-07	**2.37E-05**
SAMA Dose-Risk	5.49	9.10	1.83	11.62	1.05	0.01	0.01	0.01	0.04	**29.17**
SAMA OECR	$4,642	$23,005	$1,896	$17,476	$1,151	$3	$1	$4	$14	**$48,193**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 6 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,524,031	$63,969	$100,000	**-$36,031**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.6 PHASE II SAMA NUMBER 10: IMPROVED PROCEDURES/EQUIPMENT TO PREVENT BORON DILUTION

Description: An important action in the BSEP accident response for ATWS sequences is the control of low pressure injection systems to prevent boron dilution after depressurization. Potential means of improving the reliability of the action include enhancing procedures to clarify instructions and/or improving the injection system controls.

The procedures governing the prevention of boron dilution were reviewed and determined to be clear. No changes to these procedures were identified that would justify a measurable change in the HEP for the action.

LPCI controls could be upgraded to include the dial-in flow rate controls similar to what is used for Feedwater systems. Flow control valves would also be required in place of the existing injection valves in order to allow variable flow. This would improve the man-machine interface and would allow the operators to more accurately control the injection flow rate. The HEP was adjusted by lowering the error rates for controlling the flow rate and for reading the flow rate. Based on these assumptions, the independent HEP was reduced from 4.3×10^{-2} to 3.4×10^{-2}. The dependent failure rates were adjusted to account for the change in the action's independent failure probability.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 10 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
OPER-DILUTE	Recovery file change: 4.3×10^{-2} to 3.4×10^{-2}
XOP-COM2-13	Recovery file change: NONE
XOP-COM2-15	Recovery file change: 1.0×10^{-2} to 9.8×10^{-3}
XOP-COM2-14	Recovery file change: NONE
XOP-COM2-12	Recovery file change: 9.1×10^{-3} to 8.5×10^{-3}

F.6.6.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 10

The results from this case indicate a 0.5 percent reduction in CDF (CDF_{new}=4.17x10^{-5} per year), a 1.4 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.0 per year), and a 0.8 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,105 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 10 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.03E-06	3.79E-06	1.53E-06	1.05E-05	3.31E-06	5.09E-08	2.01E-06	7.16E-08	2.34E-07	**2.36E-05**
SAMA Dose-Risk	5.25	9.14	1.73	11.71	1.06	0.01	0.01	0.01	0.04	**28.95**
SAMA OECR	$4,436	$23,092	$1,787	$17,617	$1,151	$3	$1	$4	$14	**$48,105**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 10 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,513,166	$74,834	$434,775	**-$359,941**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.7 PHASE II SAMA NUMBER 11: ENHANCE THE MAIN CONTROL ROOM (MRC) TO INCLUDE CAPABILITY TO PERFORM 480V AC SUBSTATION CROSS-TIE

Description: Providing the MCR with the capability to perform the 480V AC substation cross-tie can potentially improve operator reliability. Modifications which would allow the action to be performed entirely within the MCR would reduce the time required to perform the action and simplify the manipulations required for the action.

It was assumed that the manipulation time for this action would be reduced from 30 minutes to 15 minutes based on the simplification of controls, the relocation of the controls onto a single, functionally grouped panel, and on the elimination of ex-control room travel requirements.

It was also assumed that the breakers that were previously required to be "racked in" are maintained in a ready state. No local action is assumed to be required to prepare the breakers for operation.

In addition, the man machine interface is assumed to be improved through placement of the controls on a functionally grouped, well lit, and labeled control panel. Based on these assumptions, the independent HEP was reduced from $6.9x10^{-2}$ to $2.1x10^{-2}$. The dependent failure rates were adjusted to account for the change in the action's independent failure probability.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 11 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
XOP-480X1(2)	Recovery file change: $6.9x10^{-2}$ to $2.1x10^{-2}$
XOP-COM3-03	Recovery file change: $9.9x10^{-5}$ to $6.0x10^{-5}$
XOP-COM2-21	Recovery file change: $7.0x10^{-4}$ to $4.2x10^{-4}$
XOP-COM2-19	Recovery file change: $6.6x10^{-3}$ to $2.0x10^{-3}$
XOP-COM2-17	Recovery file change: $1.4x10^{-2}$ to $8.2x10^{-3}$

F.6.7.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 11

The results from this case indicate a 1.4 percent reduction in CDF (CDF_{new}=$4.13x10^{-5}$ per year), a 2.5 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.6 per year), and a 3.4 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $46,855 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 11 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.56E-06	1.62E-06	1.04E-05	3.31E-06	4.12E-08	2.01E-06	7.06E-08	2.33E-07	**2.34E-05**
SAMA Dose-Risk	5.49	8.59	1.83	11.59	1.05	0.01	0.01	0.01	0.04	**28.63**
SAMA OECR	$4,642	$21,703	$1,896	$17,442	$1,151	$2	$1	$4	$14	**$46,855**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 11 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,384,334	$203,666	$434,775	**-$231,109**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.8 PHASE II SAMA NUMBER 12: ENHANCE THE MAIN CONTROL ROOM (MCR) TO INCLUDE CAPABILITY TO ALIGN THE ALTERNATE DC POWER SUPPLY TO SPECIFIC DC PANELS

Description: BSEP includes alternate DC power connections to several DC panels. Currently, aligning the alternate supply to the panel requires local operator action. If the MCR was modified such that the action could be performed without any local action, the time required to perform the action and the types of manipulations associated with the action would be simplified. This could potentially improve the reliability of the action.

It was assumed that the manipulation time for this action would be reduced from 5 minutes to 2 minutes based on the simplification of controls, the relocation of the controls onto a single, functionally grouped panel, and on the elimination of ex-control room travel requirements.

It was also assumed that the breaker controls are functionally grouped, labeled in an easy to read manner, and placed in a well lit area.

The error contributors for step omission were considered to remain the same and no modifications were made to those components of the HEP.

Based on these assumptions, the independent HEP was reduced from 1.2×10^{-1} to 8.4×10^{-2}. The dependent failure rates were adjusted to account for the change in the action's independent failure probability.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 12 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
XOP-DCPALTDC1(2)	Recovery file change: 1.2×10^{-1} to 8.4×10^{-2}
XOP-COM2-16	Recovery file change: 7.9×10^{-3} to 5.6×10^{-3}
XOP-COM2-17	Recovery file change: 1.4×10^{-2} to 9.7×10^{-3}

F.6.8.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 12

The results from this case indicate a 1.2 percent reduction in CDF ($CDF_{new}=4.14 \times 10^{-5}$ per year), a 1.6 percent reduction in dose-risk ($\text{Dose-Risk}_{new}=28.9$ per year), and a 1.6

percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$47,700 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 12 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.75E-06	1.62E-06	1.03E-05	3.28E-06	5.09E-08	1.99E-06	7.16E-08	2.25E-07	**2.34E-05**
SAMA Dose-Risk	5.49	9.03	1.83	11.42	1.05	0.01	0.01	0.01	0.04	**28.89**
SAMA OECR	\$4,636	\$22,822	\$1,896	\$17,182	\$1,142	\$3	\$1	\$4	\$14	**\$47,700**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 12 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
\$9,588,000	\$9,454,965	\$133,035	\$434,775	**-\$301,740**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.9 PHASE II SAMA NUMBER 13: INTER-UNIT CRD CROSS-TIE

Description: Installation of a CRD cross-tie is a potential method of reducing the core damage contribution attributed to CRD mitigation. Given that a single unit requires one pump for successful injection or charging the drive headers, loss of the running pump followed by failure of the standby pump could be mitigated by using the opposite unit's standby pump to provide flow. However, performing a cross-tie to the opposite unit's CRD system may also fail the opposite unit's system. No credit is allowed for mitigating the loss of CRD initiating event due to the time required to determine that the cross-tie would not introduce a common failure to the opposite unit. The same is considered to be true for ATWS events.

Some potential exists for correctly identifying the cause for the loss of CRD in time to allow successful RPV make-up. A lumped event with an estimated failure probability of 5×10^{-2} was used to represent the hardware failures and operator errors for this SAMA modification.

The power dependency was addressed using the E1 and E2 emergency buses. Loss of either is assumed to imply loss of a CRD pump on the opposite unit, which would preclude CRD X-tie.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 13 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
CRDXTIE	New lumped event for CRD cross-tie (hardware and operator error) with a failure probability of $5x10^{-2}$.
CRD2INJECT: CRD SYSTEM FAILS TO PROVIDE HIGH PRESSURE MAKEUP TO THE RPV	• Changed CRD2INJECT to and "AND" gate • Added new "OR" gate G002 • Added new "OR" gate G003
G002: UNIT CRD	New "OR" gate with the following inputs: • CRD2G-CH-PRESS • RHR2GFLOODA • CRD2G-FLOW • %2TCRD
G003: CRD-XTIE	New "OR" gate with the following inputs: • New basic event CRDXTIE • New "OR" gate G008
G008: CRD X-TIE POWER	New "OR" gate with the following inputs: • ACP-G4160E2 • ACP-G4160E1
• #U2-ATWS: FAILURE OF FWS AND CRD TO MAINTAIN LEVEL • #X1U4: FAILURE TO CONTROL LOWERED WATER LEVEL WITH RCIC	Deleted CRD2INJECT
• #U2-ATWS: FAILURE OF FWS AND CRD TO MAINTAIN LEVEL • #X1U4: FAILURE TO CONTROL LOWERED WATER LEVEL WITH RCIC	Added new "OR" gate CRD2INJATWS
CRD2INJATWS: CRD SYSTEM FAILS TO PROVIDE HIGH-PRESSURE MAKEUP TO REACTOR VESSEL (ATWS)	New "OR" gate with the following inputs: • CRD2G-CH-PRESS • RHR2GFLOODA • CRD2G-FLOW • %2TCRD

F.6.9.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 13

The results from this case indicate an 6.4 percent reduction in CDF ($CDF_{new}=3.92x10^{-5}$ per year), a 9.3 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=26.6 per year), and a 12.6 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$42,358 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 13 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	2.94E-06	1.62E-06	1.00E-05	3.21E-06	3.93E-09	1.78E-06	7.16E-08	2.09E-07	**2.20E-05**
SAMA Dose-Risk	5.47	7.10	1.83	11.15	1.03	0.00	0.01	0.01	0.04	**26.63**
SAMA OECR	$4,622	$17,930	$1,895	$16,775	$1,118	$0	$1	$4	$13	**$42,358**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 13 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,769,336	$818,664	$836,870	**-$18,206**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.10 PHASE II SAMA NUMBER 15: DIVERSE EDG HVAC LOGIC

Description: Failure of the HVAC logic to start the EDG room fans or to open exhaust dampers on high temperature could be mitigated through the installation of a diverse set of fan actuation logic. The backup logic would reduce the reliance on operators to perform a fan start on loss of the current automatic actuation logic.

It was assumed that the alternate logic could be represented with a lumped event with a $1X10^{-2}$ failure probability. This is assumed to account for hardware failures of the new logic and support system dependencies.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 15 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
ALT-LOGIC: ALTERNATE DIVISION FAILS TO PROVIDE SIGNAL	New lumped event for failure of the alternate HVAC logic hardware and support dependencies (1E-2 failure probability)

Phase II SAMA Number 15 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
• DGH-G1FNSIG1-AC: NO START SIGNAL TO EXHAUST FAN E • DGH-G1FNSIG1X-AC: NO START SIGNAL TO EXHAUST FAN E • DGH-G1FNSIG2-AC: NO START SIGNAL TO EXHAUST FAN F • DGH-G1FNSIG2X-AC: NO START SIGNAL TO EXHAUST FAN F • DGH-G2AOD1-1AC: FAILURE OF SIGNAL TO OPEN DAMPER FOR CELL 1 • DGH-G2AOD2-1AC: FAILURE OF SIGNAL TO OPEN DAMPER FOR CELL 2 • DGH-G2AOD3-1AC: FAILURE OF SIGNAL TO OPEN DAMPER FOR CELL 3 • DGH-G2AOD4-1AC: FAILURE OF SIGNAL TO OPEN DAMPER FOR CELL 4 • DGH-G2FNSIG3-AC: NO START SIGNAL TO EXHAUST FAN G • DGH-G2FNSIG3X-AC: NO START SIGNAL TO EXHAUST FAN G • DGH-G2FNSIG4-AC: NO START SIGNAL TO EXHAUST FAN H • DGH-G2FNSIG4X-AC: NO START SIGNAL TO EXHAUST FAN H	Added ALT-LOGIC event

F.6.10.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 15

The results from this case indicate a 3.1 percent reduction in CDF (CDF_{new}=4.06x10^{-5} per year), an 2.4 percent reduction in dose-risk (Dose-$Risk_{new}$=28.6 per year), and a 2.5 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,272 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 15 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.73E-06	1.62E-06	1.01E-05	3.30E-06	5.09E-08	2.00E-06	6.40E-08	2.32E-07	**2.32E-05**
SAMA Dose-Risk	5.48	8.98	1.83	11.22	1.05	0.01	0.01	0.01	0.04	**28.64**
SAMA OECR	$4,633	$22,701	$1,895	$16,873	$1,149	$3	$1	$4	$14	**$47,272**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 15 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,320,084	$267,916	$200,000	**$67,916**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

F.6.11 PHASE II SAMA NUMBER 16: DIVERSE SWING DG AIR COMPRESSOR

Description: A shared, diverse, diesel driven air compressor would reduce the impact of CCF of the diesel generator starting air compressors at BSEP. One compressor could be shared by the two units to reduce costs. Alternatively, 1) a portable compressor could be procured that could be aligned to either unit at a potentially lower cost, or 2) nitrogen bottles could be aligned to provide the pressurized gas supply. Given that the cost of a portable compressor is likely to be less than installing a permanent, swing compressor and that the risk reduction for the two systems is considered to be approximately equivalent, the portable compressor is the most likely candidate to be cost beneficial and is pursued here. The portable nitrogen bottles have a finite supply relative to the mission time and are considered to be a less desirable alternative than the portable compressor.

It was assumed that the portable compressor could be connected to the output of the current air compressors and provide the required capacity for the system. It is also assumed that a single compressor can be moved between divisions to maintain control air demand, as required.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below. It was assumed that the common cause failure event used to identify this SAMA dominates the risk associated with starting air compressor failure. Elimination of the CCF event was used to estimate the risk reduction associated with implementing the portable air compressor.

Phase II SAMA Number 16 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
EDG2MDC-44SU2AC: COMMON CAUSE FAILURE OF UNIT 2 DG AIR COMPRESSORS TO START	Set to 0.0.

F.6.11.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 16

The results from this case indicate a 1.4 percent reduction in CDF (CDF_{new}=4.13x10^{-5} per year), a 1.4 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.0 per year), and a 1.4 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$47,791 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 16 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.75E-06	1.62E-06	1.03E-05	3.31E-06	5.09E-08	2.01E-06	7.00E-08	2.33E-07	**2.35E-05**
SAMA Dose-Risk	5.49	9.04	1.83	11.47	1.05	0.01	0.01	0.01	0.04	**28.95**
SAMA OECR	$4,639	$22,834	$1,895	$17,251	$1,150	$3	$1	$4	$14	**$47,791**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 16 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,452,183	$135,817	$159,078	**-$23,261**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.12 PHASE II SAMA NUMBER 17: PROVIDE ALTERNATE FEEDS TO PANELS SUPPLIED ONLY BY DC BUS 2A-1

Description: Installing alternate DC feeds to the loads that are currently only supported by DC bus 2A-1 may reduce plant risk through diversification of the power supplies. The failure of this bus precludes supplying the supported loads through the bus using a portable generator. These loads must be isolated from the 2A-1 bus and powered by an alternate connection. A potential solution would be to provide alternate connections to the supported panels from the opposite division. This connection already exists for panel DP-6A (to bus 2B-2).

Operator action evaluations for aligning the alternate DC supply already exist for BSEP. This action was assumed to apply to the alignment of the 2B-1 DC supply to the loads normally supplied by 2A-1. It was also initially assumed that the equipment used to supply the alternate feed would be similar to the alternate line feed lines that exist for the other 2A-1 panels.

However, temporary connections from portable generators are viewed as a more cost effective change. Procurement of a portable generator for MCC 2XDA, DP-12A, and DP-4A along with the required connection upgrades, procedure changes, and training is judged to be less resource intensive than providing permanent connections to the 2B-1 DC bus.

In addition, the portable generators are not limited by the battery life for SBO conditions nor are they susceptible to common cause failures of the DC system. It was assumed the operator action to align the alternate power supply was applicable to the portable

generator alignment, which assumes complete dependence between the actions. As this action is assigned a relatively high failure rate (1.2E-1), it is assumed to dominate the hardware failures related to the operation of the generator. No additional hardware failures have been modeled for the generator.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 17 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
DCP-G1050: LOSS OF POWER TO EITHER 125V DC SUPPLY TO MOTOR CONTROL CENTER	• Added “AND” gate G001 • Moved DCP2G2A125VP from DCP-G1050 to G001 • Added Op action OPER-DCPALTDC2 under G001
• DCP-GDP12A: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 12A • DCP-GDP4A: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 4A • DCP-GDP12A-D: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 12A - DEMAND ONLY • DCP-GDP4A-D: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 4A - DEMAND ONLY • DCP-GDP12AX-AC: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 12A • DCP-GDP12A-XD: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 12A -DEMAND ONLY • DCP-GDP4A-XD: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 4A - DEMAND ONLY • DCP-GDP4A-CH: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 4A (LONG-TERM CHARGER ONLY)	Similar changes were made to these gates.

F.6.12.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 17

The results from this case indicate a 19.1 percent reduction in CDF (CDF_{new}=3.39x10^{-5} per year), a 13.1 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=25.5 per year), and a 13.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$41,854 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 17 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.09E-06	3.38E-06	1.62E-06	8.25E-06	2.88E-06	5.09E-08	9.95E-07	7.16E-08	1.25E-07	**1.95E-05**
SAMA Dose-Risk	5.39	8.16	1.83	9.16	0.92	0.01	0.01	0.01	0.02	**25.50**
SAMA OECR	$4,553	$20,614	$1,895	$13,775	$1,002	$3	$0	$4	$7	**$41,854**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 17 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,021,438	$1,566,562	$489,277	**$1,077,285**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

F.6.13 PHASE II SAMA NUMBER 18: PROVIDE ALTERNATE FEEDS TO ESSENTIAL LOADS DIRECTLY FROM AN ALTERNATE "E" BUS

Description: Failure of a 4kV bus results in loss of power to essential loads and precludes emergency cross-tie actions due to the bus fault. A potential means of mitigating the bus failure would be to provide alternate power feeds from the remaining 4kV power supplies. This would require the addition of the means to connect temporary cables to specific loads from other emergency buses or through the addition of permanent alternate bus connections similar to those that exist for some DC panels.

In order to simplify the modeling for this SAMA, alternate power to the emergency buses was assumed to be available despite bus failure rather that inserting alternate power connections to each 4kV load. This was modeled by setting the failure probabilities for the loss of 4kV bus initiators to 0.0. This method implicitly assumes 100 percent reliability of the alignment action and power availability.

Some of the 4kV bus failure initiators in the BSEP model are related to instrumentation and the availability of system start signals, etc. No credit was taken for mitigating these events as they may be required early and the power re-alignment would not be available at that time.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 18 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
%1TE_E1: LOSS OF 4160V AC BUS E1 %1TE_E2: LOSS OF 4160V AC BUS E2 %2TE_E3: LOSS OF 4160V AC BUS E3 %2TE_E4: LOSS OF 4160V AC BUS E4	Set to 0.0

F.6.13.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 18

The results from this case indicate a 3.1 percent reduction in CDF (CDF_{new}=4.06x10^{-5} per year), a 3.9 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.2 per year), and a 5.1 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $46,009 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 18 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	3.47E-06	1.62E-06	1.03E-05	3.26E-06	3.79E-08	1.90E-06	7.16E-08	2.21E-07	**2.30E-05**
SAMA Dose-Risk	5.48	8.37	1.83	11.41	1.04	0.01	0.01	0.01	0.04	**28.21**
SAMA OECR	$4,632	$21,155	$1,895	$17,173	$1,134	$2	$1	$4	$13	**$46,009**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 18 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,228,686	$359,314	$434,775	**-$75,461**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.14 PHASE II SAMA NUMBER 19: PROVIDE AN ALTERNATE MEANS OF SUPPLYING THE INSTRUMENT AIR HEADER

Description: Given the loss of the "D" air compressor in conjunction with the failure of at least two of three reciprocating compressors or their flow paths results in loss of IA. Procurement of an additional compressor that could be aligned to the supply header would reduce the risk of loss of instrument air provided that it could be aligned in time to prevent the development of the initiating event. It is assumed that the alternate compressor has the capacity to supply the full Instrument Air system load and that the compressor is engine driven such that there are no power dependencies.

It is also assumed that the alternate compressor can be started and aligned to mitigate loss of a compressor during other accident scenarios that were not initiated by loss of instrument air events.

The alternate compressor is assumed to share the "D" compressor's flow path from the "D" receiver forward. This shared flowpath was used with a lumped event (ALTIAN) to

represent the failure probability of the alternate compressor alignment (hardware and operator error). Based on engineering judgement, $1x10^{-2}$ was used for this failure probability as it is consistent with start and run failures for the BSEP compressors. Operator error could account for a greater failure contribution; however, no timeline of the accident is available to allow for a detailed HRA. In addition, the results are not highly sensitive to the value of ALTIAN. The CDF only increases to $4.035x10^{-5}$ from $4.029x10^{-5}$ when $1x10^{-1}$ is used in place of $1x10^{-2}$ for ALTIAN. Until a detailed HRA is available for ALTIAN, $1x10^{-2}$ will be used to show increased benefit.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 19 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
G001: ALTERNATE IAN COMPRESSOR "E"	New "OR" gate • Add basic event ALTIAN with failure probability $1x10^{-2}$ • Add gate IAN2G1103 (flow path)
G002: ALTERNATE IAN COMPRESSOR "E" FOR IE CASES	New "OR" gate • Add basic event ALTIAN with failure probability of $1x10^{-2}$ • Add new "OR" gate IAN2 G1103_IE
IAN2 G1103_IE: LINE FAILURES (IE)	New "OR" gate including • IAN2TNK-RP_D • IAN2XVN-OC_V783
IAN2GIANIE: LOSS OF INSTRUMENT AIR	Add gate G002
IAN2G1090: NO AIR FROM AIR COMPRESSOR HEADER	Add gate G001

F.6.14.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 19

The results from this case indicate a 3.8 percent reduction in CDF ($CDF_{new}=4.03x10^{-5}$ per year), an 8.1 percent reduction in dose-risk ($Dose\text{-}Risk_{new}=27.0$ per year), and an 11.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$42,829 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 19 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	2.93E-06	1.61E-06	1.04E-05	3.28E-06	1.26E-08	1.97E-06	7.04E-08	2.30E-07	**2.26E-05**
SAMA Dose-Risk	5.47	7.06	1.82	11.51	1.05	0.00	0.01	0.01	0.04	**26.98**
SAMA OECR	$4,625	$17,837	$1,889	$17,316	$1,141	$1	$1	$4	$14	**$42,829**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 19 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,950,277	$637,723	$489,277	**$148,446**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

It should be noted that a modification is currently being developed for the Instrument Air System that will significantly alter the system configuration and reliability. The three reciprocating air compressors will be replaced with a single, more reliable compressor. A cross-tie will be installed, operable from the control room, vs the current manual cross-tie. The modified system is planned to be operated with the cross-tie valve open. The system will be able to provide instrument air to both BSEP units assuming the loss of one of the D compressors and one of the new replacement compressors. Without a fully developed model to evaluate the reliability of the revised system, the impact of this SAMA on plant risk after the modifications are made is difficult to determine. However, as the potential for common cause failure of the compressors in the revised system is considered to be a possible contributor to system failure, it may be appropriate to analyze the benefit of a portable compressor once the revised system is incorporated into the PSA model. This modification is planned for implementation in 2007.

F.6.15 PHASE II SAMA NUMBER 20: ENHANCE THE MAIN CONTROL ROOM (MCR) TO INCLUDE CAPABILITY TO SWAP AC POWER SUPPLIES TO THE BATTERY CHARGERS

Description: The action to perform the alignment of the alternate AC supply to the battery chargers is currently included in the Alternate Safe Shutdown Procedures. As the EOPs do not include the guidance required to perform these steps, the internal events model does not credit the action. This SAMA assumes that the battery charger breaker controls are enhanced such that they are available within the MCR and that the EOPs are updated to include the required guidance for the alignment action.

As the BSEP model already includes this action in the structure with a value of 1.0, the recovery file was updated with an estimated failure probability of $1x10^{-2}$ for the action. This HEP is based on a similar type of action (OPER-DCPALTDC1(2); $1.2x10^{-1}$), but the failure probability has been reduced based on: 1) improved man-machine interface, 2) reduced travel time, and 3) the improved performance shaping factors and support that would be present in the MCR compared with local conditions. The reduction is not based on a requantification of the action; rather, it is based on engineering judgement considering these factors.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 20 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
OPER-DC1(2)BALT: OPERATOR FAILS TO SWITCH CHARGER TO ALTERNATE AC POWER SUPPLY-UNIT 2	Basic event data change: 1.0 to $1x10^{-2}$

F.6.15.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 20

The results from this case indicate a 1.4 percent reduction in CDF (CDF_{new}=$4.13x10^{-5}$ per year), a 2.0 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.8 per year), and a 2.1 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,486 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 20 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	3.74E-06	1.62E-06	1.02E-05	3.27E-06	5.09E-08	1.97E-06	7.16E-08	2.22E-07	**2.33E-05**
SAMA Dose-Risk	5.48	9.00	1.83	11.33	1.04	0.01	0.01	0.01	0.04	**28.76**
SAMA OECR	$4,632	$22,748	$1,895	$17,053	$1,138	$3	$1	$4	$13	**$47,486**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 20 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,422,693	$165,307	$434,775	**-$269,468**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.16 PHASE II SAMA NUMBER 21: ENHANCE CRD LOGIC

Description: Inclusion of logic and support components within the CRD system to automate flow path protection would improve CRD availability. Currently, a clogged filter requires local, manual action to restore the flow path after the operator diagnoses the problem. If sensors were included which automatically opened the alternate

flowpath around the filters on high differential pressure across the running filter, the loss of CRD initiating event probability could be reduced.

The CRD suction filters (S001A and S001B) and the drive path filters (D003A and D003B) have been identified as important contributors to CRD failure. An automated bypass line around these filters requires differential pressure sensor integration with actuation logic for each of the four filters. For each pair of filters, a single, shared bypass line is assumed to be required. The suction path filters already have a bypass line, which includes manual valve V306. This valve is assumed to be replaced with an MOV that is connected to the actuation logic. The drive path filters do not currently have a bypass line; thus, new piping is required to provide an automated bypass flow path in addition to the MOV.

To simplify the modeling process, no linked dependencies or actuation logic dependencies were included in the model changes. A lumped event representing auto bypass logic and power supply failures was included with an assumed failure probability of $5x10^{-4}$. The bypass MOVs were included with a $3x10^{-3}$ failure probability, which is typical of other plant MOVs.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 21 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
CRD2GCRDIE-30C: NO FLOW FROM SOURCE TO CRD - TRAIN A FILTER	• Added “AND” gate G001under CRD2GCRDIE-30C • Deleted basic events CDS2XVN-OC_V305, CDS2XVN-OC_V308, and CRD2FLT-PG_S001A
G001: PLUGGING NOT ABATED	• Added “OR” gate G003 • Added “OR” gate G009
G003: BYPASS LINE FAILS TO OPEN	• Added basic event “AUTOBYPASS” at $5x10^{-4}$ • Added basic event CRDBYPMOV1 at $3x10^{-3}$
G009: NO FLOW FROM SOURCE TO CRD - TRAIN A FILTER	Added basic events CDS2XVN-OC_V305, CDS2XVN-OC_V308, and CRD2FLT-PG_S001A
• CRD2GCRDIE-30D: NO FLOW FROM SOURCE TO CRD - TRAIN B FILTER • CRD2GCRDIE-30A: NO FLOW FROM PUMPS TO CRD - TRAIN A DRIVE WATER FILTER • CRD2GCRDIE-30B: NO FLOW FROM PUMPS TO CRD - TRAIN B DRIVE WATER FILTER	Similar changes made to these gates.

F.6.16.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 21

The results from this case indicate a 2.9 percent reduction in CDF (CDF_{new}=$4.07x10^{-5}$ per year), a 2.3 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.7 per year), and a 2.2 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$47,429 per year). A

further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 21 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.08E-06	3.72E-06	1.57E-06	1.03E-05	3.25E-06	5.09E-08	1.88E-06	7.16E-08	2.21E-07	**2.32E-05**
SAMA Dose-Risk	5.36	8.98	1.78	11.45	1.04	0.01	0.01	0.01	0.04	**28.67**
SAMA OECR	$4,528	$22,685	$1,841	$17,223	$1,131	$3	$1	$4	$13	**$47,429**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 21 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,341,293	$246,707	$500,000	**-$253,293**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.17 PHASE II SAMA NUMBER 22: INSTALL SELF COOLED CRD PUMPS

Description: RBCCW currently provides cooling to the CRD pumps. If the CRD pumps were changed such that they used the process fluid as a cooling medium, the dependence on RBCCW would be removed. The Loss of RBCCW initiating event, however, is retained. This is because failure of RBCCW would require a plant shutdown due to the cooling dependence of several other non-modeled systems.

This SAMA is considered to require the purchase of new, self cooled pumps and removing/capping old RBCCW cooling lines to the CRD system. To simplify the modeling process for this SAMA, implementation is assumed to be represented through the removal of the CRD cooling dependence.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 22 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
CRD2G-PMP-AO: INSUFFICIENT FLOW - CRD PUMP A OPERATING	Deleted gate RCC2G-CRDA for RBCCW cooling dependency
CRD2G-PMP-BO: INSUFFICIENT FLOW - CRD PUMP B OPERATING	Deleted gate RCC2G-CRDB for RBCCW cooling dependency

F.6.17.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 22

The results from this case indicate a 1.2 percent reduction in CDF (CDF_{new}=4.14x10^{-5} per year), a 1.8 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.8 per year), and a 2.4 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,347 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 22 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.64E-06	1.62E-06	1.05E-05	3.29E-06	4.25E-08	1.97E-06	7.16E-08	2.29E-07	**2.35E-05**
SAMA Dose-Risk	5.49	8.77	1.83	11.62	1.05	0.01	0.01	0.01	0.04	**28.83**
SAMA OECR	$4,638	$22,172	$1,895	$17,475	$1,145	$2	$1	$4	$14	**$47,347**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 22 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,434,602	$153,398	$500,000	**-$346,602**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.18 PHASE II SAMA NUMBER 29: PORTABLE EDG FUEL OIL TRANSFER PUMP

Description: A diverse, engine driven, portable diesel fuel oil transfer pump would provide additional means of supplying the EDG day tank in the event that common cause pump failure prevents operation of the existing pumps.

It is assumed that a single pump can be procured that would serve to supply all four of the BSEP emergency diesel generators. A $1x10^{-2}$ failure probability has been assumed for the portable transfer pump hardware failures and operator error. This is based on an industry example for an alignment of a portable 480V AC generator, which is considered to be similar in complexity and timing ($1.5x10^{-2}$). The results are not sensitive to this value (CDF=$4.068x10^{-5}$ @ $1x10^{-3}$ and CDF=$4.074x10^{-5}$ @ $1x10^{-1}$).

The pump is assumed to be engine driven and no power dependencies are assumed to be applicable.

The Progress Energy staff has estimated the cost of implementation for a SAMA with a similar impact on the diesel fuel oil system. A pump bypass line could be installed that would allow a gravity feed from the 4 day diesel fuel oil tank to the diesel day tank (EDG saddle tank). This line would include a manual isolation valve and a throttle valve to control flow to the saddle tank and maintain the required fuel supply for the operating diesel generator. The failure rate assumed for the alignment and operation of the portable fuel oil transfer pump as applied in the SAMA quantification is $1x10^{-2}$. It is judged that the operation of the bypass line would be approximately the same. Given that a plant specific cost estimate for the bypass line is available ($186,861), this estimate is used as a surrogate for this SAMA.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 29 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
EDG-G1080: FAILURE OF DIESEL GENERATOR 1 FUEL OIL SYSTEM	• Added “AND” gate G001 • Deleted “OR” gate EDG-G1082
G001: FAILURE OF FUEL OIL TO EDG 1 MAIN TANK SUPPLY FROM NORMAL AND PORTABLE PUMPS	• Added “OR” gate EDG-G1082 • Added basic event DGFOXFER
DGFOXFER: PORTABLE DG FO TRANSFER PUMP FAILURE	New basic event for transfer pump failure. Failure probability is $1x10^{-2}$
• EDG-G1080-AC • EDG-G2080 • EDG-2080-AC • EDG-G3080 • EDG-G3080-AC • EDG-G4080 • EDG-G4080-AC	Changes similar to those above made to these gates.

F.6.18.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 29

The results from this case indicate a 2.9 percent reduction in CDF (CDF_{new}=$4.07x10^{-5}$ per year), a 2.3 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.7 per year), and a 2.4 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,326 per year). A further breakdown of this information is provided below according to release category.

Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 29 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.73E-06	1.62E-06	1.01E-05	3.30E-06	5.09E-08	2.00E-06	6.60E-08	2.32E-07	**2.33E-05**
SAMA Dose-Risk	5.48	8.98	1.83	11.26	1.05	0.01	0.01	0.01	0.04	**28.68**
SAMA OECR	$4,634	$22,692	$1,895	$16,934	$1,149	$3	$1	$4	$14	**$47,326**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 29 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,337,719	$250,281	$186,861	**$63,420**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

F.6.19 PHASE II SAMA NUMBER 30: IMPROVE ALTERNATE SHUTDOWN PANEL

Description: The results of the BSEP fire model indicate that 53.3 percent of the fire risk is related to control room fires. A dominant factor in control room evacuation scenarios is the ability of the operators to control the plant from the alternate shutdown panel and locally, at specific system panels. This SAMA assumes that the human action component of this failure probability could be reduced by a factor of 5 if the alternate shutdown panel were enhanced to include at least one complete division of safe shutdown equipment controls.

The existing fire model assumes that the failure probability for safe shut down from outside the control room is 1.15×10^{-1}. This includes a 0.1 operator failure probability and a 0.015 hardware failure probability. Reducing the human error component by a factor of 5 results in a revised failure probability for ex-control room safe shutdown of 3.5×10^{-2}.

The impact of this change is estimated using available information from the fire model and engineering judgment. No model quantification was performed for this evaluation.

It is assumed that if the portion of the BSEP CDF and release consequences related to control room evacuation can be identified that an averted cost-risk can be calculated for

this SAMA. The steps used to perform this calculation are provided below and include the following items:

- Determine the percentage of the overall MMACR attributable to external events
- Determine the percentage of the external events MMACR contribution attributable to fire events
- Determine the percentage of the fire component of the MMACR attributable to control room fires
- Determine the percentage of the control room fire component of the MMACR attributable to scenarios that require control room evacuation
- Calculate the reduction in the control room evacuation component of the MMACR that would occur if the enhanced alternate shutdown panel was installed

The baseline assumption for external events contributions in the BSEP SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MMACR is $4,794,000, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that the seismic analysis was a margins analysis and did not produce a CDF. For the purposes of this calculation, it is assumed that the fire events comprise 75 percent of the external events risk. This corresponds to a cost-risk of $3,595,500.

Based on the Brunswick IPEEE RAI response, control room fires comprise 53.3 percent of the fire risk, which yields a cost-risk of $1,916,402. The IPEEE indicates that 92.7 percent of the control room fire CDF is comprised of scenarios requiring evacuation of the control room. This corresponds to an evacuation based cost-risk of $1,776,504.

The ratio of the revised ex-control room shut down failure probability to the original value is 0.035/0.115 = 0.304. If this is multiplied by the evacuation based cost-risk of $1,776,504, the product is the revised cost-risk for evacuation based shut down ($540,675). The averted cost-risk is the difference between the original evacuation based cost-risk and the revised value ($1,235,829).

The cost of implementation for this SAMA is based on a proposed upgrade of a control room from a standard layout to one that incorporates enhanced computer displays for plant parameters and procedure information. The cost of this estimate was $600,000 per unit in 1994 dollars (Reference 1) and applies to a change made during the design phase of the plant. Assuming a 2.75 percent annual inflation rate, the current cost of this modification would be about $765,928 per unit and $1,531,855 for the site. Because the cost estimate was performed for a changed during the design phase and because the proposed changes are judged to be more limited in scope than the

upgrade of the alternate shutdown panel, this is considered to be a lower bound estimate for this SAMA's cost of implementation.

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 30 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,352,171	$1,235,829	$1,531,855	**-$296,026**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.20 PHASE II SAMA NUMBER 31: IMPROVED ALTERNATE SHUTDOWN TRAINING AND EQUIPMENT

Description: The results of the BSEP fire model indicate that 53.3 percent of the fire risk is related to control room fires. A dominant factor in control room evacuation scenarios is the ability of the operators to control the plant from the alternate shutdown panel and locally, at specific system panels. Improved training on operating the plant from outside the control room may reduce the human error probability for required actions. Improved communication equipment and plans for coordination among local operators may also reduce the error rate. Together, these enhancements are assumed to reduce the ex-control room shut down failure probability by 10 percent.

The existing fire model assumes that the failure probability for safe shut down from outside the control room is 1.15×10^{-1}. This includes a 0.1 operator failure probability and a 0.015 hardware failure probability. Reducing the human error component by 10 percent results in a failure probability for ex-control room safe shutdown of 1.05×10^{-1}.

The impact of this change is estimated using available information from the fire model and engineering judgment. No model quantification was performed for this evaluation.

It is assumed that if the portion of the BSEP CDF and release consequences related to control room evacuation can be identified that an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below and include the following items:

- Determine the percentage of the overall MMACR attributable to external events.
- Determine the percentage of the external events MMACR contribution attributable to fire events.
- Determine the percentage of the fire component of the MMACR attributable to control room fires.

- Determine the percentage of the control room fire component of the MMACR attributable to scenarios that require control room evacuation.

- Calculate the reduction in the control room evacuation component of the MMACR that would occur if the training program was enhanced and the communications equipment was improved.

The baseline assumption for external events contributions in the BSEP SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MMACR is $4,794,000, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that the seismic analysis was a margins analysis and did not produce a CDF. For the purposes of this calculation, it is assumed that the fire events comprise 75 percent of the external events risk. This corresponds to a cost-risk of $3,595,000.

Based on the Brunswick IPEEE RAI response, control room fires comprise 53.3 percent of the fire risk, which yields a cost-risk of $1,916,402. The IPEEE indicates that 92.7 percent of the control room fire CDF is comprised of scenarios requiring evacuation of the control room. This corresponds to an evacuation based cost-risk of $1,776,504.

The ratio of the revised ex-control room shut down failure probability to the original value is 0.105/0.115 = 0.913. If this is multiplied by the evacuation based cost-risk of $1,776,504, the product is the revised cost-risk for evacuation based shut down ($1,622,026). The averted cost-risk is the difference between the original evacuation based cost-risk and the revised value ($154,479).

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 31 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,433,521	$154,479	$250,000	**-$95,521**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.21 PHASE II SAMA NUMBER 32: ADD AUTOMATIC FIRE SUPPRESSION SYSTEM

Description: The results of the BSEP fire model indicate that 13.1 percent of the fire risk is related to fires in the 20’ level of the Reactor building North Central and North West, 53.3 percent from the main control room, and 3.0 percent from the switchgear rooms.

These rooms do not have automatic suppression systems and installation of these types of systems has been suggested as a potential means of reducing plant risk.

For the main control room, an automatic suppression system would not provide a significant safety benefit. The sensing devices used for fires include both fuse elements that melt given high temperature and smoke detectors. These types of actuation devices would only actuate after the fire has progressed to a point that would cause evacuation of the control room. Even if the auto suppression system actuated prior to evacuation, the consequences of actuation would require evacuation. Halon or CO2 systems would asphyxiate any personnel remaining in the MCR and water would damage the control equipment. Given that the MCR fire risk is dominated by failure to shut down the reactor from outside the control room, extremely limited benefit is judged to exist for auto suppression systems in the MCR.

For the switchgear room, high voltage source fires are major contributors to the room's fire risk. High voltage fires have been recognized as being non-responsive to gas suppression systems. As the gas concentration goes down with time, the fire will re-ignite. In addition, the actuation of the automatic systems requires high heat or smoke concentration. Again, these are indicators of a fire that has matured and would likely have already damaged the equipment in the room. Automatic suppression systems are more effective at preventing the spread of fires than at preventing damage to equipment in a given area. Limited benefit is considered to exist related to installation of an auto fire suppression system in the E4 switchgear room.

The impact of automatic suppression systems for the 20' level of the reactor building North Central and North West is also considered to be small. Given the nature of the detection system, as mentioned above, the means for saving the equipment within the areas is limited. The installation cost for these systems can be extremely large due to the need to make the fire areas "gas tight" as self sealing. In addition, due to the personnel risk related to asphyxiation in the self sealing areas where gas suppression systems are used, these types of systems are being removed from some plants.

Automatic suppression systems are not considered to address the risk issues for either the main control room or the switchgear room and are not pursued further.

Installation of these types of systems may be possible for the 20' level of the reactor building, but the cost would be prohibitive. The cost benefit estimates are shown below:

The potential impact of installing an automatic gas suppression system in the 20' reactor building North Central and North West areas is estimated using available information from the fire model and engineering judgment. No model quantification was performed for this evaluation.

It is assumed that if the portion of the BSEP CDF and release consequences related to fires in the 20' North Central and North West areas can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below and include the following items:

- Determine the percentage of the overall MMACR attributable to external events.
- Determine the percentage of the external events MMACR contribution attributable to fire events.
- Determine the percentage of the fire component of the MMACR attributable to the 20’ reactor building North Central and North West areas.
- Calculate the reduction in the 20’ reactor building North Central and North West area component of the MMACR that would occur if a Halon system were implemented.

The baseline assumption for external events contributions in the BSEP SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MMACR is $4,794,000, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that the seismic analysis was a margins analysis and did not produce a CDF. For the purposes of this calculation, it is assumed that the fire events comprise 75 percent of the external events risk. This corresponds to a cost-risk of $3,595,000.

Based on the Brunswick IPEEE RAI response, fires in the 20’ Reactor building North Central and North West areas comprise 13.1 percent of the fire risk, which yields a cost-risk of $471,011.

The IPEEE cites a Halon system hardware failure probability of 0.05 and this can be used to estimate the risk reduction if the system were installed in this area. Given that the Halon system operated, it is assumed to be successful in terminating the fire event and preventing equipment damage. Thus, the averted cost-risk for this case is $471,011* 0.95 = $447,460 for the site.

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 32 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,140,540	$447,460	$750,000	**-$302,540**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology. Furthermore, the estimated cost of implementation is judged to be conservative (low), and would likely increase with a detailed engineering study.

F.6.22 PHASE II SAMA NUMBER 33: IMPROVE FIRE BARRIERS BETWEEN CABINETS IN THE CABLE SPREADING ROOM

Description: The results of the BSEP fire model indicate that 4.3 percent of the fire risk is related to sequences with fires starting in the Unit 2 cable spreading room. It was noted in the Brunswick IPEEE that both cabinets containing critical equipment and non-critical equipment are contributors to risk. The non-critical cabinet fires are contributors due to the potential of the fires to spread to the cabinets containing critical equipment. Improving fire barriers within the non-critical cabinets has been identified as a potential means of reducing risk by preventing the spread of these fires and precluding damage to critical equipment.

Review of the IPEEE indicates that fires in non-critical cabinets contribute 2.8 percent of cable spreading room CDF. This is based on fires in the cabinets without safe shutdown equipment (SSE) (non-critical) spreading to cabinets with SSE (critical) as identified in IPEEE Tables 4.5-4B and 4.5-7. The non-critical cabinet fire CDF contribution is the sum of the CDF contributions from the critical cabinets impacted by non-critical cabinet fires. This conservatively includes the fires started in the critical cabinets. The following table provides a summary:

Equipment (from IPEEE)	Node Number (from IPEEE)	Potential Spread to
H07	HY1	**120 VAC Emergency Panel 2D**
HY0	H06	**E7 Distribution Panel 2A**
H08	RE7	**Disconnect switch for XFMR 1E6**
	RE8	**Disconnect switch for XFMR 1E7**
H40	HY4	**RPS Distribution Panel 1C72-P001**

It is assumed that the averted cost-risk associated with fires in non-critical cabinets can be calculated if the total contribution of the non-critical cabinets is known. For the purposes of this evaluation, all of the risk associated with these cabinets is assumed to be eliminated through the installation of improved fire barriers in the non-critical cabinets.

No partial credit is taken for placing fire barriers in critical cabinets to prevent the spread of the initiating event fire to other critical cabinets.

Based on the information in the IPEEE and engineering judgment, the component of the MMACR associated with non-critical cabinet fires and an averted cost-risk for this SAMA can be approximated. The steps used to perform this calculation are provided below and include the following items:

- Determine the percentage of the overall MMACR attributable to external events.
- Determine the percentage of the external events MMACR contribution attributable to fire events.

- Determine the percentage of the fire component of the MMACR attributable to cable spreading room fires.
- Determine the percentage of the cable spreading room fire component of the MMACR attributable to scenarios related to non-critical cabinet fires.
- Calculate the reduction in the non-critical cabinet fire component of the MMACR that would occur if the fire barriers were installed.

The baseline assumption for external events contributions in the BSEP SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MMACR is $4,794,000, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that the seismic analysis was a margins analysis and did not produce a CDF. For the purposes of this calculation, it is assumed that the fire events comprise 75 percent of the external events risk. This corresponds to a cost-risk of $3,595,500.

Based on the Brunswick IPEEE RAI response, cable spreading room fires comprise 4.3 percent of the fire risk, which yields a cost-risk of $154,606. The IPEEE indicates that 2.8 percent of the cable spreading room fire CDF is due to non-critical cabinet fires. This reduces the relevant cost-risk to $4,329.

It is assumed that all of this risk can be eliminated through the implementation of the fire barriers; thus, the averted cost-risk for this SAMA is $4,329.

The cost of implementation for this SAMA, including planning, engineering, labor, and hardware is assigned an assumed value of $50,000 per unit, for a total of $100,000.

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 33 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,583,671	$4,329	$100,000	**-$95,671**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.23 PHASE II SAMA NUMBER 35: USE FIREWATER AS A BACKUP FOR EDG COOLING

Description: Failure of cooling water to the EDGs is an important event for some plants. Loss of cooling water will result in overheating of the EDGs and subsequent failure. Providing an alternate cooling source to the EDGs to provide cooling when the normal means has failed is a potential method of reducing risk. The existing BSEP fire water system could be used as the alternate cooling source.

This SAMA assumes that the required piping changes and connections would be made such that the fire water system could be used to provide the required flow to the EDGs. A lumped event representing the operator action to align the firewater system to the EDGs is used to represent this SAMA. Additional hardware failures are potential contributors to the failure of this alignment; however, for simplicity, they are not included. This method increases the measured risk reduction compared with the more realistic case in which the fire water system failures would also be included.

OPER-DGCOOL is assigned a failure probability of $1x10^{-2}$. Given the extensive hardware changes to include permanent, alternate piping that will eliminate the need for fire hose connections, this task is considered to be relatively easy. An industry example for aligning a spare diesel to an emergency bus has been assigned a failure probability of 5.8E-2 and the alignment is highly complicated. Based on engineering judgement, $1x10^{-2}$ is considered appropriate.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 35 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
OPER-DGCOOL: OPERATOR FAILS TO ALIGN ALTERNATE COOLING	New basic event with $1x10^{-2}$ failure probability
EDG-G1029: LOSS OF COOLING TO DIESEL GENERATOR 1 COOLING WATER	• Add new “AND” gate G034 • Delete gate SWS-G1DG-AC
G034: LOSS OF EDG COOLING FROM NORMAL SOURCES	Add gate SWS-G1DG-AC and new basic event OPER-DG-COOL
• EDG-G1029-AC: LOSS OF COOLING TO DIESEL GENERATOR 1 COOLING WATER • EDG-G2029: LOSS OF COOLING TO DIESEL GENERATOR 2 COOLING WATER • EDG-G2029-AC: LOSS OF COOLING TO DIESEL GENERATOR 2 COOLING WATER • EDG-G3029: LOSS OF COOLING TO DIESEL GENERATOR 3 COOLING WATER • EDG-G3029-AC: LOSS OF COOLING TO DIESEL GENERATOR 3 COOLING WATER • EDG-G4029: LOSS OF COOLING TO DIESEL GENERATOR 4 COOLING WATER • EDG-G4029-AC: LOSS OF COOLING TO DIESEL GENERATOR 4 COOLING WATER	Similar changes made to these gates.

F.6.23.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 35

The results from this case indicate a 1.0 percent reduction in CDF (CDF_{new}=4.15x10^{-5} per year), a 0.7 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.1 per year), and a 0.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,146 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 35 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.78E-06	1.62E-06	1.04E-05	3.31E-06	5.09E-08	2.01E-06	6.96E-08	2.34E-07	**2.36E-05**
SAMA Dose-Risk	5.49	9.10	1.83	11.59	1.06	0.01	0.01	0.01	0.04	**29.14**
SAMA OECR	$4,640	$22,999	$1,895	$17,439	$1,151	$3	$1	$4	$14	**$48,146**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 35 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,507,558	$80,442	$2,000,000	**-$1,919,558**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.24 PHASE II SAMA NUMBER 36: USE FIRE WATER AS A BACKUP FOR CONTAINMENT SPRAY

Description: Containment spray is important for BSEP because it (1) provides a means of scrubbing fission products that are not otherwise scrubbed (e.g., in the case where the suppression pool is bypassed); and, (2) providing water to cool the core debris on the drywell floor to limit non-condensable gas generation and to limit drywell heating and the associated temperature induced failures that can lead to containment failure. Assuming that the 120 psig Fire Protection system can provide the required 1000 gpm flow, the impact is limited due to the dependence on the containment spray valves. However, this SAMA proposes to provide an alternate means of providing containment spray flow using the existing BSEP fire water system. It should be noted here that 1000 gpm may not provide for an effective spray pattern, but will compensate for boil-off due

to decay heat and result in some amount of water over the core debris to scrub fission products.

For BSEP, the containment spray system is not credited in the Level 1 model for accident mitigation. The Level 2 model considers containment spray for fission product scrubbing and containment floor flooding, as mentioned above.

For the purposes of this evaluation, the fire water system is assumed to be aligned to the "B" loop containment spray path. A lumped event representing the operator action to align the firewater system to containment spray path "B" is used to represent this SAMA. The value is set to 0.5 to represent high dependence on the existing containment spray alignment action. Additional hardware failures are potential contributors to the failure of this alignment; however, for simplicity, they are not included. This method increases the measured risk reduction compared with the more realistic case in which the fire water system failures would also be included.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 36 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
ALT-DWS: FWS TO DWS ALIGNMENT GIVEN FAILURE OF OPER-CNS	New basic event with $5x10^{-1}$ failure probability for fire water system alignment to containment spray
TD1: WATER INJECTION TO CONTAINMENT UNAVAILABLE (TD)	Added "OR" gate G040
G040: OP FAILS TO ALIGN ALT DWS OR FLOW PATH FAILS	• Added new basic event ALT-DWS • Added gates RHR2G-CNS-F016B and RHR2G-CNS-F021B • Added basic event RHR2PTF-TM-LOOPB

F.6.24.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 36

The results from this case indicate a 0.0 percent reduction in CDF (CDF_{new}=4.19x10^{-5} per year), a 3.3 percent reduction in dose-risk (Dose-$Risk_{new}$=28.4 per year), and a 3.8 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $46,662 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 36 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.65E-06	1.62E-06	1.00E-05	3.30E-06	4.63E-08	2.01E-06	7.17E-08	2.34E-07	**2.31E-05**
SAMA Dose-Risk	5.50	8.78	1.83	11.13	1.05	0.01	0.01	0.01	0.04	**28.37**
SAMA OECR	$4,643	$22,198	$1,899	$16,750	$1,150	$3	$1	$4	$14	**$46,662**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 36 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,424,834	$163,166	$100,000	**$63,166**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology This cost estimate was judged by the plant staff to be extremely conservative. This SAMA would not likely be cost beneficial with a detailed cost estimate.

F.6.25 PHASE II SAMA NUMBER 37: LOW PRESSURE RCIC OPERATION

Description: For sequences in which high pressure injection is initially available and containment heat removal has failed, impingement on the HCTL will require the operators to depressurize the reactor. Loss of RPV pressure is assumed to fail the turbine driven injection systems and motor driven, low pressure injection systems are assumed to be required for continued injection. If the low pressure injection systems fail, there is currently no means of providing inventory makeup.

A potential enhancement is the use of RCIC at low RPV pressure. This could be implemented through a modification of the EOPs to direct the operators to stop depressurization early (at approximately 100 psig). Alternatively, it could be demonstrated that RCIC is capable of operating at lower RPV pressures. Assuming that one of these methods is performed, RCIC injection could be maintained after HCTL depressurization or restarted given failure of the motor driven, low pressure injection systems.

This enhancement would not provide benefit in SBO sequences given that battery life is expected to be a maximum of about 4 hours while HCTL would not be reached until about 4.5 hours. RCIC control power would be lost at 4 hours and extending the operating regime beyond HCTL would not allow further operation of RCIC.

RCIC is also considered as a potential injection system after containment venting. However, given that the pump is located in the reactor building, there is an added potential for system failure due to harsh environmental conditions caused by the venting action. The environmental failure probability is assumed to be 0.1.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 37 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
#V: FAILURE OF LOW PRESSURE INJECTION	Added New "OR" gate RCI2G1R. (#V is used in LOCA cases as well as for Transient. While LP RCIC operation would not likely be available in all LOCA cases, the additional benefit is small and for ease of modeling, it has not been removed).
RCI2G1R: USE OF RCIC AT LOW RPV PRESSURE	New "OR" gate comprised of the following: • "OR" gate RCI2G-INJECT-B • "OR" gate RCI2G-INJECT • "OR" gate RHR2GFLOODB • NEW "AND" gate G008
G008: PATCH TO EXCLUDE CREDIT IN AN SBO	New "AND" gate comprised of the following: • "AND" gate DCP-G1206 • "AND" gate DCP-G1006
#V2: LOSS OF LOW-PRESSURE INJECTION FOLLOWING WETWELL FAILURE	Added new "OR" gate G011
G011: LP RCIC FAILS AFTER WETWELL FAILURE	New "OR" gate comprised of the following: • New basic event ENV1 • "OR" gate RCI2G1R
ENV1: RCIC FAILS DUE TO ADVERSE ENVIRONMENTAL CONDITIONS	New basic event with assumed failure probability of 0.1.

F.6.25.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 37

The results from this case indicate a 0.4 percent reduction in CDF (CDF_{new}=4.17x10^{-5} per year), a 0.7 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.1 per year), and a 0.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,146 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 37 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.78E-06	1.62E-06	1.04E-05	3.31E-06	5.09E-08	2.01E-06	6.96E-08	2.34E-07	**2.36E-05**
SAMA Dose-Risk	5.49	9.10	1.83	11.59	1.06	0.01	0.01	0.01	0.04	**29.14**
SAMA OECR	$4,640	$22,999	$1,895	$17,439	$1,151	$3	$1	$4	$14	**$48,146**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 37 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,536,037	$51,963	$200,000	**-$148,037**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.26 PHASE II SAMA NUMBER 25: PROCEDURALIZE BATTERY CHARGER HIGH VOLTAGE SHUTDOWN CIRCUIT INHIBIT

Description: The 125 V battery chargers at BSEP are equipped with high voltage shutdown circuit boards designed to open the charger AC feeder breaker via a shunt trip device when the charger output voltage exceeds 143V. This circuit was added to the chargers by plant modifications to prevent half scrams from being generated as a result of high DC system voltages that caused the RPS and ECCS system inverters to shutdown. Shutdown of the inverters results in loss of power to the 24 VDC power supplies for the RPS/ECCS logic circuitry, which in turn results in the generation of half scram signals. The high DC system voltage was the result of switching the charger from float to equalize voltage and the follow up attempt to fine tune the equalize voltage using the voltage adjusting potentiometer. Movement of the charger pot would inadvertently yield an output voltage higher than the inverter trip setting causing it to shutdown. It was deemed appropriate at that time to shutdown the inverter (momentarily that is) than to create a half scram signal.

The high voltage shutdown circuit in the battery charger makes it possible for the charger to trip when attempting to start DC motors in the HPCI/RCIC system with the battery separated from the distribution system (i.e., charger is the sole source of power). The reason is the sudden application and removal of the high motor inrush current which causes the charger voltage regulating circuit to momentarily overshoot above the high voltage shutdown circuit setpoint (143V) and trip the charger AC input power breaker. This overshoot does not occur when the battery is connected to the system because the battery behaves as a large capacitor bank that filters out such voltage transients. Per input obtained from the battery charger vendor, the largest motor load whose starting will not result in a charger trip cannot be quantified. The only way this can be established is via field testing, which is not feasible. Due to the uncertainty in the DC system response, additional system modifications to eliminate the potential charger trip actuation are difficult to design and/or test. A potentially available means of eliminating the loss of the battery chargers when the batteries are not available is to inhibit the trip circuitry.

This SAMA is defined as the development and implementation of procedures to direct the defeat of the trip logic given that the batteries have failed or have been disconnected from the DC circuit. It should be noted that re-energizing the ECCS system inverters which have been shutdown due to high voltage conditions may have adverse effects that could increase the cost of implementation and make this an inappropriate SAMA alternative

The impacts of this SAMA are estimated through the application of a supplementary recovery file. The file is applied after the normal cutset development process is complete and acts on the flags used to designate charger trip given battery failure. The supplementary recovery file is summarized below:

Phase II SAMA Number 25 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
CHRGRTRPREC: Recovery event representing the failure probability of inhibiting the battery charger high voltage trip logic ($5x10^{-2}$).	Add the recovery to the cutsets with the following events/event combinations: • DCP2REC-XXTRP2A1, DCP2REC-XXTRP2B2 • DCP2REC-XXTRP2A1 • DCP2REC-XXTRP2B2 • DCP2REC-XXTRP2A2

F.6.26.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 25

The results from this case indicate an 8.8 percent reduction in CDF (CDF_{new}=$4.16x10^{-5}$ per year), a 0.5 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.2 per year), and a 0.5 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,234 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 25 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.78E-06	1.62E-06	1.05E-05	3.29E-06	5.09E-08	1.97E-06	7.16E-08	2.30E-07	**2.36E-05**
SAMA Dose-Risk	5.49	9.11	1.83	11.64	1.05	0.01	0.01	0.01	0.04	**29.19**
SAMA OECR	$4,639	$23,024	$1,895	$17,510	$1,144	$3	$1	$4	$14	**$48,234**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 25 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,124,070	$463,930	$50,000	**$413,930**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

F.6.27 PHASE II SAMA NUMBER 34: SUPPLEMENTAL POWER SUPPLIES FOR OFFSITE POWER RECOVERY AFTER BATTERY DEPLETION DURING SBO

Description: Given a loss of offsite power at BSEP, the plant can be re-aligned to the grid when it is available assuming that onsite AC and DC power are also available. However, switchyard power dependencies complicate offsite power recovery in prolonged station blackout (SBO) conditions.

The Power Circuit Breakers (PCBs), Oil Circuit Breakers (OCBs), and Motor Operated Disconnects used to align offsite power to the plant through the switchyard require both AC and DC power to function. DC power is used for control functions as well as for motive power while AC support is required to run the air compressors that supply the air closing pistons. DC power is available from the station batteries until they are depleted and the air system contains receivers that maintain inventory typically sufficient for a few breaker strokes. For long term SBO cases, the definition of which varies depending on equipment operation and load shed status, the station batteries and air receivers are considered to be depleted. For SBO conditions, the above implies that offsite power cannot be restored until an onsite AC (and DC) source is made available.

The current BSEP PRA model allows AC power recovery at up to 30 minutes after batteries are assumed to be depleted to account for boildown and core heatup after loss of injection. While this does not coincide with a strict interpretation of the dependence factors, it is not considered unreasonable as no credit is taken for successful load shed in the model.

The 30 minute time period used in the BSEP model to account for boildown and fuel heatup for core damage given loss of injection is shorter than the true available time to core damage for the longer term accidents. Credit for longer times to core damage could be taken for AC power recovery in the longer term accidents if a means were available to align the switchyard. This SAMA proposes that supplemental AC and DC power sources be procured and that procedures be fully developed to align the sources for switchyard operation.

This SAMA could be performed using 480v AC generators to power the station battery chargers and the switchyard air compressors, or, portable DC generators could be used to supply the DC power loads and bypass potential battery charger failures.

This SAMA has been represented through changes to the recovery file. The AC power recovery terms were modified based on the following assumptions:

- No additional credit for recoveries with loss of injection at 1 hour or less
- Add 1 additional hour for the loss of injection at 2 and 5 hours
- Add 2 additional hours for losses of injection at over 12 hours

The recovery file changes that were made to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 34 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
X-AC-2H: AC Power Recovery Failure Probability	Changed from $1.33x10^{-1}$ to $1.20x10^{-1}$
X-AC-5H: AC Power Recovery Failure Probability	Changed from $9.30x10^{-2}$ to $8.76x10^{-2}$
X-AC-12H: AC Power Recovery Failure Probability	Changed from $4.02x10^{-2}$ to $3.35x10^{-2}$
X-AC-12RNLS: AC Power Recovery Failure Probability	Changed from $2.81x10^{-2}$ to $2.26x10^{-2}$
X-AC-13H: AC Power Recovery Failure Probability	Changed from $3.56x10^{-2}$ to $2.98x10^{-2}$
X-AC-14H: AC Power Recovery Failure Probability	Changed from $3.16x10^{-2}$ to $2.64x10^{-2}$
X-AC-16H: AC Power Recovery Failure Probability	Changed from $2.49x10^{-2}$ to $2.08x10^{-2}$
X-AC-17H: AC Power Recovery Failure Probability	Changed from $2.20x10^{-2}$ to $1.84x10^{-2}$
X-AC-18H: AC Power Recovery Failure Probability	Changed from $1.96x10^{-2}$ to $1.63x10^{-2}$
X-AC-18RNLS: AC Power Recovery Failure Probability	Changed from $1.18x10^{-2}$ to $9.51x10^{-3}$
X-AC-19H: AC Power Recovery Failure Probability	Changed from $1.73x10^{-2}$ to $1.45x10^{-2}$

F.6.27.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 34

The results from this case indicate a 5.5 percent reduction in CDF ($CDF_{new}=3.96x10^{-5}$ per year), a 4.5 percent reduction in dose-risk ($Dose\text{-}Risk_{new}=28.0$ per year), and a 4.8 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $46,174 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 34 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	3.64E-06	1.62E-06	9.76E-06	3.30E-06	5.09E-08	2.00E-06	6.27E-08	2.34E-07	**2.28E-05**
SAMA Dose-Risk	5.48	8.78	1.83	10.83	1.05	0.01	0.01	0.01	0.04	**28.04**
SAMA OECR	$4,630	$22,184	$1,895	$16,297	$1,147	$3	$1	$4	$14	**$46,174**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 34 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,102,491	$485,509	$489,277	**-$3,768**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.28 PHASE II SAMA ANALYSIS SUMMARY

The SAMA candidates which could not be eliminated from consideration by the baseline screening process or other PSA insights required the performance of a detailed analysis of the averted cost-risk and SAMA implementation costs. SAMA candidates are potentially justified only if the averted cost-risk resulting from the modification is greater than the cost of implementing the SAMA. Several of the SAMAs analyzed were found to be cost-beneficial as defined by the methodology used in this study. However, this evaluation should not necessarily be considered a definitive guide in determining the disposition of a plant modification that has been analyzed using other engineering methods. These results are intended to provide information about the relative estimated risk benefit associated with a plant change or modification compared with its cost of implementation and should be used as an aid in the decision making process. The results of the detailed analysis are shown below:

Summary of the Detailed SAMA Analyses

Phase II SAMA ID	Averted Cost- Risk	Cost of Implementation	Net Value	Cost Beneficial?
1	$1,912,557	$489,277	$1,423,280	Yes
3	$59,244	$434,775	-$375,531	No
4	$1,299,690	$4,000,000	-$2,700,310	No
5	$1,069,849	>>$1,000,000	Large Negative	No
6	$63,969	$100,000	-$36,031	No
10	$74,834	$434,775	-$359,941	No
11	$203,666	$434,775	-$231,109	No
12	$133,035	$434,775	-$301,740	No
13	$818,664	$836,870	-$18,206	No
15	$267,916	$200,000	$67,916	Yes
16	$135,817	$159,078	-$23,261	No
17	$1,566,562	$489,277	$1,077,285	Yes
18	$359,314	$434,775	-$75,461	No
19	$637,723	489,277	$148,446	Yes

Summary of the Detailed SAMA Analyses

Phase II SAMA ID	Averted Cost- Risk	Cost of Implementation	Net Value	Cost Beneficial?
20	$165,307	$434,775	-$269,468	No
21	$246,707	$500,000	-$253,293	No
22	$153,398	$500,000	-$346,602	No
25	$463,930	$50,000	$413,930	Yes
29	$250,281	$186,861	$63,420	Yes
30	$1,235,829	$1,531,855	-$290,026	No
31	$154,479	$250,000	-$95,521	No
32	$447,460	$750,000	-$302,540	No
33	$4,329	$100,000	-$95,671	No
34	$485,509	$489,277	-$3,768	No
35	$80,442	$2,000,000	-$1,919,558	No
36	$163,166	$100,000	$63,166	Yes
37	$51,963	$200,000	-$148,037	No

F.7 UNCERTAINTY ANALYSIS

The following two uncertainties were further investigated as to their impact on the overall SAMA evaluation:

- Assume a discount rate of 3 percent, instead of 7 percent used in the original base case analysis.
- Use the 95th percentile PSA results in place of the mean PSA results.

F.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 7 percent has been changed to 3 percent and the modified maximum averted cost-risk was re-calculated using the methodology outlined in Section F.4. The Phase I screening against the MMACR was re-examined using the revised MMACR to identify any SAMA candidates that could no longer be screened based on the premise that their costs of implementation exceeded all possible benefit. In addition, the Phase II analysis was re-performed using the 3 percent RDR.

Implementation of the 3 percent RDR increased the MMACR by 18.6 percent compared with the case where a 7 percent RDR was used. This relates to an increase in the MMACR from $9,588,000 to $11,376,000. The Phase I SAMA list was reviewed to determine if such an increase in the MMACR would impact the disposition of any SAMAs. The single SAMA screened on high cost would not be retained for Phase II analysis even with the 18.6 percent increase in MMACR.

The Phase II SAMAs are dispositioned based on PSA insights or detailed analysis. All of the PSA insights used to screen the SAMAs are still applicable given the use of the 3 percent real discount rate. The SAMA candidates screened based on these insights are considered to be addressed and are not investigated further.

The remaining Phase II SAMAs were dispositioned based on the results of a SAMA specific cost-benefit analysis. This step has been re-performed using the 3 percent real discount rate to calculate the net values for the SAMAs.

As shown below, the determination of cost effectiveness changed for several of the Phase II SAMAs when the 3 percent RDR was used in lieu of 7 percent. Implementation of these SAMAs should be considered.

Summary of the Detailed SAMA Analyses

Phase II SAMA ID	Cost of Implementation	Averted Cost- Risk (7 percent RDR)	Net Value (7 percent RDR)	Averted Cost- Risk (3 percent RDR)	Net Value (3 percent RDR)	Change in Cost Effectiveness?
1	$489,277	$1,912,557	$1,423,280	$2,257,193	$1,767,916	No
3	$434,775	$59,244	-$375,531	$72,304	-$362,471	No
4	$4,000,000	$1,299,690	-$2,700,310	$1,521,536	-$2,478,464	No
5	>>$1,000,000	$1,069,849	Large Negative	$1,229,341	Large Negative	No
6	$100,000	$63,969	-$36,031	$74,900	-$25,100	No
10	$434,775	$74,834	-$359,941	$94,912	-$339,863	No
11	$434,775	$203,666	-$231,109	$255,618	-$179,157	No
12	$434,775	$133,035	-$301,740	$161,750	-$273,025	No
13	$836,870	$818,664	-$18,206	$1,013,571	$176,701	Yes
15	$200,000	$267,916	$67,916	$311,591	$111,591	No
16	$159,078	$135,817	-$23,261	$160,808	$1,730	Yes
17	$489,277	$1,566,562	$1,077,285	$1,802,691	$1,313,414	No
18	$434,775	$359,314	-$75,461	$439,307	$4,534	Yes
19	$489,277	$637,723	$148,446	$813,856	$324,579	No
20	$434,775	$165,307	-$269,468	$202,017	-$232,758	No
21	$500,000	$246,707	-$253,293	$286,785	-$213,215	No
22	$500,000	$153,398	-$346,602	$190,205	-$309,795	No
25	$50,000	$463,930	$413,930	$469,586	$419,586	No
29	$186,861	$250,281	$63,420	$291,778	$104,917	No
30	$1,531,855	$1,235,829	-$290,026	$1,466,290	-$65,565	No
31	$250,000	$154,479	-$95,521	$183,286	-$66,714	No
32	$750,000	$447,460	-$302,540	$530,904	-$219,096	No
33	$100,000	$4,329	-$95,671	$5,136	-$94,864	No
34	$489,277	$485,509	-$3,768	$567,352	$78,075	Yes
35	$2,000,000	$80,442	-$1,919,558	$93,088	-$1,906,912	No
36	$100,000	$163,166	$63,166	$228,001	$128,001	No
37	$200,000	$51,963	-$148,037	$64,884	-$135,116	No

F.7.2 95TH PERCENTILE PSA RESULTS

The results of the Phase I screening process itself can be impacted by implementing conservative values from the PSA's uncertainty distribution. Use of the 95th percentile PSA results will increase the modified maximum averted cost-risk 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 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 PSA results on the Phase I SAMA analysis has been examined. The modified maximum averted cost-risk is the primary Phase I criteria affected by PSA uncertainty. Thus, this sensitivity is focused on recalculating the MMACR using the 95th percentile PSA results and re-performing the Phase I screening process.

An estimate of the uncertainty inherent in the Brunswick Unit 2 Level 1 PRA model has been calculated using the software UNCERT32. The following assumptions have been applied in developing this calculation.

1. All failure data was assumed to be distributed lognormally.
2. When an error factor was contained in the basic event database, it was assumed to be correct without any further verification.
3. All common cause failure events in the model were assigned an error factor of 10.0.
4. Initiating events which did not have an error factor in the database were assigned an error factor of 10.0.
5. Operator actions which did not have an error factor in the database were assigned an error factor of 10.0.
6. Calculated and periodically updated maintenance unavailabilities were assigned an error factor of 8.6. Otherwise, maintenance unavailabilities were assigned an error factor of 10.0.
7. Conditional probabilities were assigned an error factor of 5.0.
8. Flag events and split fractions were assigned an error factor of 1.0.
9. Events without an error factor in the database which were identical to a type code failure mode were assigned the corresponding error factor from the type code database.
10. Operator actions in the cutsets set to a value of 1.0 were changed to be 1.0 in the database with an error factor of 1.0 (these events are essentially flag events).

The Unit 2 model of record MOR03 (Reference 22) was used for this analysis. The MOR03 database files **BNP12.BE/.GT/.TC** and cutset file **B2510AAR.CUT** (produced in Reference 23) were used.

The basic event database was purged of records not applicable to Unit 2 MOR03 to simplify checks of the error factors. Error factor data was added to the database for basic events and generic type codes based upon the latest documentation from References 24 to 27 and as updated per data in Reference 22. Additional error factor data was incorporated as necessary based upon the assumptions above.

The tabulated results generated by UNCERT32 are provided below:

PARAMETER	VALUE
Mean	8.85×10^{-05}
5%	1.86×10^{-05}
Median	3.62×10^{-05}
95%	9.83×10^{-05}
Standard Deviation	3.62×10^{-03}

The PSA uncertainty calculation identifies the 95th percentile CDF as 9.83×10^{-5}/yr. This is a factor of 2.35 greater than the CDF point estimate produced by the BSEP PSA.

As the same type of uncertainty analysis was not available for the Level 2 and Level 3 results, the 95th percentile results were estimated. The dose-risk and offsite economic cost-risk were increased by a factor of 2.35 to simulate the increase in the CDF resulting from the use of the 95th percentile results. The "95th percentile" dose-risk and offsite economic cost-risk are 69.0 person-rem/yr and $113,956/yr, respectively. The corresponding modified maximum averted cost-risk is $22.5 million.

The initial SAMA list has been re-examined using the revised modified maximum averted cost-risk to identify SAMAs that would be retained for the Phase II analysis. Those SAMAs that were previously screened due to costs of implementation that exceeded $9.94 million are now retained if the costs of implementation are less than $22.5 million. The only additional SAMA candidate that would be retained for Phase II analysis is SAMA 25 (additional EDG). Given that the SAMA 25 cost of implementation is 89 percent of the revised MMACR, this SAMA is not considered further. The impact of the installation of an additional EDG is judged to be limited due common cause failure. In addition, the current model results indicate that the diesel generators contribute to less than 40 percent of the CDF; thus, the EDG could not be cost beneficial even if the system was 100 percent reliable.

PHASE II IMPACT

As mentioned above, it was necessary to make an assumption about the 95th percentile PSA results for the Level 2 and 3 analyses. The assumption that has been made is that the 95th percentile results for the Level 2 and 3 models can be represented by increasing the base dose-risk and offsite economic cost-risk in proportion to the Level 1 results. The factor of 2.35 is also assumed to propagate through the results for the model runs performed for the Phase II detailed calculations. This means that the averted cost-risks for each case will be increased by the same factor.

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.

Phase II SAMA ID	Cost of Implementation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
1	$489,277	$1,912,557	$1,423,280	$4,494,509	$4,005,232	No
3	$434,775	$59,244	-$375,531	$139,223	-$295,552	No
4	$4,000,000	$1,299,690	-$2,700,310	$3,054,272	-$945,728	No

Phase II SAMA ID	Cost of Implementation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
5	>>$1,000,000	$1,069,849	Large Negative	$2,514,145	Large Negative	No
6	$100,000	$63,969	-$36,031	$150,327	$50,327	Yes
10	$434,775	$74,834	-$359,941	$175,860	-$258,915	No
11	$434,775	$203,666	-$231,109	$478,615	$43,840	Yes
12	$434,775	$133,035	-$301,740	$312,632	-$122,143	No
13	$836,870	$818,664	-$18,206	$1,923,860	$1,086,990	Yes
15	$200,000	$267,916	$67,916	$629,603	$429,603	No
16	$159,078	$135,817	-$23,261	$319,170	$160,092	Yes
17	$489,277	$1,566,562	$1,077,285	$3,681,421	$3,192,144	No
18	$434,775	$359,314	-$75,461	$844,388	$409,613	Yes
19	$489,277	$637,723	$148,446	$1,498,649	$1,009,372	No
20	$434,775	$165,307	-$269,468	$388,471	-$46,304	No
21	$500,000	$246,707	-$253,293	$579,761	$79,761	Yes
22	$500,000	$153,398	-$346,602	$360,485	-$139,515	No
25	$50,000	$463,930	$413,930	$1,090,236	$1,040,236	No
29	$186,861	$250,281	$63,420	$588,160	$401,299	No
30	$1,531,855	$1,235,829	-$290,026	$2,904,198	$1,372,343	Yes
31	$250,000	$154,479	-$95,521	$363,026	$113,026	Yes
32	$750,000	$447,460	-$302,540	$1,051,531	$301,531	Yes
33	$100,000	$4,329	-$95,671	$10,173	-$89,827	No
34	$489,277	$485,509	-$3,768	$1,140,946	$651,669	Yes
35	$2,000,000	$80,442	-$1,919,558	$189,039	-$1,810,961	No
36	$100,000	$163,166	$63,166	$383,440	$283,440	No
37	$200,000	$51,963	-$148,037	$122,113	-$77,887	No

When the 95th percentile PSA results are used, several of the SAMAs that were previously classified as “not cost effective”, are determined to be cost effective. However, the use of the 95th percentile PSA results is not considered to provide the most realistic assessment of the cost effectiveness of a SAMA.

F.8 CONCLUSIONS

The benefits of revising the operational strategies in place at BSEP and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. Use of the PSA 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 a much larger future population. The results of this study indicate that of the identified potential improvements that can be made at BSEP, several are cost beneficial based on the methodology applied in this analysis and warrant further review for potential implementation.

F.9 TABLES AND FIGURES

TABLE F-1
SUMMARY OF THE CORE DAMAGE FREQUENCY BY ACCIDENT SEQUENCE SUBCLASS FOR BRUNSWICK UNIT 2

Accident Class Designator	Subclass	Definition	CAFTA Model (per Rx Yr)(7)
Class I	A	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.	1.21E-5
	B	Accident sequences involving a station blackout and loss of coolant inventory makeup.	IBE 6.11E-6(6) IBL 9.51E-6(6)
	C	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	ε(1)
	D	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	4.17E-6
	E	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high and DC power is unavailable.	(2)
Class II	A	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	8.76E-7
	L	Accident sequences involving a loss of containment heat removal with the RPV breached but no initial core damage; core damage induced post containment failure.	2.82E-7
	V	Class IIA and III except that the vent operates as designed; loss of makeup occurs at some time following vent initiation. Suppression pool saturated but intact.	ε(3)
Class III (LOCA)	A	Accident sequences leading to core damage conditions initiated by vessel rupture where the containment integrity is not breached in the initial time phase of the accident.	2.19E-6
	B	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	ε (4)
	C	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	3.04E-6
	D	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	ε(5)

TABLE F-1
SUMMARY OF THE CORE DAMAGE FREQUENCY BY ACCIDENT SEQUENCE SUBCLASS FOR BRUNSWICK UNIT 2

Accident Class Designator	Subclass	Definition	CAFTA Model (per Rx Yr)(7)
Class IV (ATWS)	A	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	2.30E-6
	L	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	1.00E-6
Class V	---	Unisolated LOCA outside containment.	2.99E-7
		Total CDF	4.19E-5

Notes to Table F-1

(1) Class IC accidents resulted in no cutsets above the truncation limit.

(2) Class IE accidents are binned with Class IA accidents in the current BSEP PRA.

(3) Class IIV accidents are negligible in the current BSEP PRA (i.e., the Level 1 model assumes 0.0 likelihood of successful venting causing injection failure).

(4) Class IIIB accidents resulted in no cutsets above the truncation limit.

(5) Class IIID accidents are negligible in the current BSEP PRA. A large LOCA coincident with vapor suppression system failure is judged sufficiently low frequency that the scenario is not explicitly modeled.

(6) The Class IB cutsets are divided into Class IBE (i.e., early station blackout) and Class IBL (i.e., late station blackout) for the Level 2 analysis. Class IBE is defined as station blackout with core damage in less than 4 hours and includes all cutsets in which 2 or less hours were credited for AC power recovery (i.e., AC power recovery events X-AC-0H, X-AC-1H and X-AC-2H). Class IBL is defined as station blackout with core damage after 6 hours and includes all cutsets in which 5 or more hours are credited for AC power recovery (i.e., AC power recovery events X-AC-5H, X-AC-12H, X-AC-12RNLS, X-AC-13H, X-AC-14H, X-AC-16H, and X-AC-18H).

(7) ε = Negligible frequency from Level 1 PSA.

TABLE F-2
RELEASE SEVERITY AND TIMING CLASSIFICATION SCHEME (SEVERITY, TIMING)

Release Severity Source Term Release Fraction		Release Timing	
Classification Category	**Cs Iodide % in Release**	**Classification Category**	**Time of Release(1)**
High (H)	greater than 10	Late (L)	greater than 24 hours
Moderate (M)	1 to 10	Intermediate (I)	6 to 24 hours
Low (L)	0.1 to 1	Early (E)	less than 6 hours
Low-Low (LL)	less than 0.1		
No iodine (OK)	0		

TABLE F-3
SUMMARY OF CONTAINMENT EVALUATION

INPUT		OUTPUT	
LEVEL 1 PSA		**CET EVALUATION**	
Core Damage Frequency	**Characterization of Release**	**Release Bin[(1)]**	**Release Frequency (Per Year)**
4.19E-5	Little or No Release	OK	1.81E-5
	Low Public Risk Impact	LL and Late	2.34E-7
		LL and I	7.17E-8
		LL and E	Negligible
		L and Late[(2)]	2.01E-6
		L and I	5.09E-8
		L and E	3.30E-6
	Moderate Public Risk Impact	M and Late [(2)]	Negligible
		M and I	1.06E-5
		M and E	1.62E-6
	High Release	H and Late[(2)]	Negligible
		H and I	3.79E-6
		H and E	2.13E-6

[(1)]See Table F-2 for nomenclature on the release bins.

[(2)]One of the areas that PRA tools are somewhat limited is in the estimation of recovery or repair during extended times such as 24 hours. Some estimates would indicate that response over such an extended time could be very extensive and highly successful. Therefore, it can be argued that virtually no accidents that take beyond 24 hours to release should be considered to be a significant potential contributor to public risk.

(1) Relative to the declaration of a General Emergency.

TABLE F-4
SUMMARY OF BSEP UNIT 2 LEVEL 2 RELEASE CATEGORY FREQUENCIES[(1), (2)]

Class	Adjusted CDF	Intact	H/E	H/I	H/L	M/E	M/I	M/L	L/E	L/I	L/L	LL/E	LL/I	LL/L	Total Release
IA	1.21E-05	6.43E-06	5.40E-08	4.61E-07	N/A	N/A	2.67E-06	N/A	6.18E-07	0.00E+00	1.72E-06	N/A	0.00E+00	1.50E-07	5.67E-06
IBE	6.11E-06	3.87E-06	1.80E-08	2.35E-07	N/A	N/A	1.90E-06	N/A	1.13E-08	0.00E+00	2.76E-08	N/A	4.38E-08	0.00E+00	2.24E-06
IBL	9.51E-06	5.37E-06	1.91E-08	6.62E-07	N/A	N/A	3.40E-06	N/A	8.24E-09	0.00E+00	1.87E-08	N/A	2.78E-08	0.00E+00	4.13E-06
ID	4.17E-06	5.27E-07	3.36E-08	4.31E-07	N/A	N/A	2.59E-06	N/A	2.66E-07	0.00E+00	2.46E-07	N/A	0.00E+00	8.37E-08	3.65E-06
IIA(3)	8.76E-07	0.00E+00	N/A	8.25E-07	N/A	N/A	0.00E+00	N/A	N/A	5.09E-08	N/A	N/A	0.00E+00	N/A	8.76E-07
IIL(4)	2.82E-07	0.00E+00	N/A	2.82E-07	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	2.82E-07
IIIA	2.19E-06	5.97E-08	4.44E-08	4.15E-09	0.00E+00	N/A	0.00E+00	0.00E+00	2.08E-06	0.00E+00	0.00E+00	N/A	0.00E+00	0.00E+00	2.13E-06
IIIC	3.04E-06	1.81E-06	1.18E-08	8.93E-07	0.00E+00	N/A	0.00E+00	0.00E+00	3.24E-07	0.00E+00	0.00E+00	N/A	0.00E+00	0.00E+00	1.23E-06
IVA	2.30E-06	0.00E+00	1.15E-06	N/A	N/A	1.13E-06	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	2.28E-06
IVL	1.00E-06	0.00E+00	5.02E-07	N/A	N/A	4.96E-07	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	9.98E-07
V	2.99E-07	0.00E+00	2.99E-07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.99E-07
Total	4.19E-05	1.81E-05	2.13E-06	3.79E-06	0.00E+00	1.62E-06	1.06E-05	0.00E+00	3.30E-06	5.09E-08	2.01E-06	0.00E+00	7.17E-08	2.34E-07	2.38E-05

(1) The results are based on PRAQuant file BNP2-L2.QNT. The Level 2 model was quantified at a truncation value of 5E-10/yr for most sequences. The Class II, IV, and V CET sequences were quantified at a truncation value of 5E-11/yr.

(2) N/A indicates that the accident class did not contribute to release of that specific category.

(3) Due to truncation issues, the total Class IIA release frequency was calculated to be 7.96E-7/yr. This calculated result is less than the total Class IIA CDF. Therefore, to represent the total release correctly, the individual Class IIA end state totals are increased proportionally by a factor of 1.1 (i.e., 8.76E-7/7.96E-7) to equal the total Class IIA CDF of 8.76E-7/yr.

(4) Due to truncation issues, the total Class IIL release frequency was calculated to be 2.71E-7/yr. This calculated result is less than the total Class IIL CDF. Therefore, to represent the total release correctly, the individual Class IIL end state totals are increased proportionally by a factor of 1.04 (i.e., 2.82E-7/2.71E-7) to equal the total Class IIA CDF of 2.82E-7/yr.

TABLE F-5
BSEP SOURCE TERM SUMMARY

	Release Category[1]											
	H/E	H/I	H/L(6)	M/E	M/I	M/L(6)	L/E	L/I	L/L	LL/E	LL/I	LL/L
Bin Frequency	2.13E-06	3.79E-06	0.00E+00	1.62E-06	1.06E-05	0.00E+00	3.30E-06	5.09E-08	2.01E-06	0.00E+00	7.17E-08	2.34E-07
MAAP Run	BR0085	BR0090	BR0090[2]	BR0083	BR0066	BR0070	BR0088	BR0064	BR0063	NA	BR0069	BR0069[3]
Time after Scram when General Emergency is declared	45 min	5 min	5 min	45 min	45 min	60 min[4]	45 min	55 min	55 min		45 min	
Fission Product Group:												
1) Noble												
Total Release % at 48 Hours	100	88	88	100	88	100	22	99	100		100	
Start of Release (hr)	45 min	11.6 hr	24 hr	45 min	15.5 hr	31.1 hr	6.3 hr	16 hr	29.2 hr		29 hr	
End of Release (hr)	2 hr	11.6 hr	24 hr	2.5 hr	15.5 hr	31.1 hr	6.3 hr	22 hr	32 hr		29 hr	
2) CsI												
Total Release % at 48 Hours	34	3.24E+01	32.4	7.7	9.3	2.6	0.15	0.19	1.40E-03		2.40E-03	
Start of Release (hr)	45 min	11.6 hr	24 hr	2.4 hr	15.5 hr	31.1 hr	6.3 hr	16 hr	29.2 hr		29 hr	
End of Release (hr)	4 hr	36 hr	36 hr	4 hr	36 hr	72 hr	6.3 hr	36 hr	34 hr		36 hr	
3) TeO2												
Total Release % at 48 Hours	4.4	21.7	21.7	0.82	6.6	2	0.27	7.00E-04	6.60E-05		1.80E-02	
Start of Release (hr)	45 min	11.6 hr	24 hr	45 min	15.5 hr	31.1 hr	6.3 hr	16 hr	2.5 hr		29 hr	
End of Release (hr)	4 hr	28 hr	36 hr	4 hr	16.0 hr	50.0 hr	6.3 hr	36 hr	2.5 hr		36 hr	
4) SrO												
Total Release % at 48 Hours	0.12	5.30E-04	5.30E-04	2.80E-02	1.70E-04	1.50E-02	2.10E-05	0.015	1.80E-09		9.00E-08	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	3.0 hr	35.0 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	11.6 hr	24 hr	8 hr	6.0 hr	40 hr	6.3 hr	31 hr	2.5 hr		2 hr	
5) MoO2												
Total Release % at 48 Hours	2.60E-02	1.50E-04	1.50E-04	8.20E-04	1.70E-05	6.30E-04	3.00E-05	3.00E-08	2.80E-08		3.40E-07	
Start of Release (hr)	2.4 hr	1 hr	24 hr	45 min	2.0 hr	31.1 hr	6.3 hr	2.5 hr	2.5 hr		2 hr	
End of Release (hr)	2.4 hr	1 hr	24 hr	2 hr	36.0 hr	31.1 hr	6.3 hr	2.5 hr	2.5 hr		2 hr	
6) CsOH												
Total Release % at 48 Hours	5	31.9	31.9	1.3	3.5	1.5	0.5	9.60E-02	1.30E-03		0.14	
Start of Release (hr)	45 min	11.6 hr	24 hr	45 min	15.5 hr	31.1 hr	6.3 hr	16 hr	29.2 hr		29 hr	
End of Release (hr)	4 hr	36 hr	36 hr	36 hr	24 hr	40.0 hr	6.3 hr	36 hr	36 hr		36 hr	
7) BaO												
Total Release % at 48 Hours	0.08	1.60E-03	1.60E-03	0.014	1.10E-03	7.30E-03	4.80E-05	7.20E-03	6.70E-09		4.30E-07	
Start of Release (hr)	2.4	11.6 hr	24 hr	2.4 hr	15.5 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	36 hr	36 hr	8 hr	36 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
8) La2O3												
Total Release % at 48 Hours	6.00E-03	2.80E-05	2.80E-05	1.80E-03	2.10E-05	2.00E-04	4.00E-06	1.40E-04	2.60E-10		3.60E-08	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	3.0 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	11.6 hr	24 hr	4 hr	6.0 hr	40 hr	6.3 hr	31 hr	2.5 hr		2 hr	
9) CeO2												
Total Release % at 48 Hours	5.20E-02	1.90E-04	1.90E-04	1.50E-02	1.10E-04	3.30E-03	5.00E-06	2.30E-03	6.50E-10		6.00E-08	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	3 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	11.6 hr	24 hr	6 hr	6 hr	40 hr	6.3 hr	31 hr	2.5 hr		2 hr	
10) Sb												
Total Release % at 48 Hours	10.8	49.7	49.7	3.7	25	1.1	1.1	0.53	1.20E-03		1.3	
Start of Release (hr)	2.4	11.6 hr	24 hr	2.4 hr	15.5 hr	35 hr	6.3 hr	31 hr	29.2 hr		29 hr	
End of Release (hr)	14 hr	36 hr	36 hr	20 hr	28 hr	45 hr	6.3 hr	36 hr	36 hr		32 hr	
11) Te2												
Total Release % at 48 Hours	1.4	1.2	1.2	0.5	7.70E-01	0.81	2.40E-05	0.37	9.10E-06		2.70E-04	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	15.5 hr	35 hr	6.3 hr	31 hr	29.2 hr		29 hr	
End of Release (hr)	16 hr	24 hr	36 hr	24 hr	24 hr	55 hr	6.3 hr	36 hr	29.2 hr		32 hr	
12) UO2												
Total Release % at 48 Hours	2.20E-04	3.00E-05	3.00E-05	7.60E-05	2.30E-05	1.30E-05	5.00E-08	4.00E-06	3.00E-14		5.00E-10	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	15.5 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	36 hr	36 hr	8 hr	36 hr	45 hr	6.3 hr	36 hr	2.5 hr		2 hr	

(1) Puff releases are denoted in the table by those entries with equivalent start and end times.
(2) Case BR0090 results shifted to 24 hr release to represent "Late" release
(3) Results for release category LL/I will be used for LL/L
(4) General Emergency based on loss of containment heat removal and assumed to be declared at 60 minutes

(5) Mass of TeO2 Generated for each case	82 lb	84 lb	84 lb	82 lb	85 lb	81 lb	85 lb	82 lb	82 lb		85 lb	

(6) Revised Level 2 results indicate negligible contributions for the M/L and H/L release categories; however, the source term information has been retained for reference purposes.

TABLE F-6
ESTIMATED POPULATION DISTRIBUTION WITHIN A 10-MILE RADIUS OF BSEP, YEAR 2036

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles	10-mile total
N	40	81	95	131	636	2,391	3,374
NNE	40	88	95	95	142	1,089	1,549
NE	40	88	95	95	142	7,144	7,604
ENE	40	121	47	95	142	10,318	10,763
E	40	162	243	195	150	273	1,063
ESE	40	162	184	113	142	123	764
SE	40	162	126	113	150	131	722
SSE	40	121	108	113	135	405	922
S	40	181	333	240	192	653	1,639
SSW	40	750	2,208	459	573	74	4,104
SW	40	180	331	437	631	143	1,762
WSW	40	121	243	409	725	6,807	8,345
W	40	28	258	616	662	6,601	8,205
WNW	40	28	85	113	113	1,977	2,356
NW	40	69	85	113	141	1,140	1,588
NNW	40	121	76	462	851	2,282	3,832
Total	640	2,463	4,612	3,799	5,527	41,551	58,592

TABLE F-7
ESTIMATED POPULATION DISTRIBUTION WITHIN A 50-MILE RADIUS OF BSEP, YEAR 2036

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile total
N	3,374	13,715	18,832	8,664	16,269	60,854
NNE	1,549	117,933	101,274	22,404	22,703	265,863
NE	7,604	74,599	63,184	21,619	15,394	182,400
ENE	10,763	982	0	0	0	11,745
E	1,063	0	0	0	0	1,063
ESE	764	0	0	0	0	764
SE	722	0	0	0	0	722
SSE	922	0	0	0	0	922
S	1,639	0	0	0	0	1,639
SSW	4,104	0	0	0	0	4,104
SW	1,762	0	0	0	0	1,762
WSW	8,345	0	0	0	0	8,345
W	8,205	23,295	26,007	56,649	67,085	181,241
WNW	2,356	11,272	8,452	8,561	28,113	58,754
NW	1,588	3,354	3,202	4,741	25,278	38,163
NNW	3,832	4,536	7,137	6,313	7,675	29,493
Total	58,592	249,686	228,088	128,951	182,517	847,834

TABLE F-8
ESTIMATED ANNUAL POPULATION GROWTH RATE WITHIN A 10-MILE RADIUS OF BSEP

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles
N	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
NNE	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
NE	1.0435	1.0435	1.0435	1.0435	1.0435	1.0386
ENE	1.0435	1.0435	1.0435	1.0435	1.0435	1.0333
E	1.0435	1.0435	1.0435	1.0365	1.0333	1.0333
ESE	1.0435	1.0435	1.0435	1.0435	1.0333	1.0333
SE	1.0435	1.0435	1.0435	1.0435	1.0430	1.0435
SSE	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
S	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
SSW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
SW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
WSW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
W	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
WNW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
NW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
NNW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435

TABLE F-9
ESTIMATED ANNUAL POPULATION GROWTH RATE WITHIN A 10 TO 50-MILE RADIUS OF BSEP

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles
N	See Table F-8	1.0435	1.0423	1.0400	1.0386
NNE	See Table F-8	1.0386	1.0342	1.0421	1.0424
NE	See Table F-8	1.0333	1.0347	1.0424	1.0251
ENE	See Table F-8	1.0333	0	0	0
E	See Table F-8	0	0	0	0
ESE	See Table F-8	0	0	0	0
SE	See Table F-8	0	0	0	0
SSE	See Table F-8	0	0	0	0
S	See Table F-8	0	0	0	0
SSW	See Table F-8	0	0	0	0
SW	See Table F-8	0	0	0	0
WSW	See Table F-8	0	0	0	0
W	See Table F-8	1.0435	1.0435	1.0387	1.0365
WNW	See Table F-8	1.0435	1.0435	1.0224	1.0185
NW	See Table F-8	1.0435	1.0317	1.0115	1.0105
NNW	See Table F-8	1.0435	1.0241	1.0131	1.0126

TABLE F-10
ESTIMATED BSEP CORE INVENTORY

Nuclide	Core Inventory (Becquerels)	Nuclide	Core Inventory (Becquerels)
Co-58	$1.654x10^{16}$	Te-131m	$4.132x10^{17}$
Co-60	$1.980x10^{16}$	Te-132	$4.039x10^{18}$
Kr-85	$2.710x10^{16}$	I-131	$2.792x10^{18}$
Kr-85m	$9.853x10^{17}$	I-132	$4.101x10^{18}$
Kr-87	$1.792x10^{18}$	I-133	$5.860x10^{18}$
Kr-88	$2.418x10^{18}$	I-134	$6.413x10^{18}$
Rb-86	$1.516x10^{15}$	I-135	$5.516x10^{18}$
Sr-89	$3.001x10^{18}$	Xe-133	$5.868x10^{18}$
Sr-90	$2.123x10^{17}$	Xe-135	$1.395x10^{18}$
Sr-91	$3.898x10^{18}$	Cs-134	$4.572x10^{17}$
Sr-92	$4.072x10^{18}$	Cs-136	$1.226x10^{17}$
Y-90	$2.274x10^{17}$	Cs-137	$2.737x10^{17}$
Y-91	$3.662x10^{18}$	Ba-139	$5.402x10^{18}$
Y-92	$4.088x10^{18}$	Ba-140	$5.328x10^{18}$
Y-93	$4.649x10^{18}$	La-140	$5.437x10^{18}$
Zr-95	$4.819x10^{18}$	La-141	$5.020x10^{18}$
Zr-97	$4.962x10^{18}$	La-142	$4.830x10^{18}$
Nb-95	$4.560x10^{18}$	Ce-141	$4.838x10^{18}$
Mo-99	$5.258x10^{18}$	Ce-143	$4.710x10^{18}$
Tc-99m	$4.538x10^{18}$	Ce-144	$3.138x10^{18}$
Ru-103	$3.985x10^{18}$	Pr-143	$4.610x10^{18}$
Ru-105	$2.659x10^{18}$	Nd-147	$2.060x10^{18}$
Ru-106	$1.084x10^{18}$	Np-239	$6.141x10^{19}$
Rh-105	$1.984x10^{18}$	Pu-238	$4.270x10^{15}$
Sb-127	$2.514x10^{17}$	Pu-239	$1.083x10^{15}$
Sb-129	$8.726x10^{17}$	Pu-240	$1.355x10^{15}$
Te-127	$2.434x10^{17}$	Pu-241	$2.333x10^{17}$
Te-127m	$3.276X10^{16}$	Am-241	$2.372x10^{14}$
Te-129	$8.186x10^{17}$	Cm-242	$6.264x10^{16}$
Te-129m	$2.152x10^{17}$	Cm-244	$3.380x10^{15}$

TABLE F-11
MACCS RELEASE CATEGORIES VS. BSEP RELEASE CATEGORIES

MACCS Release Categories	BSEP Release Categories
Xe/Kr	1 – noble gases
I	2 – CsI
Cs	2 & 6 – CsI and CsOH
Te	3 & 11- TeO_2 & Te_2
Sr	4 – SrO
Ru	5 – MoO_2 (Mo is in Ru MACCS category)
La	8 – La_2O_3
Ce	9 – CeO_2 & UO_2
Ba	7 – BaO
Sb (supplemental category)	10 – Sb

TABLE F-12
RESULTS OF BSEP LEVEL 3 PSA ANALYSIS

Sequence	H/E	H/I	M/E	M/I	L/E	L/I	L/L	LL/I	LL/L	SUM
Population dose risk (person-rem) 0-50 miles	5.495	9.134	1.831	11.766	1.053	0.008	0.011	0.013	0.042	**29.35**
Total economic cost risk ($) 0-50 miles	4,643	23,081	1,895	17,702	1,148	3	1	4	14	**48,492**

The total baseline release frequency analyzed is 2.38×10^{-5}. MACCS2 calculated the annual baseline population dose risk within 50 miles at 29.35 person-rem. The total annual economic risk was calculated at $48,492.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
%TE_S	2.30E-02	1.542	LOSS OF OFFSITE POWER (SITE)	Install protective covers on switchyard insulators to prevent salt-spray related shorts or proceduralize equipment wash-down after severe weather
%2T_T	2.70E+00	1.374	TURBINE TRIP INITIATOR	The application of the Maintenance Rule is considered to have improved plant operations through focused maintenance plans. PSA applications have also helped to identify areas for improvement in plant practices, equipment availability and operation. No credible, potentially cost effective means of further reducing the turbine trip frequency have been identified. The equipment and operator actions important to mitigating turbine trip initiators is judged to be addressed by the other components in this list.
BUSFAULT	3.90E-01	1.154	FRACTION OF LOSS OF BUS THAT ARE NON-RECOVERABLE	N/A
DCP2BAT-XXDEP2B	1.00E+00	1.151	BATTERY BANK 2B DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
DCP2BAT-XXDEP2A	1.00E+00	1.139	BATTERY BANK 2A DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
X-AC-12H	4.02E-02	1.133	LOSP RECOVERY 12 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
X-AC-2H	1.33E-01	1.128	LOSP RECOVERY 2 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
SRV-DEMAND1	6.36E-01	1.127	7 OF 11 SRVS DEMANDED ISOLATION TRANSIENT	No SAMAs identified.
RCI2TDP-FR-RCTDP	2.30E-01	1.112	RCIC TURBINE-DRIVEN PUMP FAILS TO RUN	High pressure injection reliability could be improved through the addition of a direct drive diesel injection pump (encompassed by SAMA 205, Table A-1).
EDG2DGN-FR-003	7.40E-02	1.106	DIESEL GENERATOR 3 FAILS TO RUN	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)
OPER-ALTUNITXC	1.00E+00	1.090	OPERATORS FAIL TO MANUALLY ALIGN POWER FROM OPPOSITE UNIT	Ensure all buses that can be cross-tied have procedures to perform cross-tie.
%2T_C	1.80E-01	1.090	LOSS OF CONDENSER VACUUM	No SAMAs identified.
EDG2DGN-FR-004	7.40E-02	1.083	DIESEL GENERATOR 4 FAILS TO RUN	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
X-AC-16H	2.49E-02	1.076	LOSP RECOVERY 16 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
DCP2REC-XXTRP2A1	1.00E+00	1.073	CHARGER 2A-1 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Ensure procedures and training exist to isolate failures and reload the buses. Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
DCP2REC-XXTRP2B2	1.00E+00	1.072	CHARGER 2B-2 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Ensure procedures and training exist to isolate failures and reload the buses. Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A 1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
EDG1DGN-FR-001	7.40E-02	1.070	DIESEL GENERATOR 1 FAILS TO RUN	Install an additional Diesel Generator (SAMA 118, Table A-1)
HPC2TDP-FR-HPTDP	7.40E-02	1.068	HPCI TURBINE-DRIVEN PUMP FAILS TO RUN	High pressure injection reliability could be improved through the addition of a direct drive diesel injection pump (encompassed by SAMA 205, Table A-1). Maximizing CRD flow for high pressure injection is also a potential improvement (SAMA 197, Table A-1).
EDG1DGN-FR-002	7.40E-02	1.064	DIESEL GENERATOR 2 FAILS TO RUN	Install an additional Diesel Generator (SAMA 118, Table A 1)
%2T_DC2B2	2.90E-03	1.062	LOSS OF 125V DC PANEL 2B2	No suggestions.
SRV2SRV-CCF-511	7.57E-06	1.050	SUM OF CCF - ANY FIVE SRVs FAIL TO OPEN	Diversify SRVs by replacing some valves with valves of a different design.
IAN2CKV-44ALL	4.50E-05	1.049	COMMON CAUSE FAILURE OF ALL SRV AIR CHECK VALVES TO OPEN	Diversify check valves by replacing some valves with valves of a different design or by installing bypass lines

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
IAN2CKV-443456	4.50E-05	1.049	COMMON CAUSE FAILURE OF CHECK VALVES V313, V314, V315 AND V316 TO OPEN	Diversify check valves by replacing some valves with valves of a different design or by installing bypass lines
RPS2MBIND	1.00E-05	1.049	MECHANICAL BINDING OF CONTROL RODS	This failure is important for BSEP in combination with operator failure to control level to prevent boron washout. Improvements in boron injection will not significantly reduce risk. A potential enhancement is the improvement of EOPs to reduce the failure probability of injection control. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.
OPER-480X2	1.00E+00	1.047	OPERATORS FAIL TO MANUALLY CONNECT UNIT 2 SUBSTATIONS E7 AND E8	Provide capability in the main control room to perform 480V AC substation X-tie.
OPER-DCPALTDC2	1.00E+00	1.043	OPERATOR FAILS TO ALIGN DC BUS TO STANDBY DC POWER SUPPLY - UNIT2	Provide capability in the main control room to perform DC supply swap.
%2TCRD	1.00E+00	1.043	LOSS OF CONTROL ROD DRIVE	An inter-unit CRD cross-tie could improve accident mitigation for this initiator. Alternate boron injection methods are addressed for event "RPS2MBIND".
ICC2LPW-CF-XUALL	3.73E-06	1.041	CCF OF ALL XU POWER SUPPLY PANELS	Use of portable 120V AC generators could supply power to required panels.
OPER-DILUTE	1.00E+00	1.040	OPERATOR FAILS TO PRECLUDE BORON WASHOUT DURING LOW PRESSURE INJECTION	A potential enhancement is the improvement of EOPs to reduce the failure probability of injection control. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.
OPER-DGHMAN	1.00E+00	1.040	OPERATORS FAIL TO MANUALLY START EXHAUST FAN	Add a diverse logic set and thermocouple powered directly from the EDG.
XOP-DGHMAN	6.10E-03	1.036	OPER-DGHMAN	Add a diverse logic set and thermocouple powered directly from the EDG.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
X-AC-1H	2.09E-01	1.035	LOSP RECOVERY 1 HOUR	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
XOP-COM2-16	7.90E-03	1.034	OPER-DCPALTDC1 OPER-ALTUNITXC OR OPER-DCPALTDC1 OPER-ALTUNITXC	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1) provides an additional option in this case.
%2T_M	7.30E-02	1.032	MSIV CLOSURE INITIATOR: T(M)	Digital instrumentation already incorporated. No suggestions.
CRD2SCRAM	6.00E-06	1.027	FAILURE OF CONTROL ROD DRIVE SCRAM VALVES	Alternate boron injection methods and injection flow control modifications for preventing boron dilution are potential enhancements and are addressed for event "RPS2MBIND".
DCP2REC-34A1A2B2	2.37E-07	1.026	COMMON CAUSE FAILURE OF CHARGER 2A-1, 2A-2 AND 2B-2	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
DCP2REC-24A1B2	5.20E-07	1.025	COMMON CAUSE FAILURE OF CHARGER 2A-1 AND 2B-2	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
%2TE_U2	1.40E-02	1.024	LOSS OF OFFSITE POWER TO UNIT 2	Implement procedures to spray down electrical component after sever weather to prevent shorting from salt spray.
OPER-LLEVEL1	1.00E+00	1.023	OPERATOR FAILS TO CONTROL LOWERED WATER LEVEL WITH HPCI DURING ATWS	No suggestions.
EDG2DGN-TM-D003	1.40E-02	1.022	DIESEL GENERATOR 3 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
X-AC-5H	9.30E-02	1.021	LOSP RECOVERY 5 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
XOP-ALTUNITXC1	7.00E-02	1.020	OPER-ALTUNITXC	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1).
DCP0REC-44ALL	1.76E-07	1.019	COMMON CAUSE FAILURE OF BOTH UNIT 1 AND UNIT 2 CHARGERS	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1).
XOP-DEPRESS	6.90E-03	1.019	OPER-DEPRESS	Alternate depressurization methods are not credited for BSEP. The following alternate depressurization paths are available given failure of the normal means: main condenser via the turbine bypass valves, main steam line drains, HPCI, RCIC, SJAE, RFP, RWCU in recirc mode, and RWCU in blowdown mode. Lack of credit in the model for these methods artificially inflates the importance of depressurization. Additional depressurization methods are not pursued further as the benefit is judged to be small considering the availability of the existing procedures to use the alternate pathways identified above.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
OPER-DEPRESS	1.00E+00	1.019	OPERATOR FAILS TO MANUALLY INITIATE AND ALIGN LOW-PRESSURE SYSTEMS	Alternate depressurization methods are not credited for BSEP. The following alternate depressurization paths are available given failure of the normal means: main condenser via the turbine bypass valves, main steam line drains, HPCI, RCIC, SJAE, RFP, RWCU in recirc mode, and RWCU in blowdown mode. Lack of credit in the model for these methods artificially inflates the importance of depressurization. Additional depressurization methods are not pursued further as the benefit is judged to be small considering the availability of the existing procedures to use the alternate pathways identified above.
%2T_DC2A1	2.90E-03	1.019	LOSS OF 125V DC PANEL 2A1	Provide alternate feeds to buses supplied only by panel 2A-1.
DCP0BAT-44ALL	2.19E-07	1.018	COMMON CAUSE FAILURE OF UNIT 1 AND UNIT 2 BATTERIES	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1).
X-AC-18H	1.96E-02	1.018	LOSP RECOVERY 18 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
%2TE_E4	2.00E-03	1.018	LOSS OF 4160V AC BUS E4	Provide capability to tie to individual 4kV loads from other E-buses.
EDG2DGN-TM-D004	1.40E-02	1.018	DIESEL GENERATOR 4 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)
OPER-GENDISC	1.00E+00	1.017	OPERATORS FAIL TO ESTABLISH BACKFEED	Provide capability to perform the action from the MCR.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
ACP0BKR-44-1234	2.04E-04	1.016	COMMON CAUSE FAILURE OF AT LEAST ONE BREAKER FOR EACH E-BUS	These breakers are related to load sequencer operation for automatic start. Manual start actions would mitigate this failure and they are proceduralized, but not credited. The importance of this event is artificially inflated by not including the manual start actions for the EDGs and no SAMA is judged to be warranted to address this event.
OPER-LLEVEL2	1.00E+00	1.016	OPERATOR FAILS TO CONTROL LOWERED WATER LEVEL WITH RCIC DURING ATWS	No suggestions.
SRV2SRV-OO-F013L	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013L FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013K	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013K FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013J	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013J FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013H	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013H FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013G	1.70E-02	1.016	NON-ADS SAFETY RELIEF VALVE B21-F013G FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013F	1.70E-02	1.016	NON-ADS SAFETY RELIEF VALVE B21-F013F FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013E	1.70E-02	1.016	NON-ADS SAFETY RELIEF VALVE B21-F013E FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013D	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013D FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013C	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013C FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013B	1.70E-02	1.016	NON-ADS SAFETY RELIEF VALVE B21-F013B FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013A	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013A FAILS TO RECLOSE	No suggestions.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
EDG0DGN-44-EDGR	6.19E-04	1.016	COMMON CAUSE FAILURE OF 4 OF 4 DIESEL GENERATORS TO RUN	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)
XOP-ALTUNITXC	1.80E-02	1.016	OPER-ALTUNITXC AND NON-OPERS	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1).
EDG1DGN-TM-D001	1.40E-02	1.015	DIESEL GENERATOR 1 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Install an additional Diesel Generator (SAMA 118, Table A-1)
EDG2MDC-44SU2AC	1.22E-03	1.015	COMMON CAUSE FAILURE OF UNIT 2 DG AIR COMPRESSORS TO START	Add a diverse compressor that can be aligned to either unit.
OPER-DC2BALT	1.00E+00	1.015	OPERATOR FAILS TO SWITCH CHARGER TO ALTERNATE AC POWER SUPPLY-UNIT 2	Provide MCR capability to perform action.
DGH0TTE-LOTE1608	4.95E-02	1.014	THERMOSTAT TE-1608 FAILS LOW	Add a diverse logic set and thermocouple powered directly from the EDG.
%2TE_E8	2.00E-03	1.014	LOSS OF 480V AC SUBSTATION E8	Provide MCR capability to perform action to cross-tie to alternate 480v substation (if E8 not faulted).
OPER-FPS1	1.00E+00	1.014	OPERATOR FAILS TO ALIGN FIREWATER FOR COOLANT INJECTION FLOW (ONE UNIT)	Provide MCR capability to perform fire protection injection alignment.
CRD2FLT-PG_S001A	8.23E-02	1.014	FILTER S001A PLUGGED	Provide logic to automatically open the alternate filter path and the bypass on high differential pressure across the running filter.
CRD2FLT-PG_D003A	8.23E-02	1.014	CRD DRIVE WATER FILTER C11/C12-D003A PLUGS	Provide logic to automatically open the alternate filter path and the bypass on high differential pressure across the running filter.
EDG1DGN-TM-D002	1.40E-02	1.014	DIESEL GENERATOR 2 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Install an additional Diesel Generator (SAMA 118, Table A-1)

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
%2TE_E7	2.00E-03	1.013	LOSS OF 480V AC SUBSTATION E7	Provide MCR capability to perform action to cross-tie to alternate 480v substation (if E7 not faulted). Provide power to loads directly from other 480v substation.
XOP-COM2-15	1.00E-02	1.013	OPER-LLEVEL2 OPER-DILUTE	Treated separately above.
EDG2DGN-24-DG34R	1.95E-03	1.012	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 3 AND 4	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)
DCP2REC-LP2B2	1.06E-04	1.012	CHARGER 2B-2 FAILS	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
%2TE_E3	2.00E-03	1.012	LOSS OF 4160V AC BUS E3	Provide capability to tie to individual 4kV loads from other E-buses.
DCP2BAT-24A1B2	1.45E-07	1.012	COMMON CAUSE FAILURE OF BATTERY 2A-1 AND 2B-2	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
FL-PT-N021-HI	1.00E+00	1.012	FLAG - N021 PRESSURE TRANSMITTERS FAILING HIGH	Operator actions already exist to back up the logic failure (manual alignment of the low pressure systems). No suggestions.
DCP2BAT-TM2A1	1.14E-04	1.011	BATTERY 2A-1 UNAVAILABLE DUE TO TEST OR MAINTENANCE	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
%2TRCC	1.00E+00	1.011	LOSS OF RBCCW	RBCCW is responsible for CRD pump cooling in the PSA. If the CRD pumps were self cooled, this dependence could be removed.
XOP-DILUTE	4.30E-02	1.011	OPER-DILUTE	A potential enhancement is the improvement of EOPs to reduce the failure probability of injection control. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
DCP2BAT-TM2B2	1.14E-04	1.011	BATTERY 2B-2 UNAVAILABLE DUE TO TEST OR MAINTENANCE	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
DCP2REC-LP2A1	1.06E-04	1.011	CHARGER 2A-1 FAILS	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
%2TF14	3.50E-07	1.011	INTERNAL FLOOD TF14: FAILS CONDENSATE AND FLOODS CABLE SPREADING ROOM	No suggestions.
EDG2DGN-FS-003	6.30E-03	1.011	DIESEL GENERATOR 3 FAILS TO START	Install an additional Diesel Generator (SAMA 118, Table A-1)
DCP2REC-34A1B1B2	2.37E-07	1.011	COMMON CAUSE FAILURE OF CHARGER 2A-1, 2B-1 AND 2B-2	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
ICC2PTT-CF-ECCSH	1.00E-05	1.01	CCF OF ALL ECCS PRESSURE TRANSMITTERS HIGH	Provide a manual override switch for the ECCS Low Pressure Permissive.
ICC2INV-CF-XUALL	1.08E-06	1.01	CCF OF ALL XU PANEL POWER SUPPLY INVERTERS	Use of portable 120V AC generators could supply power to required panels.
%2TIAN	1.00E+00	1.01	LOSS OF INSTRUMENT AIR	Provide a portable, diesel air compressor that can be connected to the air header.
IAN2MDC-FR_CMPD	9.30E-01	1.01	AIR COMPRESSOR D FAILS TO RUN (ANNUAL)	Provide a portable, diesel air compressor that can be connected to the air header.
EDG1DGN-24-DG12R	1.95E-03	1.01	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 1 AND 2	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
CAC2PHE-SC-INERT	9.90E-01	1.76	CONTAINMENT INERTED; VENTING NOT REQUIRED	N/A - success event.
TDI2XHE-TM-LPS1	9.00E-01	1.752	OPERATOR FAILS TO RECOVER LOW PRESSURE SYSTEMS	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
CAC2AOV-FN-NOACP	1.00E+00	1.608	NO AC POWER AVAILABLE TO OPEN COMBUSTIBLE GAS VENT VALVES	In the event that AC power was available for venting, the containment would be inerted 99% of the time and venting would be required only 1% of the time. The RRW value implies a risk reduction that is not available. No changes suggested.
%TE_S	2.30E-02	1.565	LOSS OF OFFSITE POWER (SITE)	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2T_T	2.70E+00	1.412	TURBINE TRIP INITIATOR	Addressed in the Level 1 RRW list or subsumed by a similar event.
ACP2XHE-TM-OFFLR	6.30E-01	1.329	OFFSITE AC POWER NOT RECOVERED DURING RX TIME FRAME (IBL)	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
ACP2XHE-TM-ONSLR	1.00E+00	1.329	ONSITE EMERG. AC POWER NOT RECOV. DURING RX TIME FRAME (IBL)	Install a 5th, diverse diesel.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
ACP2XHE-TM-OFFSL	7.60E-01	1.329	OFFSITE AC POWER NOT RECOVERED DURING TD TIME FRAME (IBL)	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
ACP2XHE-TM-ONSTL	1.00E+00	1.329	ONSITE EMERG. AC POWER NOT RECOV. DURING TD TIME FRAME (IBL)	Install a 5th, diverse diesel.
RXM2XHE-TM-INJ	9.00E-01	1.319	OPERATOR FAILS TO RECOVER INJECTION BEFORE RPV MELT	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
OPN2-DEP-OP5-SUC	8.50E-01	1.262	SUCCESSFUL RPV DEPRESSURIZATION (CLASS IBL)	N/A - success event.
BUSFAULT	3.90E-01	1.245	FRACTION OF LOSS OF BUS THAT ARE NON-RECOVERABLE	N/A
RXM2EST-NO-FAIL	1.00E+00	1.239	FAILURE OF RX (CLASS ID, II, IIIA, IV)	This vessel melt event is based on nature of the sequence in which it is used. Alternate injection systems, such as a direct drive diesel pump, may be beneficial in reducing the magnitude of these types of sequences. However, crediting the current alternate systems should be reviewed prior to pursuing these methods.
OPER-ALTINJ	5.40E-01	1.218	OP FAILS TO ALIGN ALT. INJ. SOURCES IN LEVEL2	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
OPN2-DEP-OP1-SUC	9.00E-01	1.197	SUCCESSFUL RPV DEPRESSURIZATION (CLASS IA)	N/A - success event.
TDI2XHE-TM-LPS2	1.00E+00	1.196	OPERATOR FAILS TO RECOVER LOW PRESSURE SYSTEMS	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
OPER-ALTUNITXC	1.00E+00	1.175	OPERATORS FAIL TO MANUALLY ALIGN POWER FROM OPPOSITE UNIT	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-FR-003	7.40E-02	1.153	DIESEL GENERATOR 3 FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
ACP2XHE-TM-OFFER	5.20E-01	1.15	OFFSITE AC POWER NOT RECOVERED DURING RX TIME FRAME (IBE)	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
ACP2XHE-TM-ONSER	1.00E+00	1.15	ONSITE EMERG. AC POWER NOT RECOV. DURING RX TIME FRAME (IBE)	Install a 5th, diverse diesel.
ACP2XHE-TM-OFFE	6.90E-01	1.15	OFFSITE AC POWER NOT RECOVERED DURING TD TIME FRAME (IBE)	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
ACP2XHE-TM-ONSTE	1.00E+00	1.15	ONSITE EMERG. AC POWER NOT RECOV. DURING TD TIME FRAME (IBE)	Install a 5th, diverse diesel.
DCP2BAT-XXDEP2B	1.00E+00	1.148	BATTERY BANK 2B DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-12H	4.02E-02	1.134	LOSP RECOVERY 12 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
SRV2ALT-DE-METH	1.00E+00	1.133	ALTERNATE DEPRESS. METHODS NOT CREDITED	Alternate depressurization methods are not credited for BSEP. The following alternate depressurization paths are available given failure of the normal means: main condenser via the turbine bypass valves, main steam line drains, HPCI, RCIC, SJAE, RFP, RWCU in recirc mode, and RWCU in blowdown mode. Lack of credit in the model for these methods artificially inflates the importance of depressurization. Additional depressurization methods are not pursued further as the benefit is judged to be small considering the availability of the existing procedures to use the alternate pathways identified above.
SRV2MCS-NO-PRES	9.00E-01	1.133	PRESSURE TRANSIENT DOES NOT FAIL MECHANICAL SYSTEMS	N/A - success event.
SRV2PHE-NO-CMP	2.50E-01	1.133	SRVs DO NOT FAIL OPEN DURING CORE MELT PROGRESSION	No suggestions for cost effective SRV improvement.
SRV2PHE-NO-TEMP	9.00E-01	1.133	HIGH PRIM SYS TEMP DOES NOT CAUSE FAIL OF RCS PRESS. BOUND	N/A - success event.
DCP2REC-XXTRP2A1	1.00E+00	1.133	CHARGER 2A-1 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPN2-DEP-OP7-SUC	9.50E-01	1.131	SUCCESSFUL RPV DEPRESSURIZATION (CLASS IBE)	N/A - success event.
%2T_DC2B2	2.90E-03	1.131	LOSS OF 125V DC PANEL 2B2	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2REC-XXTRP2B2	1.00E+00	1.129	CHARGER 2B-2 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-2H	1.33E-01	1.113	LOSP RECOVERY 2 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DCPALTDC2	1.00E+00	1.113	OPERATOR FAILS TO ALIGN DC BUS TO STANDBY DC POWER SUPPLY - UNIT2	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
NCN2PHE-NO-L1CNT	1.00E+00	1.112	LG CONT. FAILURE GIVEN CONT. FAILED IN LEVEL 1 (CLASS IV)	No suggestions.
DWT2PHE-SC-ATWS	9.90E-01	1.11	DW INTACT FOR ATWS EVENTS (CLASS IV)	N/A - success event.
WWB2PHE-NO-ATWS	5.00E-01	1.11	WW WATER SPACE FAILURE FOR ATWS EVENTS (CLASS IV)	No suggestions.
OPER-480X2	1.00E+00	1.11	OPERATORS FAIL TO MANUALLY CONNECT UNIT 2 SUBSTATIONS E7 AND E8	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-FR-004	7.40E-02	1.105	DIESEL GENERATOR 4 FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2BAT-XXDEP2A	1.00E+00	1.098	BATTERY BANK 2A DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DEPRESS	1.00E+00	1.094	OPERATOR FAILS TO MANUALLY INITIATE AND ALIGN LOW-PRESSURE SYSTEMS	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-COM2-16	7.90E-03	1.091	OPER-DCPALTDC1 OPER-ALTUNITXC OR OPER-DCPALTDC1 OPER-ALTUNITXC	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-16H	2.49E-02	1.09	LOSP RECOVERY 16 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG1DGN-FR-001	7.40E-02	1.083	DIESEL GENERATOR 1 FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV-DEMAND1	6.36E-01	1.079	7 OF 11 SRVS DEMANDED ISOLATION TRANSIENT	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG1DGN-FR-002	7.40E-02	1.074	DIESEL GENERATOR 2 FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPN2-DEP-OP8-SUC	9.80E-01	1.066	SUCCESSFUL RPV DEPRESSURIZATION (CLASS IVA)	N/A - success event.
RPS2MBIND	1.00E-05	1.064	MECHANICAL BINDING OF CONTROL RODS	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP0BAT-44ALL	2.19E-07	1.064	COMMON CAUSE FAILURE OF UNIT 1 AND UNIT 2 BATTERIES	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
DCP1BAT-XXDEP1A	1.00E+00	1.056	BATTERY BANK 1A DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DILUTE	1.00E+00	1.052	OPERATOR FAILS TO PRECLUDE BORON WASHOUT DURING LOW PRESSURE INJECTION	Addressed in the Level 1 RRW list or subsumed by a similar event.
ICC2LPW-CF-XUALL	3.73E-06	1.044	CCF OF ALL XU POWER SUPPLY PANELS	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DEPRESSRPV	5.20E-01	1.043	OP FAILS TO DEPRESS BEFORE RPV FAILS GIVEN RPV DEPRESS. FAILED IN LVL1	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DGHMAN	1.00E+00	1.04	OPERATORS FAIL TO MANUALLY START EXHAUST FAN	Addressed in the Level 1 RRW list or subsumed by a similar event.
NCN2PHE-NO-LOWTM	5.70E-01	1.038	LG CONT. FAILURE AT LOW DW TEMP. (CLASS I, III WITH NO RPV BREACH OR CLASS II)	No suggestions.
DCP2REC-XXTRP2B1	1.00E+00	1.038	CHARGER 2B-1 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Addressed in the Level 1 RRW list or subsumed by a similar event.
CRD2SCRAM	6.00E-06	1.035	FAILURE OF CONTROL ROD DRIVE SCRAM VALVES	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-GENDISC	1.00E+00	1.035	OPERATORS FAIL TO ESTABLISH BACKFEED	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-DGHMAN	6.10E-03	1.033	OPER-DGHMAN	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-1H	2.09E-01	1.031	LOSP RECOVERY 1 HOUR	Addressed in the Level 1 RRW list or subsumed by a similar event.
DWT2PHE-NO-LOWTM	7.80E-01	1.031	DW NOT INTACT AT LOW DW TEMP (CLASS I, III WITH NO RPV BREACH OR CLASS II)	No suggestions.
DCP0REC-44ALL	1.76E-07	1.031	COMMON CAUSE FAILURE OF BOTH UNIT 1 AND UNIT 2 CHARGERS	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
OPER-LLEVEL1	1.00E+00	1.03	OPERATOR FAILS TO CONTROL LOWERED WATER LEVEL WITH HPCI DURING ATWS	Addressed in the Level 1 RRW list or subsumed by a similar event.
NCN2PHE-LK-LOWTM	4.30E-01	1.03	SM CONT. FAILURE AT LOW DW TEMP. (CLASS I, III WITH NO RPV BREACH OR CLASS II)	No suggestions.
ACP2XHE-TM-POWER	1.00E+00	1.03	OPERATOR FAILS TO RESTORE AC POWER DURING BOIL-OFF	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
OPER-FPS1	1.00E+00	1.029	OPERATOR FAILS TO ALIGN FIREWATER FOR COOLANT INJECTION FLOW (ONE UNIT)	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-ALTINJ2	5.10E-01	1.029	OP FAILS TO ALIGN ALT. INJ. SOURCES IN LEVEL2	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
%2TE_E4	2.00E-03	1.028	LOSS OF 4160V AC BUS E4	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-5H	9.30E-02	1.025	LOSP RECOVERY 5 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-18H	1.96E-02	1.025	LOSP RECOVERY 18 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DC2BALT	1.00E+00	1.025	OPERATOR FAILS TO SWITCH CHARGER TO ALTERNATE AC POWER SUPPLY-UNIT 2	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-TM-D003	1.40E-02	1.024	DIESEL GENERATOR 3 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
%2T_C	1.80E-01	1.024	LOSS OF CONDENSER VACUUM	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-44-EDGR	6.19E-04	1.023	COMMON CAUSE FAILURE OF 4 OF 4 DIESEL GENERATORS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TE_U2	1.40E-02	1.022	LOSS OF OFFSITE POWER TO UNIT 2	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TF14	3.50E-07	1.022	INTERNAL FLOOD TF14: FAILS CONDENSATE AND FLOODS CABLE SPREADING ROOM	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-LLEVEL2	1.00E+00	1.021	OPERATOR FAILS TO CONTROL LOWERED WATER LEVEL WITH RCIC DURING ATWS	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-ALTUNITXC	1.80E-02	1.021	OPER-ALTUNITXC AND NON-OPERS	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-ALTUNITXC1	7.00E-02	1.02	OPER-ALTUNITXC	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2MDC-44SU2AC	1.22E-03	1.019	COMMON CAUSE FAILURE OF UNIT 2 DG AIR COMPRESSORS TO START	Addressed in the Level 1 RRW list or subsumed by a similar event.
CNT2CNT-CO-BYPSS	1.00E+00	1.019	CONTAINMENT ISOLATION FAILURE (CLASS V)	Provide redundant and diverse limit switches to each containment isolation valve.
OPER-SWRHR-C	1.00E+00	1.018	OPERATORS FAIL TO LOCALLY CLOSE THE SW VALVES FOR FW INJECTION	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
XOR-SWRHR-C	1.00E-01	1.018	OPER-SWRHR-C	Addressed as independent event.
ACP0BKR-44-1234	2.04E-04	1.017	COMMON CAUSE FAILURE OF AT LEAST ONE BREAKER FOR EACH E-BUS	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-COM2-15	1.00E-02	1.017	OPER-LLEVEL2 OPER-DILUTE	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TCSW	1.00E+00	1.017	LOSS OF CONVENTIONAL SERVICE WATER	No suggestions.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
RCI2TDP-FR-RCTDP	2.30E-01	1.017	RCIC TURBINE-DRIVEN PUMP FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TF7	1.55E-05	1.017	INTERNAL FLOOD TF7: FAILS ALL PUMPS AT -17 LEVEL	Install a direct drive diesel injection pump and locate it outside of the flood areas. Investigate credit for injection with the fire water system.
OPER-SWRHR-O	1.00E+00	1.016	OPERATORS FAIL TO LOCALLY OPEN THE DISCHARGE VALVES FOR RHR INJECTION	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
XOR-SWRHR-O	1.00E-01	1.016	OPER-SWRHR-O	Addressed as independent event.
EDG2DGN-TM-D004	1.40E-02	1.016	DIESEL GENERATOR 4 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-24-DG34R	1.95E-03	1.016	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 3 AND 4	Addressed in the Level 1 RRW list or subsumed by a similar event.
DGH0TTE-LOTE1608	4.95E-02	1.016	THERMOSTAT TE-1608 FAILS LOW	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TE_E8	2.00E-03	1.016	LOSS OF 480V AC SUBSTATION E8	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TCRD	1.00E+00	1.016	LOSS OF CONTROL ROD DRIVE	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2BAT-24A1B2	1.45E-07	1.015	COMMON CAUSE FAILURE OF BATTERY 2A-1 AND 2B-2	Addressed in the Level 1 RRW list or subsumed by a similar event.
SWS2MDP-33_CSW2	7.59E-03	1.015	COMMON CAUSE FAILURE OF ALL UNIT 2 CSW PUMPS TO RUN	Investigate potential improvements in the inter-unit SW cross-ties.
%2T_DC2A1	2.90E-03	1.014	LOSS OF 125V DC PANEL 2A1	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-DILUTE	4.30E-02	1.014	OPER-DILUTE	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG1DGN-TM-D001	1.40E-02	1.014	DIESEL GENERATOR 1 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2BAT-TM2A1	1.14E-04	1.013	BATTERY 2A-1 UNAVAILABLE DUE TO TEST OR MAINTENANCE	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
SRV2SRV-OO-F013A	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013A FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013B	1.70E-02	1.013	NON-ADS SAFETY RELIEF VALVE B21-F013B FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013C	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013C FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013D	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013D FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013E	1.70E-02	1.013	NON-ADS SAFETY RELIEF VALVE B21-F013E FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013F	1.70E-02	1.013	NON-ADS SAFETY RELIEF VALVE B21-F013F FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013G	1.70E-02	1.013	NON-ADS SAFETY RELIEF VALVE B21-F013G FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013H	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013H FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013J	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013J FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013K	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013K FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013L	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013L FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SWS2XVN-OC-V442	2.11E-05	1.013	MANUAL VALVE 2 SW V442 FAILS TO REMAIN OPEN	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-FPS1	9.60E-02	1.013	OPER-FPS1	Addressed in the Level 1 RRW list or subsumed by a similar event.
ACP0TFM-LP-E8	3.12E-05	1.013	TRANSFORMER 4160/480 E4 TO E8 FAILURE NO POWER	Provide capability in the main control room to perform 480V AC substation X-tie.
%2TE_E7	2.00E-03	1.012	LOSS OF 480V AC SUBSTATION E7	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TE_E3	2.00E-03	1.012	LOSS OF 4160V AC BUS E3	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
OPER-FWS-INJ	1.00E+00	1.012	OPERATORS FAIL TO PROPERLY CONTROL CONDENSATE INJECTION FLOW RATE	No suggestions.
EDG1DGN-TM-D002	1.40E-02	1.012	DIESEL GENERATOR 2 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG1DGN-24-DG12R	1.95E-03	1.012	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 1 AND 2	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-WVDHR	1.00E+00	1.012	OPERATORS FAIL TO INITIATE WETWELL VENTING FOR DHR	No suggestions.
XOP-WVDHR	1.50E-03	1.012	OPER-WVDHR	No suggestions.
SWS2CKV-OO-V22	5.40E-04	1.012	CHECK VALVE SW V-22 FAILS TO CLOSE	Proceduralize MOV closure from the control room and back-up local operations to isolate flow diversion.
XOP-DEPRESS	6.90E-03	1.012	OPER-DEPRESS	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2BAT-TM2B2	1.14E-04	1.011	BATTERY 2B-2 UNAVAILABLE DUE TO TEST OR MAINTENANCE	Addressed in the Level 1 RRW list or subsumed by a similar event.
ICC2INV-CF-XUALL	1.08E-06	1.011	CCF OF ALL XU PANEL POWER SUPPLY INVERTERS	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-34-D123R	2.94E-04	1.011	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 1, 2 AND 3	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-34-D124R	2.94E-04	1.011	COMMON CAUSE FAILURE TO RUN OF DIESEL GENRATORS 1, 2 AND 4	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-34-D134R	2.94E-04	1.011	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 1, 3 AND 4	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-34-D234R	2.94E-04	1.011	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 2, 3 AND 4	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-GENDISC	1.80E-01	1.011	OPER-GENDISC	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
XOP-COM2-14	1.60E-02	1.01	OPER-LLEVEL1 OPER-DILUTE	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-FS-003	6.30E-03	1.01	DIESEL GENERATOR 3 FAILS TO START	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-480X1	1.00E+00	1.01	OPERATORS FAIL TO MANUALLY CONNECT UNIT1 SUBSTATIONS E5 AND E6	Provide capability in the main control room to perform 480V AC substation X-tie.

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
1	Salt-spray guards/insulator wash-down	Severe storms can potentially cause shorts in the BSEP switchyard due to salt buildup on the electrical insulators. Potential means of reducing this risk include: 1) A barrier that would block salt spray and prevent buildup on switchyard components, 2) Installation of fresh water sprayers that could be used to prevent buildup of salt during severe weather, and 3) procedures to direct manual washing of switchyard components during severe weather.	Brunswick Level 1 Internal Events RRW Listing	A recovery plan already exists at BSEP to restore the plant to operation after severe weather to wash down the switchyard components (Reference 21). Screened from further analysis.	N/A
2	Portable generator for DC power	DC power availability is important for supporting HPCI/RCIC operation during an SBO. While battery life is limited to about four hours, DC power availability could be extended indefinitely if a portable generator was available to supply power to the required loads. This could be done using an AC generator to supply one of the plant's existing battery chargers (with load shed), or, a DC generator could be used to supply specific DC loads.	Brunswick Level 1 Internal Events RRW Listing	The cost of implementation for this enhancement has been estimated at $489,277 (Progress Energy Staff). This estimate was based on a 480V AC generator required for supplying the station battery chargers. Retained for Phase II analysis.	1

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
3	Inter-unit DC Cross-tie	Failure of a unit's DC power system could be mitigated through the use of a cross-tie to the opposite unit given that the cause of the initial failure is isolated.	Brunswick Level 1 Internal Events RRW Listing	This enhancement is considered to be similar in scope to the addition of an interdivisional AC cross-tie. This cost of implementation has been estimated to be $1,119,000 in Reference 3. Retained for Phase II analysis.	2
4	Provide the Main Control Room with the capability to align the UAT to the "E" buses.	Given a Loss of Off-site Power (LOOP) event with failure of the Startup Auxiliary Transformer (SAT), power can be aligned to the "E" buses by backfeeding through the Unit Auxiliary Transformer (UAT). This action would be desirable given the unavailability of the bus's EDG and failure of a cross-tie to an alternate 4kV bus. Providing controls within the main control room to perform this action reduces the time required to perform the manipulation and simplifies the human action required for successful execution of the alignment.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	The cost of implementation for this enhancement is estimated based on the adjusted cost of installing the remote AC cross-tie in the BSEP main control room in 1993. The scope of this SAMA is considered to be comparable to the remote AC cross-tie enhancement and is used directly after adjusting for inflation. The remote AC cross-tie enhancement capability was implemented between1991 and 1993 at a cost of $341,000 for the site (References 19 and 20). Using an estimated inflation rate of 2.75% per year between 1993 and 2003, the cost in 2003 dollars is $434,775. Retained for Phase II analysis.	3

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
5	Direct drive diesel injection pump	High pressure injection capability could be enhanced through the addition of a direct drive diesel pump. The risk reduction would be greatly enhanced if it was capable of providing the electric power needed to operated the associated injection valves. Additional benefit would be gained if it could be located outside the reactor building or in an area that would preclude flood damage.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	The cost of this SAMA is estimated to be approximately $4,000,000 for the site based on a comparison to the condensate cooling enhancement that was considered for the BSEP Extended Power Uprate (Progress Energy Staff). Retained for Phase II analysis.	4
6	Enhanced/Maximize CRD flow	The off-normal procedures could be modified to direct CRD flow enhancement as a potential high pressure injection method. This would include opening all strainer paths and bypasses to obtain the greatest flow rate from the current pumps. (This appears to be done already, but it is not credited because flow is still not enough for make-up early after SCRAM.)	Brunswick Level 1 and Level 2 Internal Events RRW Listing	Flow maximization is possible at BSEP, but calculations show that use of the maximized flow configuration will not initially maintain reactor vessel level after SCRAM. In order for this SAMA to be effective, hardware changes are required to increase the CRD flowrate. Some flow enhancing changes are considered possible for less than the MMACR and this SAMA is retained for Phase II analysis.	5

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
7	Proceduralize all potential 4kV bus cross-tie actions	Modifying emergency procedures to direct the E3 to E4 cross-tie enhances plant response.	Brunswick Level 1 Internal Events RRW Listing	Progress Energy estimates that the procedure changes, verification and validation, and training for this change would require at least $75,000 given the complexity of the BSEP electrical system. Additional system analysis efforts would require $25,000 for a total of $100,000. Retained for Phase II analysis.	6
8	Improve Off-site power recovery procedures	Improvement of off-site power recovery is a potential means of reducing plant risk. Procedures and recovery techniques may be reviewed to identify potential enhancements.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	BSEP applied the criteria documented in NUMARC 91-04 to screen the plant for vulnerabilities. While no vulnerabilities were found, enhancements were implemented based on the weaknesses identified by the IPE (Reference 17). These enhancements included 1) development of load shed procedures to increase the time to battery depletion, and 2) hardware and procedure changes to allow off-site power restoration via a backfeed from the switchyard through the main and unit auxiliary transformers. No additional procedural improvements have been identified that would provide a measurable increase in off-site power recovery reliability. Screened from further analysis.	N/A - Already Implemented

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
9	Diversify SRVs	Replacing some of the SRVs with an alternate design is a potential means of reducing the common cause failure of the BSEP SRVs.	Brunswick Level 1 Internal Events RRW Listing	Replacement of PWR PORVs with larger components was estimated to cost $2.7 million in Reference 3. This is judged to be approximately the same scope as this SAMA (replace 3 of 7 ADS SRVs). If this estimate is doubled to account for dual unit application, the cost is $5.4 million, which is less than the BSEP MMACR. Retained for Phase II analysis.	7
10	Diversify SRV air header supply check valves	The four check valves which supply the SRV air headers are all of the same design at BSEP. The impact of common cause failure of all four check valves could be reduced by installing solenoid operated valve bypass lines around at least 2 of these valves. This would increase the likelihood that at least one division would be available to supply motive power to the SRVs. Simply replacing the check valves with check valves of a different design is not considered to alter the common cause group enough to preclude 4/4 failure.	Brunswick Level 1 Internal Events RRW Listing	The installation of two bypass lines per unit is judged to be less than the BSEP MMACR. Retained for Phase II analysis.	8

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
11	Diversify SRV air supply check valves	BSEP includes a CCF event which represents failure of all 22 SRV air supply check valves (B21-V036* and B21-V27*). As CCF of these valves is primarily important to depressurization cases for the BSEP PRA, only 3 SRVs are required for success. Installing solenoid operated valve bypass lines around the air supply check valves for 3 SRVs per unit would provide a means of supplying air to 3 SRVs through a diverse set of valves. This would reduce the impact of 22/22 check valve CCF. Simply replacing the check valves with check valves of a different design is not considered to alter the common cause group enough to preclude 22/22 failure.	Brunswick Level 1 Internal Events RRW Listing	The replacement of 3 check valves per unit with an alternate design and the increased cost of maintaining a diverse population of valves is judged to potentially be less than the BSEP MMACR. Retained for Phase II analysis.	9

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
12	Improved Procedures/Equipment to Prevent Boron Dilution	Improved procedures and/or training for controlling low pressure injection to prevent boron dilution is a potential means of reducing the risk of ATWS sequences. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	The costs of procedure and training enhancements are less than the BSEP MMACR. The operator action for preventing boron washout and the governing procedures should be reviewed to determine if there are any weaknesses that could potentially be improved. Modification of the LPCI controls is also judged to be less than the MMACR. Retained for Phase II analysis.	10
13	Enhance the Main Control Room (MCR) to include capability to perform 480V AC substation cross-tie	Providing the MCR with the capability to perform the 480V AC substation cross-tie can potentially improve operator reliability. Modification which would allow the action to be performed entirely within the MCR would reduce the time required to perform the action and simplify the manipulations required for the action.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	Modification of the Main Control Room controls and the related equipment changes to allow 480v AC crosstie from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA. This is less than the MMACR. Retained for Phase II analysis.	11

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
14	Enhance the Main Control Room (MCR) to include capability to align the alternate DC power supply to specific DC panels	BSEP includes alternate DC power connections to several DC panels. Currently, aligning the alternate supply to the panel requires local operator action. If the MCR was modified such that the action could be performed without any local action, the time required to perform the action and the types of manipulations associated with the action would be simplified. This could potentially improve the reliability of the action.	Brunswick Level 1 Internal Events RRW Listing	The cost of implementation for this enhancement is estimated based on the adjusted cost of installing the remote AC cross-tie in the BSEP main control room in 1993. The scope of this SAMA is considered to be comparable to the remote AC cross-tie enhancement and is used directly after adjusting for inflation. The remote AC cross-tie enhancement capability was implemented between1991 and 1993 at a cost of $341,000 for the site (References 19 and 20). Using an estimated inflation rate of 2.75% per year between 1993 and 2003, the cost in 2003 dollars is $434,775. This is less that the MMACR and is retained for Phase II analysis.	12
15	Inter-unit CRD cross-tie	Installation of a CRD cross-tie is a potential method of recovering from a loss of CRD on a given unit.	Brunswick Level 1 Internal Events RRW Listing	Modifications to CRD system piping are estimated to be $836,870 (Progress Energy Staff). Retained for Phase II analysis.	13
16	Portable 120V AC generator	CCF of all 120V AC panels has been identified as an important contributor at BSEP. Alignment of portable 120V AC generators to specific loads may reduce plant risk.	Brunswick Level 1 Internal Events RRW Listing	The cost of implementation for this enhancement has been estimated at $84,078 for a single unit site (Reference 16). To account for implementation at both BSEP units, this cost is doubled to yield $168,156. Retained for Phase II analysis.	14

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
17	Diverse EDG HVAC logic	Failure of the HVAC logic to start the EDG room fans or to open exhaust dampers on high temperature could be mitigated through the installation of a diverse set of fan actuation logic. The backup logic would reduce the reliance on operators to perform a fan start on loss of the current logic.	Brunswick Level 1 and Level 2 Internal Events RRW Listing, Edwin I. Hatch Application for License Renewal	The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the cost of implementation would be $200,000, which is less than the MMACR. Retained for Phase II analysis.	15
18	Diverse swing DG air compressor	A shared, diverse, diesel driven air compressor would reduce the impact of CCF of the EDG starting air compressors at BSEP. One compressor could be shared by the two units to reduce costs. Alternatively, 1) a portable compressor could be procured that could be aligned to any of the four diesels at a potentially lower cost, 2) nitrogen bottles could be aligned to provide the pressure source, or 3) the starting air system could be crosstied between units in the event that the opposite unit’s systems are available.	Brunswick Level 1 Internal Events RRW Listing	The installation of a portable air compressor is considered to be similar in scope to the installation of a portable power generator. As the portable compressor could be shared between the units and the procedure/training development would be nearly identical, the single unit cost of implementation is used for the BSEP site. Providing the capability to cross-connect EDG air start is not pursued as CCF may fail all compressors. Retained for Phase II analysis.	16

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
19	Provide alternate feeds to panels supplied only by DC bus 2A-1	Installing alternate DC feeds to the loads that are currently only supported by DC panel 2A-1 may reduce plant risk through diversification of the power supplies.	Brunswick Level 1 Internal Events RRW Listing	The cost of implementation for this SAMA could be based on an estimate for installing alternate feeds from the opposite switchboard similar to those that exist for other DC panels; however, a more cost effective solution is judged to be the use of portable generators that can be directly connected to the un-powered DC panels. As noted in Phase II SAMA 1, the cost of implementation for portable generators has been estimated to be $489,277 for the site. This is less than the MMACR and has been retained for Phase II analysis.	17
20	Provide alternate feeds to essential loads directly from an alternate "E" bus	Given the loss of an "E" bus, inclusion of alternate feed lines to specific loads would provide a means of bypassing the faulted bus.	Brunswick Level 1 Internal Events RRW Listing	Modification of the AC system to allow alignment of alternate feeds to the 4kV loads is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA. This is less than the MMACR. Retained for Phase II analysis.	18

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
21	Provide an alternate means of supplying the Instrument Air header	Given the loss of the "D" air compressor in conjunction with the failure of at least two of three reciprocating compressors or their flow paths results in loss of IA. Procurement of an additional, portable compressor that could be aligned to the supply header would reduce the risk of loss of instrument air.	Brunswick Level 1 Internal Events RRW Listing	The cost of this SAMA is judged to be less than $10 million. Retained for Phase II analysis.	19
22	Enhance the Main Control Room (MRC) to include capability to swap AC power supplies to the battery chargers	This enhancement would reduce the time required to perform the power swap and simplify the manipulations required of the operator.	Brunswick Level 1 Internal Events RRW Listing	Modification of the Main Control Room controls and the related equipment changes to allow alignment of the alternate 480v AC supply to the 2B-1 and 2B-2 battery chargers from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	20

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
23	Enhance CRD logic	Inclusion of logic and support components within the CRD system to automate flow path protection would improve CRD availability. Currently, a clogged filter requires local, manual action to restore the flow path after the operator diagnoses the problem. If sensors were included which automatically opened the alternate filter flowpath and the bypass line on high differential pressure across the running filter, the loss of CRD probability could be reduced.	Brunswick Level 1 Internal Events RRW Listing	The logic portion of this change is considered to be similar in scope to the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the cost of installing enhanced CRD logic is estimated to be $200,000. A new MOV has to be installed in the suction filter bypass line and the drive path filter bypass requires both an MOV and new piping. These hardware mods are assumed to cost $75,000 each; thus, for both plants, an additional $300,000 is added to the cost of implementation. The total cost for this SAMA is then $500,000 for the site. As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase II analysis.	21

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
24	Install Self Cooled CRD pumps	The Loss of RBCCW initiating event could be removed from the PSA if the CRD pumps used the process fluid as a cooling mechanism. The CRD pump suction source is the CST, which is an acceptable cooling medium.	Brunswick Level 1 Internal Events RRW Listing	Reference 1 estimates that a suppression pool jockey pump could be installed for about $120,000 per pump and that an additional service water pump could be installed for $6 million per unit. The cost of a installing new, self cooled CRD pumps is judged to be closer to the SP jockey pump cost of implementation than for the addition of SW pump. However, old cooling lines must be removed and capped in addition to installing the new pumps, which will increase the implementation cost. Assuming the pumps can be replaced for $100,000 each and that an additional $50,000 is required to address old cooling line issues per unit, the cost of implementation for this SAMA is $500,000 for the site.	22
25	Additional Diesel Generator	This SAMA would help mitigate LOOP events and would reduce the risk of on-line maintenance. Benefit would be increased if the additional diesel generator could 1) be substituted for any current diesel that is in maintenance and 2) if the diesel was of a diverse design such that common cause failure dependence was minimized.	Brunswick Level 1and Level 2 Internal Events RRW Listing and Brunswick IPE	The cost of installing an additional generator has been estimated to cost significantly greater than $20 million in Reference 3. This is greater than the BSEP MMACR and is screened from further review.	N/A

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
26	Manual Override Switch for the Low Pressure Permissive	Common cause failure of the ECCS pressure transmitters is a potential common cause failure of the ECCS initiation function. If a manual bypass switch were installed, failure of the pressure sensor could be bypassed in a timely manner.	Brunswick Level 1 Internal Events RRW Listing	This change is considered to be of more limited scope than the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the upper bound cost of installing a bypass switch for the low pressure permissive is estimated to be $200,000, which is less than the MMACR. Retained for Phase II analysis.	23
27	Not Used				

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
28	Proceduralize Battery Charger High Voltage Shutdown Circuit Inhibit	Given loss or unavailability of station batteries, voltage transients occurring from the loading and unloading of equipment can cause actuation of the charger high voltage trip circuit. Disabling this circuit when the batteries are disconnected from the DC circuit would prevent this trip and allow the chargers to remain on-line.	General Cutset Review	Procedure changes are less than the BSEP MMACR. Retained for Phase II analysis.	25
29	Enhance Containment Isolation Valve Indication	Providing diverse, redundant limit switches on the containment isolation valves would reduce the potential for faulty valve position indication leading to open containment penetrations.	Brunswick Level 2 Internal Events RRW Listing	This change is considered to be of more limited scope than the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the upper bound cost of installing improved containment isolation valve indication equipment is estimated to be $200,000, which is less than the MMACR. Retained for Phase II analysis.	26
30	Improve Inter-Unit SW Cross-tie	Loss of Service Water pump events could be mitigated if full cross-tie capabilities were implemented at BSEP.	Brunswick Level 2 Internal Events RRW Listing	The cost to install an inter-unit SW cross-tie is estimated to cost less than the BSEP MMACR. Retained for Phase II analysis.	27

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
31	Proceduralize Isolation of Flow Diversion	Failure of a running SW pump combined with a check valve failed in the open position will create a flow diversion. Procedures to isolate a failed pump would reduce the flow diversion risk.	Brunswick Level 2 Internal Events RRW Listing	Procedure changes to include actions failed Service Water pumps are estimated to be $50,000 for the site. Retained for Phase II analysis.	28

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
32	Portable EDG Fuel Oil Transfer Pump	A diverse, engine driven, portable diesel fuel oil transfer pump would provide additional means of supplying the EDG day tank in the event that common cause failure prevents operation of the existing pumps.	Brunswick Level 2 Internal Events RRW Listing	Procurement of a portable fuel oil pump, the associated fuel line, and the required storage space in combination with the development of operating procedures is judged to be similar in scope to SAMA 2. The same cost of implementation could be applied to this SAMA ($84,078). The Progress Energy staff has estimated the cost of implementation for a SAMA with a similar impact on the diesel fuel oil system. A pump bypass line could be installed that would allow a gravity feed from the 4 day diesel fuel oil tank to the diesel day tank (EDG saddle tank). This line would include a manual isolation valve and a throttle valve to control flow to the saddle tank and maintain the required fuel supply for the operating diesel generator. The failure rate assumed for the alignment and operation of the portable fuel oil transfer pump as applied in the SAMA quantification is $1x10^{-2}$. It is judged that the operation of the bypass line would be approximately the same. Given that a plant specific cost estimate for the bypass line is available ($186,861), this estimate is used as a surrogate for this SAMA. Retained for Phase II analysis.	29

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
33	Improve Alternate Shutdown Panel	A large portion of the Internal Fire model sequences includes failure of the operators to control the reactor from the Alternate Shutdown Panel. If the controls on this panel could be upgraded, the failure probability for controlling the plant from the Alternate Shutdown Panel could be reduced. Potential improvements include 1) providing a full set of "B" division controls that are the same as those used in the MCR so that a minimum number of local actions would be required, and 2) provide both "A" and "B" division controls on the Alternate Shutdown Panel.	Brunswick Fire Model Results	Reference 1 estimated the cost of installing enhanced computer aided instrumentation to be about $600,000 in 1994. Upgrading the Alternate Shutdown Panel to contain at least a full complement of "B" division controls is judged to require at least an equal investment of resources. For implementation at both units, $1.2 million in 1994 dollars would be required. Using an estimated inflation rate of 2.75% per year between 1994 and 2003, the cost in 2003 dollars is $1,531,855. As this estimate is less than the BSEP MMACR, it has been retained for Phase II analysis.	30
34	Improved Alternate Shutdown Training and Equipment	Improved training on operating the plant from the alternate shutdown panel may reduce the human error probability for required actions. Improved communication equipment and plans for coordination among local operators may also reduce the error rate.	Brunswick Fire Model Results	Training enhancements, procedural changes, and improved communications systems are estimated to cost less than the BSEP MMACR. Retained for Phase II analysis.	31

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
35	Add Automatic Fire Suppression System	1) The Unit 2 Reactor Building 20' North and South areas contain cable trays that are not protected by an automatic fire suppression system. These fire areas are relatively small contributors to the Brunswick fire induced CDF, but some benefit may be possible through such a change. 2) Automatic CO2 suppression in the control room cabinets may be beneficial. 3) Automatic suppression in the Switchgear Rooms may also reduce risk.	Brunswick Fire Model Results	Fire suppression system expansion is judged to cost less than the BSEP MMARC. Retained for Phase II analysis.	32
36	Prohibit Transient Combustibles in the Cable Spreading Room and/or Require Fire Suppression Personnel to Be Present During Work That May Cause a Fire	Procedures to limit the presence of transient combustibles and ignition sources may reduce the potential for a fire in the Cable Spreading Room. The presence of fire suppression personnel during activities that may start fires would improve the probability that any fire would be quickly suppressed.	Brunswick Fire Model Results	Transient combustibles are already restricted by procedures in the BSEP cable spreading room. In addition, any "hot" work that introduces potential ignition sources to the plant is required to include a fire watch as part of the work team. This SAMA is considered to already be addressed for BSEP.	N/A

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
37	Improve Fire Barriers Between Cabinets in the Cable Spreading Room	Fire proof barriers between the electrical cabinets would reduce fire damage. Fires that start in non-vital cabinets would pose minimal risk as the potential to spread to other cabinets would be greatly decreased.	Brunswick Fire Model Results	Fire barrier improvement is judged to cost less than the BSEP MMARC. Retained for Phase II analysis.	33
38	Add Alternate/Manual Methods for Containment Venting	A large portion of the Internal Fire model sequences includes loss of long term decay heat removal capability. Changes to allow manual operation of the containment vent valves or installation of an independent power supply and controls may enhance the ability to remove decay heat in fire scenarios. Use of portable nitrogen bottles or a portable compressor may also be an option for providing motive power to the valves.	Brunswick Fire Model Results, Quad Cities Application for License Renewal, Dresden Application for License Renewal	This SAMA addresses the same issues as Phase I SAMA 27 and is considered to be subsumed by the corresponding evaluation.	N/A

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
39	Supplemental Power Supplies for Offsite Power Recovery After Battery Depletion During SBO	This would allow the recovery of offsite power after station battery depletion.	Brunswick IPE	DC generators could be used to provide power to operate the power control breakers while a 480V AC generator could supply the air compressors for breaker support. The cost for this enhancement is considered to be equivalent to using portable generators to back up the station batteries. The cost of implementation for that SAMA was estimated to be $489,277 and is also applied to this SAMA. Retained for Phase II analysis.	34
40	Use Firewater as a Backup for EDG Cooling	Loss of NSW and CSW to the EDGs could be mitigated if a backup cooling method was available.	Calvert Cliffs Application for License Renewal, Edwin I. Hatch Application for License Renewal	The cost of this SAMA has been estimated to be about $500,000 per EDG in Reference 3. For BSEP, the cost of implementation for the site is $2 million. Retained for Phase II analysis.	35

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
41	Auto Re-Fill of the CST	This would allow continued injection from HPCI, RCIC, Core Spray, and RHR given unavailability of the suppression pool due to clogging or high temperature.	H. B.. Robinson Application for License Renewal	Re-fill of the CST is not currently credited for BSEP; however, procedures exist for aligning the diesel fire pump for make up, as required. Changes could be made to provide a permanently aligned, automated make-up system, however, sufficient inventory exists in the CST to provide makeup for transients for the 24 hour mission time. For non-transient initiators, the available makeup alignment would not have the capacity to keep up with required flow and the changes required to upgrade the system are considered to be out of scope for this SAMA. Auto-refill of the CST would not provide a significant safety benefit for BSEP and it is screened from further analysis.	N/A
42	Use Firewater as a Backup for Containment Spray	SAMA would provide redundant containment spray function without the cost of installing a new system	Dresden Application for License Renewal	The cost of this enhancement has been estimated to be $565,000 per unit is Reference 3. This estimate is considered to be high for BSEP given the existing flowpath between the firewater and RHR systems. Procedure updates are estimated to cost $50,000 for BSEP and the engineering analysis to support the enhancement is assumed to cost at least $50,000. $100,000 is used for the cost of implementation for the site. Retained for Phase II analysis.	36

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
43	Demonstrate RCIC Operation Following Depressurization	Ensuring operability of RCIC after depressurization would provide the operators with a potential method of injection after depressurization on HCTL. Alternatively, procedures could be revised to stop depressurization at 100 psig to maintain RCIC in a known operational region.	Quad Cities Application for License Renewal	Operation of RCIC regardless of suppression pool cooling would improve low pressure injection capability at BSEP. $200K is estimated to be required for procedural enhancements with engineering analysis and extensive training. These changes are well within the BSEP MMACR. Retained for Phase II analysis.	37
44	Clarify Procedures to Control Containment Venting Near PCPL	Complete blowdown of the containment will reduce the pressure head on the suppression pool and the NPSH for any pumps using the suppression pool as a suction source may drop below the required level. The EOPs could be enhanced to explicitly include directions for the operators to control containment pressure within a band near PCPL. This would prevent loss of pump suction while preventing containment overpressurization.	Quad Cities Application for License Renewal	The BSEP containment vent procedure (0EOP-01-SEP-01) provides directions to throttle the vent valves to maintain containment pressure as dictated by the SCO. Inclusion of this step in the procedure is based on the knowledge that maintaining containment pressure near PCPL may be required to retain the suppression pool as an injection suction source. The intent of this SAMA is judged to be addressed by the current procedures and the addition of an explicit control band may reduce the existing flexibility available to the operations staff. Alterations to include an explicit containment pressure control band in the containment vent procedure is not judged to provide any measurable benefit. Screened from further analysis.	N/A

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
1	2	Portable generator for DC power	DC power availability is important for supporting HPCI/RCIC operation during an SBO. While battery life is limited to about four hours, DC power availability could be extended indefinitely if a portable generator was available to supply power to the required loads. This could be done using an AC generator to supply one of the plant's existing battery chargers (with load shed), or, a DC generator could be used to supply specific DC loads.	(1)	The cost of implementation for this enhancement has been estimated at $489,277 for a single unit site (Progress Energy staff).	Implementation of portable DC generators is estimated to yield an averted cost-risk of $1,912,557, which is substantially greater than the cost of implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.1 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
2	3	Inter-unit DC Cross-tie	Failure of a unit's DC power system could be mitigated through the use of a cross-tie to the opposite unit given that the cause of the initial failure is isolated.	(1)	This enhancement is considered to be similar in scope to the addition of an interdivisional AC cross-tie. This cost of implementation has been estimated to be $1,119,000 in Reference 3.	This enhancement is bounded by Phase II SAMA 1. The benefit of a DC cross-tie is more limited than the portable generators because 1) in SBO conditions, the batteries have a limited life and the chargers are unavailable, 2) the cost of installing the cross-tie hardware is greater than the cost of implementing portable generators, and 3) inter-unit cross-tie presents the potential of failing the DC system on the opposite unit. This SAMA is considered to be subsumed by Phase II SAMA 1 and is not pursued further.	Subsumed by Phase II SAMA 1.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
3	4	Provide the Main Control Room with the capability to align the UAT to the "E" buses.	Given a Loss of Off-site Power (LOOP) event with failure of the Startup Auxiliary Transformer (SAT), power can be aligned to the "E" buses by backfeeding through the Unit Auxiliary Transformer (UAT). This action would be desirable given the unavailability of the bus's EDG and failure of a cross-tie to an alternate 4kV bus. Providing controls within the main control room to perform this action reduces the time required to perform the manipulation and simplifies the human action required for successful execution of the alignment.	(1)	The cost of implementation for this enhancement is estimated based on the adjusted cost of installing the remote AC cross-tie in the BSEP main control room in 1993. The scope of this SAMA is considered to be comparable to the remote AC cross-tie enhancement and is used directly after adjusting for inflation. The remote AC cross-tie enhancement capability was implemented between1991 and 1993 at a cost of $341,000 for the site (References 19 and 20). Using an estimated inflation rate of 2.75% per year between 1993 and 2003, the cost in 2003 dollars is $434,775.	Installation of equipment in the main control room to allow remote alignment of power to the "E" buses through the UAT primarily impacts the manipulation time for this action. Accounting for this reduction in manipulation time results in an averted cost-risk of only $59,244. As this is less than the estimated cost of implementation ($434,775), this SAMA is not cost beneficial.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.2 for additional details.
4	5	Direct drive diesel injection pump	High pressure injection capability could be enhanced through the addition of a direct drive diesel pump. The risk reduction would be greatly enhanced if it was capable of providing the electric power needed to operated the associated injection valves. Additional benefit would be gained if it could be located outside the reactor building or in an area that would preclude flood damage.	(1), (2)	The cost of this SAMA is estimated to be approximately $4,000,000 for the site based on a comparison to the condensate cooling enhancement that was considered for the BSEP Extended Power Uprate (Progress Energy staff).	The averted cost-risk for implementation of a direct drive, high pressure diesel injection pump has been estimated to be $1,299,690 for the BSEP site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.3 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
5	6	Enhanced/Maximize CRD flow	The off-normal procedures could be modified to direct CRD flow enhancement as a potential high pressure injection method. This would include opening all strainer paths and bypasses to obtain the greatest flow rate from the current pumps. (This appear to be done already, but it is not credited because flow is still not enough for make-up early after SCRAM.)	(1), (2)	The existing piping system cannot handle any significant increased flow. The capacity is approximately 200 gpm, vs 500+ gpm that would be needed for a Small Break Loss of Coolant Accident. Also, significant electrical work would be needed for an upgrade. By engineering judgement, this SAMA is concluded to be prohibitively expensive.	The averted cost-risk for implementation of enhanced CRD has been estimated to be $1,069,849 for the BSEP site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.4 for additional details.
6	7	Proceduralize all potential 4kV bus cross-tie actions	Modifying emergency procedures to direct the E3 to E4 cross-tie enhances plant response.	(1)	Progress Energy estimates that the procedure changes, verification and validation, and training for this change would require at least $75,000 given the complexity of the BSEP electrical system. Additional system analysis efforts would require $25,000 for a total of $100,000.	Incorporation of the additional cross-tie credit has a limited impact due to the existing common mode failures between the inter-divisional bus cross-tie and the inter-unit cross-tie. The results of a model run indicate that the averted cost-risk for this SAMA is $63,969, which is less than the cost of implementation.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.5 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
7	9	Diversify SRVs	Replacing some of the SRVs with an alternate design is a potential means of reducing the common cause failure of the BSEP SRVs.	(1)	Replacement of PWR PORVs with larger components was estimated to cost $2.7 million in Reference 3. This is judged to be approximately the same scope as this SAMA (replace 5 of 11 SRVs). If this estimate is doubled to account for dual unit application, the cost is $5.4 million.	The RRW for common cause failure of 5 of 11 SRVs is 1.050 based on CDF. For Level 2 contributors, it is only 1.003. Implementation of this SAMA has been approximated by 1) assuming that replacement of 5 of 11 SRVs will eliminate the CCF event used to identify this SAMA, 2) that the impact on external events is the same as it is for internal events, and 3) the Level 2 impact can be estimated by applying the RRW factor of 1.003 to the Dose-Risk and Economic Cost-Risk results. The resulting averted cost-risk is only $251,314 for the site and the SAMA's net value is -$5,148,686. In addition, use of alternate valves that are subjected to the same conditions to perform the same function in the same system does not necessarily preclude the effects of CCF.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
8	10	Diversify SRV air header supply check valves	The four check valves which supply the SRV air headers are all of the same design at BSEP. The impact of common cause failure of all four check valves could be reduced by installing solenoid operated valve bypass lines around at least 2 of these valves. This would increase the likelihood that at least one division would be available to supply motive power to the SRVs. Simply replacing the check valves with check valves of a different design is not considered to alter the common cause group enough to preclude 4/4 failure.	(1)	The cost of installing 2 bypass lines with solenoid operated valves per unit is estimated to be greater than $500,000 assuming $100,000 for each valve and replacement labor and at least $100,000 in analysis and documentation updates.	The RRW for common cause failure of 4 of 4 SRV air header supply check valves is 1.049 based on CDF. For Level 2 contributors, it is only 1.0. Implementation of this SAMA has been approximated by 1) assuming that use of the bypass lines will eliminate the CCF event used to identify this SAMA, and 2) that the impact on external events is the same as it is for internal events. The resulting averted cost-risk is only $237,322 for the site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
9	11	Diversify SRV air supply check valves	BSEP includes a CCF event which represents failure of all 22 SRV air supply check valves (B21-V036* and B21-V27*). As CCF of these valves is primarily important to depressurization cases for the BSEP PRA, only 3 SRVs are required for success. Installing solenoid operated valve bypass lines around the air supply check valves for 3 SRVs per unit would provide a means of supplying air to 3 SRVs through a diverse set of valves. This would reduce the impact of 22/22 check valve CCF. Simply replacing the check valves with check valves of a different design is not considered to alter the common cause group enough to preclude 22/22 failure.	(1)	The cost of installing 3 bypass lines with solenoid operated valves per unit is estimated to be greater than $700,000 assuming $100,000 for each valve and replacement labor and at least $100,000 for analysis and documentation updates.	The RRW for common cause failure of 22 of 22 SRV air supply check valves is 1.049 based on CDF. For Level 2 contributors, it is only 1.0. Implementation of this SAMA has been approximated by 1) assuming that installation of the bypass lines will eliminate the global CCF event used to identify this SAMA, and 2) that the impact on external events is the same as it is for internal events. The resulting averted cost-risk is only $237,322 for the site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
10	12	Improved Procedures/Equipment to Prevent Boron Dilution	Improved procedures and/or training for controlling low pressure injection to prevent boron dilution is a potential means of reducing the risk of ATWS sequences. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.	(1), (2)	Modification of the Main Control Room controls and the related equipment changes to the pumps, logic, and instrumentation to support "dial-in" flow control for LPCI is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	Review of the EOPs confirmed that clear guidance exists on controlling injection flow in an ATWS and no enhancements were identified that would yield a measurable benefit. Installation of a dial in flow control for LPCI was judged to be a potential means of improving man-machine interface. The impact of this enhancement was quantified and determined to yield an averted cost-risk of $74,834 for the site. This is less than the cost of implementation and has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.6 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
11	13	Enhance the Main Control Room (MRC) to include capability to perform 480V AC substation cross-tie	Providing the MCR with the capability to perform the 480V AC substation cross-tie can potentially improve operator reliability. Modifications which would allow the action to be performed entirely within the MCR would reduce the time required to perform the action and simplify the manipulations required for the action.	(1), (2)	Modification of the Main Control Room controls and the related equipment changes to allow 480v AC crosstie from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	Installation of equipment in the main control room to allow remote alignment of the 480v AC crossties reduces the action's manipulation time, improves man-machine interface, and reduces the control manipulations for this action. The estimated averted cost-risk associated with this SAMA is $203,666. As this is less than the estimated cost of implementation ($434,775), this SAMA is not cost beneficial.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.7 for additional information.
12	14	Enhance the Main Control Room (MCR) to include capability to align the alternate DC power supply to specific DC panels	BSEP includes alternate DC power connections to several DC panels. Currently, aligning the alternate supply to the panel requires local operator action. If the MCR was modified such that the action could be performed without any local action, the time required to perform the action and the types of manipulations associated with the action would be simplified. This could potentially improve the reliability of the action.	(1)	Modification of the Main Control Room controls and the related equipment changes to allow alternate DC power alignment from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	Installation of equipment in the main control room to allow remote alignment of the alternate DC power supplies reduces the action's manipulation time and improves man-machine interface for this action. The estimated averted cost-risk associated with this SAMA is $133,035. As this is less than the estimated cost of implementation ($434,775), this SAMA is not cost beneficial.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.8 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
13	15	Inter-unit CRD cross-tie	Installation of a CRD cross-tie is a potential method of recovering from a loss of CRD on a given unit.	(1)	Modifications to CRD system piping are estimated to be $836,870 (Progress Energy staff).	Installation of an inter-unit CRD cross-tie would provide an additional high pressure injection method. The estimated averted cost-risk associated with implementation of this SAMA is $818,664.	The cost of implementation is more than the averted cost-risk for this SAMA. Refer to Section F.6.9 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
14	16	Portable 120V AC generator	CCF of all 120V AC panels has been identified as an important contributor at BSEP. Alignment of portable 120V AC generators to specific loads may reduce plant risk.	(1)	The cost of implementation for this enhancement has been estimated at $84,078 for a single unit site (Reference 16). To account for implementation at both BSEP units, this cost is doubled to yield $168,156.	Loss of the 120v AC panels is important for Medium LOCA sequences with no injection. The time to core damage for these sequences is only about 11 minutes (MAAP Run BR0026), which is less than the 1 hour manipulation time required for portable generator alignment taken from an industry example. It should be noted that this alignment time is for a single generator alignment to a single panel whereas this SAMA would potentially require multiple generator alignment to several panels. The importance of 120v AC panel failure may also be exaggerated for BSEP given that manual initiation of injection systems is not credited on RPS failure. This SAMA is not an effective means of reducing plant risk and is screened from further consideration.	Screened from further consideration. No significant benefit.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
15	17	Diverse EDG HVAC logic	Failure of the HVAC logic to start the EDG room fans or to open exhaust dampers on high temperature could be mitigated through the installation of a diverse set of fan actuation logic. The backup logic would reduce the reliance on operators to perform a fan start on loss of the current logic.	(1), (2), (3)	The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the cost of implementation would be $200,000.	The impact of adding an additional logic train to the EDG HVAC system has been quantified assuming a lumped event for an alternate logic train. The risk reduction is commensurate with the RRW value for the event used to identify this SAMA and the associated averted cost-risk has been estimated to be $267,916. As the cost implementation is less than the averted cost-risk, this SAMA has been retained for potential implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.10 for additional details.
16	18	Diverse swing DG air compressor	A shared, diverse, diesel driven air compressor would reduce the impact of CCF of the EDG starting air compressors at BSEP. One compressor could be shared by the two units to reduce costs. Alternatively, 1) a portable compressor could be procured that could be aligned to any of the four diesels at a potentially lower cost, or 2) nitrogen bottles could be aligned to provide the pressure source.	(1)	The installation of a portable air compressor is considered to be similar in scope to the installation of a portable power generator. As the portable compressor could be shared between the units and the procedure/training development would be nearly identical, the single unit cost of implementation is used for the BSEP site. Providing the capability to cross-connect EDG air start is not pursued as CCF may fail all compressors. Retained for Phase II analysis.	The impact of adding the capability to align a portable air compressor to the EDG starting air system has been estimated to yield an averted cost-risk of $135,817. As the cost implementation is less than the averted cost-risk, this SAMA has been retained for potential implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.11 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
17	19	Provide alternate feeds to panels supplied only by DC bus 2A-1	Installing alternate DC feeds to the loads that are currently only supported by DC panel 2A-1 may reduce plant risk through diversification of the power supplies.	(1)	The cost of implementation for this SAMA could be based on an estimate for installing alternate feeds from the opposite switchboard similar to those that exist for other DC panels; however, a more cost effective solution is judged to be the use of portable generators that can be directly connected to the un-powered DC panels. As noted in Phase II SAMA 1, the cost of implementation for portable generators has been estimated to be $489,277 for the site.	The averted cost-risk for this SAMA has been estimated to be $1,566,562. As this estimate is greater than the cost of implementation, it has been retained for possible implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.12 for additional details.
18	20	Provide alternate feeds to essential loads directly from an alternate "E" bus	Given the loss of an "E" bus, inclusion of alternate feed lines to specific loads would provide a means of bypassing the faulted bus.	(1)	Modification of the AC system to allow alignment of alternate feeds to the 4kV loads is considered to be greater in scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used as a lower bound for the implementation cost for this SAMA.	The averted cost-risk associated with providing the capability to align alternate feeds to required 4kV loads has been estimated to be $359,314. This is less than the cost of implementation estimated for this SAMA and is screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.13 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
19	21	Provide an alternate means of supplying the Instrument Air header	Given the loss of the "D" air compressor in conjunction with the failure of at least two of three reciprocating compressors or their flow paths results in loss of IA. Procurement of an additional, portable compressor that could be aligned to the supply header would reduce the risk of loss of instrument air.	(1)	The scope of this SAMA is considered to be similar in scope to Phase II SAMA 1. The cost of implementation for that SAMA is used as a surrogate for the portable air compressor that is analyzed here.	The addition of an alternate compressor reduces the risk of loss of instrument air scenarios. The averted cost-associated with the installation of an engine driven air compressor is $637,723.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.14 for additional information.
20	22	Enhance the Main Control Room (MRC) to include capability to swap AC power supplies to the battery chargers	This enhancement would reduce the time required to perform the power swap and simplify the manipulations required of the operator.	(1)	Modification of the Main Control Room controls and the related equipment changes to allow alignment of the alternate 480v AC supply to the 2B-1 and 2B-2 battery chargers from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	Credit is not currently taken for the alternate power alignment action for the chargers. Directions exist for this action in the auxiliary safe shutdown procedures, but are not included in the normal EOPs. This SAMA assumes that the action is made available to the operators for any condition requiring alternate feed to the chargers and that the MCR in enhanced to include controls to perform the alignment. The estimated cost-risk associated with this enhancement is $165,307. As this is less than the cost of implementation, it is screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.15 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
21	23	Enhance CRD logic	Inclusion of logic and support components within the CRD system to automate flow path protection would improve CRD availability. Currently, a clogged filter requires local, manual action to restore the flow path after the operator diagnoses the problem. If sensors were included which automatically opened the alternate filter flowpath and the bypass line on high differential pressure across the running filter, the loss of CRD probability could be reduced.	(1)	The logic portion of this change is considered to be similar in scope to the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the cost of installing enhanced CRD logic is estimated to be $200,000. A new MOV has to be installed in the suction filter bypass line and the drive path filter bypass requires both an MOV and new piping. These hardware mods are assumed to cost $75,000 each; thus, for both plants, an additional $300,000 is added to the cost of implementation. The total cost for this SAMA is then $500,000 for the site.	This SAMA accounts for installation of the logic and required flowpath elements to allow automatic bypass of CRD suction and drive path filter clogging events. Both the "A" and "B" trains are assumed to be equipped with this capability. The averted cost-risk associated with this SAMA has been estimated to be $246,707. As this is less than the cost of implementation, this SAMA has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.16 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
22	24	Install Self Cooled CRD pumps	The Loss of RBCCW initiating event could be removed from the PSA if the CRD pumps used the process fluid as a cooling mechanism. The CRD pump suction source is the CST, which is an acceptable cooling medium.	(1)	Reference 1 estimates that a suppression pool jockey pump could be installed for about $120,000 per pump and that an additional service water pump could be installed for $6 million per unit. The cost of a installing new, self cooled CRD pumps is judged to be closer to the SP jockey pump cost of implementation than for the addition of SW pump. However, old cooling lines must be removed and capped in addition to installing the new pumps, which will increase the implementation cost. Assuming the pumps can be replaced for $100,000 each and that an additional $50,000 is required to address old cooling line issues per unit, the cost of implementation for this SAMA is $500,000 for the site.	The averted cost-risk associated with removing the cooling dependency from CRD and removing the loss of RBCCW initiating event from the model is only $153,398 for the site. This is less than the cost of implementation and is screened from further consideration.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.17 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
23	26	Manual Override Switch for the Low Pressure Permissive	Common cause failure of the ECCS pressure transmitters is a potential common cause failure of the ECCS initiation function. If a manual bypass switch were installed, failure of the pressure sensor could be bypassed in a timely manner.	(1)	This change is considered to be of more limited scope than the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the upper bound cost of installing a bypass switch for the low pressure permissive is estimated to be $200,000.	The RRW value for CCF of the ECCS pressure sensors is 1.01 based on CDF and is only included in cutsets below the truncation limit for the Level 2 quantification. The averted cost-risk associated with this low RRW value is $47,464 for the site. As this is less than the estimated cost of implementation, it has been excluded from further consideration.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.
24	27	Not used.					
25	28	Proceduralize Battery Charger High Voltage Shutdown Circuit Inhibit	Given loss or unavailability of station batteries, voltage transients occurring from the loading and unloading of equipment can cause actuation of the charger high voltage trip circuit. Disabling this circuit when the batteries are disconnected from the DC circuit would prevent this trip and allow the chargers to remain on-line.	(9)	$50,000 to $100,000 is estimated to be required for procedure updates.	Assuming a failure rate of $5x10^{-2}$ for the performance of the proposed logic bypass procedure, the averted cost-risk is estimate to be $463,930. As the averted cost-risk is greater than the cost of implementation, this SAMA is retained for further consideration.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.26 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
26	29	Enhance Containment Isolation Valve Indication	Providing diverse, redundant limit switches on the containment isolation valves would reduce the potential for faulty valve position indication leading to open containment penetrations.	(2)	This change is considered to be of more limited scope than the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the upper bound cost of installing improved containment isolation valve indication equipment is estimated to be $200,000.	Based on cutset analysis, removal of containment isolation failures has an associated averted cost risk of only about $129,924 for the site. This estimate is based on elimination the 2.99E-7/yr containment bypass contribution to the core damage frequency and high-early release frequency. The true benefit of SAMAs related to ISLOCA mitigation is more limited than this estimate as any proposed measure would not be 100 percent effective in mitigating these accidents. As the estimated averted cost risk is less than the cost of implementation for this SAMA, it has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
27	30	Improve Inter-Unit SW Cross-tie	Loss of Service Water pump events could be mitigated if full cross-tie capabilities were implemented at BSEP.	(2)	The cost to install an inter-unit SW cross-tie is estimated to cost at least $100,000 per unit due to the need for the hardware modifications related to piping changes.	Service Water Common Cause Failure event used to identify this SAMA has an RRW value of 1.007 for CDF and 1.015 for the dominant Level 2 contributors. This corresponds to an averted cost-risk of only $103,491 for the site. This is less than the $200,000 cost estimated for this SAMA and is screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.
28	31	Proceduralize Isolation of Flow Diversion	Failure of a running SW pump combined with a check valve failed in the open position will create a flow diversion. Procedures to isolate a failed pump would reduce the flow diversion risk.	(2)	Not Estimated.	The Brunswick abnormal operating procedures already include steps to isolate the discharge valves of any pumps that are not running; however, no credit is taken for this isolation action in the current BSEP PRA model. As this action is already directed and because the importance of flow divergence is artificially inflated by model conservatisms, this SAMA is screened from further analysis.	Screened from further analysis. Already Implemented.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
29	32	Portable EDG Fuel Oil Transfer Pump	A diverse, engine driven, portable diesel fuel oil transfer pump would provide additional means of supplying the EDG day tank in the event that common cause failure prevents operation of the existing pumps.	(2)	Procurement of a portable fuel oil pump, the associated fuel line, and the required storage space in combination with the development of operating procedures is judged to be similar in scope to SAMA 2. The same cost of implementation could be applied to this SAMA ($84,078). The Progress Energy staff has estimated the cost of implementation for a SAMA with a similar impact on the diesel fuel oil system. A pump bypass line could be installed that would allow a gravity feed from the 4 day diesel fuel oil tank to the diesel day tank (EDG saddle tank). This line would include a manual isolation valve and a throttle valve to control flow to the saddle tank and maintain the required fuel supply for the operating diesel generator. The failure rate assumed for the alignment and operation of the portable fuel oil transfer pump as applied in the SAMA quantification is $1x10^{-2}$. It is judged that the operation of the bypass line would be approximately the same. Given that a plant specific cost estimate for the bypass line is available ($186,861), this estimate is used as a surrogate for this SAMA.	The PSA model was modified to include the capability of aligning a portable fuel oil transfer pump to provide makeup to the DG day tanks given failure of the normal pumps. Assuming a lumped failure probability for the pump and operator action to align the equipment, the associated averted cost-risk is $250,281. As this is greater than the associated cost of implementation, it has been retained for potential implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.18 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
30	33	Improve Alternate Shutdown Panel	A large portion of the Internal Fire model sequences includes failure of the operators to control the reactor from the Alternate Shutdown Panel. If the controls on this panel could be upgraded, the failure probability for controlling the plant from the Alternate Shutdown Panel could be reduced. Potential improvements include 1) providing a full set of "B" division controls that are the same as those used in the MCR so that a minimum number of local actions would be required, and 2) provide both "A" and "B" division controls on the Alternate Shutdown Panel.	(4)	Reference 1 estimated the cost of installing enhanced computer aided instrumentation to be about $600,000 in 1994. Upgrading the Alternate Shutdown Panel to contain at least a full complement of "B" division controls is judged to require at least an equal investment of resources. For implementation at both units, $1.2 million in 1994 dollars would be required. Using an estimated inflation rate of 2.75% per year between 1994 and 2003, the cost in 2003 dollars is $1,531,855.	The averted cost risk for this SAMA has been estimated to be $1,235,829. As this is less than the estimated cost of implementation, it has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.19 for additional information.
31	34	Improved Alternate Shutdown Training and Equipment	Improved training on operating the plant from the alternate shutdown panel may reduce the human error probability for required actions. Improved communication equipment and plans for coordination among local operators may also reduce the error rate.	(4)	This SAMA would require an estimated $250,000 in procedure development work, as well as substantial operator training, including some dose cost, in addition to equipment (Progress Energy staff).	Assuming that improved communication equipment and further training on alternate shutdown practices will result in a 10 percent improvement in the alternate shutdown failure rate yields an averted cost-risk of $154,479.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.20 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
32	35	Add Automatic Fire Suppression System	1) The Unit 2 Reactor Building 20' North and South areas contain cable trays that are not protected by an automatic fire suppression system. These fire areas are relatively small contributors to the Brunswick fire induced CDF, but some benefit may be possible through such a change. 2) Automatic CO2 suppression in the control room cabinets may be beneficial. 3) Automatic suppression in the Switchgear Rooms may also reduce risk.	(4)	Implementation of this SAMA would effectively involve three medium-size and –complexity modifications. Engineering judgement yields an estimate of approximately $750,000 for the engineering for these modifications to the two BSEP units (Progress Energy staff).	Automatic suppression systems are not considered to be effective risk reduction means for the MCR or switchgear rooms. The averted cost-risk of installing a Halon system in the reactor building 20' North and South areas has been estimated to be $447,460 for the site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.21 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
33	37	Improve Fire Barriers Between Cabinets in the Cable Spreading Room	Fire proof barriers between the electrical cabinets would reduce fire damage. Fires that start in non-vital cabinets would pose minimal risk as the potential to spread to other cabinets would be greatly decreased.	(4)	Not Estimated.	Cable spreading room fires account for only $154,607 of the estimated $3,595,500 in fire related cost-risk. Based on a review of the IPEEE information related to fire spreading in the cable spreading room, only 2.8 percent of this CDF contribution could be mitigated through the addition of fire barriers. This corresponds to approximately $4,329, which is less than any credible hardware modification cost. Screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.22 for additional information.
34	39	Supplemental Power Supplies for Off-Site Power Recovery After Battery Depletion During SBO	This would allow the recovery of offsite power after station battery depletion.	(5)	DC generators could be used to provide power to operate the power control breakers while a 480v AC generator could supply line compressors for breaker support. The cost for this enhancement is considered to be equivalent to using portable generators to back up the station batteries. The cost of implementation for that SAMA was estimated to be $489,277 and is also applied to this SAMA.	Allowing longer times for AC power recovery after battery depletion in an SBO based on switchyard power support yields an estimated cost-risk of $485,509. This is less than the cost of implementation.	The cost of implementation is more than the averted cost-risk for this SAMA. Refer to Section F.6.27 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
35	40	Use Firewater as a Backup for EDG Cooling	Loss of NSW and CSW to the EDGs could be mitigated if a backup cooling method was available.	(3), (6)	The cost of this SAMA has been estimated to be about $500,000 per EDG in Reference 3. For BSEP, the cost of implementation for the site is $2 million.	Plant changes to allow alignment of the Firewater system for alternate EDG cooling provides a means of supporting EDG operation given loss of Service Water. For BSEP, the Service Water system is diverse and provides a reliable source of cooling to the EDGs and the implementation of an alternate cooling method has a limited impact. The estimated averted cost-risk of this SAMA is $80,442. As this is less than the cost of implementation, it has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.23 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
36	42	Use Firewater as a Backup for Containment Spray	SAMA would provide redundant containment spray function without the cost of installing a new system	(7)	The cost of this enhancement has been estimated to be $50,000 for procedure changes and an additional $50,000 for analysis to support the change for the site.	Containment spray is important because it (1) provides a means of scrubbing fission products that are not otherwise scrubbed (e.g., in the case where the suppression pool is bypassed); and, (2) providing water to cool the core debris on the drywell floor to limit non-condensable gas generation and to limit drywell heating and the associated temperature induced failures that can lead to containment failure. Assuming that the 120 psig Fire Protection system can provide the required 1000 gpm flow, the impact is limited due to the dependence on the containment spray valves. The estimated cost-risk for this SAMA is $163,166 for the site. As this is greater than the cost of implementation, this SAMA has been retained for further analysis.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.24 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
37	43	Demonstrate RCIC Operation Following Depressurizatio n	Ensuring operability of RCIC after depressurization would provide the operators with a potential method of injection after depressurization on HCTL. Alternatively, procedures could be revised to stop depressurization at 100 psig to maintain RCIC in a known operational region.	(8)	Operation of RCIC regardless of suppression pool cooling would improve low pressure injection capability at BSEP. $200K is estimated to be required for procedural enhancements with engineering analysis and extensive training to support the enhancement.	Given the dependence of RCIC on DC power for operation in SBO sequences and the fact that HCTL challenges will not occur until after battery depletion, this SAMA will not provide benefit to Brunswick in an SBO. However, some benefit exists non-SBO cases. The BSEP model was changed to reflect the added capability of RCIC to run at low pressure. The results indicate an averted cost-risk of $51,963. As this is less than the cost of implementation, this SAMA has been screened from further consideration.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.25 for additional information.

(1) Brunswick Level 1 Internal Events RRW Listing
(2) Brunswick Level 2 Internal Events RRW Listing
(3) Edwin I. Hatch Application for License Renewal
(4) Brunswick Fire Model Results
(5) Brunswick IPE
(6) Calvert Cliffs Application for License Renewal
(7) Dresden Application for License Renewal
(8) Quad Cities Application for License Renewal
(9) General Cutset Review

Figure F-1
SAMA Screening Process

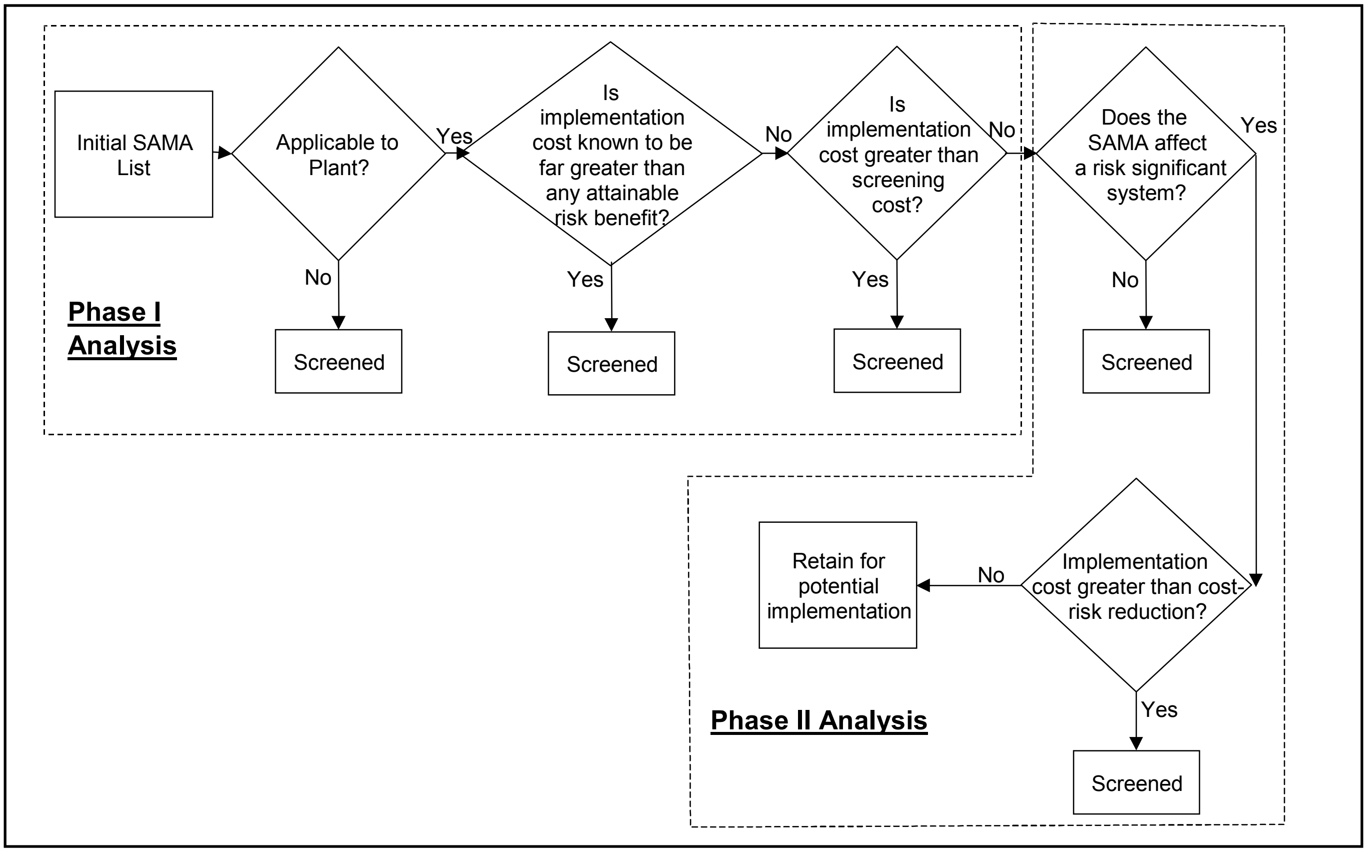


Figure F-2
Brunswick Unit 2 MOR03
Contribution to CDF by Initiator

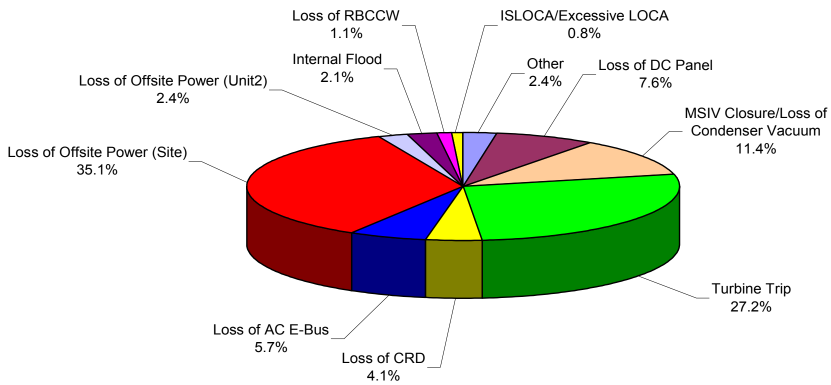


Figure F-3
Contribution to CDF by System

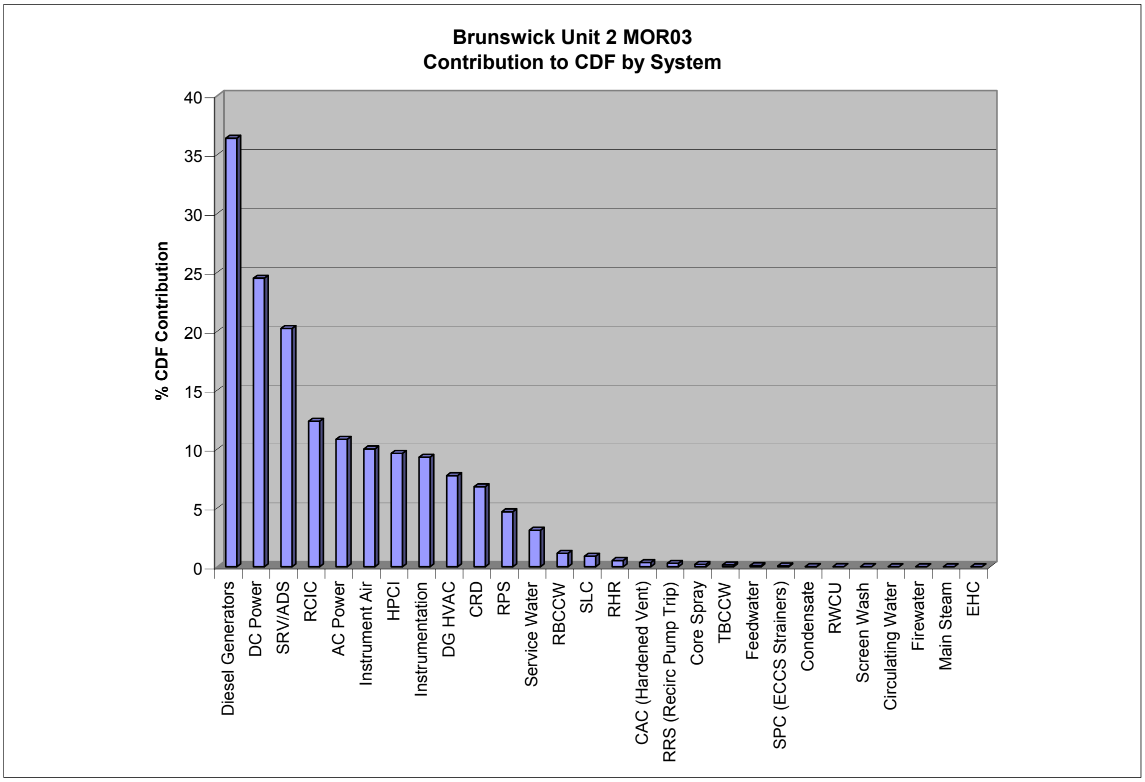


Figure F-4
System RAW Ranking (CDF)

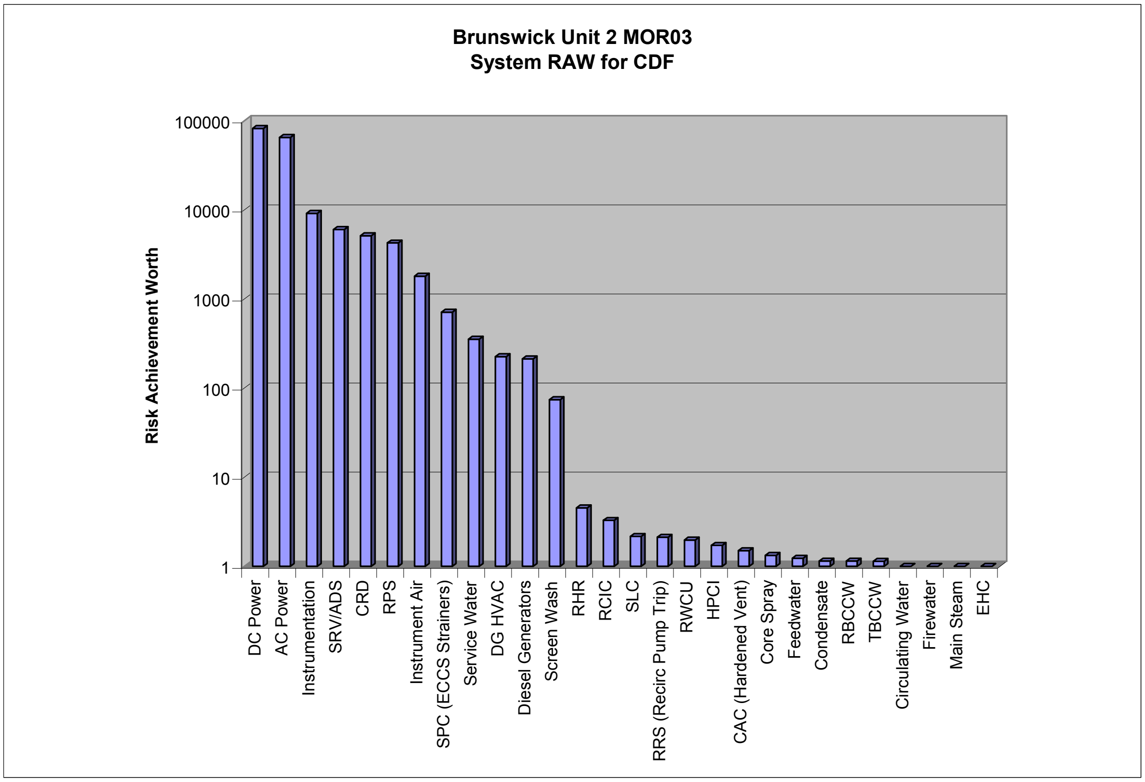


Figure F-5
Summary of Release Magnitudes

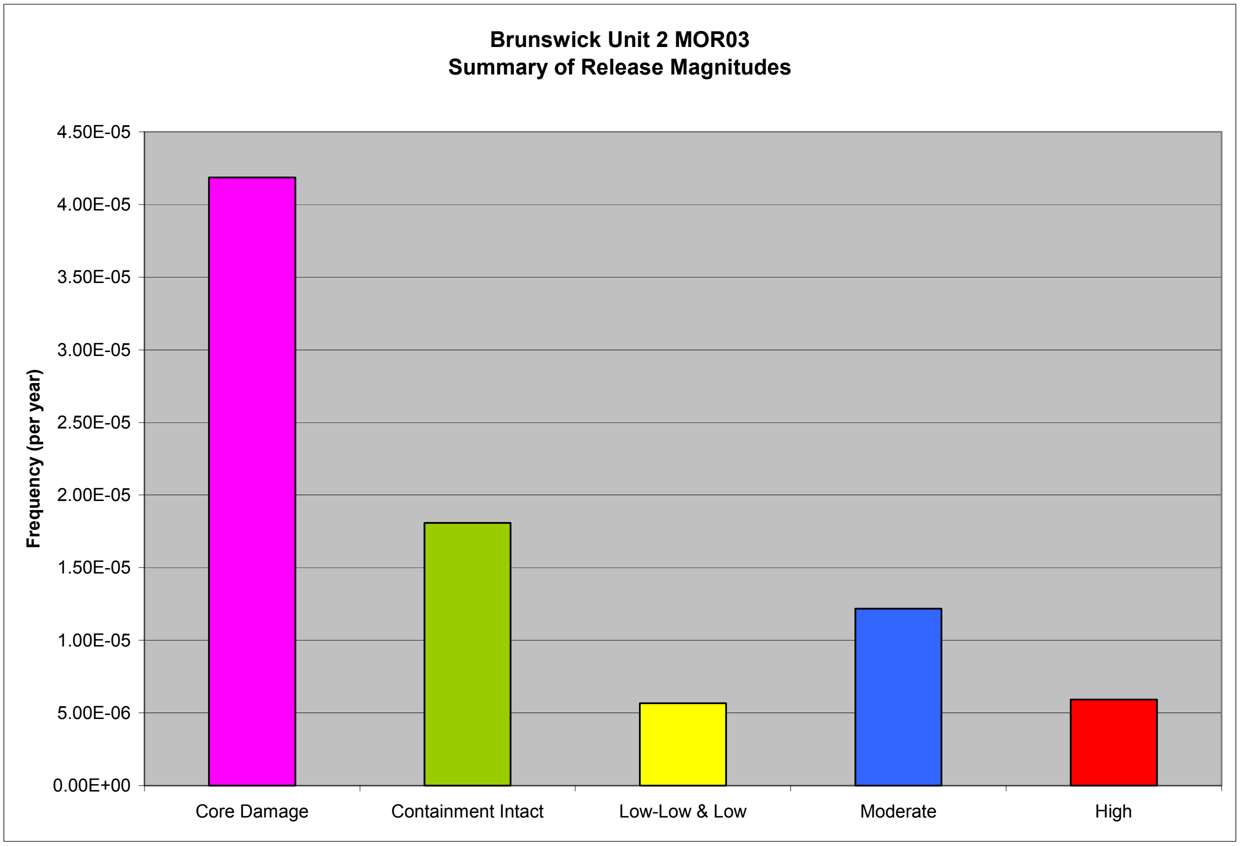


Figure F-6
Comparison of Contributors to the LERF Category

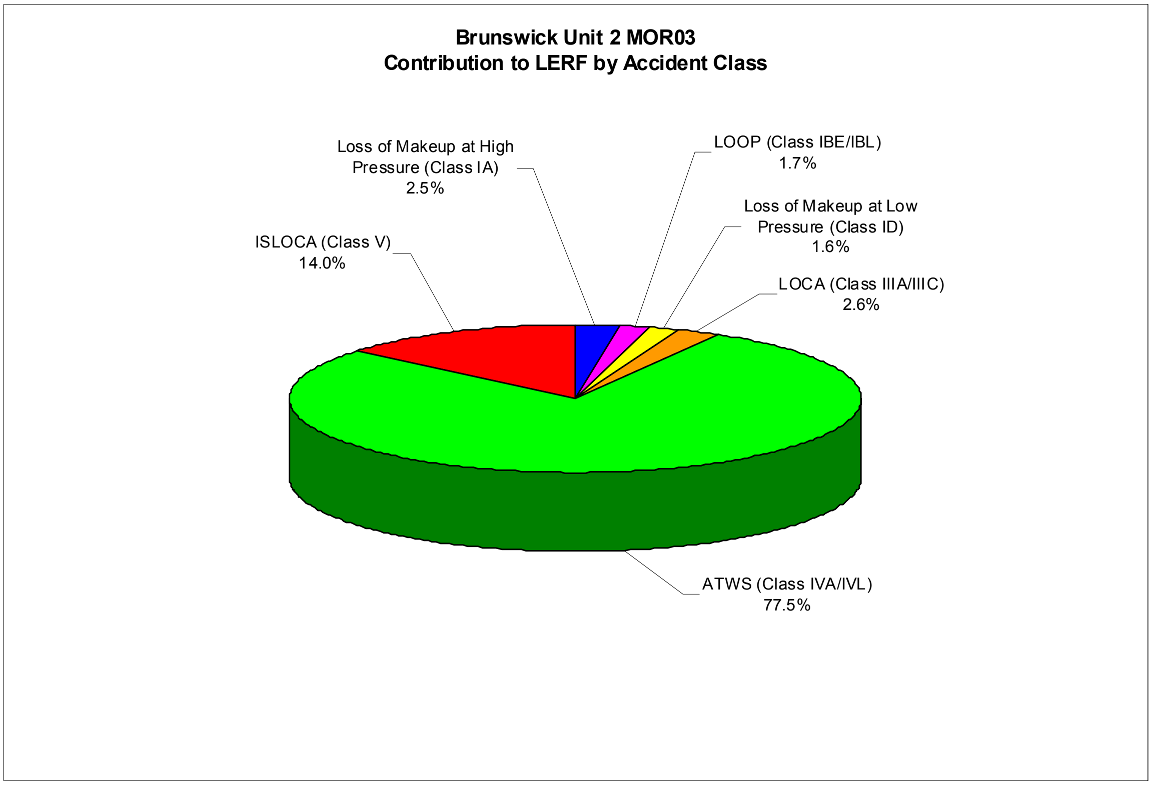
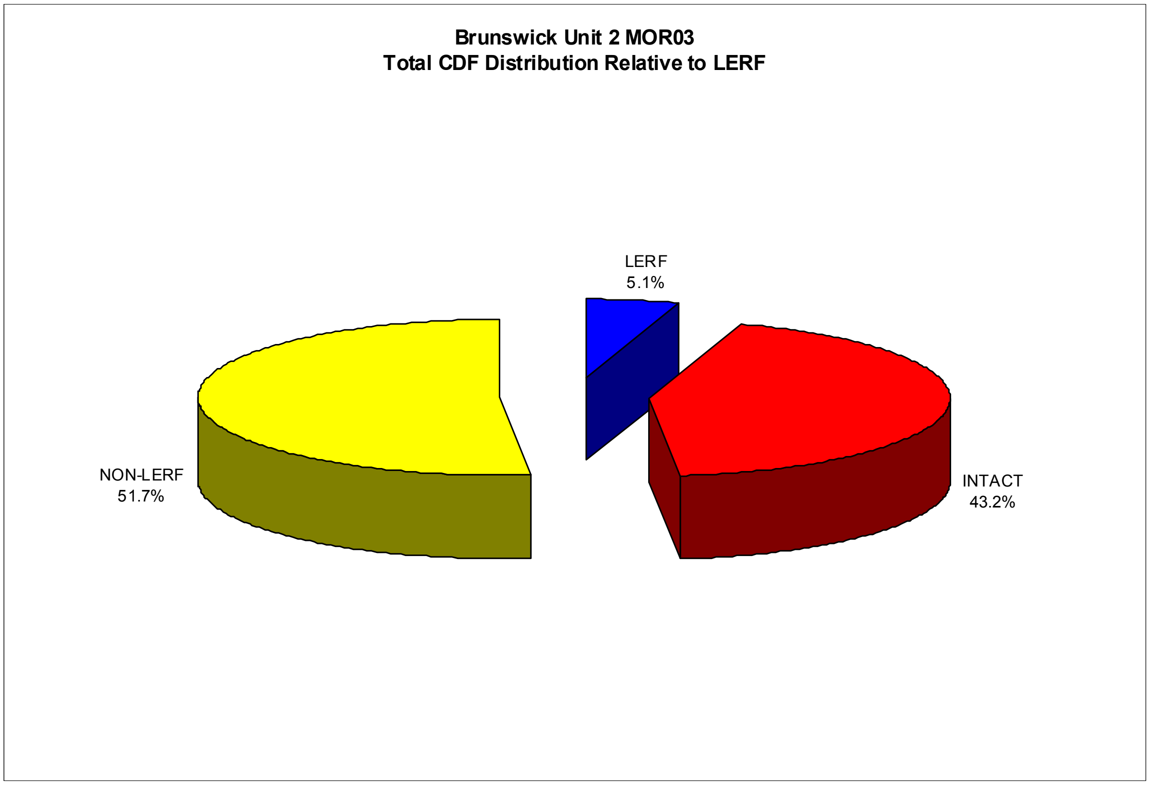


Figure F-7
Total CDF Distribution Relative to LERF



F.10 REFERENCES

1. GE Nuclear Energy, "Technical Support Document for the ABWR," 25A5680, Rev. 1, November 1994.

2. U.S. Nuclear Regulatory Commission, "Regulatory Analysis Technical Evaluation Handbook," NUREG/BR-0184, 1997.

3. Calvert Cliffs Application for License Renewal, Attachment 2, Appendix F, "Severe Accident Mitigation Alternatives Analysis," April 1998.

4. Applicant's Environmental Report; Operating License Renewal Stage; H. B. Robinson Steam Electric Plant Unit No. 2, Appendix F Severe Accident Mitigation Alternatives, Letter, J. W. Moyer, CP&L, to United States Nuclear Regulatory Commission, June 14, 2002, Application for Renewal of Operating License. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/robinson.html.

5. Edwin I. Hatch Nuclear Plant Application for License Renewal, Environmental Report, Appendix D, Attachment F, February 2000.

6. Peach Bottom Application for License Renewal, Appendix E, Environmental Report, Appendix G, "Severe Accident Mitigation Alternatives."

7. Applicant's Environmental Report; Operating License Renewal Stage; Dresden Nuclear Power Station Units 2 and 3, Section 4.20 Severe Accident Mitigation Alternatives (SAMA) and Appendix F SAMA Analysis, Letter, Benjamin, Exelon, to U. S. Nuclear Regulatory Commission, January 3, 2003, Application for Renewed Operating Licenses. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/dresden-quad.html.

8. Applicant's Environmental Report; Operating License Renewal Stage; Quad Cities Nuclear Power Station Units 1 and 2, Section 4.20 Severe Accident Mitigation Alternatives (SAMA) and Appendix F SAMA Analysis, Letter, Benjamin, Exelon, to U. S. Nuclear Regulatory Commission, January 3, 2003, Application for Renewed Operating Licenses. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/dresden-quad.html

9. R. E. Oliver et al, "Brunswick Steam Electric Plant Individual Plant Examination Submittal," CP&L, August 1992.

10. R. E. Oliver et al, "Brunswick Steam Electric Plant Individual Plant Examination for External Events Submittal," CP&L, June 1995.

11. Boiling Water Reactors Owners' Group, "Brunswick PRA Peer Review Report," December 7, 2001.

12. EPRI NP-6041, “A Methodology for Assessment of Nuclear Power Plant Seismic Margin,” Revision 1, August 1991.

13. Letter from Mr. Allen Hansen (United States Nuclear Regulatory Commission) to Mr. J. S. Keenan (CP&L), dated August 5, 1999, “Completion of Licensing Action and Issuance of Safety Evaluation Regarding USI A-46 Program Implementation at Brunswick Steam Electric Plant, Unit Nos. 1 and 2, Resolution of Safety Issue USI A-46, Supplement No. 1 to Generic Letter (GL) 87-02 (TAC. NOS. M69433/69434)”, Docket Nos. 50-325 and 50-324.

14. EGG-SSRE-9747, Improved Estimates of Separation Distances to Prevent Unacceptable Damage to Nuclear Power Plant Structures from Hydrogen Detonation for Gaseous Hydrogen Storage, EG&G Idaho Inc. June, 1993.

15. NUREG/CR-5465, “Review of the Brunswick Steam Electric Plant Probabilistic Risk Assessment,” November 1989.

16. Letter from Mr. Stephen A. Byrne (SCE&G) to Mr. Gregory F. Suber (United States Nuclear Regulatory Commission), “Response to SAMA Request For Additional Information,” April 2003, Docket Number 50/395.

17. Letter from Mr. Allen Hansen (United States Nuclear Regulatory Commission) to Mr. J. S. Keenan (CP&L), dated January 21, 2000, “NRC Staff’s Evaluation of the Brunswick Steam Electric Plant, Units 1 and 2, Individual Plant Examination (IPE) Submittal (TAC Nos. 74387 and 74388”, Docket Nos. 50-325 and 50-324.

18. Letter from Mr. Stephen A. Byrne (SCE&G) to Mr. Gregory F. Suber (United States Nuclear Regulatory Commission), “Response to SAMA Request for Additional Information, Supplement II,” May 21, 2003, Docket Number 50/395.

19. Brunswick Steam Electric Plant, “4kv Bus Crosstie,” Plant Modification 90-001, Project Control Number 04220A, Unit 1, Completed in 1993.

20. Brunswick Steam Electric Plant, “4kv Bus Crosstie,” Plant Modification 90-002 Project Control Number 04220B Unit 2 Completed in 1991.

21. Plant Operating Manual, Volume XIII, Plant Emergency Procedure, 0PEP-02.6, “Severe Weather,” Revision 9.

22. EC 49660, “PSA Model Update 2003,” Rev. 0, May 2003.

23. BNP-PSA-030, “PSA Model Section 5.0 Sequence Quantification,” Rev. 3, March 2003.

24. BNP-PSA-004, “PSA Model Appendix B Component Failure Database”

25. BNP-PSA-028, “PSA Model Section 3.0 Initiating Events Assessment”

26. BNP-PSA-032, “PSA Model Appendix C Initiating Events Assessment”

27. BNP-PSA-034, “PSA Model Appendix E HRA”

28. Chanin, D. and Young, M., Code Manual for MACCS2: Volume 1, User’s-Guide, SAND 97-0594, 1997.

29. NUREG-1150, “Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants,” U. S. Nuclear Regulatory Commission, Washington, D.C., June 1989.

30. Radiological Emergency Response Plan, “Plant Operating Manual, Volume XIII, Emergency Response Plan,” Brunswick Nuclear Plant.

31. U.S. Census Bureau, Census 2000 Summary File 1 (SF 1) – 100 percent data. Available online at: http://www.census.gov/Press-Release/www/2001/SumFile1.html.

32. U.S. Census Bureau, Census 2000 Redistricting Data (P.L. 94-171) Summary File and 1990 Census. Table 1 – Counties in Alphabetic Sort within State, 1990 and 2000 Population, Numeric and Percent Change: 1990 to 2000. Internet Release date: April 2, 2001. Available online at: http://www.census.gov/population/cen2000/phc-t4/tab01.xls

33. U.S. Department of Agriculture, “1997 Census of Agriculture,” National Agricultural Statistics Service, 1998.

34. North Carolina Department of Agriculture, “Usual Planting and Harvesting Dates Field Crops and Vegetables,” Agricultural Statistics Division, http://www.agr.state.nc.us/stats/crop_fld/crpphdyr.htm, Internet Release date: February 11, 2003.

35. Southern Nuclear Operating Company, "Severe Accident Mitigation Alternatives at the Edwin I. Hatch Nuclear Plant." Attachment F of Appendix D (Applicant's Environmental Report - Operating License Renewal Stage) of Edwin I. Hatch Nuclear Plant Application for License Renewal. February 2000.

36. NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Calvert Cliffs Nuclear Power Plant,” Supplement 1, U.S. Nuclear Regulatory Commission, Washington, D.C., February 1999.

37. George C. Holzworth, “Mixing Heights, Wind Speeds, and Potential For Urban Air Pollution Throughout the Contiguous United States,” Environmental Protection Agency, Office of Air Programs, Research Triangle Park, N.C., January 1972.

38. Brunswick PSA Independent Peer Review, ERIN Engineering and Research, Inc., May 30, 2000.

39. Letter from Mr. William Lewis (CP&L) to USNRC Document Control Desk, “Response to Request for Additional Information Individual Plant Examination for External Events (IPEEE) Generic Letter 88-20, Supplement 4”, BSEP-96-0290, August 15, 1996.

ADDENDUM TO APPENDIX F
SEVERE ACCIDENT MITIGATION ALTERNATIVES

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 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 core damage frequency 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 service water or from a station blackout event.
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.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 service water.	SAMA would allow HPSI to be extended after a loss of service water.
19	Use fire protection system 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 service water pumps.	SAMA would reduce the frequency of the loss of component cooling water and service water.
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 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 fire protection system or by installing a component cooling water cross-tie.
23	8.a. Additional Service Water 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 control room 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 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 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 fire protection system and/or standby gas treatment system hardware and procedures.	SAMA would improve fission product scrubbing in severe accidents.
47	Create a reactor cavity flooding system.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 fire protection system 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 station blackouts or LOCAs which render the suppression pool unavailable as an injection source due to heat up.
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

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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
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

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 fire protection system 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.
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.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to Enhanced AC/DC Reliability/Availability		
90	Proceduralize alignment of spare diesel to shutdown board after loss of offsite power and failure of the diesel normally supplying it.	SAMA would reduce the SBO frequency.
91	Provide an additional diesel generator.	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 offsite power, and defeats one half of the low vessel pressure permissive for 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 diesel generator, reliability.
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 offsite power after an SBO.	SAMA would reduce human error probability during offsite power 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.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 diesel generators, which would contribute to enhanced diesel reliability.
108	Use fire protection system as a backup source for diesel cooling.	This SAMA would provide a redundant and diverse source of cooling for the diesel generators, which would contribute to enhanced diesel reliability.
109	Provide a connection to an alternate source of offsite power.	SAMA would reduce the probability of a loss of offsite power event.
110	Bury offsite power lines.	SAMA could improve offsite power reliability, particularly during severe weather.
111	Replace anchor bolts on diesel generator 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), auxiliary feedwater 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 Diesel Generator Trips	SAMA would allow D/Gs to operate for longer.
115	2.i. 16 hour Station Blackout Injection	SAMA includes improved capability to cope with longer station blackout scenarios.
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 offsite power.
118	9.d. Additional Diesel Generator	SAMA would reduce the SBO frequency.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 Station Blackout 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		
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.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 residual heat removal (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.
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.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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: a rupture in the RCP seal cooler of the component cooling system, an ISLOCA in a shutdown cooling line, and an auxiliary feedwater (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.
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.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 condensate storage tank (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 diesel generator for the CST make-up pumps	This SAMA would allow continued inventory make-up to the CST during an SBO.
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.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
177	Use Main FW 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 low pressure safety injection 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 human error probability of recirculation failure.
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.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
188	Replace 2 of the 4 safety injection (SI) pumps with diesel-powered pumps.	This SAMA would reduce the SI system common cause failure 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/reactor core isolation cooling backpressure trip setpoints	This SAMA would ensure high pressure core injection/reactor core isolation cooling availability when high suppression pool temperatures exist.
191	Improve the reliability of the automatic depressurization system.	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 HPCI.	SAMA would allow for extended duration of HPCI availability.
195	Increase available net positive suction head (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	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
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

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 fire protection system 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.
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 safety relief valves.	This SAMA would extend operation of safety relief valves 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.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
ATWS Mitigation		
215	Install MG set trip breakers in control room	This SAMA would provide trip breakers for the MG sets in the control room. In some plants, MG set breaker trip requires action to be taken outside of the control room. Adding control capability to the control room 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 FW 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 safety relief valve (SRV) reseat reliability.	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.
224	Use control rod drive (CRD) for alternate boron injection.	SAMA provides an additional system to address ATWS with SLC failure or unavailability.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 be 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 high pressure melt ejection.
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 control rod drive flow CV failure position	Change failure position to the "fail-safest" position.
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 main steam isolation valves. This SAMA would also guard against or prevent consequential multiple SGTR following a Main Steam Line Break event.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 safety relief valves 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 high pressure coolant injection scenarios
243	Enhance RPV depressurization procedures	SAMA would decrease the likelihood of core damage in loss of high pressure coolant injection scenarios
244	Replace mercury switches on fire protection systems	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 fire protection 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.
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

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
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 main control room 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 Condensate Storage Tank	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.
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.