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APPENDIX C

TECHNICAL SPECIFICATIONS

APPENDIX C - TECHNICAL SPECIFICATIONS

Technical Specifications

Baltimore Gas and Electric Company has not identified the need to add new Technical Specifications for License Renewal. Baltimore Gas and Electric Company identified the need to modify two existing Technical Specifications to address Time Limited Aging Analyses, as discussed in Appendix A Sections 2.1.3.2 and 2.1.3.6. These changes will be submitted, when appropriate, under the normal license amendment process.

ATTACHMENT (2)

APPLICANT'S ENVIRONMENTAL REPORT -

OPERATING LICENSE RENEWAL STAGE

ATTACHMENT (2)

Applicant's Environmental Report -

Operating License Renewal Stage

Calvert Cliffs Nuclear Power Plant Units 1 and 2

Baltimore Gas & Electric Company
Docket Nos. 50-317 and 50-318
April 8, 1998

ATTACHMENT (2)

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ACRONYMS AND ABBREVIATIONS

AFW	Auxiliary Feedwater
BGE	Baltimore Gas and Electric Company
Btu	British thermal units
CCNPP	Calvert Cliffs Nuclear Power Plant
CCPRA	Calvert Cliffs Probabilistic Risk Assessment (Model)
CFR	Code of Federal Regulations
COE	Cost of Enhancement
COMAR	Code of Maryland Regulations
DOE	U.S. Department of Energy
EDG	Emergency Diesel Generator
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
FES	Final Environmental Statement
FONSI	Finding of no significant impact
FP	Fire Protection
FR	Federal Register
GEIS	Generic Environmental Impact Statement
gpd	gallons per day
gpm	gallons per minute
IPE	Individual Plant Examination
ISO	International Standards Organization
kV	kilovolt
kWh	kilowatt-hour
kWh/m^2	kilowatt-hours per square meter
MACCS	Melcor Accident Consequences Code System
MW	megawatt
MWd/MTU	megawatt-days per metric ton of uranium
MWe	megawatts-electric
NEPA	National Environmental Policy Act
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission

PM_{10}	Particulate matter having a diameter of 10 microns or less
SAMA	Severe Accident Mitigation Alternative
SAMDA	Severe Accident Mitigation Design Alternative
SHPO	State Historic Preservation Office
SMITTR	Surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping
SRW	Service Water
USC	United States Code

SUMMARY

In compliance with U.S. Nuclear Regulatory Commission (NRC) requirements, this environmental report describes the Baltimore Gas and Electric Company (BGE) proposal to renew the Calvert Cliffs Nuclear Power Plant (CCNPP) Units 1 and 2 Operating Licenses, alternatives to the proposed action, environmental impacts of the proposed action and alternatives, and the CCNPP compliance status.

S.1 Background

The NRC licenses the operation of domestic nuclear power plants as directed in the Atomic Energy Act and implementing Commission regulations. These licenses have durations of up to 40 years, and NRC regulations enable license renewal to extend operations by periods of up to 20 years. Because of the time needed for licensees to arrange alternative generation capacity if NRC did not approve license renewal, the Commission expects them to submit renewal applications 10 to 20 years before the existing license expires.

Baltimore Gas and Electric Company has prepared this environmental report in connection with its application to NRC to renew the CCNPP licenses. License renewal applications must include an environmental report that complies with NRC regulatory requirements. The NRC has prepared a generic environmental impact statement (GEIS) that resolves a number of potential environmental issues that need to be considered for license renewal. The Commission will prepare a site-specific supplement to the GEIS before approving an applicant's license renewal, obtaining input from the environmental report. Nuclear Regulatory Commission regulations require the environmental report to address issues that the Commission could not resolve generically. License renewal applicants are responsible for providing the required information, as well as any new and significant information of which an applicant is aware that would make the conclusions in the GEIS inaccurate for the applicant's plant.

Baltimore Gas and Electric Company operates CCNPP Units 1 and 2 in accordance with NRC licenses DPR-53 and DPR-69, respectively. The Unit 1 license will expire on July 31, 2014, and the Unit 2 license on August 13, 2016. Baltimore Gas and Electric Company is applying to NRC for renewal of both licenses, which would enable 20 additional years of operation (i.e., until July 31, 2034, for Unit 1 and August 13, 2036, for Unit 2). In preparing this report, BGE has followed NRC regulatory language and incorporated insights gained during a series of public meetings with NRC staff on the report.

Section 1.2 provides more background information.

S.2 Purpose of and Need for Agency Action

The purpose and need for the proposed action (CCNPP operating license renewal) is to provide an option that enables power generation beyond the terms of the current operating licenses for CCNPP Units 1 and 2 to meet future system generating needs, as such needs may be determined by the State of Maryland, BGE, and, where authorized, Federal (other than NRC) decision makers.

S.3 Description of the Proposed Action

Calvert Cliffs Nuclear Power Plant is in Calvert County, Maryland, on the west bank of the Chesapeake Bay, approximately 40 miles southeast of Washington, DC, and 7.5 miles north of Solomons Island, Maryland (Figure S-1). The plant has two pressurized-water reactors. Each unit has a design rating for a net electrical power output of 845 megawatts (MW), and each operates at a maximum core thermal power output level of 2,700 MW-thermal. A once-through heat dissipation system transfers heat energy from the plant to the Chesapeake Bay using shoreline intake and offshore discharge structures.

The CCNPP fuel is uranium dioxide in the form of pellets with an enrichment up to 5 percent by weight uranium-235. The NRC has licensed CCNPP to operate on a 24-month refueling cycle, and a fuel burnup limit of 60,000 megawatt-days per metric ton of uranium (MWd/MTU). Baltimore Gas and Electric Company stores CCNPP spent fuel onsite in a spent fuel pool and in dry storage.

Baltimore Gas and Electric Company uses groundwater to supply process and domestic-use water at CCNPP. The State of Maryland has permitted BGE to withdraw no more than 450,000 gallons a day from the Aquia Aquifer. Calvert Cliffs withdraws an average of about 225,000 gallons a day (157 gallons a minute) and has never approached the permit limit.

Calvert Cliffs' transmission facilities consist of three separate three-phase, 500-kilovolt (kV) transmission lines (Figure S-1). Two circuits deliver power to the Waugh Chapel Substation, located near the Company's load center, through two 500-kV lines. A third line connects CCNPP to the Chalk Point generating station, which is a facility of Potomac Electric Power Company.

Baltimore Gas and Electric Company currently has a CCNPP workforce of approximately 1,770 (1997) during routine operations. The workforce comes predominantly from Calvert and St. Mary's Counties. Approximately 60 percent of the employees (1,062) live in Calvert County, 16 percent live in St. Mary's County, and the remaining 24 percent live in other locations. The site workforce increases by as many as 700 temporary workers during refueling outages that occur about once a year with a duration of 1 to 3 months.

In compliance with NRC regulations, BGE has analyzed the effects of plant aging and identified activities needed for CCNPP to operate an additional 20 years. Baltimore Gas and Electric Company conservatively assumes that renewal of the CCNPP licenses would require the addition of no more than 60 workers throughout extended operations to perform license renewal surveillance, monitoring, inspection, testing, trending, and reporting. Baltimore Gas and Electric Company has no plans to perform major refurbishment activities at CCNPP for license renewal.

Section 2.1 describes the proposed action in more detail, and Chapter 5 discusses the status of CCNPP compliance with permit, license, and other approval requirements.

S.4 Alternatives

Calvert Cliffs provides about 12,000,000 MW-hours of electricity annually to more than 1,000,000 customers in a 2,300-square mile area. In compliance with NRC requirements, this environmental report identifies feasible alternatives to license renewal, and the bases for concluding that some alternatives are not feasible.

This report describes as feasible new coal- and gas-fired generation capacity and imported electric power. To minimize environmental impacts from the construction and operation of new generation capacity and so as not to bias the analysis in this report toward license renewal, BGE assumed that it would construct this capacity at the Calvert Cliffs site and reuse a number of existing CCNPP facilities (intake and discharge structures, office and parking facilities, transmission lines, etc.). Coal-fired capacity would employ an average of 1,500 workers during the 5-year construction period building three 600-megawatt-electric (MWe) (International Standards Organization [ISO] rating) units with 600-foot stacks, and an average of 220 workers during operation. Coal-fired capacity would require daily barge delivery of 15,300 tons of coal and 840 tons of lime/limestone, and the dedication of 600 onsite acres for the disposal of waste (ash and scrubber sludge). Gas-fired capacity would employ an average of 500 workers during the 3-year construction period building four 440-MWe (ISO rating) combined-cycle[1] units with 230-foot stacks that would connect to an existing gas line adjacent to the site, and an average of 125 workers during operation. The imported electric power alternative would involve the purchase of power from the grid, which would be generated at existing or new electric plants.

Baltimore Gas and Electric Company considered other alternatives including wind, solar, hydropower, geothermal, wood energy, municipal solid waste, other biomass-derived fuels, oil, new nuclear power plant construction, delayed retirement of other BGE baseload fossil-fuel fired generating plants, and conservation. Baltimore Gas and Electric Company determined that none of these would be a feasible alternative to CCNPP license renewal.

Section 2.2 discusses alternatives in more detail.

S.5 Environmental Impacts

Table S-1 summarizes the proposed action, feasible alternatives, and the environmental impacts that differentiate the proposed action from the alternatives. The principle differences would be impacts to air, aesthetics, and land use.

Air Impacts -- Coal- and gas-fired generation alternatives would introduce moderate air impacts due to emission of pollutants such as nitrogen oxides, sulfur oxides, carbon monoxide, and particulate emissions that would not occur if NRC renewed the CCNPP license. Baltimore Gas and Electric Company assumes that the power purchase alternative could result in generator construction somewhere, which would introduce the same type of air impacts. These impacts are of concern due to their association with the issues of human health, regional acid rain, and global climatic change.

Aesthetic Impacts -- The Calvert Cliffs site is on a relatively undeveloped Chesapeake Bay coastline, and the plant is in a topographically low area that is visible only from the water. Coal- and gas-fired alternatives would require the construction of large structures on higher ground that would be visible for miles inland, as well as further across the water. These alternatives would introduce a moderate to large aesthetic impact that would also be associated with a gas- or coal-fired generation source under the power purchase alternative.

Land Use Impacts -- All the alternatives would introduce some new land use impacts due to the need to convert existing uses to new generating capacity. The coal-fired alternative would have the largest impact due to its need for ash and scrubber waste disposal acreage that, in turn, would introduce a risk of groundwater contamination.

Other environmental impacts are not as strong of a discriminator between the proposed action and alternatives and include aquatic, groundwater, socioeconomic, and terrestrial resources impacts.

1 Combined-cycle units use a combustion turbine to drive an electric generator and a combustion gas heat recovery boiler that generates steam to drive another electric generator.

The NRC GEIS identifies as small a number of environmental effects of license renewal, and BGE has identified no new or significant information that would make these conclusions inapplicable to CCNPP. In compliance with NRC regulations, Chapter 4 discusses other environmental effects and concludes that they would be small. Chapter 4 also discusses the environmental effects of the alternatives.

Table S-1
COMPARISON OF ALTERNATIVES FOR LICENSE RENEWAL OF CCNPP[a]

	Proposed Action	Alternative 1 - Coal-Fired	Alternative 2 - Gas-Fired	Alternative 3 - Import
Description	CCNPP license renewal for 20 years 60 additional workers above existing workforce (1,770)	New construction on the Calvert Cliffs site Three 600-MWe (ISO rating), tangentially-fired, dry bottom units Pulverized bituminous coal, 13,000 Btu/lb, 10% ash, 0.8% sulfur Low nitrogen burners, overfire air, selective catalytic reduction (95% NO_x reduction efficiency) Wet lime/limestone flue gas de-sulfurization system (95% removal efficiency) Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency) Daily barge delivery of 15,300 tons of coal and 840 tons of lime/limestone Average 1,500 construction workers (peak 2,000) for 5 years, 220 permanent workers	New construction on the Calvert Cliffs site Four 440-MWe (ISO rating) combined cycle units Natural gas, 1,000 Btu/scf, 10 Million ft^3/hr Backup low-sulfur No. 2 fuel oil Dry, low nitrogen burners, selective catalytic reduction with water injection for backup oil firing Average 500 construction workers (peak 750) for 3 years, 125 permanent workers	Imported electric power (purchase) Could involve new construction of generation and transmission capacity

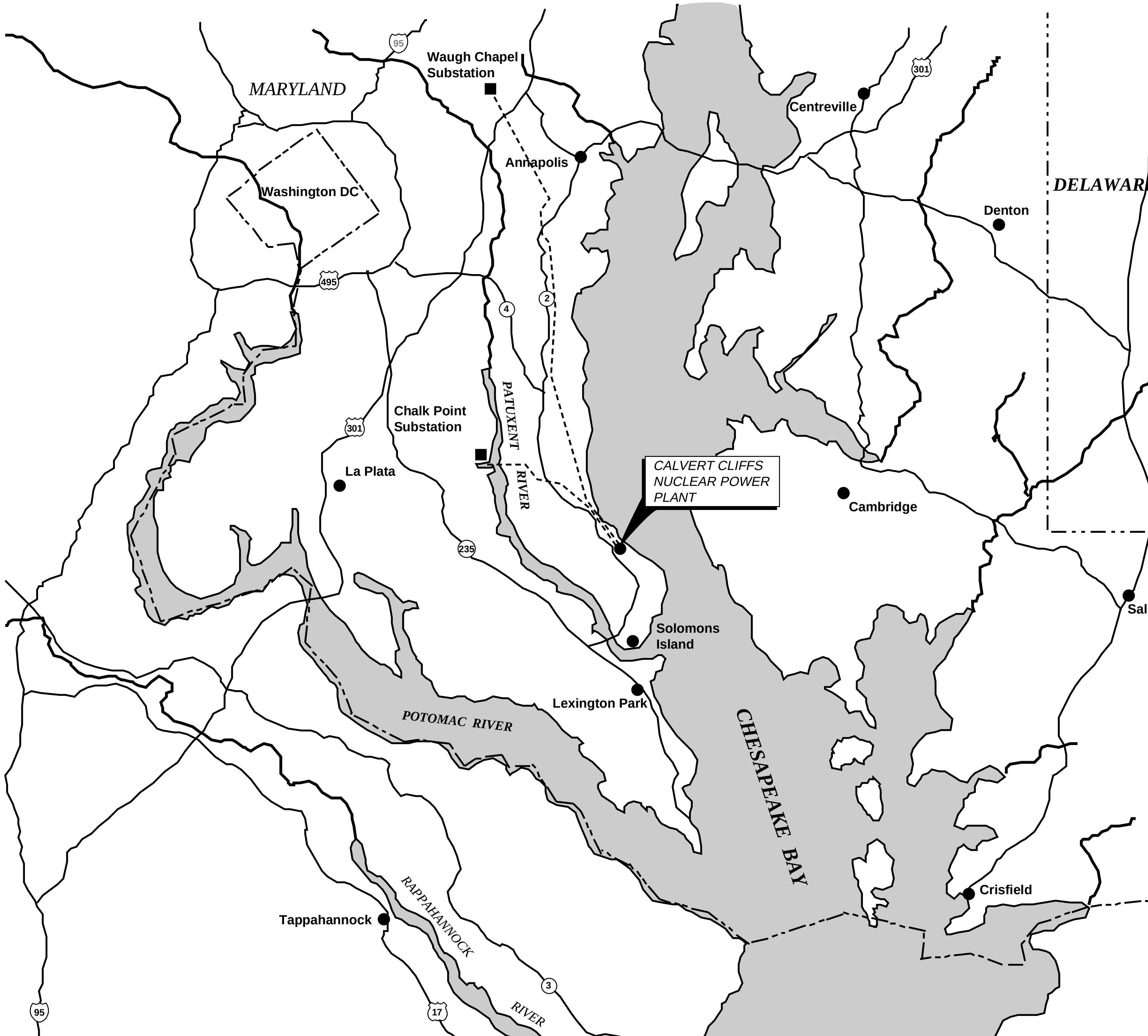
Table S-1
COMPARISON OF ALTERNATIVES FOR LICENSE RENEWAL OF CCNPP[a]

	Proposed Action	Alternative 1 - Coal-Fired	Alternative 2 - Gas-Fired	Alternative 3 - Import
Resource impacts				
Air	Small, Category 1	Moderate - 3,600 tons SO_x/year; 1,680 tons NO_x/year; 234 tons filterable particulates and 54 tons PM_{10}/year; 1,170 tons CO/year. Offsets necessary for NO_x emissions	Moderate - 386 tons NO_x/year. Offsets necessary	Small to Large - Depends on technology used to generate power
Aesthetics	Small - Category 1	Large - 3 new, 200-foot power plant structures and 600-foot stacks potentially visible for 40 miles in relatively non-industrialized area. Closed-cycle cooling alternative could also introduce 520-foot cooling towers and associated plumes	Moderate - New 100-foot turbine building, 230-foot exhaust stacks. Closed-cycle cooling alternative would introduce plumes and another noise source	Small to Large - For new construction, impacts could be similar to Alternative 1 depending on location
Aquatic ecology	Small - 316(a) and (b) approvals obtained, operational history demonstrates small impacts	Small - Impacts would not exceed proposed action	Small - Impacts would be less than proposed action	Small to Large - New construction could cause habitat loss due to conversion to industrial use depending on location
Groundwater	Small - Withdrawal 157 gallons per minute (gpm). Predicted drawdown of Aquia Aquifer to be few inches a year; estimated cumulative drawdown for license renewal period to be approximately 1.2 feet	Large - Withdrawal 2,400 gpm due to SO_2 emission control needs. Regional sensitivity due to impact of nearby municipal withdrawals	Small - Similar to proposed action	Small to Large - New construction could add new source of groundwater withdrawal depending on location
Land	Small - Land use changes due to license renewal not likely	Moderate - 300 acres for power block construction and coal pile; 600 acres for waste (ash and scrubber sludge) disposal	Small- 60 acres for power block construction; 10 acres for pipeline construction	Small to Large - New construction could convert existing land use to power generation

Table S-1
COMPARISON OF ALTERNATIVES FOR LICENSE RENEWAL OF CCNPP[a]

	Proposed Action	Alternative 1 - Coal-Fired	Alternative 2 - Gas-Fired	Alternative 3 - Import
Socioeconomic	Small - 3% decrease in available housing units; less than 1% increase in output of local water supply system; no anticipated impacts to education system and transportation system	Moderate - Temporary increase in impacts during 5-year construction period from 1,500 workers, then impact of loss of tax and employment base due to reduction of CCNPP workforce from 1,770 to 220	Small - Temporary increase in impacts during 3-year construction period from 500 workers, then impact of loss of tax and employment base due to reduction of size of CCNPP workforce from 1,770 to 125	Small to Large - New construction could introduce worker population impacts on housing and public services depending on location and technology
Terrestrial ecology	Small - Changes due to license renewal not likely	Small - Some low-value (previously disturbed) habitat would be lost	Small to Moderate - Some low-value (previously disturbed) habitat would be lost	Small to Large - New construction could lose habitat due to conversion to industrial use depending on location
Waste management	Small - Category 1	Moderate- 1.5 million tons of ash and scrubber sludge a year	Small due to little combustion or pollution control byproducts	Small to Large - Depends on technology

Btu = British thermal units.
CO = carbon monoxide.
ft^3 = cubic feet.
lb = pound.
NO_x = nitrogen oxides.
PM_{10} = particulate matter with diameter of 10 microns or less.
scf = standard cubic foot.
SO_x = Sulfur oxides.
a. Category 1 = License renewal environmental issue that NRC has defined as small for all plants (10 Code of Federal Regulations [CFR] Part 51 Subpart A, Appendix B, Table B-1, Footnotes 2 and 3).



MARYLAND
Waugh Chapel Substation
Annapolis
Washington DC
Centreville
DELAWARE
Denton
Chalk Point Substation
PATUXENT RIVER
La Plata
CALVERT CLIFFS NUCLEAR POWER PLANT
Cambridge
Solomons Island
Lexington Park
POTOMAC RIVER
CHESAPEAKE BAY
Crisfield
Tappahannock
RAPPAHANNOCK RIVER
95
301
495
4
2
235
3
17

1.0 INTRODUCTION

1.1 Purpose of and Need for Action

The NRC licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act and implementing NRC regulations. Baltimore Gas and Electric Company operates CCNPP Units 1 and 2 pursuant to NRC Operating Licenses DPR-53 and DPR-69, respectively. The Unit 1 license expires July 31, 2014, and the Unit 2 license expires August 13, 2016. Baltimore Gas and Electric Company has prepared this environmental report in connection with its application to NRC, as provided for by NRC regulation, to renew the CCNPP licenses.

The purpose and need for the proposed action, CCNPP license renewal, as stated by NRC is 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." (61 Federal Register [FR] 28467 - 28496, pg. 28472)

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

1.2 Environmental Report Scope and Methodology

In 1996, the NRC amended its environmental protection regulations for domestic licensing to establish new requirements for the environmental review of applications to renew the operating licenses of nuclear power plants.[1] The amended NRC regulations, at 10 CFR 51.53(c)[2], require that an applicant for renewal of a license to operate a nuclear power plant submit with its application a separate document entitled "Applicant's Environmental Report - Operating License Renewal Stage."

In determining the information to include in the CCNPP Environmental Report, BGE has relied on the regulatory language and the following supporting documents that provide insight into the regulatory requirements:

- NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," May 1996
- NUREG-1440, "Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses," May 1996
- NUREG-1529, "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," May 1996

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1 61FR28467; 61FR39555; and 61FR66537.

2 Title 10, Code of Federal Regulations, Part 51, Section 51.53(c).

It is BGE's understanding that NRC will use this environmental report as input in preparing a supplemental environmental impact statement (EIS) for CCNPP license renewal. Absent other NRC guidance on environmental report format,[3] BGE has organized this environmental report format to parallel NRC EIS format guidance. [4] In this way, the environmental report format should facilitate NRC review and EIS preparation. Baltimore Gas and Electric Company has validated this approach through meetings with NRC staff and by submitting a template, or annotated outline, for NRC staff comment. Baltimore Gas and Electric Company incorporated staff comments, and NRC staff agreed that an environmental report that follows the template outline, with the level of detail contained in the template examples, would contain sufficient information for the NRC staff to begin its formal review (Reference 1).

Table 1-1 indicates where the environmental report responds to each requirement of 10 CFR 51.53(c). In turn, each responsive section is prefaced by a boxed quote of the regulatory language and applicable supporting document language.

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3 NRC is drafting a regulatory guide and a standard review plan for preparation and review of a renewal stage environmental report.

4 10 CFR 51, Subpart A, Appendix A, as adopted by reference at 10 CFR 51.70(b).

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

Regulatory Requirement	Responsive Environmental Report Section	Support Sections
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)	2.1 Proposed Action	
10 CFR 51.53(c)(2)	2.1.6 Modifications	
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	4.2 Alternatives	2.2
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)	1.1 Purpose of and Need for Action	
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	4.3.1 Unavoidable Adverse Impacts	4.1
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	4.4 Short-Term Use Versus Long-Term Productivity	4.1
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	4.3.2 Irreversible or Irretrievable Resource Commitments	4.3.1
10 CFR 51.53(c)(3)(ii)(B)	4.1.4 Heat Shock	2.1.3, 3.1.1, Appendix B
10 CFR 51.53(c)(3)(ii)(B)	4.1.2 Entrainment	2.1.3, 3.1.1, Appendix B
10 CFR 51.53(c)(3)(ii)(B)	4.1.3 Impingement	2.1.3, 3.1.1, Appendix B
10 CFR 51.53(c)(3)(ii)(C)	4.1.5 Groundwater Use	2.1.4, 3.2, Appendix C
10 CFR 51.53(c)(3)(ii)(E)	4.1.6 Terrestrial Resources	2.1.6, 3.1.2
10 CFR 51.53(c)(3)(ii)(E)	4.1.7 Threatened and Endangered Species	2.1.6, 3.1.3, Appendix D
10 CFR 51.53(c)(3)(ii)(F)	4.1.8 Air Quality	2.1.7, 3.3
10 CFR 51.53(c)(3)(ii)(H)	4.1.9 Electric Shock	2.1.5
10 CFR 51.53(c)(3)(ii)(I)	4.1.10 Housing Impacts	2.1.6, 2.1.7, 3.4, 3.8
10 CFR 51.53(c)(3)(ii)(I)	4.1.13 Offsite Land Use, Refurbishment	2.1.6, 2.1.7, 3.6, 3.8
10 CFR 51.53(c)(3)(ii)(I)	4.1.14 Offsite Land Use, License Renewal Term	2.1.7, 3.6, 3.8
10 CFR 51.53(c)(3)(ii)(I)	4.1.12 Public Services, Education	2.1.6, 2.1.7, 3.5, 3.8
10 CFR 51.53(c)(3)(ii)(I)	4.1.11 Public Services, Public Utilities	2.1.6, 2.1.7, 3.5, 3.8
10 CFR 51.53(c)(3)(ii)(J)	4.1.15 Public Services, Transportation	2.1.6, 2.1.7, 3.5, 3.8
10 CFR 51.53(c)(3)(ii)(K)	4.1.16 Historic and Archaeological Resources	2.1.6, 3.7, Appendix E
10 CFR 51.53(c)(3)(ii)(L)	4.1.17 Severe Accident Mitigation Alternatives	3.8, Appendix F
10 CFR 51.53(c)(3)(ii)(M)	4.1.18 Transportation	2.1.2, Appendix G
10 CFR 51.53(c)(3)(iv)	4.1.19 New and Significant Information	
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	Chapter 5 Compliance Status	Appendix H

2.0 ALTERNATIVES INCLUDING PROPOSED ACTION

2.1 Proposed Action

2.1.1 General Plant Information

Calvert Cliffs Nuclear Power Plant is located in Calvert County, Maryland, on the west bank of the Chesapeake Bay, approximately halfway between the mouth of the Bay and its headwaters at the Susquehanna River. The plant site is 10.5 miles southeast of Prince Frederick, Maryland and 4.5 miles northwest of Cove Point, Maryland at latitude 38 degrees, 26 minutes, 4 seconds north and longitude 76 degrees, 26 minutes, 31 seconds west. Figures 2-1 and 2-2 illustrate the plant location.

Calvert Cliffs is a two-unit plant. Each unit is equipped with a Combustion Engineering Nuclear Steam Supply System that utilizes a pressurized-water reactor and two steam generators. Each unit has a design rating for net electrical power output of 845 MWs. The plant uses a once-through cooling water system that withdraws from and discharges into the Chesapeake Bay via shoreline intake and offshore discharge structures. Descriptions of CCNPP can be found in documentation submitted to the NRC for the original operating license and subsequent license amendments. In 1970, BGE submitted an environmental report for CCNPP (Reference 2) and, in 1973, the Atomic Energy Commission[1] issued a Final Environmental Statement (FES) for this two-unit plant (Reference 3). The FES evaluates the environmental impacts from plant activities in accordance with the National Environmental Policy Act (NEPA). Since these documents were issued, changes have occurred at CCNPP. Baltimore Gas and Electric Company has followed NRC regulatory requirements in instituting these changes, and in accordance with NEPA, NRC has evaluated resultant environmental impacts. Table 2-1 summarizes selected CCNPP NEPA documentation that addresses physical or operational plant changes (ministerial and environmental monitoring actions are not included).

In 1973, at the time that the FES was written, the Calvert Cliffs site consisted of 1,135 acres. It was estimated that CCNPP construction would permanently alter 200 acres (FES Section II.B and Table XI-4). Since that time, BGE has purchased additional property, expanding the Calvert Cliffs site to an area of 2,108 acres, of which approximately 220 acres have been altered. The NRC has previously conducted a NEPA review of the expansion (Table 2-1, Item 26). Figure 2-3 indicates the original and current site boundaries and shows the principle site structures.

Since 1973, several additional facilities have been constructed at CCNPP. Table 2-2 lists those facilities that are considered permanent (excludes temporary and minor structures) and provides general information about each. Figures 2-4 and 2-5 show the station in detail highlighting those permanent facilities constructed since plant operation began. Final Environmental Statement Section III.A described the CCNPP external appearance. As it appears from the Chesapeake Bay, the plant has changed very little since 1973. Figure 2-6, a low-level aerial photograph of CCNPP taken from the Bay looking south southwest, shows the more prevalent plant structures, including the Turbine Building and twin Containment Structures. The Interim Office Building, Intake Structure, North Service Building, and Sewage Treatment Plant are also visible from the Bay; however, due to intervening buildings and wooded hillsides, most of the other new facilities are visible only from the air. Except for the Independent Spent Fuel Storage Installation, all of the additional facilities are located on areas previously disturbed during CCNPP construction. The NRC has described the Independent Spent Fuel Storage Installation in separate NEPA documentation (Table 2-1, Item 19).

[1] Predecessor agency to NRC.

2.1.2 Nuclear Fuel and Radioactive Waste

The two CCNPP reactors are light-water-cooled reactors operated at a maximum core thermal power output level of 2,700 MW-thermal.[2] Calvert Cliffs fuel is uranium dioxide in the form of pellets contained in zirconium alloy fuel rods, tubes fitted with welded end caps, shipped by truck. Although CCNPP was originally licensed to use pellets having a uranium-235 enrichment not exceeding 4 percent by weight,[3] NRC has subsequently authorized CCNPP fuel enrichment increases to 4.1 percent and, currently, 5 percent uranium-235. For each fuel enrichment increase, NRC conducted an environmental assessment concluding no significant impact (Table 2-1, Items 8 and 18). At the same time, NRC has authorized increases in level of CCNPP fuel burnup,[4] from the original 33,000 MWd/MTU to the current limit of 60,000-MWd/MTU.

Calvert Cliffs operates on a 24-month refueling cycle (Table 2-1, Item 15) and currently stores all its spent nuclear fuel onsite in a spent fuel pool or in dry storage.[5] Calvert Cliffs also temporarily stores mixed waste[6] onsite, consistent with NRC and U.S. Environmental Protection Agency (EPA) policy and in accordance with an agreement with the Maryland Department of the Environment. Calvert Cliffs currently makes the following shipments of radioactive materials offsite by truck:

- CCNPP to high-level waste examination sites;
- CCNPP to low-level waste disposal site (Barnwell, South Carolina);
- CCNPP to an offsite processing facility for segregation, recycling, compaction, and incineration;
- Offsite processing facility to disposal site; and
- Offsite processing facility to CCNPP for reuse or storage.

All CCNPP radioactive waste shipments are packaged in accordance with NRC and U.S. Department of Transportation requirements.

2.1.3 Heat Dissipation System

Calvert Cliffs is equipped with a once-through heat dissipation system. This circulating water system removes heat energy rejected from the plant cycle in the condensers and transfers this energy to the Chesapeake Bay via the heated effluent. As described in FES Section III.D.1, the principal components of the circulating water system are the curtain wall, Intake Structure, circulating water pumps, condensers, and discharge conduits.

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2 See Table 2-1, Item 4, for reference to NRC environmental assessment of CCNPP power level increase to 2,700 megawatts-thermal.

3 Naturally occurring uranium contains several forms of uranium including approximately 0.7 percent uranium-235 (Reference 4), the form that a nuclear reactor uses. The nuclear fuel manufacturing process removes some of the other forms, resulting in a slightly higher percentage ("enrichment") of uranium-235.

4 "Burnup" is the length of use of, or total energy generated by, the nuclear fuel, and is measured as megawatt-days per metric ton.

5 See Table 2-1, Item 19 for reference to NRC environmental assessment of Calvert Cliffs Independent Spent Fuel Storage Installation.

6 Mixed waste is waste that is governed by the Atomic Energy Act (42 United States Code [USC] 2011 - 2259) as radioactive material and the Resource Conservation and Recovery Act (42 USC 6901 et seq.) as hazardous waste.

2.1.4 Groundwater Use

Final Environmental Statement Section V.B.1 discussed a CCNPP maximum permitted withdrawal rate of 600,000 gallons per day (gpd). Subsequent State permits have reduced this limit to 225,000 gpd.

Calvert Cliffs has five production wells that supply process and domestic water within the protected area vicinity, and nine wells that supply water for domestic use in outlying areas. The production wells are finished in the Aquia Aquifer (Section 3.2.2). Table 2-3 identifies these wells (Nos. 1-5), and Figure 2-7 indicates their locations (wells 1-5). Calvert Cliffs does not use de-watering pumps. A gravity drain system was installed during original plant construction to de-water plant areas.

The Maryland Department of Environment requires BGE to monitor and report withdrawal from the five production wells.[7] Table 2-4 lists the average daily withdrawal volumes and rates from these wells since 1975.[8] As shown in Table 2-4 and Figure 2-8, these production withdrawals are approximately 225,000 gpd (157 gpm), and have never approached the current permit limit of 450,000 gpd or the previous permit limit of 600,000 gpd that the FES analyzed.

2.1.5 Transmission Facilities

Final Environmental Statement Section III.B described the two separate three-phase 500-kV transmission lines (single right-of-way) from CCNPP to the Waugh Chapel Substation in Anne Arundel County (Figure 2-1). Approximately 22 miles of the lines are in Calvert County and approximately 25 miles are in Anne Arundel County with a 350- to 400-foot right-of-way.[9] These lines were constructed to deliver power generated at CCNPP to the Waugh Chapel Substation, located at a point near the Company's load center. Baltimore Gas and Electric Company has made only one change to those lines, in 1994, when BGE completed a new 500-kV line, referred to as the South Circuit (the lines to Waugh Chapel have become known as the North Circuit). At that time, BGE shifted approximately one mile of the original lines to make room for the new South Circuit lines at the point where the North and South Circuit routes diverge (Figure 2-1). The 18-mile South Circuit parallels the Waugh Chapel lines from CCNPP north approximately 9 miles before diverging in a northwesterly direction to connect with a line at the Potomac Electric Power Company Chalk Point generating station (Figure 2-1). As in the case of the North Circuit, BGE owns title to the land beneath the South Circuit lines.

At the time that BGE constructed CCNPP, the Southern Maryland Electric Cooperative constructed a 69-kV transmission line to CCNPP, connecting to an onsite substation (Figure 2-3) to provide CCNPP with offsite power. The plant is connected to the substation via underground lines. At the end of CCNPP's operating term and subsequent decommissioning, the Southern Maryland Electric Cooperative would discontinue the transfer of energy over these lines.

7 Condition imposed by CCNPP Groundwater Appropriation and Use Permit.

8 The State does not require monitoring of domestic wells.

9 Land beneath power lines is commonly called a "right-of-way" because utilities frequently do not own the underlying land but, instead, hold an easement or right-of-way that entitles a utility to construct and maintain the lines over the land. The phrase is technically incorrect as it applies to the CCNPP lines to the Waugh Chapel substation because BGE actually has title (i.e., owns) the land beneath the lines.

2.1.6 Modifications

NRC

"The report must contain a description of . . . the applicant's plans to modify the facility or its administrative control procedures as described in accordance with §54.21 of the Chapter. 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, 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." Generic Environmental Impact Statement Section 2.6.3.1, page 2-41. ["SMITTR" defined at GEIS Section 2.4, page 2-30 as surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping]

The GEIS (Reference 5) identifies SMITTR and major refurbishment activities that utilities might perform for license renewal. Performing such SMITTR and major refurbishment activities would necessitate first changing administrative control procedures, and major refurbishment activities would also involve modifying the facility. This section describes CCNPP license renewal SMITTR and refurbishment plans in order to satisfy the NRC requirement to describe facility and administrative control procedure modification plans in accordance with Section 54.21. The section also compares these activities to those that the GEIS identifies in order to form a basis for concluding whether the NRC GEIS assumptions bound CCNPP activities.

In accordance with NRC regulation,[10] BGE has performed a CCNPP aging management review and has included in the CCNPP license renewal application an integrated plant assessment that identifies how BGE would manage the effects of aging on systems, structures, and components. In some cases, existing CCNPP programs adequately address aging effects with no license renewal modification. In other cases, as summarized below, BGE has identified necessary modifications to existing programs, or development and implementation of new programs.

SMITTR Activities

The GEIS Table B-1 identifies those SMITTR activities that NRC anticipated for license renewal of pressurized-water reactor plants such as CCNPP. Calvert Cliffs' SMITTR activities attributed to the regulatory requirements of 10 CFR Part 54 are identified in the Technical Information presented in Attachment (1) of BGE's License Renewal Application package for CCNPP. Based on the evaluations presented in Attachment (1), BGE expects these SMITTR activities to be embodied in no more than 13 new programs and in modifications to approximately 5 existing programs. New programs are characterized as either a new inspection or analysis. The following new inspections are identified in Attachment (1):

- One-time walkdowns of certain component supports to confirm existing support inspections will effectively manage their aging;
- Periodic inspections of certain buried piping;

[10] 10 CFR 54 - Requirements for Renewal of Operating Licenses for Nuclear Power Plants.

- Periodic inspections of non-fire-barrier expansion joints and penetration seals in certain structures; and
- Periodic inspections of interior surfaces of certain diesel fuel oil storage tanks.

Analyses are considered to be one-time, short duration activities to extend the validity of existing Time Limited Aging Analyses, to confirm material properties of certain components, and to establish representative populations for one-time confirmatory inspections. Even though most analyses merely extend existing analyses or methods, these analyses are all categorized as new programs and include the following:

- Confirm the chemical composition of certain cast austenitic stainless steel components;
- Extend existing analyses for stress corrosion cracking of certain bolting and tie-rods;
- Extend existing analyses for stress relaxation of certain bolting and tie-rods;
- Determine crack-growth resistance in the heat-affected zone for certain stainless steel tank penetration welds;
- Extend existing depletion analyses of certain spent-fuel pool fixed neutron absorbers;
- Extend existing fatigue analyses for certain components to confirm fatigue usage monitoring of certain components continues to bound certain other components;
- Establish representative component populations for inspection to confirm effectiveness of existing mitigation activities such as the Chemistry Control Programs;
- Extend existing analyses of insulation degradation for certain electrical cables; and
- Extend existing analyses of certain environmentally-qualified electrical components.

Several existing programs will be modified to clarify or expand the scope of components, or clarify inspection requirements. Existing programs to be modified include:

- Clarify and expand the scope of certain Preventive Maintenance activities;
- Clarify the scope of certain Inservice Inspection activities;
- Clarify the scope of System Engineer walkdowns and the authority for changes to scope and periodicity;
- Clarify the scope of certain inspections for effects of boric acid leakage; and
- Add certain non-pressure boundary Alloy 600 components to the evaluations and inspection schedule of pressure boundary Alloy 600 components.

The results of the new and modified programs identified above could lead to additional periodic monitoring or to eventual modification, replacement, or repair of selected components.

Refurbishment Activities

The NRC analysis assumed that any major refurbishment work would start shortly after a renewed license had been granted and would be completed over several successive outages, including one at the end of the 40th year of plant operation. This period is referred to as the refurbishment period.

Generic Environmental Impact Statement Tables B.2 and 2-7 list license renewal refurbishment activities that NRC anticipated utilities might undertake during five refurbishment outages leading up to their current license expiration date. The major refurbishment/replacement class of activities identified by the NRC is intended to encompass actions that typically take place only once in the life of a nuclear plant, if at all. In the NRC analysis, these activities are assumed to be conducted solely for the purpose of extended plant operations and would occur during a time period just prior to the renewal term. The NRC recognizes that many plants will have undertaken various major refurbishment activities during the term of the current license, but that there may well be other plants that would undertake such tasks only to allow for extended plant operations.

While some of the activities listed in Tables B.2 and 2-7 of the GEIS have been conducted at CCNPP under the current operating license, the CCNPP Integrated Plant Assessment, conducted under 10 CFR Part 54 and included as part of this application, has not, at this time, identified any major refurbishment or replacement actions that are necessary to maintain the functionality of important systems, structures, and components during the CCNPP license renewal term.

Conclusion

Baltimore Gas and Electric Company will undertake license renewal SMITTR activities at CCNPP as identified in Attachment (1) to the Application. These activities are similar enough to the license renewal SMITTR activities identified in the GEIS that the GEIS case reasonably bounds the CCNPP case. Baltimore Gas and Electric Company has not identified the need to undertake the major refurbishment activities that the GEIS assumed for license renewal, and no other modifications have been identified that would directly affect the environment or plant effluents. Therefore, the GEIS overestimates the license renewal refurbishment activities and impacts for CCNPP.

2.1.7 Employment

Section 2.1.7 identifies the size of the current CCNPP workforce, explains the basis for predicting changes that would be attributable to license renewal, and compares GEIS and CCNPP estimates to provide a basis for determining whether GEIS assumptions bound the CCNPP case.

Current Workforce

Calvert Cliffs currently has a workforce of approximately 1,770 (1997) during routine operations, a number that is higher than the range of 600 to 800 personnel per reactor unit that GEIS Section 2.3.8.1 estimates. Approximately 80 percent of the CCNPP workforce live in the Tri-County area (Calvert, St. Mary's and Charles). The remaining 20 percent live in various locations outside of these counties. Approximately 60 percent of CCNPP workforce (1,062) live in Calvert County, 16 percent live in adjacent St. Mary's County, 4 percent live in Charles County. Approximately once a year, the site workforce increases by as many as 700 workers for temporary (1-3 months) duty during refueling outages.[11] This number is within the GEIS range of 200 and 900 additional workers per reactor outage.

License Renewal Increment

Performing the license renewal SMITTR activities that Section 2.1.6 describes would necessitate increasing the size of the CCNPP workforce by some increment. The size of this increment is a function of the work scope and the schedule within which the work must be accomplished.

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[11] CCNPP units are on 2-year refueling intervals, and BGE generally schedules outages on staggered schedules.

The GEIS assumes that NRC would renew a nuclear power plant license for a 20-year period plus the remaining duration of the current license, and that it would issue the renewal approximately 10 years prior to license expiration. In other words, the renewed license would be in effect for 30 years. The GEIS determined that the utility would initiate SMITTR activities at the time of issuance and would conduct license renewal SMITTR activities throughout the remaining 30-year life of the plant. The GEIS assumed some of these activities would be conducted during full power operation (GEIS Section B.3.1.3), but most would occur during normal refueling and 5-year and 10-year inservice refueling outages (GEIS Table B.4). The GEIS also assumes that major refurbishment activities would be scheduled for completion during the 5 outages leading up to the expiration of the current license period (i.e., during years 1-10 of the renewed license).

Baltimore Gas and Electric Company has determined that the GEIS scheduling assumptions are reasonably representative of CCNPP incremental license renewal workload scheduling. Some CCNPP license renewal SMITTR activities that Section 2.1.6 describes would be performed during outages. Although some CCNPP license renewal SMITTR activities would be one-time efforts, others would be recurring, periodic activities that would continue for the life of the plant. Baltimore Gas and Electric Company anticipates these activities to result in minor increases to the existing site workload. As noted in Section 2.1.6, however, BGE does not anticipate performing refurbishment activities assumed by the GEIS to meet the requirements of 10 CFR Part 54.

Table 2-5 and Figure 2-9 compare GEIS and CCNPP identification of license renewal outages, outage durations, license renewal labor hours, and additional personnel needed. The differences between the GEIS and CCNPP estimates are attributable to the difference in anticipated refurbishment activities; CCNPP would not have refurbishment outages, but instead would have normal refueling and 5- and 10-year inservice inspections. As shown, the GEIS estimate indicates that most of the additional personnel needed to perform license renewal SMITTR activities would typically be 60 persons during the 3-month duration of a 10-year inservice refueling. Although NRC has 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. Generic Environmental Impact Statement Section C.3.1.2 uses this approach in order to ". . . provide a realistic upper bound to potential population-driven impacts . . . ." For the purpose of performing its own analyses in this environmental report, BGE is conservatively adopting this GEIS approach with one alteration. Calvert Cliffs' license renewal plant modifications would be SMITTR activities that would be performed mostly during outages, and CCNPP Units 1 and 2 outage schedules are generally staggered so as to not coincide. Therefore, BGE believes that it is unreasonable to assume that each unit would need an additional 60 workers. Instead, as a reasonably conservative high estimate, BGE is assuming that CCNPP would require a total of 60 additional permanent workers to perform license renewal SMITTR activities.

Adding full-time workers would have the indirect effect of creating additional jobs and related population growth in the community. Baltimore Gas and Electric Company has used the Maryland employment multiplier (3.9997) (Reference 6) to calculate the number of direct and indirect jobs in service industries supported by the spending of the CCNPP workforce. For conservative analysis, BGE assumes that all of the 240 (3.9997 x 60 = 240) new jobs (direct and indirect) would be filled by in-migrating workers to the CCNPP area, the residential distribution would be similar to the current workforce, and that each in-migrating worker is equivalent to one household. Using the average Maryland family size (3.01), the total population increase resulting from the 60 additional license renewal employees is estimated to be 722. The expected distribution of this population increase within the Tri-County area is summarized below:

Description	Calvert	St. Mary's	Charles	Other	Total
License renewal employees	36	10	2	12	60
Total direct and indirect jobs	144	40	8	48	240
Number households	144	40	8	48	240
Total population	433	120	24	145	722

Conclusion

In order to provide a realistic upper bound to potential population-driven impacts, BGE conservatively assumes that renewal of CCNPP licenses would necessitate the addition of a maximum of 60 workers for the site to perform license renewal SMITTR activities; therefore, the current (1997) full time CCNPP workforce would increase by 60 for the period of extended operations, an increase of 3 percent, from 1,770 to 1,830 workers.

2.2 Alternatives

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).

"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." GEIS Section 8.1.

"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." Supplementary information to Final Rule, 61 FR 66537 - 66554, December 18, 1996, at Section II.H, page 66541, column 3.

The determination of what is a reasonable form of electric power generation within Maryland is effectively made by three entities: utilities, the Maryland Public Service Commission, and the Maryland Power Plant Research Program. Like many states, Maryland has a Public Service Commission that regulates electric power companies such as BGE. Perhaps unique among the states, Maryland has also established, within the Department of Natural Resources, the Maryland Power Plant Research Program. This State agency is required by Maryland law to review and evaluate the impacts to Maryland's environment from the construction and operation of electric power generating and transmission systems. The Power Plant Research Program summarizes these evaluations biennially and advises the Public Service Commission on environmental impacts of utility proposals. This environmental report makes extensive reference to Maryland Power Plant Research Program publications.

In considering the level of detail and analysis that it should provide for each alternative, BGE 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)].

Baltimore Gas and Electric Company determined that, as long as the environmental report provided sufficient information to clearly indicate whether an alternative would have comparable or greater environmental impact than the proposed action (i.e., license renewal), the document would support the NRC decision-making. Providing additional detail or analysis would serve no function if it would only bring to light more adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which require that the consideration of alternatives (including the proposed action) devote substantial enough treatment that reviewers may evaluate their comparative merits.[12] Chapter 2 provides only sufficient detail about alternatives to establish the basis for necessary Chapter 4 analysis of impacts.

2.2.1 Feasible Alternatives

The NRC GEIS for license renewal of commercial nuclear power plants discusses alternatives to license renewal of nuclear power generating units. The document states that coal- and gas-fired generation technologies are feasible alternatives to nuclear power plants based upon current technological and cost efficiencies, and generally discusses the types of impacts that would occur as a result of construction and operation of these types of facilities.

The principal fuel burned in Maryland's power plants is coal. In 1993, coal-fired generation accounted for roughly 57 percent of the generation in Maryland; nuclear generation (represented by CCNPP) accounted for 28 percent; and oil and gas-fired generation combined accounted for approximately 10 percent (Reference 7). Baltimore Gas and Electric Company considers coal-fired generation a feasible alternative to nuclear generation, and Section 2.2.1.1 presents coal as a feasible alternative to CCNPP license renewal. Although BGE gas-fired generation unit costs are not competitive with BGE coal and nuclear operating costs, new gas-fired technology (combined cycle) offers significant efficiency improvements and operating cost reduction (Reference 8). For this reason, Section 2.2.1.2 presents gas-fired generation as a feasible alternative to CCNPP license renewal.

The alternatives are presented as construction at the existing Calvert Cliffs site. This was done primarily to minimize the operational environmental impacts of these alternatives by taking advantage of the fact that the aquatic biota at this location are adapted to the cooling water intake and thermal discharge. The cooling water needs for a fossil-fuel-fired facility large enough to replace the CCNPP capacity would require a once-through cooling system that would work only if the facility were located on a large body of water, such as the Chesapeake Bay; such siting requirements enable a comparison between once-through and closed-cycle cooling technologies.

In addition, it is assumed that the alternatives could use the existing intake and discharge structures, switchyard, and transmission lines. This gas-fired alternative could also make use of existing gas pipeline capacity adjacent to the site. By utilizing existing structures such as these, the environmental impact of

[12] 40 CFR 1502.14(b).

construction would be reduced. Although the alternatives are presented as defined construction at a defined site, the sections also discuss how design and site variations could affect the alternative definition and the resulting environmental consequences.

The descriptions of the coal-fired and gas-fired power plants utilized in this environmental report are intended to be reasonable representations of facilities that could be used as alternative sources of energy. The descriptions are based on a combination of several existing facilities that together include the major components and technology BGE is using as alternate energy sources in this environmental report. Baltimore Gas and Electric Company chose these facilities because they are recent projects that present current technology and are documented in publicly available reports. In addition, industry and government technical publications are cited as sources of technical data and information regarding the types and quality (e.g., ash content, Btu per pound) of fossil fuels that might be burned at electrical power generating units. More detailed technical discussion defining representative coal- and gas-fired plants as alternative power sources is included in Sections 2.2.1.1 and 2.2.1.2, respectively.

The alternatives would also involve decommissioning CCNPP. When nuclear power plants permanently cease operation, they must be decommissioned in accordance with NRC regulations. The NRC defines decommissioning as the safe removal from service, reduction of residual radioactivity to a level that permits release of the property, and termination of the NRC license (10 CFR 50.2). Nuclear Regulatory Commission regulations define acceptable levels of residual radioactivity. The GEIS, (as well as NUREG-0586, "Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities," August 1988), provide a description of decommissioning activities.

Regardless of license renewal, BGE will have to comply with NRC decommissioning requirements. If NRC renews the CCNPP operating licenses, decommissioning would be postponed for an additional 20 years. If NRC does not renew the licenses, BGE would initiate decommissioning activities upon expiration of the current CCNPP operating licenses. Under the feasible alternatives addressed below, CCNPP decommissioning would be concurrent with operation of the alternatives. Baltimore Gas and Electric Company adopts by reference the GEIS description of decommissioning activities, but notes that the description is based on a larger reactor (the "reference" pressurized-water reactor is the 1,175 MW Trojan Nuclear Plant).

2.2.1.1 Coal-Fired Generation

Representative Plant

The primary source of information used to describe and size (megawatts and land use) the coal-fired alternative is Delmarva Power and Light Company documentation for its Dorchester Power Plant. Documentation for the South Carolina Electric and Gas Company Cope Power Plant was also used. These facilities are typical of currently available coal-fired technology being constructed and operated today. In addition, information from the EPA and the U.S. Department of Energy's (DOE's) Energy Information Administration technical publications on fuel specifications and best available emission control technology was utilized to specify fuel types and emission control technology that would be utilized. In some cases, BGE could use referenced data directly; in other cases, BGE appropriately scaled data to fit the size plant needed for a CCNPP alternative energy source.

For the purposes of this environmental report, it is assumed that it would take 1,800 MWe coal-fuel-fired generation to replace the 1,690-MW CCNPP. The increased size over current CCNPP capacity would be necessary to offset increased internal electrical usage for pollution control, pumping water for cooling, or transporting coal or ash up-gradient.

The typical size (megawatt) and configuration utilized by the electrical power industry in the application of coal-fired generation technology varies. The Delmarva Power and Light Company and the South Carolina Electric and Gas Company sized and phased construction of their units to match load growth projections. The Delmarva power plant consists of two 300-MW units constructed at the same site sharing common facilities and infrastructure such as rail, fuel storage, and ash disposal (Reference 9). The Cope Power Plant consists of three 385-MW units (Reference 10). Nationally, unit sizes range up to in excess of 1,000 MWs (Reference 11).

The coal-fired alternative in this report would consist of three 600-MW units (ISO rating)[13] that would burn pulverized bituminous coal.[14] Bituminous coal is the most common coal burned in coal-fired units due to its higher heating values (Reference 12). A maximum of 15,300 tons of coal and 840 tons of lime/limestone per day (Reference 9) would be delivered by barge to the existing plant dock (Figure 2-4). Coal would have a heating value of 13,000 Btu per pound and ash content of 10 percent (Reference 9). The sulfur content of the coal would be 0.8 percent (Reference 13).

Each of the three units could be 200-feet tall, would be tangentially-fired, dry-bottom boilers (Reference 12), and would include an approximately 600-foot high stack (Reference 10). This firing configuration was chosen because of the moderate uncontrolled nitrogen oxides emissions compared with other applications. Nitrogen oxides emissions controls would include low nitrogen oxide burners, overfire air, and post-combustion selective catalytic reduction. The combination of low nitrogen oxide burners and overfire air would achieve a nitrogen oxides reduction of 40 to 60 percent from uncontrolled levels. These combustion controls, along with selective catalytic reduction can achieve the current upper limit of nitrogen oxides control (95 percent reduction) (Reference 12). Based on an operating capacity factor of 83.9 percent (Reference 9), the resulting annual nitrogen oxides emissions would be approximately 560 tons per unit.[15]

Each unit would have fabric filters or electrostatic precipitators (99.9 percent particulate removal efficiency) and a wet lime/limestone flue gas de-sulfurization system (95 percent scrubber removal efficiency) (Reference 12). Based on an operating capacity factor of 83.9 percent (Reference 9), the resulting annual emissions per unit would be 78 tons of filterable particulates,[16] 18 tons of PM_{10},[17] and 1,200 tons of sulfur oxides.[18] Carbon monoxide emissions would be approximately 390 tons per year per unit.[19]

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13 An ISO (International Standards Organization) rating identifies the generator rating at standard atmospheric conditions. Standard atmospheric conditions are 59°F, 60 percent relative humidity, and 14.696 pounds per square inch atmospheric pressure.

14 The choice of pulverized coal combustion technology, as opposed to other coal combustion technologies, is consistent with recent, regional practice for new generation capacity (e.g., Delmarva Power & Light Company Dorchester Site) and is considered a reasonable alternative.

15 Calculated as follows using AP-42 (Reference 12) Table 1.1-3: 5,100 tons coal per day x 365 days per year x 0.839 capacity factor x 14.4 pounds nitrogen oxides per ton coal ÷ 2,000 pounds per ton = 11,245 tons nitrogen oxides per year (uncontrolled). Assuming 95 percent reduction efficiency: 11,245 tons nitrogen oxides per year (uncontrolled) x 0.05 = 562 tons nitrogen oxides per year per unit (controlled).

16 Calculated using the uncontrolled emission factor for filterable particulates given in AP-42 Table 1.1-4 as 10A, where A is the weight percent ash of the coal as fired; therefore, 10 x 10 percent ash = 100 pounds filterable particulates per ton coal. Filterable particulate emission calculated as follows: 5,100 tons coal per day per unit x 365 days per year x 0.839 capacity factor x 100 pounds filterable particulates per ton coal ÷ 2,000

The power block and coal pile would occupy approximately 300 acres (Reference 9). The units would be constructed at the same time with phased-in service dates to replace the power demands supplied by CCNPP and would have an operational life of 40 years (Reference 10). Constructing more, smaller units instead of three 600-MW units would offer no known environmental benefits.

The plant would use the existing CCNPP intake and discharge structures as part of a once-through cooling system. This alternative would minimize environmental impacts since minimal construction would be required to adapt the system to the coal-fired alternative. It is assumed that the coal-fired alternative cooling water volume and temperature rise would be approximately the same as for the current nuclear plant [2,600 million gpd (Reference 14) with 12°F temperature rise]. This temperature delta would comply with the existing CCNPP State Discharge Permit (Reference 15).

Construction of the coal-fired alternative would take approximately five years. The workforce during the construction period is expected to average 1,500, with a peak of 2,000, and during operations to average 220. The reduced work force size for the coal-fired alternative (1,770 to 220) would reduce the groundwater withdrawals for potable water use, but additional withdrawals would be required for wet-scrubber sulfur oxides emissions control and boiler makeup. Maximum groundwater usage is assumed to be 800 gpm per unit.

Approximately 1.5 million tons of waste per year (ash and scrubber sludge) would be disposed of onsite, requiring a plant lifetime (40 years) total of approximately 600 acres (Reference 10). Facilities would be constructed to control and treat leachate from coal storage areas and ash and scrubber waste disposal areas. The existing switchyard and transmission system would be used. It is assumed that coal-fired generation structures and facilities, including coal storage and waste disposal, would be located in one or more of the Calvert Cliffs site open areas (Figure 2-3).

As described above, the coal-fired generation alternative would necessitate converting roughly an additional 900 acres of the Calvert Cliffs site to industrial use (plant, coal storage, and ash and scrubber sludge disposal). Currently, this land is open, some is farmed, and the rest is a re-vegetated dredged spoils disposal area known as Lake Davies (Figure 2-3).

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pounds per ton = 78,090 tons filterable particulates per year per unit (uncontrolled). Assuming 99.9 percent removal efficiency: 78,090 tons filterable particulates per year per unit (uncontrolled) x 0.001 = 78 tons filterable particulates per year per unit (controlled).

17 Calculated using the uncontrolled emission factor for PM_{10} given in AP-42 Table 1.1-4 as 2.3A, where A is the weight percent ash content of coal as fired; therefore, 2.3 x 10 = 23 pounds PM_{10} per ton of coal. PM_{10} emission calculated as follows: 5,100 tons coal per day per unit x 365 days per year x 0.839 capacity factor x 23 pounds PM_{10} per ton coal ÷ 2,000 pounds per ton = 17,961 tons PM_{10} per year per unit (uncontrolled). Assuming 99.9 percent removal efficiency: 17,961 tons PM_{10} per year per unit (uncontrolled) x 0.001 = 18 tons PM_{10} per year per unit (controlled).

18 Calculated using the uncontrolled emission factor for sulfur oxides given in AP-42 Table 1.1-3 as 38S, where S is the weight percent sulfur content of coal as fired; therefore, 38 x 0.8 = 30.4 pounds sulfur per ton coal. Sulfur oxides emission calculated as follows: 5,100 tons coal per day per unit x 365 days per year x 0.839 capacity factor x 30.4 pounds sulfur oxides per ton coal ÷ 2,000 pounds per ton = 23,739 tons sulfur oxides per year per unit (uncontrolled). Assuming 95 percent removal: 23,739 tons sulfur oxides per year per unit (uncontrolled) x 0.05 = 1,187 tons sulfur oxides per year per unit (controlled).

19 Calculated as follows using AP-42 Table 3.1-2: 5,100 tons coal per day per unit x 365 days per year x 0.839 capacity factor x 0.5 pound carbon oxide per ton coal ÷ 2,000 pounds per ton = 390 tons carbon monoxide per year per unit.

Cooling System Alternatives

Baltimore Gas and Electric Company has evaluated cooling-tower-based, closed-cycle cooling system that would also use the existing intake and discharge structures, flow requirements would be less (80 percent reduction) than the once-through cooling system (Reference 16). This alternative would add an approximately 520-foot high natural draft cooling tower for each unit, which would occupy a total of 25 acres (Reference 16). Cooling water consumption, due to evaporation, would be approximately 35 million gpd at a minimum of two concentrations for cooling tower blowdown (Reference 16). Total water flow, including tempering water and tower makeup water, would be 520 million gpd. The closed-cycle cooling system would introduce cooling tower blowdown that would be at least two-and-one-half times as saline as the Chesapeake Bay. Cooling tower operation would require more electrical power than the once-through cooling system due to the modified pumping systems. The towers would discharge a plume of water vapor and a measurable amount of saltwater drift (Reference 16).

Mechanical draft cooling towers are an alternative to natural draft cooling towers. Mechanical draft cooling towers are 50- to 100-feet tall (Reference 10) but would demonstrate operational impacts similar to the natural draft towers noted above.

New Site

Construction of the coal-fired generation alternative at a new site would impact roughly an additional 150 acres (Reference 9) for offices, roads, parking areas, and a switchyard (in addition to the 900 acres needed for the plant, coal storage, and ash and scrubber sludge disposal areas). Cooling water intake and discharge structures would have to be constructed. An additional 424 acres would be needed for transmission lines, assuming the plant is sited 10 miles from the nearest substation.[20]

2.2.1.2 Gas-Fired Generation

Representative Plant

The primary source of information used to describe and scale for size (megawatt and land use) the gas-fired alternative is BGE documentation submitted to the Maryland Public Service Commission for the Perryman Power Plant coupled with EPA documentation for the Polk Power Station. The Perryman and Polk facilities are typical of current available gas-fired technology being constructed and operated today. In addition, information from the EPA and DOE's Energy Information Administration technical publications on fuel specifications and best available emission control technology was utilized to specify fuel types and emission control technology that would be utilized in the gas-fired alternative. In some cases, BGE could use referenced data directly; in other cases, BGE appropriately scaled data to fit the size plant needed for a CCNPP alternative energy source.

For the purposes of this environmental report, it is assumed that it would take 1,760-MW gas-fired generation to replace the 1,690-MW CCNPP. The increased size over current CCNPP capacity would be necessary to offset increased internal electrical usage for pollution control and pumping water for cooling, but would not be as great as for the coal-fired alternative due to reduced cooling water flow and pollution control needs.

20 Based on 350-foot right-of-way (10 miles x 5,280 feet per mile x 350 feet ÷ 43,560 square feet per acre = 424 acres)

There are several generation technologies that use natural gas as fuel. Gas-fired steam generator technology utilizes hot combustion gases to heat water to produce steam, which in turn rotates a generator to produce electricity. In simple-cycle combustion turbine technology, fuel is burned in a combustion turbine and the resulting hot combustion gases rotate the turbine to generate electricity before being emitted to the air. Combined-cycle technology uses a combination of combustion turbine technology and steam generator technology. In the combined cycle unit, hot combustion gases in the combustion turbine rotate the turbine to generate electricity; and waste combustion heat from the combustion turbine is routed through a heat recovery steam generator. There, water is turned to steam, which rotates a steam turbine to generate additional electricity. The size, type, and configuration of gas-fired generation units and plants currently operational in the United States vary and include simple-cycle combustion and combined cycle units that range from 25 MWs to 600 MWs (References 17, 18). As with coal-fired technology, units may be configured and combined at a location to produce the desired amount of megawatts, and construction can be phased to meet electrical power needs.

The gas-fired generation alternative consists of four 440-MW (ISO rating) combined-cycle units each consisting of two 155-MW simple-cycle combustion turbines and a 130-MW heat recovery steam generator. On an average annual basis, these units would generate up to 440 MWs per hour each, providing the 1,760 MWs needed to replace CCNPP. The power block area would occupy approximately 60 acres (Reference 19).

Natural gas typically having an average heating value of 1,000 Btu per cubic foot (References 11, 12) would be the primary fuel; the gas-fired alternative plant would burn approximately 10 million cubic feet per hour. Low-sulfur No. 2 fuel oil would be the backup fuel (Reference 19). Each unit would be less than 100-feet feet high and would be designed with dry, low nitrogen oxides combusters, water injection, and selective catalytic reduction (Reference 12), and would exhaust through a 230-foot stack after passing through heat recovery steam generators. This stack height is consistent with EPA Regulation 40 CFR 51.100, which addresses requirements for determining the stack height of new emission sources. Regulation 40 CFR 51.100 allows stack heights based on good engineering stack height (defined in the regulation) or modeling, but does not allow credit for offsite contaminant level reduction for taller stacks. The 230-foot height is based on the regulation's good engineering practice formula using the tallest proposed onsite facility (i.e., the 92-foot turbine building). While modeling would have to be used to justify stack height greater than 230 feet, the relatively flat terrain and low structures of the area probably mean that modeling would not support a greater stack height.

Nitrogen oxides emissions from the gas-fired alternative would be 386 tons per year.[21] There should be no solid waste products (i.e., ash) from natural gas fuel-burning.

The plant would use the existing CCNPP intake and discharge structures as part of a once-through cooling system; however, since cooling requirements would be less (70 percent reduction), flows would average approximately 1,000 million gpd (Reference 17).

Natural gas would be delivered via a newly constructed connection to the existing pipeline located parallel to Maryland Highway 2-4 near the Calvert Cliffs site, a distance of approximately 1.5 miles

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21 Calculated as follows using AP-42 Table 3.1-2 and assuming a 60 percent thermal efficiency: 1,760 megawatt (MW) ÷ 0.6 = 2,933 MW input. 2,933 MW x (1 x 10^6 watts per MW) x (0.0009486 Btu per second per watt) x (60 seconds per minute) x (60 minutes per hour) x (24 hours per day) x (365 days per year) = (8.77 x 10^{13} Btu per year) x (0.0088 pounds nitrogen oxides per 1 x 10^6 Btu) x (1 ton per 2,000 pounds) = 386 tons nitrogen oxides per year.

(Reference 20). The proposed route would follow an existing Southern Maryland Electric Cooperative power line right-of-way onto the Calvert Cliffs site adjacent to the Lake Davies area (Figure 2-3). Approximately 10 acres would be disturbed during pipeline construction. The existing line currently has sufficient reserve capacity to supply the needs of the gas-fired alternative.

Construction of the gas-fired alternative would take approximately 3 years and the work force during the construction period would average 500, with a peak of 750. The work force during operations would average 125.

Cooling System Alternatives

Baltimore Gas and Electric Company assumes that cooling for the gas-fired facility could also be accomplished by a closed-cycle system, which would also use the existing intake and discharge structures, but flow requirements would be 90 percent less than the once-through cooling system. This alternative would use an approximately 520-foot high natural draft cooling tower for each unit (Reference 16). Cooling water consumption, due to evaporation, would be approximately 10 million gpd at a minimum of two concentrations for cooling tower blowdown (Reference 16). Total water flow, including tempering water and tower makeup water, would be 152 million gpd. The closed-cycle cooling system alternative would introduce cooling tower blowdown that would be at least two-and-one-half times as saline as the Chesapeake Bay. Cooling tower operation would require more electrical power than the once-through alternative due to the modified pumping systems. Cooling towers would discharge a plume of water vapor and a small amount of saltwater drift (Reference 16).

Mechanical draft cooling towers are an alternative to natural draft cooling towers. Mechanical draft cooling towers are 50- to 100-feet tall (Reference 10) but would demonstrate operational impacts similar to the natural draft towers noted above.

New Site

Construction of the gas-fired generation plant at a new site would impact another approximately 94 acres for offices, roads, parking areas, and a switchyard (in addition to the 70 acres needed for the power block area and pipeline construction). An additional 424 acres would be needed for transmission lines, assuming the plant is sited 10 miles from the nearest substation.[22]

2.2.1.3 Imported Electrical Power

"Imported power" means power purchased and transmitted from electric generation plants that BGE does not own and that are located elsewhere within the region, nation, or Canada. In 1993, Maryland was a substantial net importer of electricity; imports represented approximately 20 percent of electrical sales within the State. Baltimore Gas and Electric Company imported approximately 2,400 gigawatt-hours, in 1993 (Reference 7). In theory, importing (purchasing) power is a feasible alternative to CCNPP license renewal. However, BGE notes that regardless of the technology used to generate imported power, the generating technology would be one of those described in this environmental report and in the GEIS. For this reason, BGE is adopting by reference, as representative of the imported electrical power alternative to CCNPP license renewal, the GEIS Chapter 8 description of other technologies.

22 Based on 350-foot right-of-way (10 miles x 5,280 feet per mile x 350 feet ÷ 43,560 square feet per acre = 424 acres).

2.2.1.4 No Action

The No-Action Alternative refers to a scenario in which NRC would not renew the CCNPP license, and BGE would decommission CCNPP after license expiration. Calvert Cliffs provides approximately 12,000,000 MW-hours of electricity annually to more than 1,000,000 customers in a 2,300-square mile area. Baltimore Gas and Electric Company presumes that this demand would be met by one of the generation alternatives presented in this document or in the GEIS. However, due to the influence of ongoing deregulation of the retail market, BGE may or may not be the ultimate supplier of power. The range of feasible replacement power options is addressed in the previous sections.

2.2.2 Other Alternatives

This section identifies alternatives to CCNPP license renewal that are not feasible, and describes why the alternatives are not feasible and will not be considered further within this environmental report.

Wind

Wind speeds in most areas of Maryland average 8 to 10 miles per hour, whereas average wind speeds of more than 12 miles per hour are normally required for wind turbines to operate efficiently. Some areas of western Maryland may have potential for use of wind energy, but these locations, found at the highest levels of sharp ridge lines, would incur high costs for land acquisition and power line construction (Reference 21). Based on the GEIS land use estimate for wind power,[23] replacement of CCNPP generating capacity, even assuming ideal wind conditions, would require dedication of almost 400 square miles, an area almost twice the size of the county in which CCNPP is located.[24] Based on the lack of good wind speeds and the amount of land needed to replace CCNPP, BGE has determined that the wind alternative is not feasible.

Solar

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 (Reference 23). Maryland receives slightly more than 3.3 kilowatt-hours of solar radiation per square meter (kWh/m^2) per day, compared to 5 to 7.2 kWh/m^2 per day in areas of the West, such as California, which are most promising for solar technologies (GEIS Section 8.3.3). Because of the area's low rate of solar radiation and high technology costs, BGE views the role of solar power in Maryland as limited to niche applications and not a feasible baseload alternative to CCNPP license renewal.

Hydropower

Approximately 4 percent, or 535 MWs, of Maryland generating capacity is hydroelectric (Reference 7). As GEIS Section 8.3.4 points out, hydropower's percentage of the country's 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 destruction of natural river courses. Based on the GEIS land use estimate for hydroelectric power,[25] replacement of CCNPP generating capacity would require flooding more than 2,600 square miles. Due to the lack of locations for siting a hydroelectric facility large enough to replace CCNPP, BGE has determined that this is not a feasible alternative to CCNPP license renewal.

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23 GEIS Section 8.3.1 estimates 150,000 acres per 1,000 megawatts-electric for wind power.

24 The land area of Calvert County is approximately 220 square miles (Reference 22).

25 GEIS Section 8.3.4 estimates 1 million acres per 1,000 megawatts-electric for hydroelectric power.

Geothermal

As illustrated by GEIS Figure 8.4, geothermal plants might be located in the western continental United States, Alaska, and Hawaii where hydrothermal reservoirs are prevalent, but would not be a feasible alternative to CCNPP license renewal in Maryland.

Wood Energy

A significant barrier to use of wood waste to generate electricity is the high delivered fuel cost. States with significant wood resources, such as California, Maine, Georgia, Minnesota, Oregon, Washington, and Michigan, benefit from using local resources. The pulp, paper, and paperboard industries, which consume large quantities of electricity, are the largest consumer of wood and wood waste for energy, benefiting from use of waste materials that could otherwise represent a disposal problem. However, the larger wood waste power plants are only 40 to 50 MWs in size. The 11.5 trillion Btu of energy estimated to be available annually from Maryland forests (Reference 21) would only produce the amount of electricity that CCNPP produces in one hour.[26] Due to the lack of sufficient resource base in the Maryland area, BGE has determined that wood waste is not a feasible alternative to renewing the CCNPP license.

Municipal Solid Waste

The decision to burn municipal waste to generate energy is usually driven by the need for an alternative to land-filling 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 (Reference 23). Baltimore Gas and Electric Company has determined that municipal solid waste would not be a feasible alternative to CCNPP 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, and gasifying energy crops (including wood waste). None of these technologies have progressed to the point of being competitive on a large scale or of being reliable enough to replace a baseload plant such as CCNPP (ethanol is primarily used as a gasoline additive for automotive fuel). For these reasons, BGE has determined that such fuels do not offer a feasible alternative to CCNPP license renewal.

Oil

Baltimore Gas and Electric Company has several oil-fired units. As Table 2-7 indicates, the cost of oil-fired operation is about eight times as expensive as nuclear and coal-fired operation. In addition, increases in oil prices are expected to make oil-fired generation increasingly more expensive than coal-fired generation (Reference 24). For these reasons, BGE has determined that oil-fired generation is not a feasible alternative to CCNPP license renewal.

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26 At an average of 10,000 BTUs per kilowatt-hour (kWh), 11 trillion BTUs would yield 1.1 million kWh per year. In 1996, CCNPP generated slightly more than 12 trillion kWh (Reference 8), or about 1.3 million kWh per hour.

Nuclear Power

Work on advanced reactor designs has continued and nuclear plant construction continues overseas. However, the cost of building a new nuclear plant and the political uncertainties that have historically surrounded many nuclear plant construction projects are among the factors that have led energy forecasters such as the Energy Information Administration to predict no new domestic orders for the duration of current forecasts - through the year 2010 (Reference 24). These are also reasons that have led BGE to conclude that new nuclear plant construction is not a feasible alternative to CCNPP license renewal.

Delayed Retirement

Calvert Cliffs Nuclear Power Plant provides about 27 percent of BGE's generating capacity and approximately 40 percent of its energy requirements. Without retiring any generating units, BGE will require additional capacity in 2000 or 2001. For this reason, BGE has determined that delayed retirement of other BGE generating units would not be a feasible alternative to CCNPP license renewal.

Conservation

The Maryland Public Service Commission requires Maryland electric utilities to implement demand-side management[27] as a means to conserve energy and to take demand-side management energy savings into account in long-range planning. Baltimore Gas and Electric Company has an extensive program of residential, commercial, and industrial programs designed to reduce both peak demands and daily energy consumption (demand-side management). Program components include the following:

- Peak clipping programs - Include energy saver switches for air conditioners, heat pumps, and water heaters, allowing BGE to interrupt electrical service to reduce load during periods of peak demand; dispersed generation, giving BGE dispatch control over customer backup generation resources; and curtailable service, allowing BGE to reduce customers' load during periods of peak demand.
- Load shifting programs - Use time-of-use rates and cool storage rebate programs to encourage shifting loads from on-peak to off-peak periods.
- Conservation programs - Promote use of high-efficiency heating, ventilating, and air conditioning; encouraging construction of energy-efficient homes and commercial buildings; improving energy efficiency in existing homes; providing incentives for use of energy-efficient lighting, motors, and compressors.

Baltimore Gas and Electric Company estimates that its demand-side management program produces an annual peak demand generation reduction of about 700 MWs, and BGE believes that it can continue to increase generation savings from demand-side management. The BGE load growth projection anticipates a demand-side management savings of about 1,000 MWs in 2016. Because these savings are part of the long-range plan for meeting projected demand, however, it is not available as an "offset" for CCNPP, and BGE does not foresee availability of another 1,690 MWs (CCNPP capacity). For these reasons, BGE has determined that demand-side management is not a feasible alternative to renewing the CCNPP license.

27 GEIS Section 8.3.14 discusses conservation technologies to conserve energy consumption. These measures generally come under the heading of "demand-side management," which is a collection of diverse measures to reduce customers' electricity consumption without adversely affecting service.

2.3 Summary Comparison

Table 2-6 summarizes the proposed action, feasible alternatives, and the environmental impacts that differentiate the proposed action from the alternatives. The principle differences would be impacts to air, aesthetics, and land use.

Air Impacts -- Coal- and gas-fired generation alternatives would introduce moderate air impacts due to emission of pollutants such as nitrogen oxides, sulfur oxides, carbon monoxide, and particulate emissions that would not occur if NRC renewed the CCNPP license. Baltimore Gas and Electric Company assumes that the power purchase alternative could result in generator construction somewhere, which would introduce the same type of air impacts. These impacts are of concern due to their association with the issues of human health, regional acid rain, and global climatic change.

Aesthetic Impacts -- The Calvert Cliffs site is on a relatively undeveloped Chesapeake Bay coastline, and the plant is in a topographically low area that is visible only from the water. Coal- and gas-fired alternatives would require the construction of large structures on higher ground that would be visible for miles inland, as well as further across the water. These alternatives would introduce a moderate to large aesthetic impact that would also be associated with a gas- or coal-fired generation source under the power purchase alternative.

Land Use Impacts -- All the alternatives would introduce some new land use impacts due to the need to convert existing uses to new generating capacity. The coal-fired alternative would have the largest impact due to its need for ash and scrubber waste disposal acreage that, in turn, would introduce a risk of groundwater contamination.

Other environmental impacts are not as strong of a discriminator between the proposed action and alternatives and include aquatic, groundwater, socioeconomic, and terrestrial resources impacts.

A number of environmental impacts have been assigned a significance level of "small" by NRC in the GEIS. Baltimore Gas and Electric Company has identified no new or significant information that would make these conclusions inapplicable to CCNPP. In compliance with NRC regulations, Chapter 4 discusses other environmental effects and concludes that they would be of small significance. Chapter 4 also discusses the environmental effects of the alternatives.

Table 2-1
NEPA DOCUMENTATION FOR CCNPP

No.	Date	Topic	BGE Submittal to NRC	NRC NEPA Documentation
1.	1970	Operation	Environmental Report; CCNPP (Reference 1)	See No. 2 below
2.	1973	Operation	Supplement to Environmental Report; CCNPP (Reference 25)	FES, (Reference 3)
3.	1976	Discharge temperature (temporary suspension of 100-hour maximum limit for temperature rise over 10°F and discharge temperature over 90°F)	License Amendment Request, Unit 1 (Reference 26)	Environmental Assessment and Finding of No Significant Impact (FONSI) (38 FR 8759) Unit 1 License Amendment No. 16 (Reference 27)
4.	1977	Power level (increase to 2,700 MW-thermal)	License Amendment Request; Unit 1 (Reference 28) and Unit 2 (Reference 29)	License Amendment Nos. 24 and 9; Environmental Impact Appraisals and Negative Declaration; Unit 1 (Reference 30) and Unit 2 (Reference 31)
5.	1979	Discharge temperature (2-year study of an increase from 10° to 12°F delta across condenser)	License Amendment Request and Submittal of Plan for Studying Environmental Impact of Increased Delta (Reference 32)	License Amendment Nos. 36 and 19; Environmental Impact Appraisal and Negative Declaration (Reference 33)
6.	1981	Refueling cycle, Unit 1, (extended to 18 months)	Unit 1 License Amendment Request; Fifth Cycle (Reference 34) and Sixth Cycle (Reference 35) Amendment to Environmental Report (Reference 36)	Conclusion that an EIS or negative declaration and environmental appraisal not needed; Unit 1 License Amendment Nos. 48 and 71 (References 37, 38)
7.	1982	Refueling cycle, Unit 2, (extended to 18 months)	Unit 2 License Amendment Request; Fourth Cycle (Reference 39) Amendment to Environmental Report (Reference 36)	Conclusion that an EIS or negative declaration and environmental impact appraisal not needed; Unit 2 License Amendment No. 31 (Reference 40)
8.	1981	Fuel enrichment (increase from 4.0 to 4.1 percent Uranium-235)	Units 1 and 2 License Amendment Request (Reference 41)	Conclusion that EIS or negative declaration and environmental impact appraisal not needed; License Amendment Nos. 63 and 45 (Reference 42)
9.	1982	Discharge requirements (delete non-radiological limits and monitoring)	Units 1 and 2 License Amendment Request (Reference 43) Supplementary Information (Reference 44)	Conclusion that EIS or negative declaration and environmental impact appraisal not needed; License Amendment Nos. 70 and 53 (Reference 45)
10.	1984	Auxiliary Feedwater (AFW) System (increase period of in-operability)	Units 1 and 2 License Amendment Request (Reference 46)	Environmental Assessment and FONSI (49 FR 30145) Unit 2 License Amendment No. 78 (Reference 47)

Table 2-1
NEPA DOCUMENTATION FOR CCNPP

No.	Date	Topic	BGE Submittal to NRC	NRC NEPA Documentation
11.	1984	Inservice inspection (extended interval)	Request for Exemption from Required Inservice Inspection Interval (Reference 48)	Environmental Assessment and FONSI (49 FR 33764) Notice of American Society of Mechanical Engineers Code Relief (Reference 49)
12.	1984-1985	License expiration (dates extended to recapture construction period)	Units 1 and 2 License Amendment Request (Reference 50)	Environmental Assessment and FONSI, (50 FR 14185) License Amendment Nos. 102 and 84 (Reference 51)
13.	1985	Inservice inspection (common Unit Nos. 1 and 2 start date)	Request for Extension of Unit 1 Inservice Inspection Interval (Reference 52)	Environmental Assessment and FONSI (50 FR 13893) Notice of Exemption (Reference 53)
14.	1985	Containment ventilation (use of hydrogen purge line)	Units 1 and 2 License Amendment Request (Reference 54) Unit 2 License Amendment Request (Reference 55) Additional information (Reference 56)	Environmental Assessment and FONSI (51 FR 791) License Amendment Nos. 115 and 98 (Reference 57)
15.	1986-1987	Refueling cycle (extended to 24 months)	Units 1 and 2 License Amendment Request (Reference 58)	Environmental Assessment and FONSI (52 FR 44249) License Amendment Nos. 128 and 110 (Reference 59)
16.	1988	Property insurance (18-month exemption from schedular requirements)	None (action initiated by NRC for each licensee)	Environmental Assessment and FONSI (53 FR 38807) Notice of Exemption (Reference 60)
17.	1988-1989	Senior reactor operator license (line management-holding requirements)	Units 1 and 2 License Amendment Request (Reference 61) Modification to License Amendment Request (Reference 62)	Environmental Assessment and FONSI (54 FR 4351) License Amendment No. 135 (Reference 63)
18.	1988-1989	Fuel enrichment (increase from 4.1 to 5.0 percent Uranium-235)	Units 1 and 2 License Amendment Request (Reference 64)	Environmental Assessment and FONSI (53 FR 4352) License Amendment Nos. 134 and 115 (Reference 65)
19.	1989	Independent Spent Fuel Storage Installation	Calvert Cliffs Independent Spent Fuel Storage Installation Application - Environmental Report (Reference 66)	Environmental Assessment and FONSI (56 FR 13196) Calvert Cliffs Independent Spent Fuel Storage Installation License (Reference 67)

Table 2-1
NEPA DOCUMENTATION FOR CCNPP

No.	Date	Topic	BGE Submittal to NRC	NRC NEPA Documentation
20.	1989	Containment local leak rate test (schedular extension)	Units 1 and 2 License Amendment Request (Reference 68) Request for Exemption (Reference 69) Response to Request for Additional Information (Reference 70)	Environmental Assessment and FONSI (53 FR 10757) Temporary Exemption and Unit 2 License Amendment No. 118 (Reference 71)
21.	1990	Final Safety Analysis Report (schedular extension for update)	Exemption Request (Reference 72)	Environmental Assessment and FONSI (55 FR 29920) Notice of Exemption (Reference 73)
22.	1990	Containment emergency lighting (exemption from Appendix R permanent installation requirement)	Exemption Request (Reference 74)	Environmental Assessment and FONSI (55 FR 33390) Notice of Exemption (Reference 75)
23.	1991	Containment local leak rate test (Appendix J schedular extension)	Request for License Amendment and Exemption (Reference 76)	Environmental Assessment and FONSI (56 FR 7420) Exemption from 10 CFR Part 50, Appendix J, Paragraph III.D.3 (Reference 77) Unit 1 License Amendment No. 152 (Reference 78)
24.	1991-1992	Containment local leak rate test (schedular extension - Appendix J, Paragraph III.D.2 and III.D.3)	Request for License Amendment and Exemption (Reference 79)	Environmental Assessment and FONSI (57 FR 2791) Notice of Exemption (Reference 80) License Amendment Nos. 168 and 147 (Reference 81)
25.	1992	Independent Spent Fuel Storage Installation	Calvert Cliffs Independent Spent Fuel Storage Installation Updated Environmental Report, Revision 1 (Reference 82)	None (10 CFR 50.59 changes)
26.	1993	Site boundary changes	Units 1 and 2 License Amendment Request (Reference 83) Supplement to the Environmental Report (Reference 84) Supplement to the License Amendment Request (Reference 85)	Environmental Assessment and FONSI (57 FR 48813) License Amendment Nos. 190 and 167 (Reference 86)

Table 2-2
CCNPP CONSTRUCTION SINCE 1973

Date	Name	Size	Appearance	Purpose	Location
1979	South Service Building	33,000 square feet (2 stories)	Steel frame, gray corrugated metal	Offices, shops	Figure 2-5
1981	Interim Office Building	14,400 square feet (2 stories)	Modular, gray wood siding	Offices	Figure 2-5
1981	Meteorological Tower	200 feet high	Self-supporting steel tower	Meteorological data collection	Figure 2-4
1983	Office Training Facility	64,900 square feet (2 stories)	Steel frame, off-white paneling	Offices, training rooms, simulator complex	Figure 2-4
1984	Materials Processing Facility	35,000 square feet (1 story)	Concrete, corrugated metal trim, off-white finish	Low-level radioactive materials management	Figure 2-4
1984	Firearms Range	6 acres	Target area, observation tower, and office trailer oriented for firing into Lake Davies berm	Plant security firearms range	Figure 2-3
1985	Visitor's Center Annex	2,800 square feet (1 story)	Wood barn siding	Public meeting rooms	Figure 2-4
1986	Nuclear Engineering Facility	56,000 square feet (2 stories)	Steel frame, off-white paneling	Office space	Figure 2-4
1987	Sewage Treatment Facility	1,800 square feet (2 stories)	Gray corrugated metal	Sewage treatment (replaced original plant)	Figure 2-5
1990	Nuclear Office Facility	105,000 square feet (3 stories)	Steel frame, off-white paneling	Offices, cafeteria	Figure 2-4
1992	Independent Spent Fuel Storage Installation	6 acres	2 rows (3 additional planned), reinforced concrete and structural steel, chain link double-fence	Dry storage of spent fuel and storage of support equipment	Figure 2-4
1993	Nuclear Security Facility	39,000 square feet (2 stories)	Steel frame, off-white paneling	Offices, access control to plant protected area	Figure 2-4
1993	Communications Tower	400 feet high	Guy-wired steel tower	Communications	Figure 2-4
1995	Safety-Related Diesel Generator Building	5,600 square feet (1 story)	Concrete, corrugated metal trim	Housing for the Safety-Related Emergency Diesel Generator (EDG)	Figure 2-5
1995	Station Blackout Diesel Generator Building	5,600 square feet (1 story)	Gray corrugated metal	Housing for the Station Blackout EDG	Figure 2-5

Table 2-3
CCNPP WATER CIRCA SUPPLY WELLS[a,b]

Number	Well Tag Number	Date Installed	Well Location	Depth (feet)	Aquifer	Use	Appropriation Permit Number	Appropriation Limit (daily average)
1.	Unknown	c1970	Protected Area vicinity	585	Aquia	Domestic and industrial in protected area	CA69G010(04)	Combined total of 450,000 gpd
2.	CA-70-0063	1970	Protected Area vicinity	637	Aquia	Domestic and industrial in protected area	CA69G010(04)	Combined total of 450,000 gpd
3.	CA-72-0041	1971	Protected Area vicinity	607	Aquia	Domestic and industrial in protected area	CA69G010(04)	Combined total of 450,000 gpd
4.	CA-73-4435	1982	Protected Area vicinity	608	Aquia	Domestic in office area	CA69G010(04)	Combined total of 450,000 gpd
5.	CA-73-4436	1982	Protected Area vicinity	621	Aquia	Domestic in office area	CA69G010(04)	Combined total of 450,000 gpd
6.	CA-73-0369	1974	Old Bay Farm	620	Aquia	Domestic in farms buildings	NA[c]	NA
7.	CA-88-1068	1989	Firearms Range	430	Piney Point	Domestic at firearms range	CA89G007(01)	500 gpd
8.	CA-81-0527	1983	Visitors Center	385	Piney Point	Domestic at visitors and educational areas	CA83G008(02)	300 gpd
9.	CA-73-3896	1980	Camp Conoy[d]	390	Nanjemoy	Domestic at pool	CA63G003(06)	Combined total of 400 gpd
10.	CA-81-2152	1986	Camp Conoy	560	Aquia	Domestic at pool	CA63G003(06)	Combined total of 400 gpd
11.	CA-73-3897	1980	Camp Conoy	415	Nanjemoy	Domestic at ball field	CA63G003	Combined total of 400 gpd
12.	CA-81-1067	1984	Camp Conoy	405	Nanjemoy	Domestic at conference center	CA63G003(06)	Combined total of 400 gpd
13.	CA-88-1636	1990	Procedure Upgrade Project Facility	420	Nanjemoy	Domestic at Procedure Upgrade Project Facility	NA	NA

a. Source: CCNPP Groundwater Appropriation Permits and well completion reports.
b. Does not include monitoring wells.
c. NA = Not applicable because withdrawal rate is below regulatory threshold.
d. Camp Conoy is an employee recreation area.

Table 2-4
CCNPP GROUNDWATER WITHDRAWALS[a]

	Daily Average	
Year	**Total Gallons**	**Gallons Per Minute**
1975	230,000	160
1976	200,000	139
1977	250,000	174
1978	230,000	160
1979	250,000	174
1980	250,000	174
1981	270,000	188
1982	270,000	188
1983	250,000	174
1984	280,000	194
1985	260,000	181
1986	260,000	181
1987	380,000	264
1988	250,000	174
1989	70,000[b]	49
1990	90,000[b]	63
1991	150,000	104
1992	150,000	104
1993	180,000	125
1994	170,000	118
1995	230,000	160
1996	290,000	201
Average	225,000	157

a. Source: Reference 7 and CCNPP groundwater withdrawal reports for indicated years.
b. Reduced groundwater withdrawals due to reactor shutdown.

Table 2-5
COMPARISON OF GEIS TO CCNPP LICENSE RENEWAL PERSONNEL ESTIMATES[a]

Outage Type	GEIS Estimates[b]	CCNPP Estimates
SMITTR activities		
None (full power operation)	0 labor hours 0 additional personnel	0 labor hours 0 additional personnel
Normal refueling	8 occurrences, each requiring: 2-month duration 3,488 labor hours 8 additional personnel	12 occurrences, each requiring: 2-month duration 3,488 labor hours 8 additional personnel
5-year inservice refueling	2 occurrences, each requiring: 3-month duration 20,935 labor hours 33 additional personnel	3 occurrences, each requiring: 3-month duration 20,935 labor hours 33 additional personnel
10-year inservice refueling	1 occurrence, requiring: 3-month duration 37,482 labor hours 60 additional personnel	2 occurrences, each requiring: 3-month duration 37,482 labor hours 60 additional personnel
Major refurbishment activities		
Current term refurbishment	4 occurrences, each requiring: 3-month duration each 45,924 labor hours 72 additional personnel	0 occurrences
Major refurbishment outage	1 occurrence, requiring: 4-month duration 219,018 labor hours 264 additional personnel	0 occurrences

a. Estimates are per reactor.
b. Source: Modified from Reference 5, Table B.4.

Table 2-6
COMPARISON OF ALTERNATIVES FOR LICENSE RENEWAL OF CCNPP[a]

	Proposed Action	Alternative 1 - Coal-Fired	Alternative 2 - Gas-Fired	Alternative 3 - Import
Description	CCNPP license renewal for 20 years 60 additional workers above existing workforce (1,770)	New construction on the Calvert Cliffs site Three 600-MWe (ISO rating), tangentially-fired, dry bottom units Pulverized bituminous coal, 13,000 Btu/lb, 10% ash, 0.8% sulfur Low nitrogen burners, overfire air, selective catalytic reduction (95% NO_x reduction efficiency) Wet lime/limestone flue gas de-sulfurization system (95% removal efficiency) Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency) Daily barge delivery of 15,300 tons of coal and 840 tons of lime/limestone Average 1,500 construction workers (peak 2,000) for 5 years, 220 permanent workers	New construction on the Calvert Cliffs site Four 440-MWe (ISO rating) combined cycle units Natural gas, 1,000 Btu/scf, 10 Million ft^3/hr Backup low-sulfur No. 2 fuel oil Dry, low nitrogen burners, selective catalytic reduction with water injection for backup oil firing Average 700 construction workers (peak 1,000) for 3 years, 125 permanent workers	Imported electric power (purchase) Could involve new construction of generation and transmission capacity

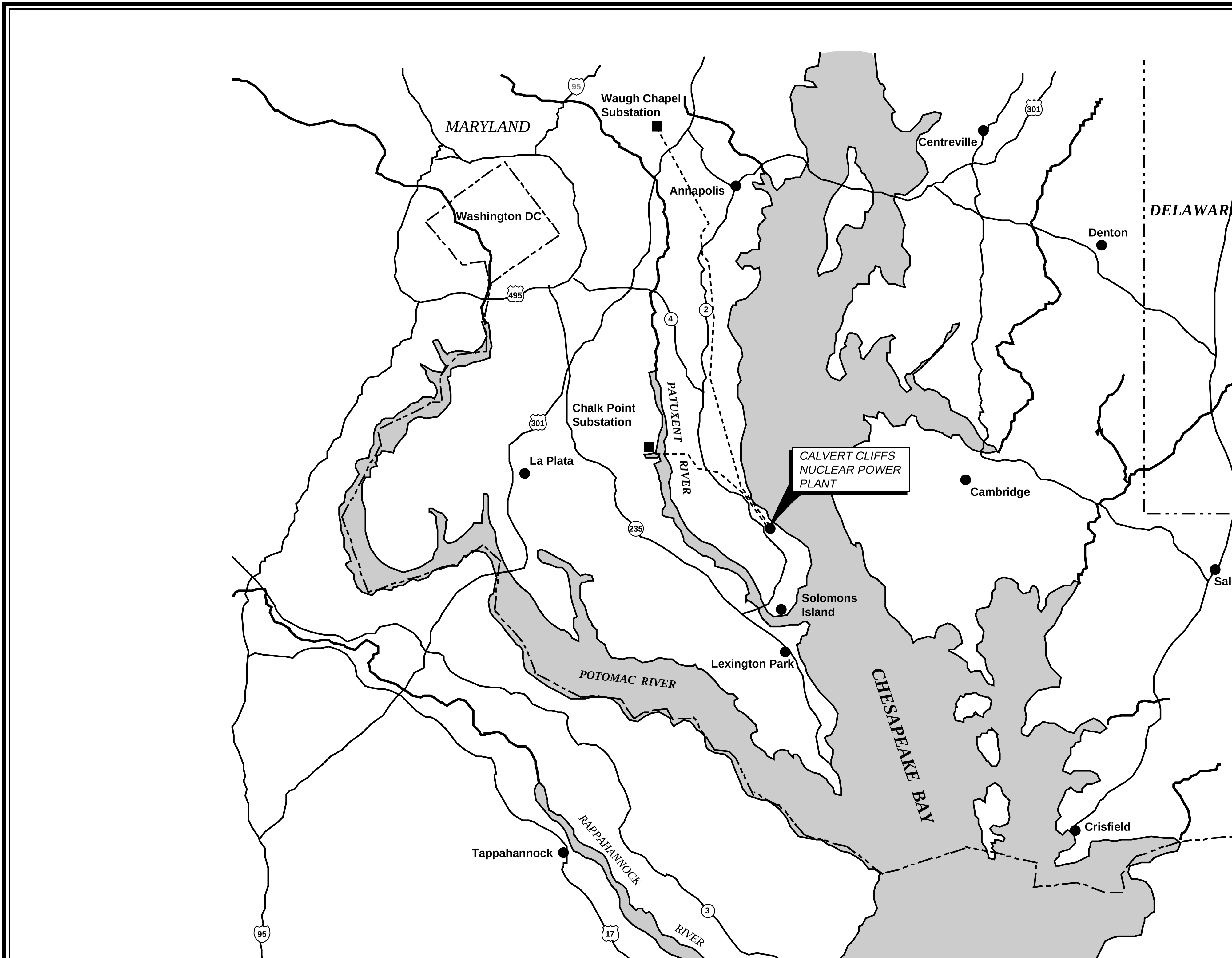
Table 2-6
COMPARISON OF ALTERNATIVES FOR LICENSE RENEWAL OF CCNPP[a]

	Proposed Action	Alternative 1 - Coal-Fired	Alternative 2 - Gas-Fired	Alternative 3 - Import
Resource impacts				
Air	Small, Category 1	Moderate - 3,600 tons SO_x/year; 1,680 tons NO_x/year; 234 tons filterable particulates and 54 tons PM_{10}/year; 1,170 tons CO/year. Offsets necessary for NO_x emissions	Moderate - 386 tons NO_x/year. Offsets necessary	Small to Large - Depends on technology used to generate power
Aesthetics	Small - Category 1	Large - 3 new, 200-foot power plant structures and 600-foot stacks potentially visible for 40 miles in relatively non-industrialized area. Closed-cycle cooling alternative could also introduce 520-foot cooling towers and associated plumes	Moderate - New 100-foot turbine building, 230-foot exhaust stacks. Closed-cycle cooling alternative would introduce plumes and another noise source	Small to Large - For new construction, impacts could be similar to Alternative 1 depending on location
Aquatic ecology	Small - 316(a) and (b) approvals obtained, operational history demonstrates small impacts	Small - Impacts would not exceed proposed action	Small - Impacts would be less than proposed action	Small to Large - New construction could cause habitat loss due to conversion to industrial use depending on location
Groundwater	Small - Withdrawal 157 gpm. Predicted drawdown of Aquia Aquifer to be few inches a year; estimated cumulative drawdown for license renewal period to be approximately 1.2 feet	Large - Withdrawal 2,400 gpm due to SO_2 emission control needs. Regional sensitivity due to impact of nearby municipal withdrawals	Small - Similar to proposed action	Small to Large - New construction could add new source of groundwater withdrawal depending on location
Land	Small - Land use changes due to license renewal not likely	Moderate - 300 acres for power block construction and coal pile; 600 acres for waste (ash and scrubber sludge) disposal	Small- 60 acres for power block construction; 10 acres for pipeline construction	Small to Large - New construction could convert existing land use to power generation

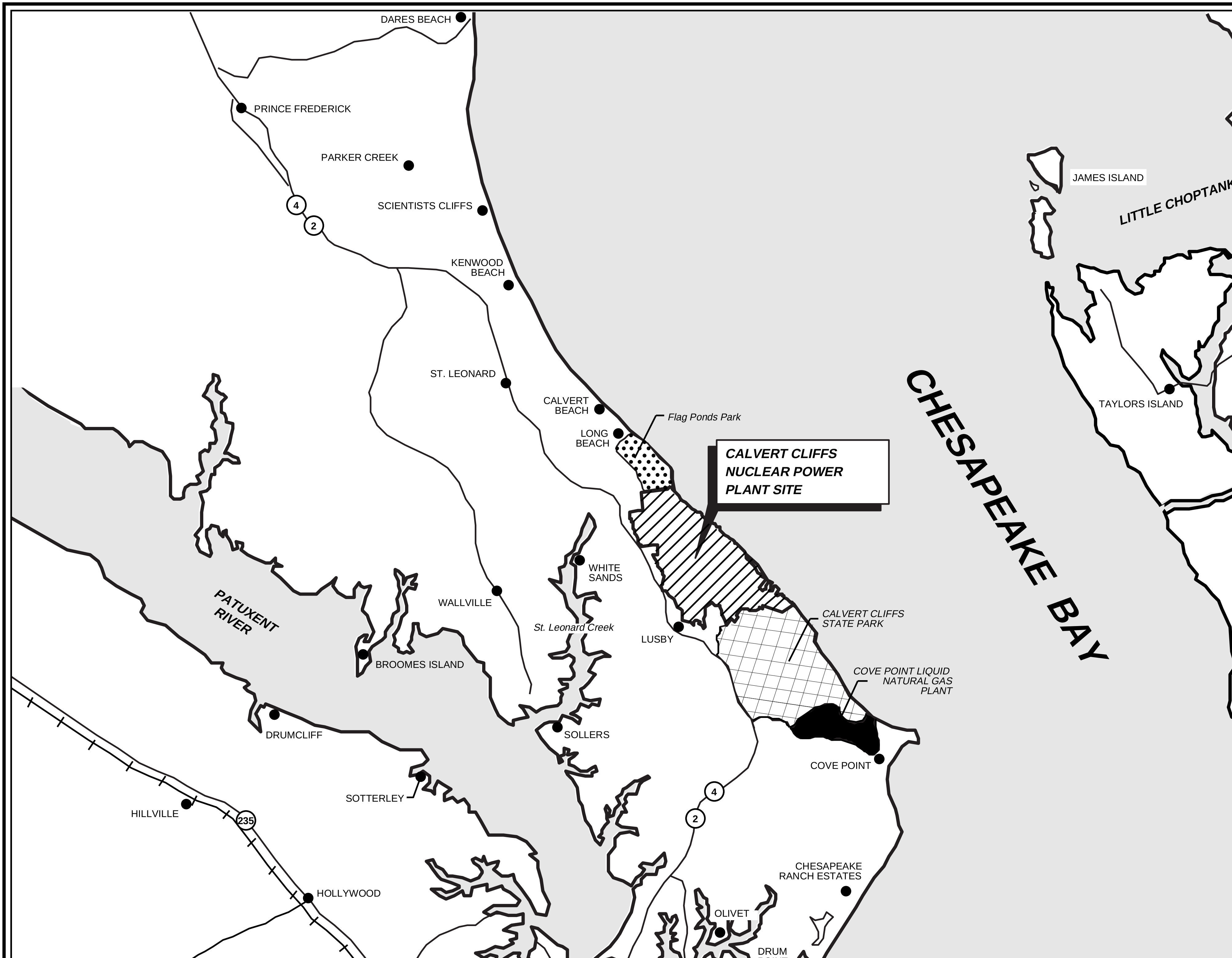
Table 2-6
COMPARISON OF ALTERNATIVES FOR LICENSE RENEWAL OF CCNPP[a]

	Proposed Action	Alternative 1 - Coal-Fired	Alternative 2 - Gas-Fired	Alternative 3 - Import
Socioeconomic	Small - 3% decrease in available housing units; less than 1% increase in output of local water supply system; no anticipated impacts to education system and transportation system	Moderate - Temporary increase in impacts during 5-year construction period from 1,500 workers, then impact of loss of tax and employment base due to reduction of CCNPP workforce from 1,770 to 220	Small - Temporary increase in impacts during 3-year construction period from 500 workers, then impact of loss of tax and employment base due to reduction of size of CCNPP workforce from 1,770 to 125	Small to Large - New construction could introduce worker population impacts on housing and public services depending on location and technology
Terrestrial ecology	Small - Changes due to license renewal not likely	Small - Some low-value (previously disturbed) habitat would be lost	Small to Moderate - Some low-value (previously disturbed) habitat would be lost	Small to Large - New construction could lose habitat due to conversion to industrial use depending on location
Waste management	Small - Category 1	Moderate- 1.5 million tons of ash and scrubber sludge a year	Small due to little combustion or pollution control byproducts	Small to Large - Depends on technology

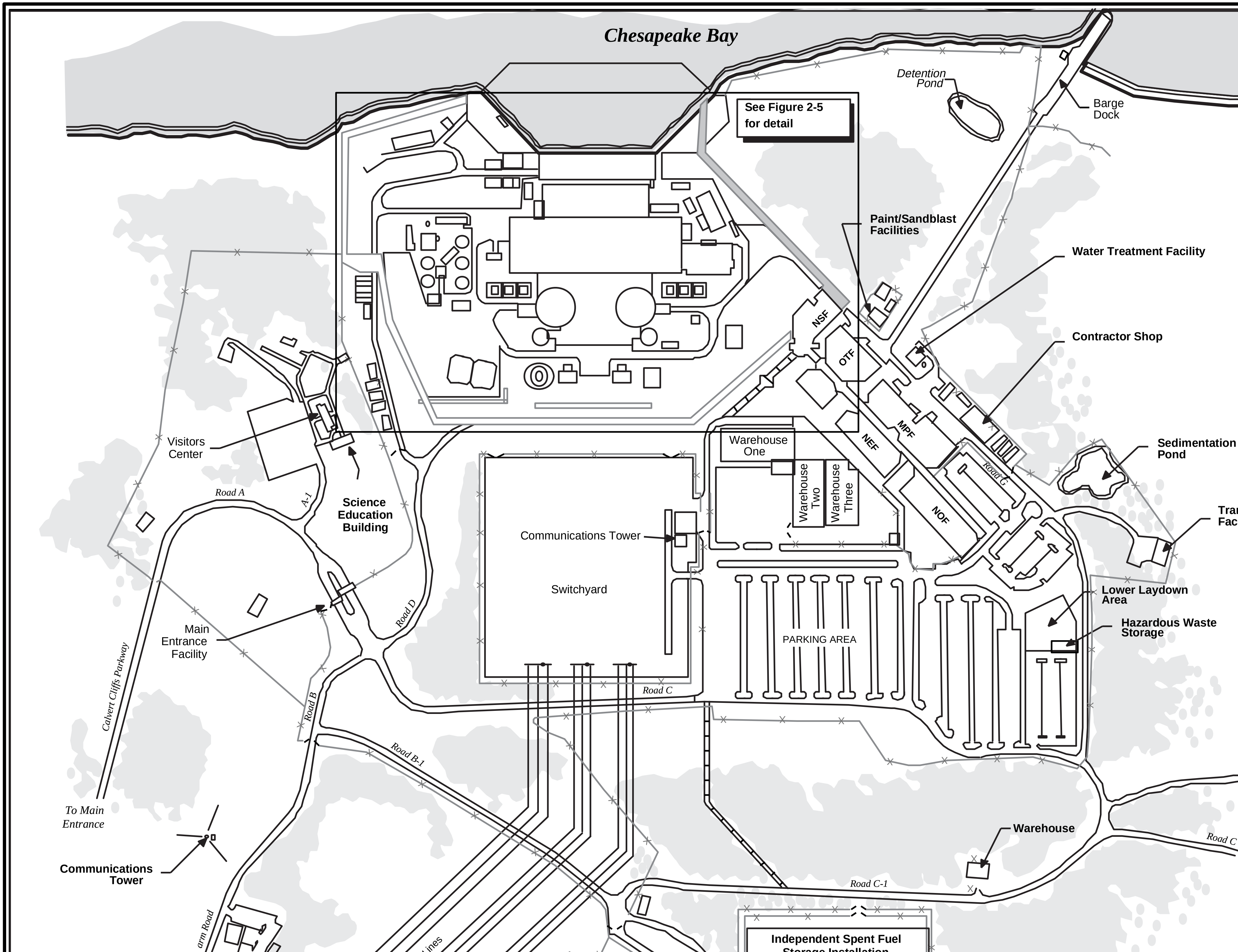
CO = carbon monoxide.
ft^3 = cubic feet.
lb = pound.
NO_x = nitrogen oxides.
scf = standard cubic foot.
SO_x = Sulfur oxides.
a. Category 1 = License renewal environmental issue that NRC has defined as small for all plants (10 CFR Part 51 Subpart A, Appendix B, Table B-1, Footnotes 2 and 3).



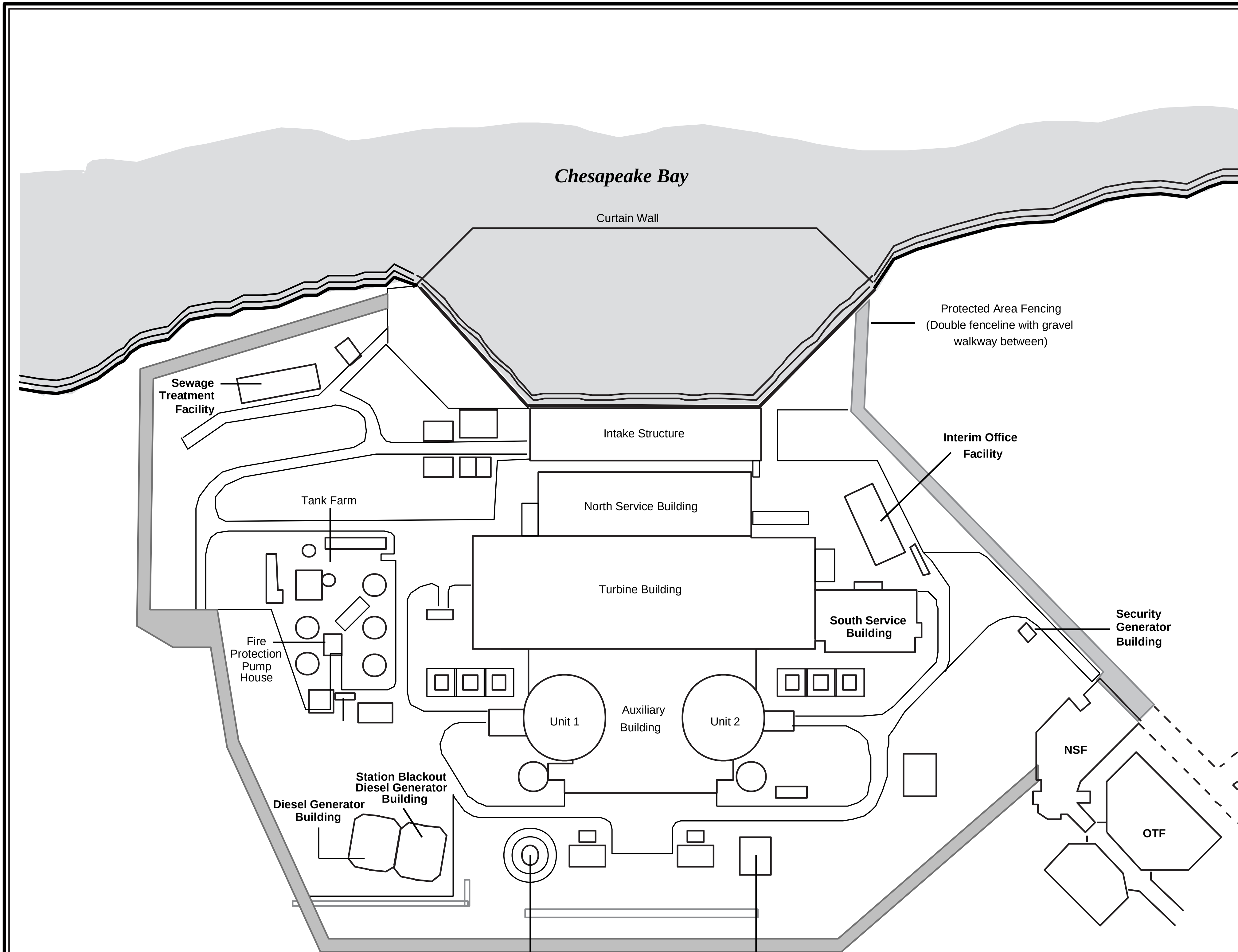
MARYLAND
DELAWAR
Waugh Chapel Substation
Annapolis
Centreville
Denton
Washington DC
Chalk Point Substation
La Plata
PATUXENT RIVER
CALVERT CLIFFS NUCLEAR POWER PLANT
Cambridge
Solomons Island
Lexington Park
POTOMAC RIVER
CHESAPEAKE BAY
Sal
Crisfield
Tappahannock
RAPPAHANNOCK RIVER
95
301
495
4
2
235
3
17


DARES BEACH
PRINCE FREDERICK
PARKER CREEK
SCIENTISTS CLIFFS
4
2
KENWOOD BEACH
ST. LEONARD
CALVERT BEACH
LONG BEACH
Flag Ponds Park
CALVERT CLIFFS NUCLEAR POWER PLANT SITE
CHESAPEAKE BAY
JAMES ISLAND
LITTLE CHOPTANK
TAYLORS ISLAND
WHITE SANDS
WALLVILLE
St. Leonard Creek
LUSBY
CALVERT CLIFFS STATE PARK
COVE POINT LIQUID NATURAL GAS PLANT
PATUXENT RIVER
BROOMES ISLAND
DRUMCLIFF
SOLLERS
COVE POINT
SOTTERLEY
HILLVILLE
235
HOLLYWOOD
CHESAPEAKE RANCH ESTATES
OLIVET
DRUM

See Figure 2-4 for detail
Chesapeake Bay
Chesapeake Bay
Approx. 1000' Chesapeake Bay Critical Area Limit
Nature Trail
Woodland
Branch
PARKWAY
CLIFFS
CAMP CONOY
ROAD C-5
ROAD C
ROAD C
ROAD F
CALVERT
ROAD B
Wetland Mitigation Area
Main Entrance
ROAD B-2
Firearm Range
Lake Davies*
Sediment Basin
Wetland
Wetland
ROAD B-1
Southern Maryland Electric Cooperative Substation
Johns
Creek
Goldstein
Branch
Lavel
Branch
To Prince Frederick
Maryland State Highway 2-4
CAMP CONOY
H.G. Trueman Road
Maryland State Highway 765
Southern Middle School
To Solomons Is



Chesapeake Bay
See Figure 2-5 for detail
Detention Pond
Barge Dock
Paint/Sandblast Facilities
Water Treatment Facility
Contractor Shop
Sedimentation Pond
NSF
OTF
MPF
NEF
NOF
Road G
Warehouse One
Warehouse Two
Warehouse Three
Visitors Center
Science Education Building
Road A
A-1
Road D
Main Entrance Facility
Communications Tower
Switchyard
Road C
PARKING AREA
Lower Laydown Area
Hazardous Waste Storage
Calvert Cliffs Parkway
Road B
Road B-1
To Main Entrance
Communications Tower
Warehouse
Road C-1
Independent Spent Fuel


Chesapeake Bay
Curtain Wall
Protected Area Fencing
(Double fenceline with gravel
walkway between)
Sewage
Treatment
Facility
Intake Structure
Interim Office
Facility
North Service Building
Tank Farm
Turbine Building
South Service
Building
Security
Generator
Building
Fire
Protection
Pump
House
Auxiliary
Building
Unit 1
Unit 2
NSF
OTF
Station Blackout
Diesel Generator
Building
Diesel Generator
Building

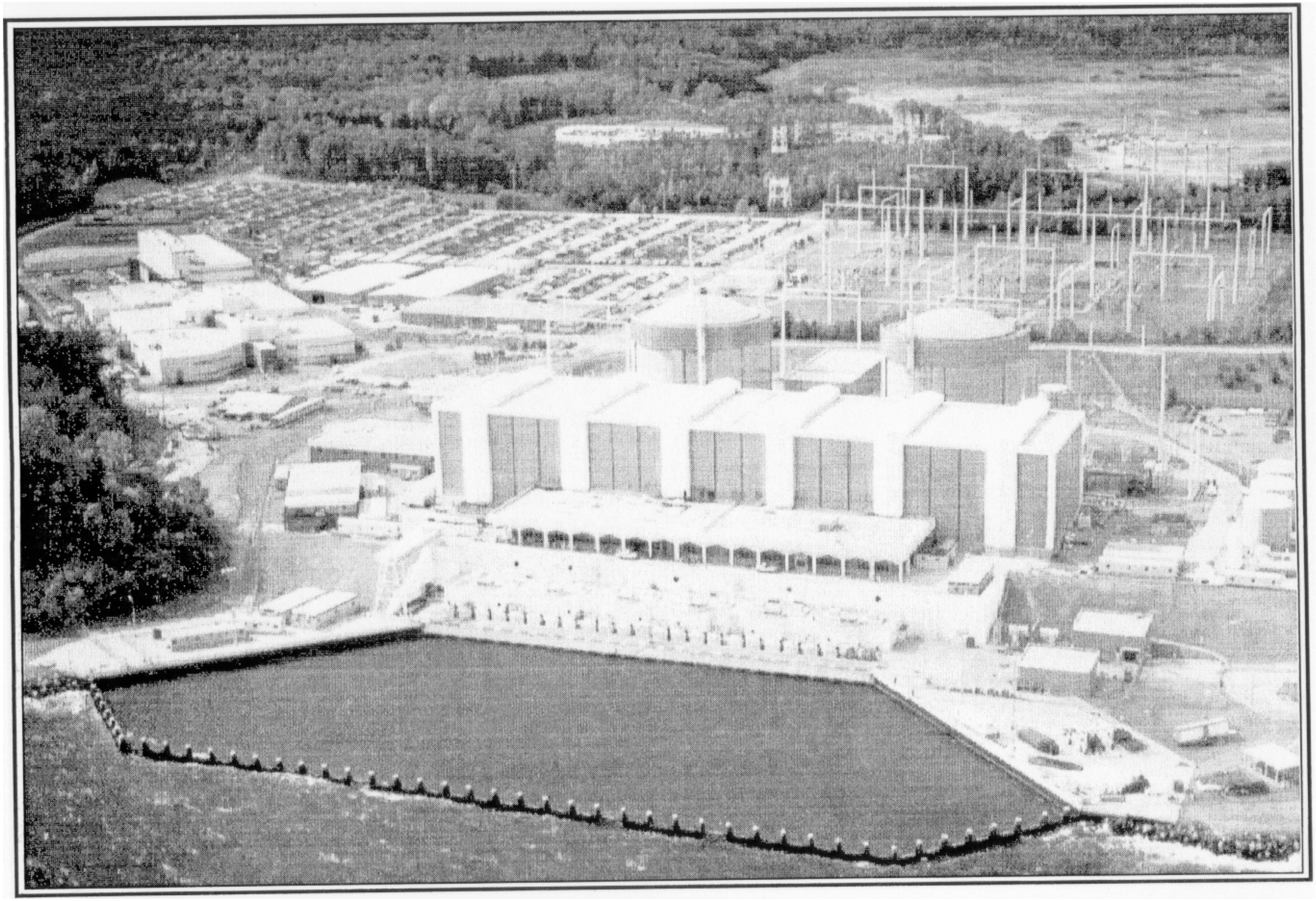
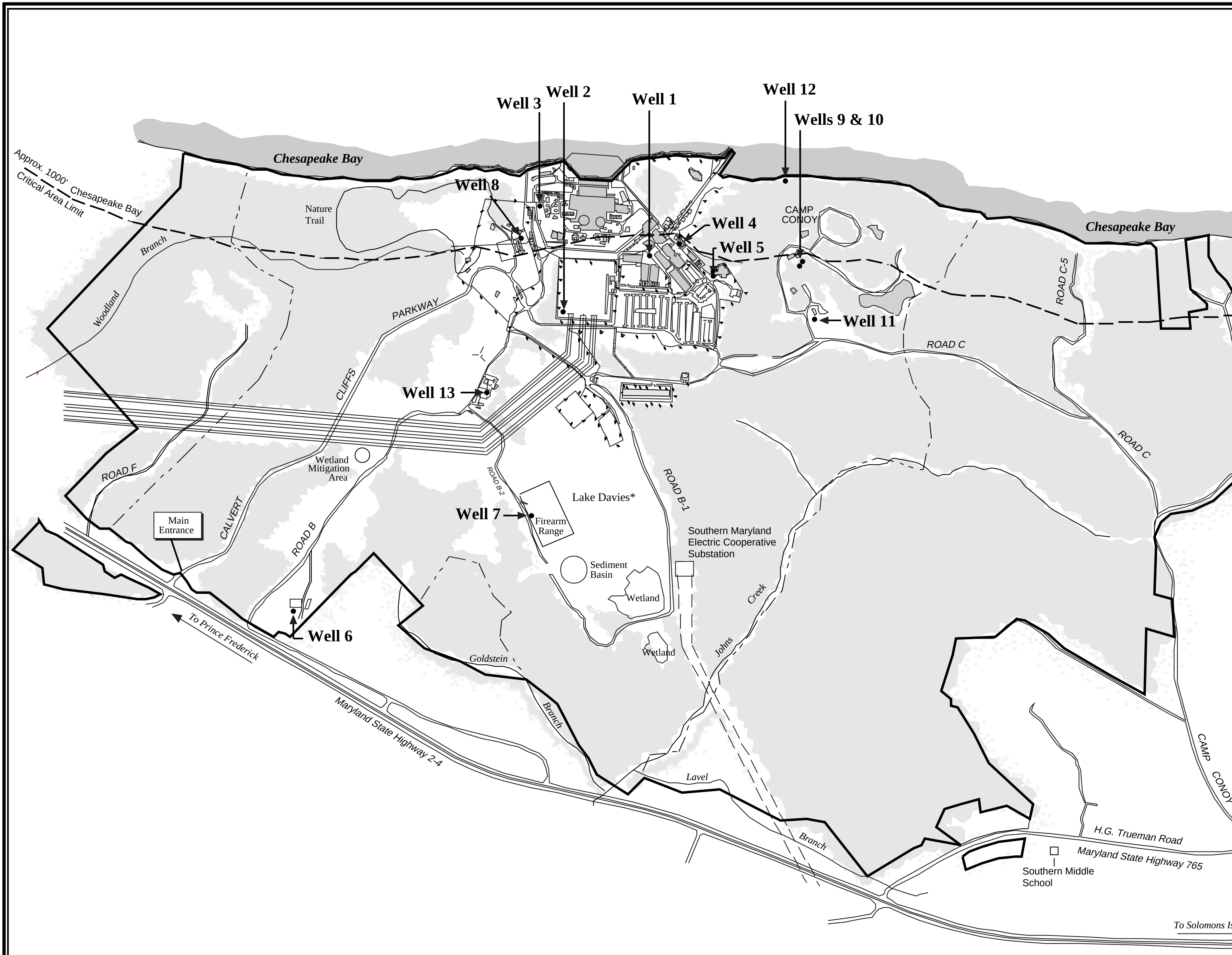


Figure 2-6. Calvert Cliffs Nuclear Power Plant.



Well 3
Well 2
Well 1
Well 12
Wells 9 & 10
Chesapeake Bay
Approx. 1000' Chesapeake Bay Critical Area Limit
Well 8
Nature Trail
Well 4
Well 5
CAMP CONOY
Chesapeake Bay
Branch
Woodland
PARKWAY
ROAD C-5
Well 11
ROAD C
CLIFFS
Well 13
ROAD C
Wetland Mitigation Area
ROAD F
ROAD B-2
ROAD B-1
Lake Davies*
Well 7
Firearm Range
Main Entrance
CALVERT
ROAD B
Southern Maryland Electric Cooperative Substation
Sediment Basin
Creek
Wetland
To Prince Frederick
Well 6
Johns
Wetland
Goldstein
Branch
Maryland State Highway 2-4
CAMP CONOY
Lavel
H.G. Trueman Road
Branch
Maryland State Highway 765
Southern Middle School
To Solomons Is

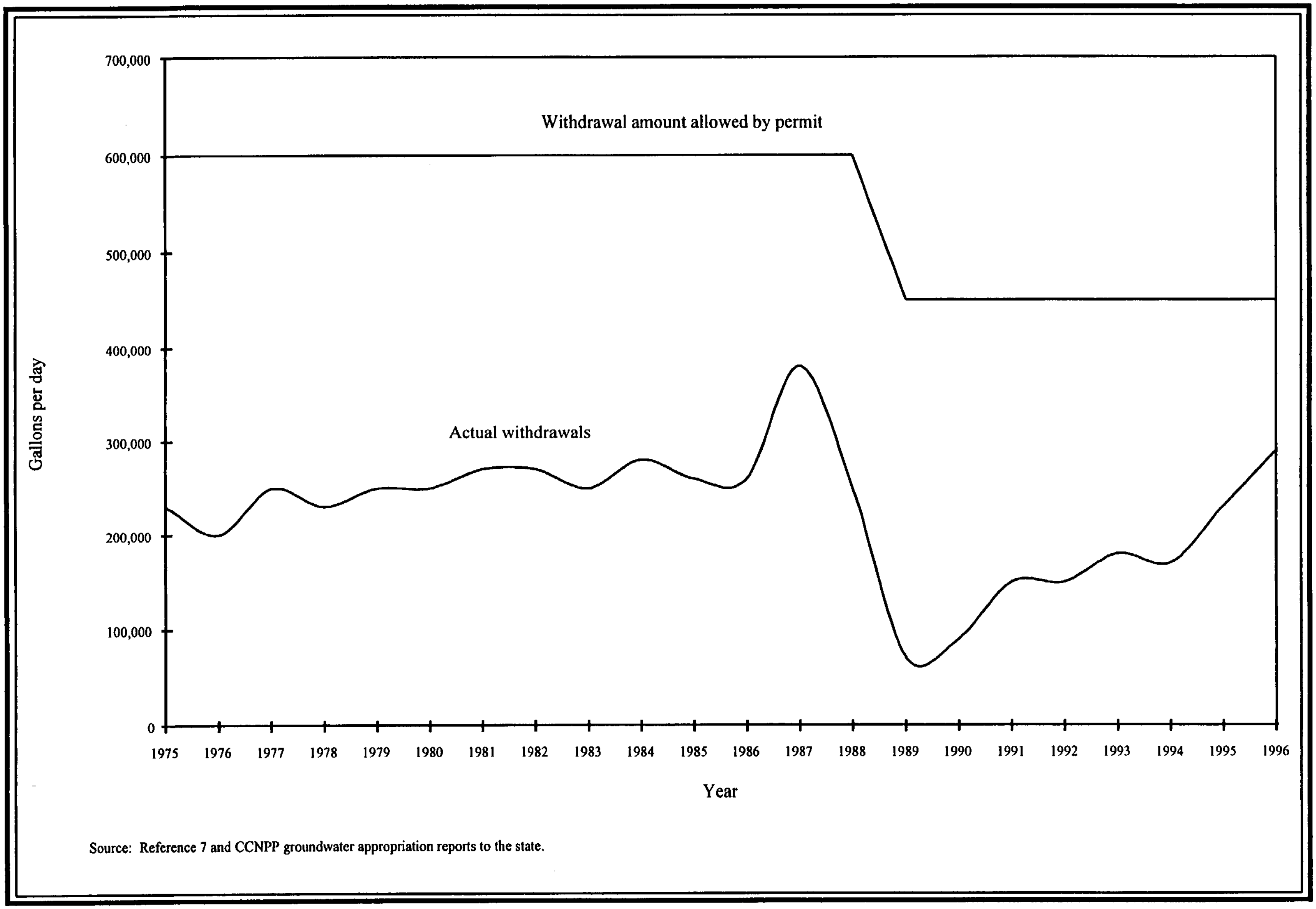


Figure 2-8. CCNPP groundwater withdrawals.

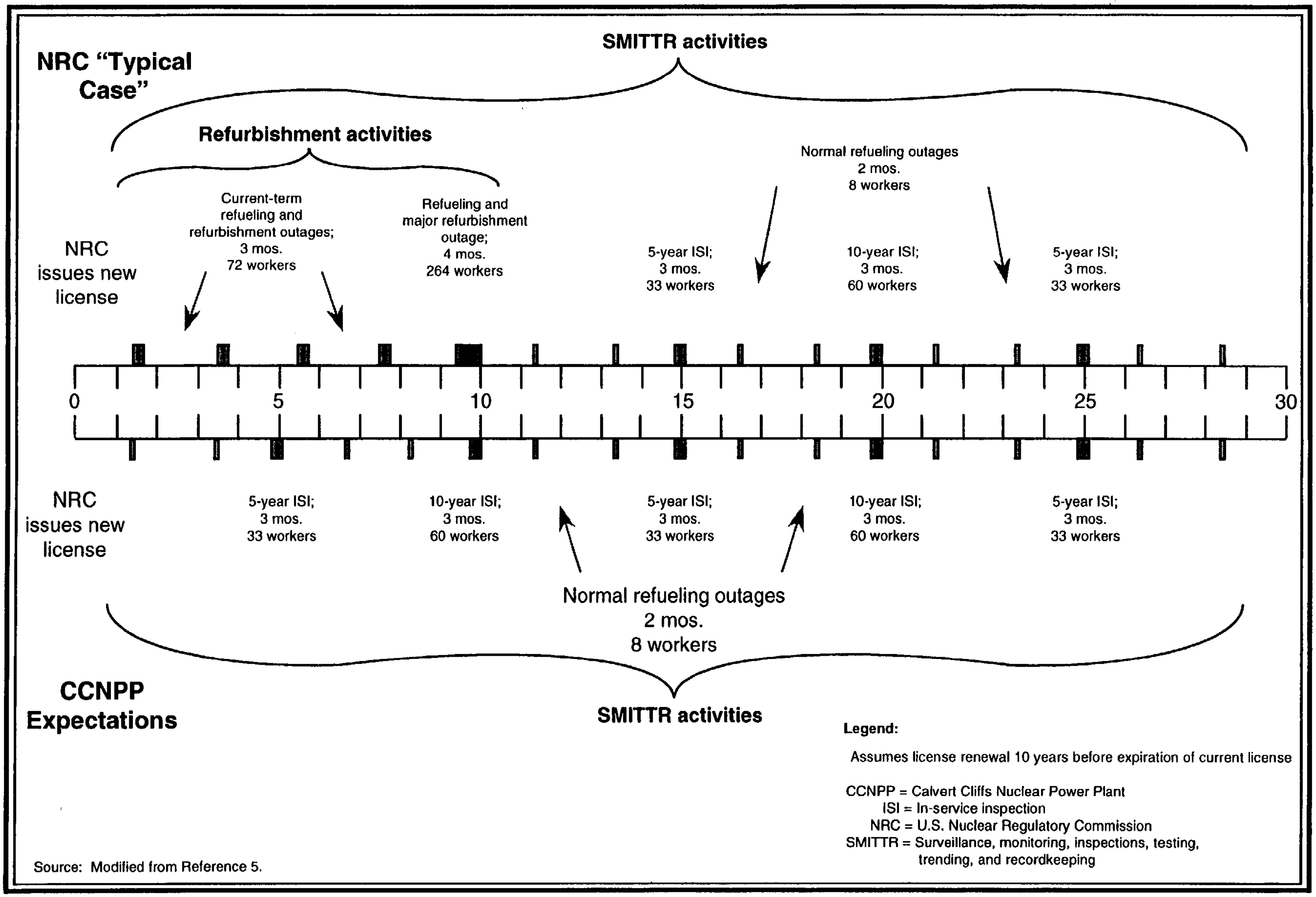


Figure 2-9. NRC assumptions and CCNPP expectations regarding plant modifications for license renewal.

3.0 AFFECTED ENVIRONMENT

3.1 Biological Resources

3.1.1 Aquatic Ecology

The CCNPP is located on the western shore of the Chesapeake Bay in the mesohaline zone (moderate salinity). Extensive characterization studies were initiated in 1968 and continued through 1972 to establish an ecological baseline for this portion of the Chesapeake Bay prior to operation of CCNPP. The FES Section II.F.2 (Reference 3) described a complex estuarine ecosystem with diverse native communities of phyto- and zooplankton, periphyton, macrobenthos, and fish; a description that remains valid today. During pre-operational surveys, recreationally and commercially important shellfish and finfish found to occur in large numbers in the vicinity of the plant included the eastern oyster, blue crab, spot, striped bass, and weakfish.

The Chesapeake Bay as a whole was once a system of vast aquatic resources; however, expanding population, development, and land use practices have resulted in the need for a concentrated restoration and management program for the Chesapeake Bay that began 14 years ago. This program, conducted through the Chesapeake Bay Agreement by the EPA's Chesapeake Bay Program, has produced tangible results. The 1996 State of the Bay Report (Reference 87) provides information on several key indicators that show the Bay's progress. For example, Bay grasses have increased 75 percent over the last 10 years, and populations of striped bass have increased dramatically.

3.1.2 Terrestrial Ecology

Final Environmental Statement Section II.F.1 provided a general description of the terrestrial ecology at CCNPP. Recently, plant communities onsite have been defined and described in detail with dominant species identified in the CCNPP License Renewal Biological Survey (Reference 88). This report describes eight plant community types on the CCNPP site including agricultural land, right-of-way, Chestnut Oak association, forested wetlands, open water and emergent wetlands, Virginia Pine association, Tulip Poplar/Sweetgum association, and old field community.

The largely forested CCNPP property is situated between two other large forested tracts to the north (Flag Ponds Park) and to the south (Calvert Cliffs State Park). Together these tracts form one of the largest contiguous and predominantly undeveloped forested areas in a region of Maryland that is characterized as a high growth area for residential and vacation home sites. In 1987, BGE foresters in consultation with the Maryland Forest, Park, and Wildlife Service developed Forest Resource Management Plans (References 89, 90, 91) for three site forested land parcels. These plans emphasize preservation and maintenance of old age hardwood species and the removal of Virginia Pine for disease and fire control. In addition, BGE has established and currently maintains a system of fire roads and fire-fighting tool caches throughout the property, and uses late summer mowing to maintain roads and log loading decks as wildlife food plots and wild turkey brooding habitat.

Final Environmental Statement Section II.F.1 described fauna that inhabit the CCNPP site to include white-tailed deer (*Odocoileus virginianus*), eastern gray squirrels (*Sciurus carolinensis*), and other common wildlife species. The State of Maryland prepared a Wildlife Management Plan for the site in 1987 that stressed management of woodlands for wild turkey and management of fields and road edges for wild turkey, bobwhite quail, and eastern cottontail rabbits. Baltimore Gas and Electric Company updated the Wildlife Management Plan in 1993 (Reference 92) to include several habitat enhancement projects including a Tiger Beetle Habitat Protection Area, an informative nature trail, Calvert Cliffs Wildlife

Habitat Committee, osprey nesting and monitoring program, bluebird nest box program, and wild turkey stocking reservoir. In recognition of the long-term commitment to wildlife habitat enhancement and preservation at CCNPP, the Wildlife Habitat Council (a non-governmental organization) certified and registered the CCNPP site as a valuable corporate wildlife habitat (Reference 93).

3.1.3 Special-Status Species

Special status species are currently protected in Maryland by two laws. On the Federal level, threatened and endangered species are protected pursuant to the Endangered Species Act of 1973. On the State level, special status species are protected pursuant to the Maryland Non-Game and Endangered Species Conservation Act (Section 10-2A-01 to Title 09 of the Annotated Code of Maryland). The purpose of these laws is to protect species of wildlife and plants that have been determined to be threatened or endangered.

One aquatic endangered species, the shortnose sturgeon (*Acipenser brevirostrum*), is known to inhabit the Chesapeake Bay. The shortnose sturgeon was first listed as an endangered species in March 1967, under the legal authority of the Endangered Species Preservation Act of 1966. The protection afforded this species under the Endangered Species Preservation Act was extended under the Endangered Species Act of 1973. Baltimore Gas and Electric Company conducted near-shore trawl surveys of fish in the vicinity of CCNPP from 1969 to 1981 and only collected small numbers of shortnose sturgeon in 1979 (Reference 94). Calvert Cliffs intake impingement studies conducted since 1975 have never collected a shortnose sturgeon. Federal and State agencies are working to reintroduce into the Chesapeake Bay the Atlantic Sturgeon (*Acipenser oxyrhynchus*), a species that the Maryland Natural Heritage Program lists as rare. Baltimore Gas and Electric Company has no record of this species at CCNPP.

On the CCNPP site, three Federally listed species presently occur and are listed as follows:

- *Cicindela puritana* - Puritan tiger beetle. This species is currently listed as threatened by the U.S. Fish and Wildlife Service and is listed as endangered by the Maryland Department of Natural Resources. This species can be found along the beach at the base of the cliffs on the CCNPP site.
- *Cicindela dorsalis* var. *dorsalis* - Northeastern beach tiger beetle. This species is currently listed as threatened by the U.S. Fish and Wildlife Service and is listed as endangered by the Maryland Department of Natural Resources. This species can be found along the beach at the base of the cliffs on the CCNPP site.
- *Haliaeetus leucocephalus* - Bald eagle. This species is currently listed as threatened by the U.S. Fish and Wildlife Service and is listed as endangered by the Maryland Department of Natural Resources. Currently, the CCNPP site has an active nest located south of Camp Conoy, and 7 offspring have fledged since 1986.

The Maryland Natural Heritage Program lists species that are rare to uncommon (occurrence between 21 and 100) and are not actively tracked by the Program as category S3 "Watch List" species (Reference 95). Two S3 species are found at CCNPP: a floating bladderwort (*Utricularia gibba*) in the littoral zone of a Camp Conoy pond and a species of milkwort (*Polygala incarnata*) along Old Field Community roads. No other known Federally listed or State listed threatened or endangered species occur on the CCNPP site.

3.2 Geology and Groundwater Hydrology

3.2.1 Geology

The following discussion summarizes geologic information in Section II.E.1 of the FES, Sections 2.4 and 2.6 of the CCNPP Updated Final Safety Analysis Report (Reference 96), and Section 2.5 of the Independent Spent Fuel Storage Installation Environmental Report (Reference 97). For additional details, see those documents.

The Calvert Cliffs site lies within the Coastal Plain Physiographic Province and is underlain by approximately 2,500 feet of sedimentary strata. Underlying these sediments are crystalline and metamorphic basement rock. There is no evidence of faulting in the site vicinity. As shown in Figure 3-1, the strata range from nearly horizontal to gently dipping to the southeast, reflecting the influence of the basement rock slope. Areas above Elevation +70[1] are Pliocene and Pleistocene silt and sand and are underlain by approximately 270 feet (Elevations +70 to -200) of the relatively impervious sediments of the Chesapeake group of Miocene age (the CCNPP power block area is Elevation +45). The Miocene-age sediments consist of horizontally stratified sandy and clayey silt with occasional interbeds of sands and shells. Approximately 350 feet of dense, relatively pervious glauconitic sand and silt of the Eocene and Paleocene age underlie the Miocene sediments (Elevations -200 to -550).

3.2.2 Groundwater Hydrology

Except as noted, the following discussion summarizes geologic information in Section V.B.1 of the FES, Sections 2.5 of the CCNPP Updated Final Safety Analysis Report (Reference 96), and Section 2.4.2 and 2.4.3 of the Independent Spent Fuel Storage Installation Environmental Report (Reference 97). For additional details, see those documents.

Table 3-1 provides a brief summary of groundwater aquifers beneath CCNPP. The site water-table occurs generally within 30 feet of the surface in Pleistocene-age deposits (above Elevation +70 at CCNPP). Groundwater flow within approximately 1,000 feet of the Chesapeake Bay at CCNPP is towards the Bay; flow west of the divide is towards surface stream valleys. Surficial soil grain size analysis suggests a maximum permeability coefficient of about 400 gpd per square foot. Use of the water-table aquifer is limited to a few domestic wells in the area. Calvert Cliffs does not withdraw from this aquifer.

Surficial deposits are underlain by approximately 250 feet of relatively impermeable deposits, the Chesapeake Group, which effectively confine the underlying artesian aquifers. The vertical component of groundwater movement through the Chesapeake Group is upward. Underlying aquifers are composed of glauconitic sand and silt of the Piney Point, Nanjemoy, and Aquia formations. The Piney Point and Nanjemoy Aquifers act as a single unit but are separated from the underlying Aquia Aquifer by a layer of clay and silt called the Nanjemoy-Marlboro confining unit. The Aquia Aquifer beneath CCNPP is approximately 100 feet thick, extending from 550 feet to 650 feet below the surface (Elevations -450 to -550).

Calvert Cliffs withdraws groundwater from the Aquia Aquifer for production and domestic uses (Section 2.1.4). This aquifer underlies much of Southern Maryland, with a recharge zone extending from Washington, DC, to Annapolis, Maryland and a downward trend to the southeast ending approximately where the Potomac River discharges to the Chesapeake Bay. The aquifer is artesian, which means that

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1 Elevations are in feet above (+) or below (-) mean sea level.

hydrostatic pressure within the formation will support a static water level that is higher in elevation than the top of the aquifer. Hydraulic gradients range from 2 feet per mile (0.0004 feet per foot) northwest of the plant to 4 feet per mile (0.0008 feet per foot) south and southwest of the plant.

Baltimore Gas and Electric Company has performed an aquifer test at one well completed in the Aquia Aquifer at the site (Reference 98). Three observation wells located at different distances from the pumping well were used in the test. Hydraulic properties obtained from this test include the transmissivity and storage coefficient of the Aquia Aquifer at each well location. Transmissivity values obtained from this test ranged from 5,640 gpd per foot to 7,400 gpd per foot. Storage coefficient values ranged from 0.000108 to 0.000251, indicating that the aquifer is confined beneath the site.

The U.S. Geological Survey and the Maryland Department of Natural Resources (Maryland Power Plant Research Program and Maryland Geological Survey) maintain a joint monitoring program of the Aquia Aquifer. This program has tracked and reported on the groundwater levels at CCNPP since 1975. In its most recent (1996) biennial report, the Maryland Power Plant Research Program indicates that during the first ten years of CCNPP operation, water level fluctuation in the Aquia Aquifer measured near the CCNPP correlated with pumping rates at the plant. Since 1989, monitoring indicates that pumping at CCNPP has not directly affected the water level in the Aquia Aquifer. Calvert Cliffs groundwater withdrawals in 1989 and 1990 were significantly lower due to the reactors not operating. During the shutdown when withdrawals were the lowest, water levels dropped sharply by approximately 25 feet, and then rose 4 feet in early 1992, only to drop an additional 12 feet by the end of 1993. During this time, groundwater withdrawals at CCNPP remained consistent with 1991 pumping rates (Figures 2-8 and 3-3). These data suggest that water levels at CCNPP are affected by pumping elsewhere. The study concludes that groundwater withdrawals in the Lexington Park and Solomons Island areas, including the Patuxent Naval Air Station, are responsible for the recent declines in the water levels at CCNPP, but that these declines are small compared to the available drawdown that remains in the Aquia Aquifer (Reference 7).

Calvert Cliffs' pre-construction static water level measurements of the Aquia aquifer ranged from -3 feet to -42 feet mean sea level (Reference 98). Calvert Cliffs' groundwater usage began with construction, but routine water table measurements did not begin until 1975, when the first unit was operating. By the end of 1976, once both units were operating, Aquia water levels had declined approximately 10 feet to Elevation -24 (Reference 99). Currently, Aquia water levels are approximately Elevation -60 (Reference 7). This means that there are approximately 490 feet of groundwater in the Aquia Aquifer beneath CCNPP (550 - 60 = 490). Figure 3-2 presents the Aquia Aquifer regional potentiometric[2] surface levels, and Figure 3-3 shows the historical decline at CCNPP.

By regulation, Maryland limits groundwater withdrawals to 80 percent of the drawdown available between the top of confined aquifers such as the Aquia and the historical pre-pumping level of the potentiometric surface [Code of Maryland Regulations (COMAR) 26.17.06.05D(3)]. The U.S. Geological Survey and the Maryland Geological Survey have used historical (1896 - 1953) data to establish the historical pre-pumping level in the CCNPP vicinity as approximately 10 feet above mean sea level (Reference 100). The top of the Aquia Aquifer at CCNPP being at -450 feet mean sea level, the historical total available draw-down at the site is 368 feet [(10 + 450) x 0.8 = 368]. Given the current Aquia water level being Elevation -60, approximately 300 feet of regulatorily available drawdown remain [368 - (10 + 60) = 298].

2 The "potentiometric surface" is the elevation of groundwater in an open, un-pumped well. Due to the effect of confining layers above the Aquia Aquifer, the Aquia potentiometric surface is higher than the aquifer itself. This results in an artesian condition.

Formations below the Aquia are either not known to be aquifers in Southern Maryland or are not utilized in Calvert County because of their depth. Section 2.4 of the CCNPP Updated Final Safety Analysis Report provides descriptive information about the formations.

3.3 Air Quality

Calvert County, in which CCNPP is located, is in attainment with all National Ambient Air Quality Standards except for ozone (40 CFR 81.321). Calvert County is classified as serious non-attainment for ozone due to its proximity to the Washington, DC, area (Reference 101). In areas classified as "serious" non-attainment for ozone, facilities are classified as major sources of volatile organic compounds and nitrogen oxides if their potential to emit equals or exceeds 50 tons per year of either pollutant (57 FR 55622). Due to the presence of the EDGs, CCNPP has the potential to emit greater than 50 tons per year for both volatile organic compounds and nitrogen oxides, and the facility is classified as a major source of volatile organic compounds and nitrogen oxides.

3.4 Housing

Between 1970 and 1990, total housing units in Calvert County increased from 7,932 to 18,974 (Reference 102). Approximately 10 percent of this growth may be attributable to the influx of the 1,062 CCNPP employees who live in Calvert County (Section 2.1.7). Based on the Maryland employment multiplier (3.9997, Reference 6), CCNPP may have accounted for more than 4,200 direct and indirect job additions to the County labor force and 40 percent of the housing growth in the County. Between 1980 and 1990, the number of housing units in the Tri-County (Calvert, St. Mary's, and Charles) area increased approximately 43 percent to a total of 81,320 units. Housing availability in the Tri-County area is not limited by growth-control measures. With a current vacancy rate of approximately 7 percent, over 5,700 of these units are available for occupancy (Reference 102).

3.5 Public Services

3.5.1 Public Utilities

Nearly all potable water used in Calvert County is from subsurface sources and is used primarily for domestic and agricultural purposes. There are 22 privately owned residential community water systems, 17 municipally owned water systems, and 24 water systems owned by corporations or institutions. Table 3-2 lists average output and depth of selected water supply systems in communities near CCNPP, as well as the estimated population served by each. The normal output from these systems is relatively small but increases substantially in the summer to accommodate seasonal increases in population (Reference 103).

In Southern Maryland, the majority of the public water supply is drawn from the Aquia Aquifer. There are some water supply systems starting to experience supply problems in the southern portion of the Tri-County area, specifically in the Solomons Island and Lexington Park areas (Figure 2-1). These systems both withdraw water from the Aquia Aquifer with an average daily output of 225,000 and 1,203,000 gpd, respectively (See Table 3-2). As a result of this large demand, the potentiometric surface in this area has dropped more than 30 feet in the last 10 years (Reference 101).

3.5.2 Education

In 1990, there were approximately 48,000 students enrolled in schools in the Tri-County area (Reference 102). In Charles County, there are 19 elementary, 6 middle, 5 high, and 17 private schools. Enrollment for the 1995-1996 school year was approximately 23,571 with approximately 15 students per teacher (Reference 104). In St. Mary's county, there are 15 elementary, 5 middle, 3 high, and 28 private schools. During the 1995-1996 school year, total enrollment in St. Mary's County was 17,268 with an average of 14 students per teacher (Reference 105).

In Calvert County, there are a total of 10 elementary, 4 middle, 3 high, and 10 private schools. During the 1995-1996 school year, total enrollment was approximately 14,332. During this period the average number of students per teacher was 16 (Reference 106). Given the rapid growth projected for Calvert County, enrollment is expected to reach 17,000 by the year 2000. Consequently, there are currently five construction projects in progress or anticipated, including the construction of two new schools in the next five years (Reference 107).

3.5.3 Transportation

Calvert County has one main four-lane road (Maryland State Highway 2-4) bisecting the County north to south with smaller roads running like veins from the main road to the water on each side. Very few of the smaller roads off Maryland Highway 2-4 connect with each other; therefore, this highway services the bulk of the traffic for the length of the County. This highway runs adjacent to the CCNPP site and provides the only access to the site (Figure 2-3).

3.6 Offsite Land Use

Final Environmental Statement Section II.C briefly discussed CCNPP regional land use. Figures 2-1 and 2-2 show the CCNPP location and general features of the surrounding area. The region surrounding the CCNPP site continues to be predominately rural in character (Table 3-3). However, since the FES was written, residential and light commercial development in Calvert County has increased, and the amount of land dedicated to farming, forests, and open space has declined (FES Section II anticipated the decline in agricultural land usage). Since 1970, open space has been converted to residential use at an average rate of nearly 1,000 acres per year. As a result of this trend, farmland in the County declined from approximately 63,000 acres to 49,000 acres between 1969 and 1982 (Reference 108). By 1992, the amount of farmland had declined to approximately 37,000 acres (Reference 109). Currently, Calvert County has adopted several land preservation and open space plans in order to preserve the rural character of the County. These programs include large-lot zoning and the Calvert County Agricultural Preservation Program (Reference 108).

Commercial, industrial, institutional, and utility development accounts for less than five percent of the County's land use. Commercial development is concentrated in and near Town Centers. Town Centers were created in 1983 as part of the implementation of the Calvert County Comprehensive Plan. Rather than allow commercial development to sprawl along Maryland Highway 2-4, this plan directs commercial growth towards Town Centers that can provide services and infrastructure, and away from environmentally-sensitive areas and farms (Reference 22).

Agriculture has been an important part of Calvert County's economy since the late 1600s. In particular, the western portion of the County, which is characterized by fields and meadows along the Patuxent River, is well suited to agriculture. Tobacco is the County's first and oldest farm product of major importance, but Calvert County tobacco production has declined due to increased competition by growers elsewhere and decreased demand for tobacco products (Reference 107). Because a large portion of the area within 50 miles of the plant is rural and forested, hunting continues to be common throughout the region (FES Section II.F.1). Popular game sought in the area include deer, turkey, geese, duck, squirrel, quail, and rabbit (Reference 110).

3.7 Cultural Resources

There are eight historic sites within a five-mile radius of CCNPP listed on the National Register of Historic Places. As described in FES Sections II.D and XII.E, two historic dwellings located on the original Calvert Cliffs site were evaluated by the Maryland Historical Trust and found to be too derelict to be nominated for inclusion on the National Register. However, photographs and some architectural elements of the structures were salvaged and are displayed in the Visitors Center (a remodeled old tobacco barn) onsite.

During 1992 and 1993, archeological surveys were conducted along a proposed South Circuit transmission line and right-of-way (Section 2.1.5). As a result, two archeological sites were examined extensively during an evaluatory testing phase. One prehistoric site was found to retain sufficient subsurface integrity to be considered eligible for inclusion on the National Register of Historic Places. The impact areas of the site were evaluated extensively, and towers were located in areas that would not affect any intact subsurface deposits (References 111, 112).

From the air, the principal visual features of the CCNPP region are the Chesapeake Bay, the Patuxent River, and countryside that is generally wooded. The distance across the Bay in the vicinity of CCNPP is approximately 6 miles and, from the shore, the far shore is a dark line on the horizon; the view up- or down-Bay is water to the horizon. From the Bay, the shoreline is wooded with widely spaced small housing developments and marinas. The CCNPP site has a 1,500-foot wide developed area approximately in the middle of 6 miles of undeveloped, wooded shoreline featuring 100-foot cliffs. These scenic resources have remained unchanged since CCNPP construction.

Scenic resources inland have changed since CCNPP construction due to area population growth. This growth has resulted in housing, commercial, and road development supplanting agricultural and wooded areas. However, Maryland Highway 2-4, which transects the area, is a State scenic highway, affording views of gently rolling, wooded countryside with interspersed development and occasional agricultural lands. Calvert Cliffs is not visible from Maryland Highway 2-4 due to intervening woods and topography.

3.8 Demography

Final Environmental Statement Section II.C estimated resident population within 50 miles of CCNPP for the years 1970 and 2010. As discussed further in Section 3.8.2, the FES projection for the year 2010 is approximately 20 percent higher than the current estimate, and is approximately the same as the current projection for the end of the license renewal period.

Sections 3.8.1 and 3.8.2 estimate resident population for 1990 and each decade through the proposed CCNPP license renewal term (2010, 2020, 2030, and 2040). The 2010 projections represent estimated population near the first year of license renewal for Unit 1 (2014), and the projections for the year 2040 represent population near the end of the renewal term (2036 for Unit 2).

Data for 1990 are based on the 1990 Census of Population (Reference 113). Projections are based on county population projections provided by State planning agencies in Delaware, Maryland, Virginia, and

Washington, DC. With the exception of Virginia, agency projections extend through the year 2020 for counties in the 50-mile radius. Agency projections for Virginia extend only to the year 2010. Projections for the remaining years in the renewal period are based on the assumption that the projected rate of population growth in each county would continue at the same rate as that projected for the last decade in the agency forecast (i.e., the rate of change from 2010 to 2020 is used as the rate of change for 2020 through 2040 for Delaware, Maryland, and Washington, DC, and the rate of change from 2000 to 2010 is used as the rate of change for 2010 through 2040 for Virginia).

3.8.1 Resident Population Within 10 Miles

The estimated resident population distribution within 10 miles of CCNPP for the years 1990, 2010, 2020, 2030, and 2040 is listed in Tables 3-4 through 3-8. Figure 3-4 illustrates the locations of the sectors identified in these tables.

Between 1970 and 1990, the population within 10 miles of CCNPP increased almost 50 percent to approximately 36,000 (Table 3-4). Current projections indicate that by the year 2010, the population within 10 miles will be about 63,000 (Table 3-5), which is approximately 5 percent higher than the FES estimate. The higher growth in the 10-mile radius is primarily related to rapid population growth in Calvert County, Maryland. Between 1980 and 1990, Calvert County was the second fastest growing county in the State. According to agency projections, it is expected to be the fastest growing county in the State through the year 2020 (Reference 22). Factors stimulating growth in Calvert County include proximity to the Washington, DC, and Baltimore metropolitan areas (1 to 1½-hour commute by car), less development and lower taxes than those areas, and less stringent land use, zoning, and development regulations compared to surrounding counties (Reference 22). Near the end of the license renewal term (2040), the population within 10 miles of CCNPP is expected to be approximately 124,000 (Table 3-8).

3.8.2 Resident Population Between 10 and 50 Miles

The estimated resident population distribution within 50 miles of CCNPP for the years 1990, 2010, 2020, 2030, and 2040 is listed in Tables 3-9 through 3-13. Figure 3-5 illustrates the locations of the sectors identified in these tables.

Between 1970 and 1990, the population within 50 miles of CCNPP increased approximately 30 percent to about 3,086,000 (Table 3-9). Current projections indicate that by the year 2010, the population within 50 miles will be approximately 3,718,000 (Table 3-10), which is about 20 percent lower than the FES estimate. This difference may be attributed to slower than expected growth in the Washington, DC, metropolitan area. In fact, the FES population estimate of 4,757,810 for the year 2010 is higher than the current projection of 4,719,000 (Table 3-13) for the year 2040. During the license renewal period, major growth areas within the 50-mile radius include Calvert, Charles, and Queen Anne's Counties in Maryland, and Stafford County in Virginia.

Table 3-14 lists the age distribution of the Calvert County population in 1992 compared to the United States population. Given the similarity in the percentage distribution for both areas, the projected percentage age distribution for the United States population in 2030 (approximately the mid-point of the license renewal term) can be used to estimate the age distribution of the population in the region surrounding the plant in the year 2030. Table 3-15 shows the projected percentage age distribution for the United States population and the estimated age distribution of the population within 10 and 50 miles of CCNPP in 2030. As shown, the population under the age of 18 is expected to represent approximately 24 percent of the total population. The largest group is expected to be comprised of individuals aged 18 to 44 years.

3.8.3 Transient Population

The transient population in the vicinity of CCNPP can be classified as daily or seasonal. Daily transients are associated with places where a large number of people gather regularly, such as local businesses, industrial facilities, and schools. Seasonal transients result from the use of recreational areas such as parks, museums, and marinas in the area. It is estimated that seasonal transients increase the Calvert County population by approximately 23 percent during the summer months (Reference 97). The daily and seasonal population associated with selected industry and recreation within 10 miles of the station is listed in Table 3-16.

Table 3-1
CALVERT COUNTY AQUIFERS[a]

Geologic Age	Description	Physical Description	Water-Bearing Properties	Thickness in Region (feet)	Approximate Elevation at CCNPP[b]
Pleistocene	Surficial deposits	Silt, sand, and some clay	Small quantities of water to shallow wells.	0 - 150	Above +70
Miocene	Chesapeake Group	Sandy and clayey silt	Yields small amounts of water in a few dug wells.	30 - 325	Between +70 and -200
Eocene	Piney Point Formation	Glauconitic sand	Yields up to 200 gpm. Important aquifer in Calvert County.	0 - 60	Between -200 and -240
	Nanjemoy Formation	Glauconitic sand with clayey layers	Yields up to 60 gpm reported. Important aquifer in Calvert County.	40 - 240	Between -240 and -300
	Nanjemoy-Marlboro	Clay, silt	Confining unit.	0 - 700	Between -300 and -450
Paleocene	Aquia Formation	Green to brown glauconitic sand	Yields up to 300 gpm. Important aquifer in Southern Maryland.	30 - 200	Between -450 and -550

a. Sources: References 96, 114.
b. Elevations are in feet above (+) or below (-) mean sea level.

Table 3-2
PUBLIC SUPPLY WELLS IN CALVERT COUNTY IN 1992[a]

Location	Population Served	Average Output (gpd)	Depth (feet)
Beaches Water	2,000	126,000	262-585
Calvert Beach	222	17,000	262-323
Cavalier County	402	45,000	542-552
Chesapeake Beach	2,500	199,000	373-550
Chesapeake Heights	612	55,000	475-595
Chesapeake Ranch Estates	3,000	225,000	355-678
Dares Beach	501	38,000	272-530
Hunting Hills	150	14,000	365-504
Kenwood Beach	255	21,000	365
Lakewood	260	23,000	335-425
Lexington Park[b]	NA[c]	1,203,000	550-600
Mason Road	50	5,000	542
Paris Oaks	147	13,000	413
Parkers Creek Knolls	30	2,000	340
Patuxent Naval Air Station[b]	NA	616,000	450-550
Prince Frederick	600	114,000	540-605
Randle Cliffs	150	1,000	NA
St. Leonard	100	12,000	603
Scientists Cliffs	500	45,000	227-633
Shores of Calvert	414	30,000	473
Solomons Island	2,000	225,000	330-430
Summit	500	40,000	480-548
Wallville Acres	21	2,000	NA
Western Shores	175	22,000	NA
White Sands	120	7,000	389

a. Source: Reference 103, except as noted.
b. Source: Reference 115. Located in St. Mary's County but included due to significance of output and proximity to CCNPP.
c. NA = not available.

Table 3-3
LAND USE IN CALVERT COUNTY IN 1993[a]

Use	Acres	Percent of Total
Farms and forests	87,394	62.0 percent
Parks and open space	4,229	3.0 percent
Institutions and utilities	4,229	3.0 percent
Residential	42,287	30.0 percent
Commercial	1,410	1.0 percent
Industrial	1,410	1.0 percent
Total	140,959	100.0 percent

a. Source: Reference 22.

Table 3-4
ESTIMATED POPULATION DISTRIBUTION IN 1990 WITHIN 10 MILES OF CCNPP[a]

Sector[b]	0-1 Mile	1-2 Miles	2-3 Miles	3-4 Miles	4-5 Miles	5-10 Miles	10-Mile Total
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	2	2
ENE	0	0	0	0	0	169	169
E	0	0	0	0	0	197	197
ESE	0	0	0	0	0	71	71
SE	2	38	84	130	105	0	359
SSE	52	180	300	420	539	1,130	2,621
S	58	179	297	410	525	8,211	9,680
SSW	58	180	279	383	424	6,705	8,029
SW	59	175	273	331	142	2,665	3,645
WSW	58	175	264	151	212	2,001	2,861
W	58	176	236	218	278	1,344	2,310
WNW	55	170	189	216	278	2,254	3,162
NW	13	68	80	120	198	2,298	2,777
NNW	0	0	0	0	0	474	474
Total	413	1,341	2,002	2,379	2,701	27,521	36,357

a. Source: Derived from Reference 113.
b. Figure 3-4 indicates location of sector.

Table 3-5
PROJECTED POPULATION DISTRIBUTION IN 2010 WITHIN 10 MILES OF CCNPP[a]

Sector[b]	0-1 Mile	1-2 Miles	2-3 Miles	3-4 Miles	4-5 Miles	5-10 Miles	10-Mile Total
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	2	2
ENE	0	0	0	0	0	179	179
E	0	0	0	0	0	209	209
ESE	0	0	0	0	0	75	75
SE	3	70	155	240	194	0	662
SSE	96	332	554	776	996	1,825	4,579
S	107	331	548	757	970	14,868	17,581
SSW	107	332	515	708	784	11,022	13,468
SW	109	323	504	612	261	3,524	5,333
WSW	107	322	488	277	392	2,733	4,319
W	107	324	435	402	514	2,450	4,232
WNW	101	313	347	399	514	4,167	5,841
NW	24	124	147	221	366	4,248	5,130
NNW	0	0	0	0	0	875	875
Total	761	2,471	3,693	4,392	4,991	46,177	62,485

a. Source: Derived from Reference 116.
b. Figure 3-4 indicates location of sector.

Table 3-6
PROJECTED POPULATION DISTRIBUTION IN 2020 WITHIN 10 MILES OF CCNPP[a]

Sector[b]	0-1 Mile	1-2 Miles	2-3 Miles	3-4 Miles	4-5 Miles	5-10 Miles	10-Mile Total
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	2	2
ENE	0	0	0	0	0	182	182
E	0	0	0	0	0	213	213
ESE	0	0	0	0	0	76	76
SE	4	90	200	309	250	0	853
SSE	123	429	715	1,001	1,285	2,217	5,770
S	138	426	707	977	1,250	19,011	22,509
SSW	138	429	664	913	1,011	13,502	16,657
SW	140	416	650	789	337	3,818	6,150
WSW	138	417	629	359	505	3,024	5,072
W	138	419	562	519	662	3,142	5,442
WNW	131	404	450	515	662	5,374	7,536
NW	30	161	190	286	472	5,479	6,618
NNW	0	0	0	0	0	1,129	1,129
Total	980	3,191	4,767	5,668	6,434	57,169	78,209

a. Source: Derived from Reference 116.
b. Figure 3-4 indicates location of sector.

Table 3-7
PROJECTED POPULATION DISTRIBUTION IN 2030 WITHIN 10 MILES OF CCNPP[a]

Sector[b]	0-1 Mile	1-2 Miles	2-3 Miles	3-4 Miles	4-5 Miles	5-10 Miles	10-Mile Total
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	2	2
ENE	0	0	0	0	0	185	185
E	0	0	0	0	0	216	216
ESE	0	0	0	0	0	77	77
SE	6	116	258	399	322	0	1,101
SSE	159	553	922	1,291	1,657	2,712	7,294
S	178	550	912	1,260	1,614	24,338	28,852
SSW	178	553	857	1,177	1,303	16,640	20,708
SW	181	537	839	1,017	436	4,138	7,148
WSW	178	537	811	464	651	3,358	5,999
W	178	540	725	669	854	4,034	7,000
WNW	169	521	580	664	854	6,929	9,717
NW	39	209	245	368	608	7,065	8,534
NNW	0	0	0	0	0	1,456	1,456
Total	1,266	4,116	6,149	7,309	8,299	71,150	98,289

a. Source: Derived from Reference 116.
b. Figure 3-4 indicates location of sector.

Table 3-8
PROJECTED POPULATION DISTRIBUTION IN 2040 WITHIN 10 MILES OF CCNPP[a]

Sector[b]	0-1 Mile	1-2 Miles	2-3 Miles	3-4 Miles	4-5 Miles	5-10 Miles	10-Mile Total
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	2	2
ENE	0	0	0	0	0	187	187
E	0	0	0	0	0	219	219
ESE	0	0	0	0	0	79	79
SE	7	150	333	515	416	0	1,421
SSE	206	713	1,189	1,665	2,137	3,336	9,246
S	229	709	1,177	1,624	2,080	31,195	37,014
SSW	229	713	1,105	1,518	1,681	20,622	25,868
SW	233	693	1,082	1,312	562	4,483	8,365
WSW	229	693	1,046	597	840	3,743	7,148
W	229	697	935	863	1,102	5,181	9,007
WNW	218	672	748	856	1,102	8,936	12,532
NW	51	269	317	475	785	9,110	11,007
NNW	0	0	0	0	0	1,878	1,878
Total	1,631	5,309	7,932	9,425	10,705	88,971	123,973

a. Source: Derived from Reference 116.
b. Figure 3-4 indicates location of sector.

Table 3-9
ESTIMATED POPULATION DISTRIBUTION IN 1990 WITHIN 50 MILES OF CCNPP[a]

Sector[b]	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	50-Mile Total
N	0	0	4,755	103,099	154,220	262,074
NNE	0	199	9,621	24,321	8,205	42,346
NE	2	1,979	13,694	15,302	12,862	43,839
ENE	169	10,449	19,585	8,998	22,817	62,018
E	197	958	1,051	6,137	60,307	68,650
ESE	71	361	416	26,220	18,838	45,906
SE	359	1	14	663	13,502	14,539
SSE	2,621	1,266	635	12,844	479	17,845
S	9,680	13,864	7,475	12,564	13,779	57,362
SSW	8,029	13,829	13,962	6,458	14,588	56,866
SW	3,645	7,222	21,808	5,836	5,243	43,754
WSW	2,861	10,129	4,757	26,296	6,836	50,879
W	2,310	10,488	16,982	25,813	42,789	98,382
WNW	3,162	7,764	41,305	52,317	262,046	366,594
NW	2,777	9,051	16,050	223,107	1,244,547	1,495,532
NNW	474	13,018	42,692	68,978	234,075	359,237
Total	36,357	100,578	214,802	618,953	2,115,133	3,085,823

a. Source: Derived from Reference 113.
b. Figure 3-5 indicates location of sector.

Table 3-10
PROJECTED POPULATION DISTRIBUTION IN 2010 WITHIN 50 MILES OF CCNPP[a]

Sector[b]	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	50-Mile Total
N	0	0	5,684	122,158	180,326	308,168
NNE	0	230	11,147	32,781	11,077	55,235
NE	2	2,107	15,865	17,832	15,465	51,271
ENE	179	11,123	20,987	9,882	30,274	72,445
E	209	1,019	1,117	7,157	73,078	82,580
ESE	75	383	442	30,930	22,239	54,069
SE	662	1	14	780	15,895	17,352
SSE	4,579	1,672	839	16,514	550	24,154
S	17,581	18,338	9,833	15,510	15,721	76,983
SSW	13,468	18,290	17,830	7,144	15,628	72,360
SW	5,333	9,551	26,877	6,813	5,432	54,006
WSW	4,319	13,396	6,804	38,057	8,682	71,258
W	4,232	13,907	24,538	40,493	66,623	149,793
WNW	5,841	12,064	65,890	75,829	361,175	520,799
NW	5,130	16,374	22,121	270,772	1,349,440	1,663,837
NNW	875	24,069	55,006	82,903	280,590	443,443
Total	62,485	142,524	284,994	775,555	2,452,195	3,717,753

a. Sources: Derived from References 116, 117, 118, 119.
b. Figure 3-5 indicates location of sector.

Table 3-11
PROJECTED POPULATION DISTRIBUTION IN 2020 WITHIN 50 MILES OF CCNPP[a]

Sector[b]	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	50-Mile Total
N	0	0	5,954	127,647	187,707	321,308
NNE	0	240	11,650	35,504	11,998	59,392
NE	2	2,140	16,580	18,669	16,321	53,712
ENE	182	11,297	21,363	10,142	32,382	75,366
E	213	1,035	1,134	7,505	77,285	87,172
ESE	76	389	449	31,698	22,752	55,364
SE	853	1	15	791	16,123	17,783
SSE	5,770	1,812	910	17,698	586	26,776
S	22,509	19,870	10,648	16,666	16,689	86,382
SSW	16,657	19,818	19,238	7,501	16,156	79,370
SW	6,150	10,349	28,988	7,282	5,522	58,291
WSW	5,072	14,516	7,594	43,246	9,645	80,073
W	5,442	15,098	27,491	46,793	76,674	171,498
WNW	7,536	14,241	76,286	86,001	405,880	589,944
NW	6,618	20,980	25,269	296,136	1,417,969	1,766,972
NNW	1,129	31,036	60,761	89,588	302,196	484,710
Total	78,209	162,822	314,330	842,867	2,615,885	4,014,113

a. Sources: Derived from References 116, 117, 118, 119.
b. Figure 3-5 indicates location of sector.

Table 3-12
PROJECTED POPULATION DISTRIBUTION IN 2030 WITHIN 50 MILES OF CCNPP[a]

Sector[b]	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	50-Mile Total
N	0	0	6,240	133,412	195,396	335,048
NNE	0	251	12,177	38,468	13,005	63,901
NE	2	2,173	17,329	19,543	17,233	56,280
ENE	185	11,471	21,744	10,412	34,639	78,451
E	216	1,051	1,150	7,871	81,735	92,023
ESE	77	396	456	32,496	23,286	56,711
SE	1,101	1	15	802	16,359	18,278
SSE	7,294	1,964	986	18,976	624	29,844
S	28,852	21,530	11,531	17,909	17,717	97,539
SSW	20,708	21,475	20,757	7,878	16,701	87,519
SW	7,148	11,215	31,286	7,796	5,618	63,063
WSW	5,999	15,730	8,486	49,194	10,725	90,134
W	7,000	16,393	30,834	54,070	88,259	196,556
WNW	9,717	16,908	88,320	97,604	456,889	669,438
NW	8,534	26,906	28,973	323,884	1,491,231	1,879,528
NNW	1,456	40,019	67,748	96,854	325,633	531,710
Total	98,289	187,483	348,032	917,169	2,795,050	4,346,023

a. Sources: Derived from References 116, 117, 118, 119.
b. Figure 3-5 indicates location of sector.

Table 3-13
PROJECTED POPULATION DISTRIBUTION IN 2040 WITHIN 50 MILES OF CCNPP[a]

Sector[b]	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	50-Mile Total
N	0	0	6,541	139,462	203,399	349,402
NNE	0	262	12,727	41,700	14,105	68,794
NE	2	2,207	18,114	20,461	18,198	58,982
ENE	187	11,649	22,139	10,695	37,053	81,723
E	219	1,068	1,170	8,257	86,445	97,159
ESE	79	402	463	33,323	23,840	58,107
SE	1,421	1	15	814	16,596	18,847
SSE	9,246	2,129	1,067	20,357	664	33,463
S	37,014	23,331	12,488	19,250	18,806	110,889
SSW	25,868	23,270	22,403	8,275	17,270	97,086
SW	8,365	12,152	33,787	8,364	5,717	68,385
WSW	7,148	17,044	9,493	56,017	11,942	101,644
W	9,007	17,807	34,618	62,487	101,630	225,549
WNW	12,532	20,186	102,258	110,857	515,198	761,031
NW	11,007	34,535	33,353	354,218	1,569,565	2,002,678
NNW	1,878	51,603	76,309	104,756	351,064	585,610
Total	123,973	217,646	386,945	999,293	2,991,492	4,719,349

a. Sources: Derived from References 116, 117, 118, 119.
b. Figure 3-5 indicates location of sector.

Table 3-14
ESTIMATED AGE DISTRIBUTION OF POPULATION IN 1990[a]

	Calvert County, Maryland		United States	
Age Group	**Number**	**Percent**	**Number**	**Percent**
Under 5	4,830	7.8 percent	19,512,000	7.6 percent
5 - 19	14,540	23.4 percent	53,523,000	21.0 percent
20 - 44	25,120	40.4 percent	101,416,000	39.8 percent
45 - 64	12,250	19.7 percent	48,348,000	19.0 percent
65 and over	5,440	8.7 percent	32,283,000	12.7 percent
Total	62,180	100.0 percent	255,082,000	100.0 percent

a. Sources: References 106, 120.

Table 3-15
PROJECTED AGE DISTRIBUTION IN 2030 BETWEEN 10 AND 50 MILES OF CCNPP[a]

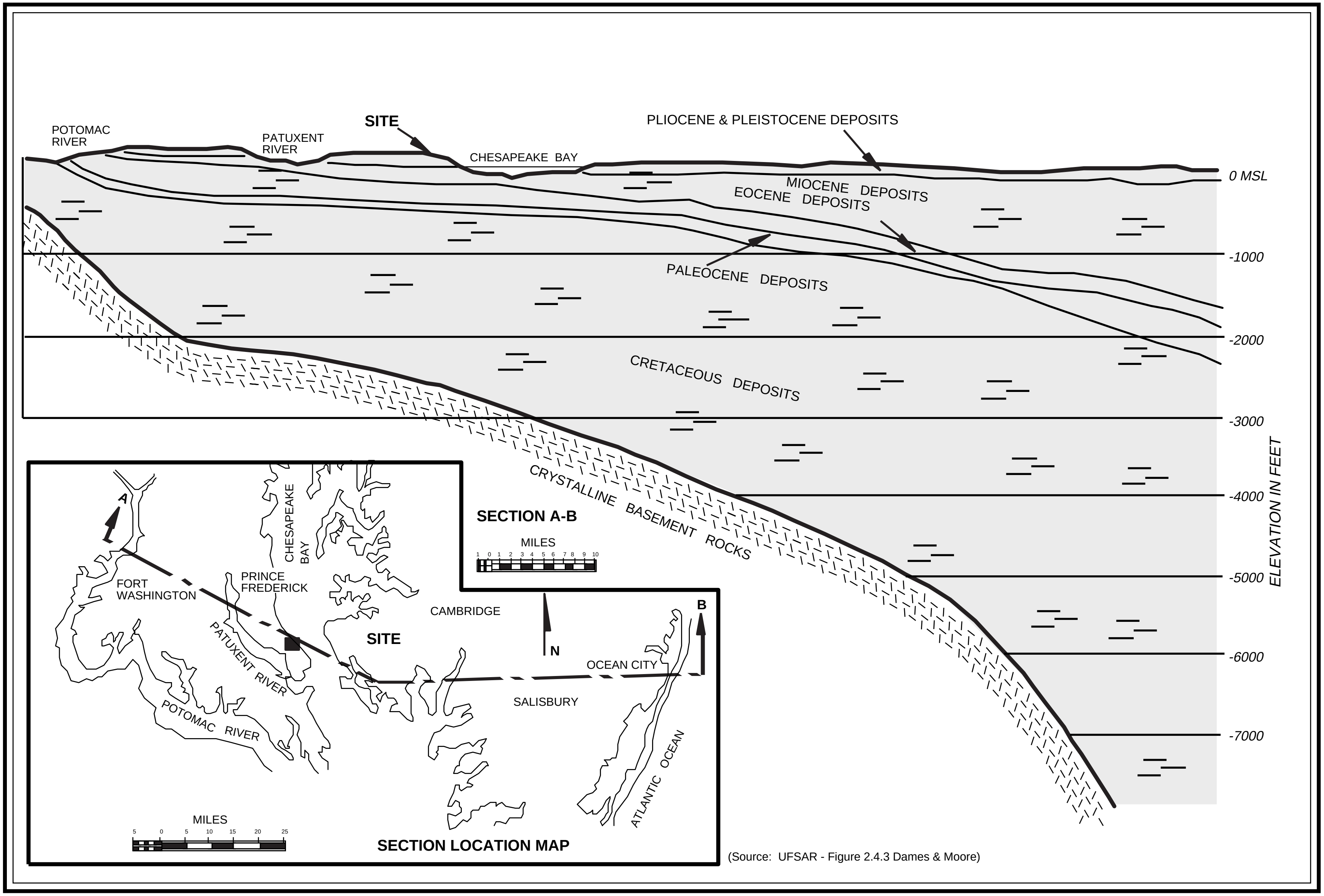
Age Group	Estimated Percentage Age Distribution of U.S. Population	Estimated Population Within 10 Miles of CCNPP[b]	Estimated Population Within 50 Miles of CCNPP[b]
Under 5	6.5 percent	6,389	282,491
5 - 17	17.2 percent	16,906	747,516
18 - 44	34.4 percent	33,811	1,495,032
45 - 64	21.8 percent	21,427	947,433
65 and over	20.1 percent	19,756	873,551
Total	100.0 percent	98,289	4,346,023

a. Source: Reference 120.
b. Total population for the areas within 10 and 50 miles of CCNPP is derived from Tables 3-7 and 3-12, respectively.

Table 3-16
TRANSIENT POPULATION ASSOCIATED WITH MAJOR FACILITIES WITHIN 10 MILES OF CCNPP[a]

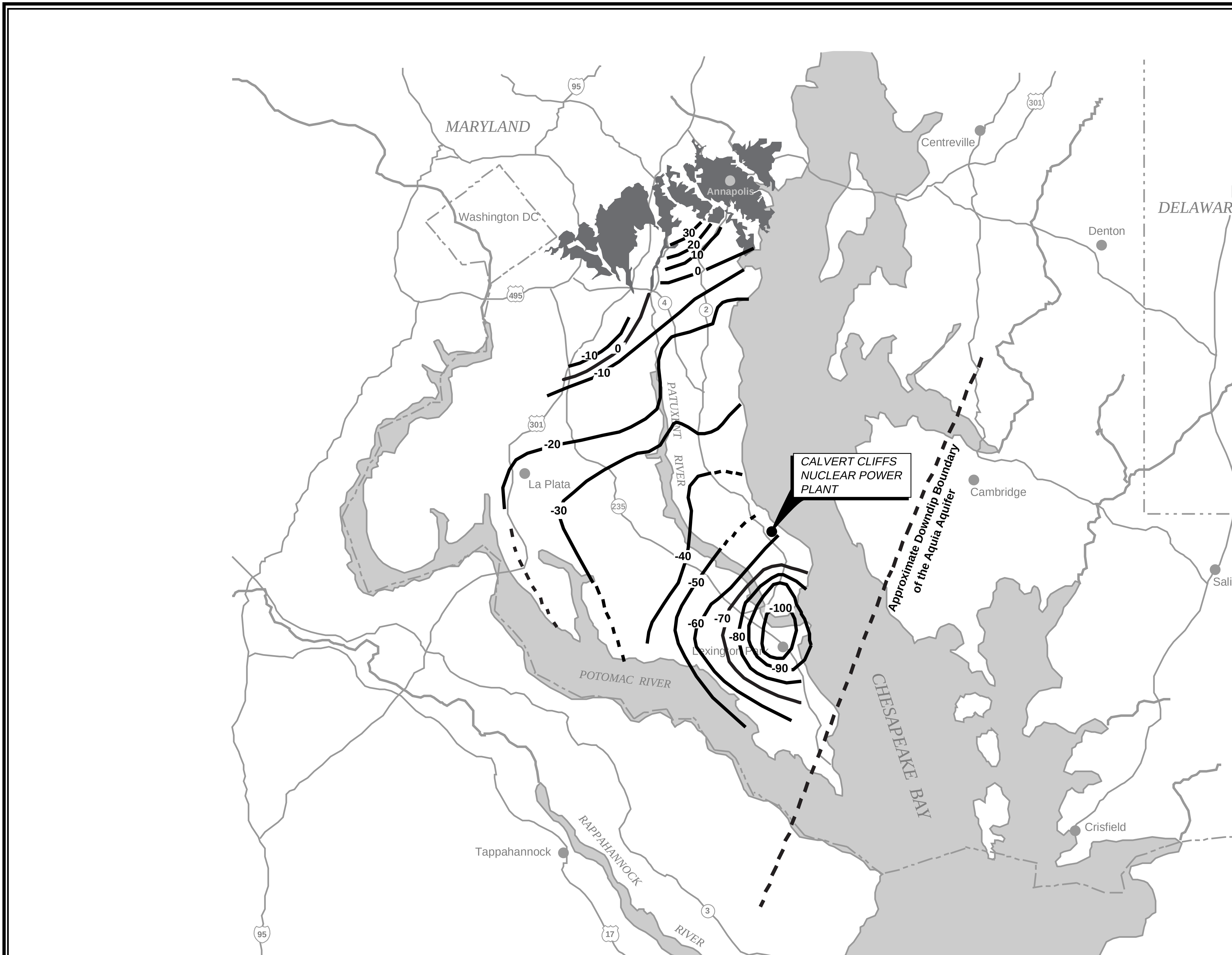
		Population	
Facility	**Location**	**Annual**	**Daily**
Patuxent Naval Air Station	6-8 miles S and SW	1,500	
Chesapeake Biological Laboratory	8-9 miles S		125
Calvert Cliffs State Park	2-4 miles S, SSE, and SE	137,500	
Jefferson Patterson State Park	5 miles SW	17,560	
Cypress Swamp Sanctuary	9-10 miles WNW	15,510	
Flag Ponds Park	1-2 miles NW	23,750	
Calvert Marine Museum	7-8 miles S	47,960	
Appeal Elementary School	4-5 miles S		820
Patuxent Elementary School	4-5 miles S		880
Mutual Elementary School	6-7 miles WNW		760
Southern Middle School	1-2 miles SSW		740
Our Lady Star of the Sea School	7-8 miles S		140
Town Creek Elementary School	9-10 miles SSW		320
St. John Elementary School	9-10 miles SW		240
Hollywood Elementary School	9-10 miles SW		270
CCNPP Visitors Center	On site	29,000	

a. Sources: References 22, 97.

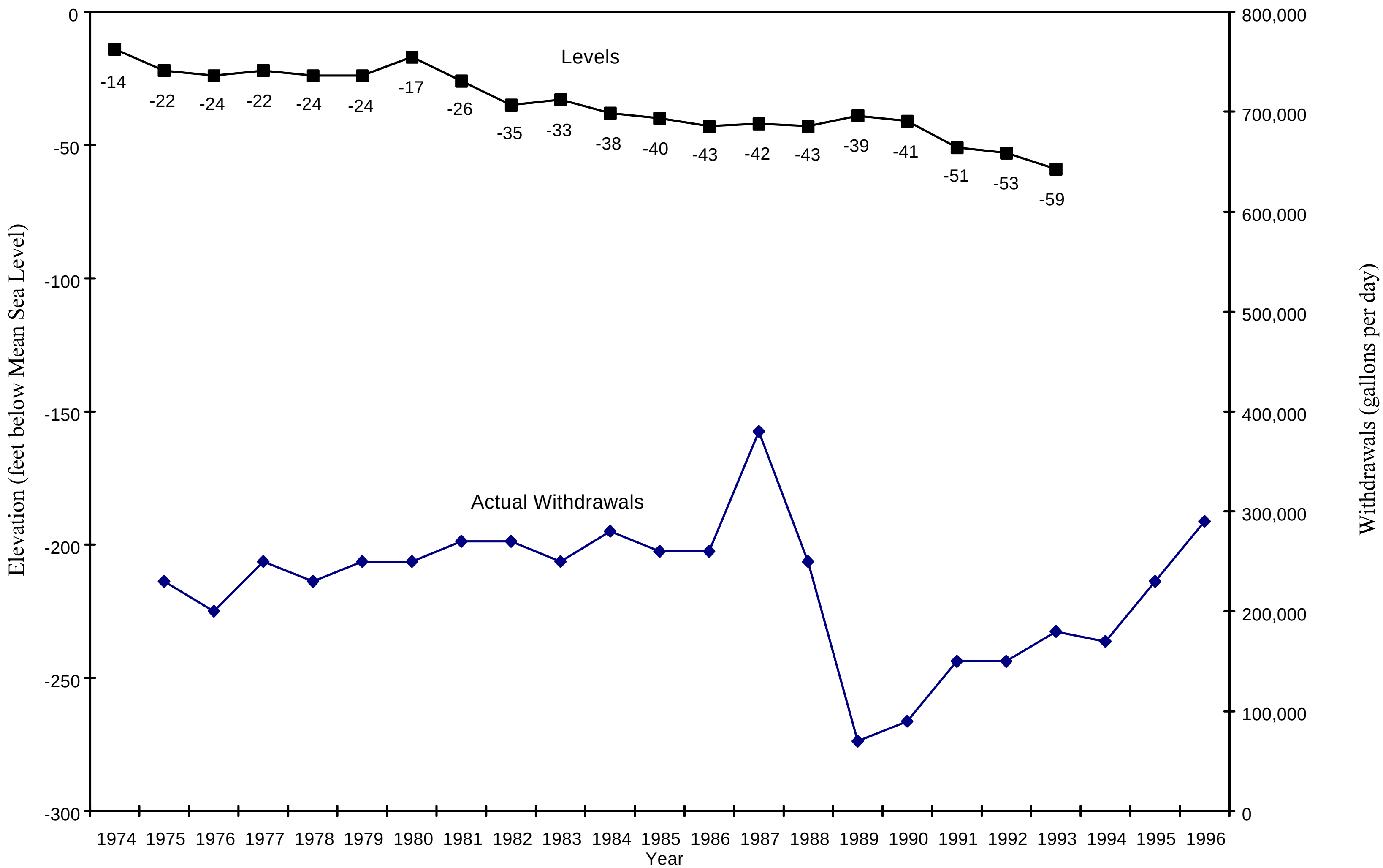


PX01-3PC

Figure 3-1. Regional geologic section - Coastal Plain.



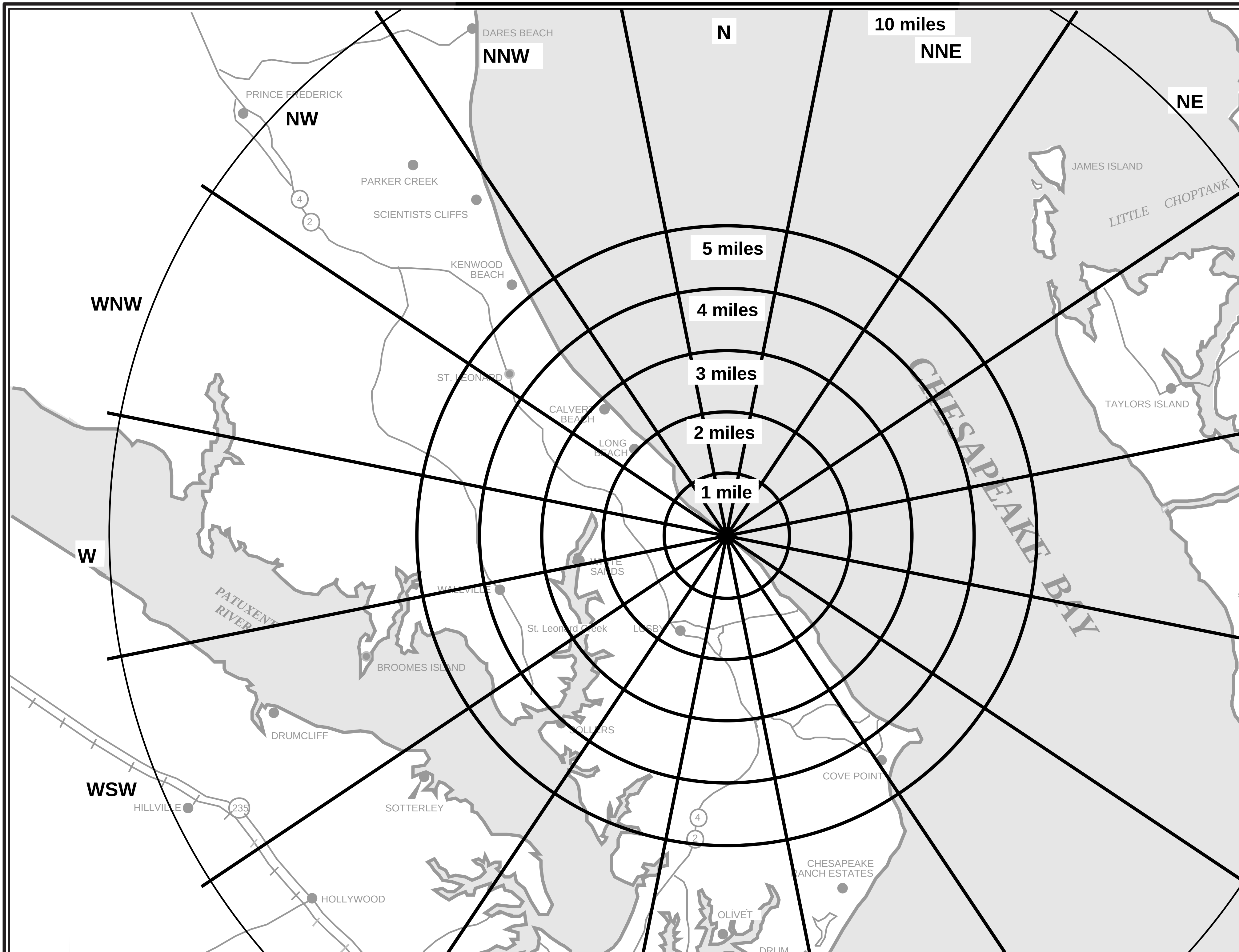
MARYLAND
Washington DC
Annapolis
Centreville
Denton
Cambridge
Crisfield
La Plata
Tappahannock
PATUXENT RIVER
POTOMAC RIVER
RAPPAHANNOCK RIVER
CHESAPEAKE BAY
CALVERT CLIFFS
NUCLEAR POWER
PLANT
Approximate Downdip Boundary
of the Aquia Aquifer
30
20
10
0
-10
-20
-30
-40
-50
-60
-70
-80
-90
-100



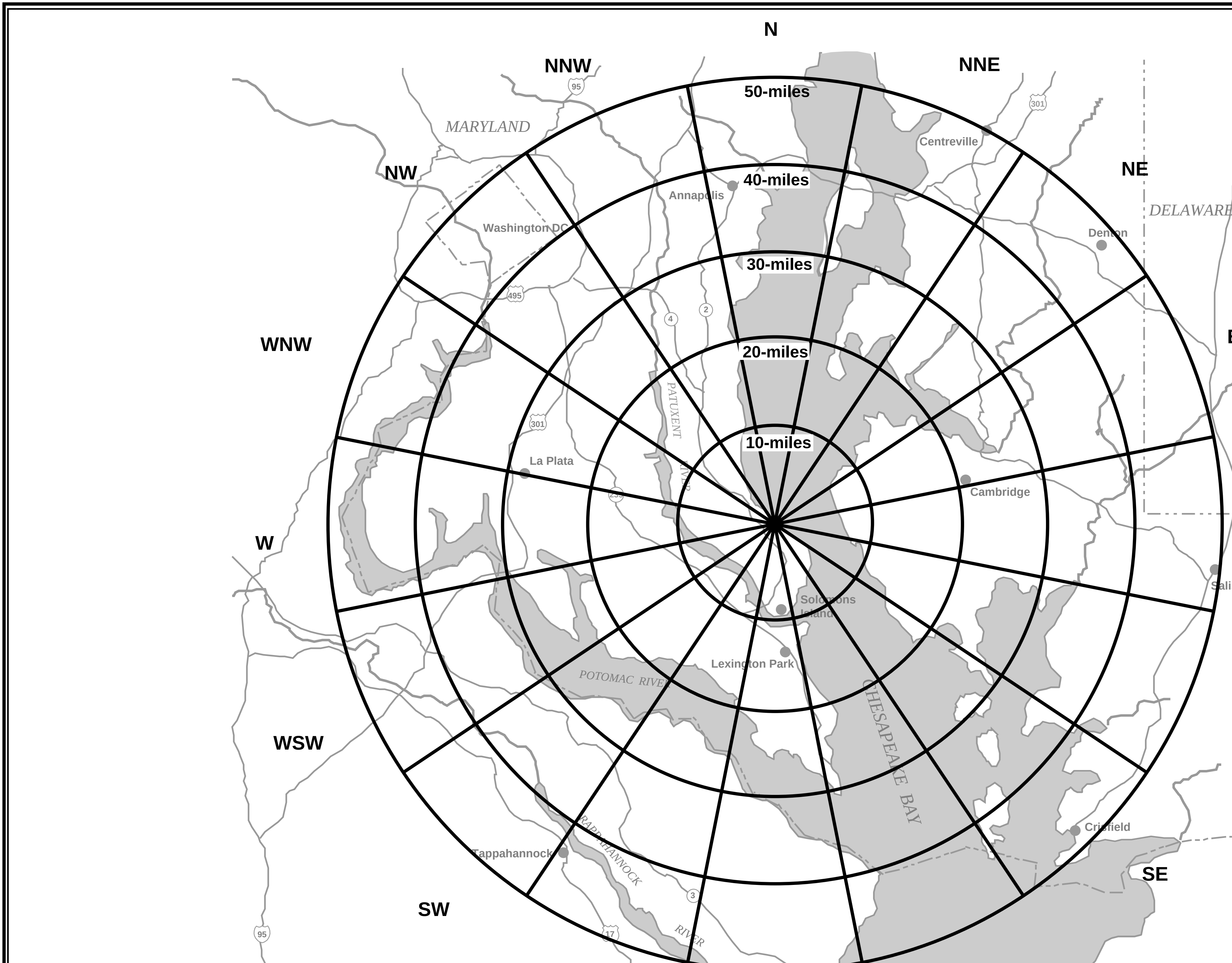
Source of water level data: References 7, 21, 99, 101, 121, 122, 123, 124, 125.

Source of withdrawal data: Reference 7 and the CCNPP groundwater appropriation reports to the State.

Figure 3-3. Aquia Aquifer potentiometric surface levels and withdrawals at CCNPP.



N
NNE
NE
NNW
NW
WNW
W
WSW
10 miles
5 miles
4 miles
3 miles
2 miles
1 mile
DARES BEACH
PRINCE FREDERICK
PARKER CREEK
SCIENTISTS CLIFFS
KENWOOD BEACH
ST. LEONARD
CALVERT BEACH
LONG BEACH
WHITE SANDS
WALLVILLE
St. Leonard Creek
LUSBY
BROOMES ISLAND
SOLLERS
COVE POINT
DRUMCLIFF
SOTTERLEY
HILLVILLE
HOLLYWOOD
CHESAPEAKE RANCH ESTATES
OLIVET
DRUM
JAMES ISLAND
LITTLE CHOPTANK
TAYLORS ISLAND
CHESAPEAKE BAY
PATUXENT RIVER
4
2
235



N
NNW
NNE
NW
NE
WNW
W
WSW
SW
SE
50-miles
40-miles
30-miles
20-miles
10-miles
MARYLAND
DELAWARE
Centreville
Annapolis
Washington DC
Denton
La Plata
Cambridge
PATUXENT
Solomons Island
Lexington Park
POTOMAC RIVER
CHESAPEAKE BAY
Tappahannock
RAPPAHANNOCK
RIVER
Crisfield

4.0 ENVIRONMENTAL CONSEQUENCES AND MITIGATING ACTIONS

4.1 Proposed Action

4.1.1 Introduction

Section 4.1 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of CCNPP's operating license. The scope of this assessment is guided by the NRC's generic analysis presented in the GEIS (Reference 5). Through this analysis, NRC identified 92 environmental issues associated with the action of license renewal. These issues were categorized as Category 1 if the following criteria were met:

- The environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristic.
- A single significance level (i.e., small, moderate, or large) has been assigned to the impacts (except for collective offsite radiological impacts from the fuel cycle and from high-level-waste and spent-fuel disposal).
- 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 not to be sufficiently beneficial to warrant implementation.

If the GEIS analysis concluded that one or more of the criteria of Category 1 could not be met, the issue was designated as a Category 2 issue and additional plant-specific review is required to be submitted by the applicant. These issues were listed with assigned categorization in Table B-1 of Appendix B to Part 51. This table has been reproduced and included in Appendix A of this report. For ease of reference, the issues have been numbered by the order in which they are listed in the regulation. Appendix A also provides a cross-reference to the section in this environmental report where each issue is discussed.

Category 1 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)

" . . . absent new and significant information, the analysis for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal . . . ." Discussion of Regulatory Requirements, 61 FR 109, June 5, 1996, pg. 28483

Chapter 4 will not include discussion of Category 1 issues. Baltimore Gas and Electric Company adopts by reference the conclusions of Table B-1 of Appendix B to Subpart A of Part 51 and the GEIS analysis for all Category 1 issues.

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)

Based upon the characteristics of the CCNPP site and physical features of the plant, only those Category 2 issues applicable to CCNPP will be analyzed in this section. There are 5 Category 2 issues that do not apply to CCNPP. These issues and the basis for exclusion are listed below:

	ISSUE	BASIS FOR EXCLUSION
13.	Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	Not applicable because CCNPP does not use a cooling pond or tower heat dissipation system.
34.	Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	Not applicable because CCNPP is not equipped with cooling towers.
35.	Groundwater use conflicts (Ranney wells)	Not applicable because CCNPP does not use Ranney wells.
39.	Groundwater quality degradation (cooling ponds at inland sites)	Not applicable because CCNPP does not use a cooling pond heat dissipation system.
57.	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	Not applicable because CCNPP does not use lakes or canals, or cooling towers or cooling ponds that discharge to a small river

For each Category 2 issue discussed in the following sections, BGE will state the issue, provide the reason NRC did not conclude it was a Category 1 issue, and include in the impact analysis how that reason applies to CCNPP. Baltimore Gas and Electric Company will conclude the analysis by identifying the significance of the impacts relative to CCNPP and discuss potential mitigative alternatives when applicable and to the extent required. The significance of the impacts associated with each issue will be identified as either small, moderate, or large consistent with NRC's standard of significance established in the GEIS 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 any important attributes of the resource.

4.1.2 Entrainment

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 in early life stages 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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 25)

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

As indicated in Sections 2.1.3 and 5.1.2, CCNPP has a once-through heat dissipation system and documentation of Clean Water Act 316(b) compliance indicating that the existing intake structure reflects the best technology available for minimizing adverse impact at CCNPP (Appendix B provides documentation). Given this determination, BGE concludes that CCNPP entrainment impacts (Issue 25) are small, and that further mitigation would be unwarranted.

4.1.3 Impingement

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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 26)

The 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; impingement impacts are small at many plants, but might be moderate or large at a few plants. Information that needs to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond); and (2) current Clean Water Act 316(b) determination or equivalent state documentation.

As indicated in Sections 2.1.3 and 5.1.2, CCNPP has a once-through heat dissipation system and documentation of Clean Water Act 316(b) compliance indicating that the existing intake structure reflects the best technology available for minimizing adverse impact at CCNPP (Appendix B provides documentation).

The Maryland Department of Natural Resources has concluded that Maryland power plants do not cause measurable depletion in fish and crab species numbers due to the large size and wide distribution of their populations (Reference 101). Baltimore Gas and Electric Company has identified no mechanism that would alter this conclusion during license renewal, and concludes that CCNPP impingement impacts (Issue 26) are small and that further mitigation is not warranted.

4.1.4 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 . . . if necessary, a 316(a) variance in accordance with 40 CFR part 125, or equivalent State permits and supporting documentation. If the applicant can not provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock . . . ." 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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 27)

The 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. Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond); and (2) evidence of a Clean Water Act 316(a) variance or equivalent state documentation.

As indicated in Sections 2.1.3 and 5.1.2, CCNPP has a once-through heat dissipation system and documentation that the CCNPP thermal discharge is in compliance with state water quality standards without recourse to a Clean Water Act 316(a) variance (Appendix B provides documentation). For this reason, BGE concludes that CCNPP heat shock impacts (Issue 27) would be small and, because the standard-setting process provides for minimizing environmental impact, further mitigation would be unwarranted.

4.1.5 Groundwater Use

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 ground-water 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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 33)

The NRC made this a Category 2 issue because it could not assign a single significance level (small, moderate, or large), and because, if there were moderate or large impacts, mitigation might be warranted. The effect of groundwater usage on neighboring groundwater users would depend on the rate of usage and the distance to the neighboring well (GEIS Section 4.8.1.1). Therefore, information to be ascertained includes: (1) CCNPP groundwater usage rate (whether greater than 100 gpm); (2) distance to neighboring well(s); and (3) impact on the neighboring well(s).

As discussed in Section 2.1.4, CCNPP groundwater usage rate averages approximately 157 gpm, making this groundwater issue applicable to CCNPP. As indicated in Section 3.2.2, CCNPP withdraws its groundwater from the Aquia Aquifer, which is located between 450 and 550 feet below the surface. The nearest neighboring well that withdraws from this level is located at Southern Middle School, approximately 2 miles away from CCNPP wells. However, as shown on Figure 2-3, there is private property located closer to the CCNPP wells. It is possible for the owner of such property to install a well in the Aquia Aquifer at any time. For this reason, BGE has evaluated the potential impact that CCNPP groundwater usage could have on a hypothetical well located at the nearest site boundary, in addition to the impact on the nearest existing well (i.e., at Southern Middle School).

In performing this evaluation, BGE considered whether particular area geological features could make it likely that other offsite well locations could be impacted to a greater degree than these two well locations. However, as indicated in Section 3.2.1, CCNPP-area geology is well known, relatively homogeneous, and has no folding, faulting, or other irregularities to suggest directed or atypical groundwater flow patterns. Therefore, BGE is confident that impact at the hypothetical well location at the nearest site boundary would be representative of the greatest impacts attributable to CCNPP groundwater usage to any offsite well location.

Groundwater use conflicts can arise if withdrawals by one user cause offsite well water levels to decrease sufficiently to cause pumping costs to increase or, in the extreme, to cause the well to pump dry. Baltimore Gas and Electric Company has calculated the drawdown that CCNPP pumpage could have on the water level in a hypothetical well located at the site boundary closest to the CCNPP well locations and screened deeper than approximately 550 feet in the Aquia Aquifer (below -450 feet). The results of these calculations are listed below (see Appendix C for sample calculations):

	Drawdown	
Year	**Increment (feet)**	**Cumulative (feet)**
1972	0	0
1975	14.0	14.0
1984	6.4	20.4
1994	1.9	22.3
2004	1.1	23.4
2014	0.8	24.2
2024	0.7	24.9
2034	0.5	25.4

As this calculation illustrates, the greatest amount of incremental drawdown would have occurred when the plant first began operation. During the 10-year period from 1984 to 1994, when the potentiometric surface of the Aquia Aquifer dropped by more than 30 feet (Section 3.2.2 and Figure 3-2), BGE could have contributed 1.9 feet of drawdown. Drawdown currently would be a few inches (less than 1 foot) per year; the cumulative impact for the period of CCNPP license renewal (e.g., years 2014 through 2034) would be approximately 1.2 feet. At the Southern Middle School, the cumulative impact for the CCNPP license renewal period would be approximately the same as for a well at the site boundary, 1.2 feet.

These indications of little offsite impact are consistent with the Maryland Department of Natural Resources conclusion that water levels in the Aquia Aquifer in the CCNPP area are most strongly influenced by withdrawals at Lexington Park, Patuxent Naval Air Station, and Solomons Island (combined pumpage approximately 2 million gallons per day; Table 3-2). Furthermore, the availability of approximately 300 feet of regulatorily available drawdown should lessen usage conflicts. Based on the evaluation presented above and available drawdown in the Aquia Aquifer, BGE expects impacts to groundwater use (Issue 33) through the license renewal term to be small.

As indicated in Section 2.1.4, CCNPP has a gravity-drain system installed in the water table to drain the power block area. Because the water-table flow within 1,000 feet of the Chesapeake Bay is towards the Bay (Section 3.2.2) and there is no private property located within this area at CCNPP, this CCNPP groundwater usage would have no impact on offsite groundwater usage of the water table aquifer.

Baltimore Gas and Electric Company has concluded that CCNPP groundwater-use impacts (Issue 33) would be small. Groundwater usage would not noticeably alter offsite groundwater usage and that the appropriate categorization of the significance of this impact is small; the environmental effect would not be detectable or would be so minor that it would not destabilize nor noticeably alter any important attributes of the resource. Groundwater usage impact mitigation measures include compensating for lost groundwater access or deepening offsite wells to facilitate recovery but, due to the small nature of the projected CCNPP impact, BGE has concluded that mitigation measures would be unwarranted.

4.1.6 Terrestrial Resources

NRC

The environmental report must contain an assessment of ". . . the impact 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 Part 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." GEIS Section 3.6

The NRC made impacts to terrestrial resources a Category 2 issue because the significance of ecological impacts cannot be determined without considering site-specific and project-specific details (GEIS Section 3.6). Aspects of the site and the project to be ascertained are: (1) the identification of important ecological resources; (2) nature of refurbishment activities; and (3) the extent of impact to plant and animal habitat.

As described in Sections 3.1.2 and 3.1.3, the CCNPP site contains eight distinct plant communities, which provide habitat for three special-status species (Puritan and Northeastern beach tiger beetles and bald eagle) and two State of Maryland watch list plant species (a floating bladderwort and a milkwort species). As described in Section 2.1.6, BGE has no plans to perform major refurbishment activities; therefore, there would be no refurbishment or other license-renewal-related construction activities to impact important plant and animal habitats. Due to the lack of major plant refurbishment, no further analysis of impacts to terrestrial resources (Issue 40) is required. Baltimore Gas and Electric Company notes that the CCNPP terrestrial environment would realize a positive impact from the continuation of existing habitat enhancement programs. These programs are described in Section 3.1.2.

4.1.7 Threatened and Endangered Species

NRC

The environmental report must contain an assessment of ". . . the impact of the proposed action on threatened and 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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 49)

The 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 and continued plant operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate Federal agency (GEIS Section 3.9 and 4.1).

Section 3.1.3 discusses terrestrial and aquatic species that occur or may occur at the CCNPP site and that have special status (e.g., threatened, endangered, State watch list). To date, the CCNPP effects on these species have been positive, through habitat protection and enhancement. As described in Section 2.1.6, BGE has no plans to perform major refurbishment activities at CCNPP. Baltimore Gas and Electric Company concludes that there would be no refurbishment-related impacts to threatened and endangered species, and impacts to the species would be positive through the license renewal term. A positive impact would be realized by the continuation of habitat protection and enhancement programs supported by continued operation. Baltimore Gas and Electric Company has initiated consultations with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service regarding CCNPP license renewal. Copies of the consultation requests to these agencies and the agency responses are provided in Appendix D.

4.1.8 Air Quality

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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 50)

The 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 the refurbishment outage (GEIS Section 3.3). Information needed would include: (1) the attainment status of the plant-site area; and (2) number of additional vehicles as a result of refurbishment activities.

Section 3.3 describes the CCNPP area air quality. As described in Section 2.1.6, BGE has no plans to perform major refurbishment activities; therefore, there would not be a CCNPP refurbishment workforce to generate vehicle emissions. Due to the lack of major plant refurbishment, no analysis of impacts to air quality (Issue 50) is required.

4.1.9 Electric Shock

> **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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 59)

The 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 criteria, NRC could not determine the significance of the electrical shock potential. Regulation 10 CFR 51.53(c)(3)(ii)(H) does not define the phrase "transmission line," but the GEIS indicates that transmission lines use voltages of about 115 or 138 kVs and higher, and that, in contrast, distribution lines use voltages below 115 or 138 kVs (Reference 5). The GEIS also indicates that the transmission line of concern is that between the plant switchyard and the intertie to the transmission system (Reference 5). Information to be ascertained includes: (1) change in line use and voltage since last analysis; (2) conformance with National Electrical Safety Code (1981) standards; and (3) potential change in land use along transmission lines since initial NEPA review.

The National Electrical Safety Code (Reference 126) identifies minimum vertical clearances to the ground for electric lines having voltages exceeding 98 kVs alternating current to ground.[1] The clearance must limit the steady-state current[2] due to electrostatic effects to 5 milliamperes if the largest anticipated vehicle were short-circuited to ground. For this determination, the lines should be evaluated assuming a final unloaded sag at 120°F. The Electric Power Research Institute has published a guide

1 Part 2, Rules 232C1c and 232D3c

2 The National Electrical Safety Code 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 have the same meaning here.

(Reference 127) and has developed a computer code called ENVIRO (Reference 128), which together are used for calculating the steady-state current value from transmission lines. The calculation is a 2-step process in which the analyst first calculates the average field strength 1 meter (3.28 feet) above the ground beneath the minimum line clearance, and second calculates the steady-state current value.

The capacity of the Southern Maryland Electric Cooperative line to CCNPP, 69 kVs, is less than the capacity that the GEIS uses to define transmission lines (115 or 138 kV or higher). In addition, the line does not connect the CCNPP switchyard to the intertie with the transmission system but, instead, is part of the Southern Maryland Electric Cooperative distribution system. Finally, the line voltage is less than the Code threshold for imposing steady-state current limits (voltages exceeding 98 kVs). For these reasons, BGE concludes that 10 CFR 51.53(c)(3)(ii)(H) does not apply to the Southern Maryland Electric Cooperative line to CCNPP.

The CCNPP South Circuit, installed in 1994, was designed to be in compliance with the Code. Baltimore Gas and Electric Company has made no changes to line voltages since installation. Because BGE owns title to the land beneath the lines, BGE controls land use and has made no changes since installation. Baltimore Gas and Electric Company adopts by reference the GEIS conclusion that the electrical shock issue is of small significance for such lines (Reference 5). Due to the small significance of the issue, mitigation measures, such as installing warning signs at road crossings or, in the extreme, increasing clearances, are not warranted.

The CCNPP North Circuit lines were installed in 1972, before the Code adopted a steady-state current limit. For this reason, BGE has conducted an evaluation of the lines' adherence to the Code's present steady-state current limit. The largest vehicle that BGE anticipates being under North Circuit lines is a tractor trailer parked on a public roadway. The minimum North Circuit design clearance above a public roadway is 31 feet at a design temperature of 212°F. Adjusted to the cooler temperature (120°F) specified by the Code, this clearance would be 37 feet. Baltimore Gas and Electric Company entered this input, together with line characteristics such as voltage, current, and conductor position into the ENVIRO code, to obtain electric field strengths at 5-foot intervals, 1 meter above the ground. The maximum calculated field strength was 7.2 kV per meter. Centering a 55-foot object at this point under, and perpendicular to, the lines (representing a tractor trailer) would expose the object to field strengths between 4.5 and 7.2 kVs per meter, with a maximum average field strength of 5.968 kVs per meter.

Using the maximum average field strength, in accordance with the Electric Power Research Institute reference book, and using the reference methodology, BGE calculated the steady-state current for a tractor trailer 55 feet long, 8 feet wide, and 13.5 feet high. The resultant value, 4.796 milliamperes, is less than the 5-milliampere limit imposed by the Code. The North Circuit design, therefore, adheres to the Code's present steady-state current limit. Baltimore Gas and Electric Company has made no changes to the North Circuit line voltage since installation but, as described in Section 2.1.5, BGE has shifted approximately one mile of right-of-way. This change was done as part of the South Circuit installation and was designed in accordance with the Code. As in the case of the South Circuit, BGE land ownership enables BGE to continue to control land usage beneath the lines. Baltimore Gas and Electric Company concludes that CCNPP transmission lines meet the National Electrical Safety Code recommendations for preventing electric shock from induced currents; therefore, further assessment of the impact of the proposed action on the potential shock hazard is not required. Baltimore Gas and Electric Company adopts by reference the GEIS conclusion that electrical shock (Issue 59) is of small significance for such lines. Due to the small significance of the issue, mitigation measures, such as installing warning signs at road crossings or, in the extreme, increasing clearances, are not warranted.

4.1.10 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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 63)

" . . . small 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." GEIS Section 4.7.1.1

The NRC made housing impacts a Category 2 issue because impact significance depends on local conditions that NRC could not predict for all plants at the time of GEIS publication (GEIS Section 3.7.2). Local conditions to be ascertained are: (1) area population categorization as small, medium, or high; and (2) applicability of growth control measures.

This issue addresses housing impacts resulting from refurbishment activities and continued operations. As described in Section 2.1.6, BGE has no plans to perform major refurbishment activities at CCNPP. Baltimore Gas and Electric Company concludes that there would be no refurbishment-related impacts to area housing. Therefore, the following discussion focuses on assessing the impacts of continued operations on local housing availability.

Appendix C of the GEIS presents a population characterization method that is based on two factors, "sparseness" and "proximity" (GEIS Section C.1.4). Sparseness measures population density and city size within 20 miles of the site, and proximity measures population density and city size within 50 miles. Each factor has four categories of density and size (GEIS Table C.1), and a matrix is used to rank the population category as low, medium, or high (GEIS Figure C.1). Calvert Cliffs was selected by the NRC to be evaluated as a potential socioeconomic case study site. The results of this evaluation, published in the GEIS, classifies the CCNPP population as "high" (GEIS Table C.2). Using the demographic data given in Section 3.8, the population density within a 20-mile radius of CCNPP is 109 persons per square mile, giving the site a sparseness Category 3. The population density within a 50-mile radius is 393 persons per square mile, giving the site a proximity Category 4. These values combine to give the CCNPP population a category measure of 4.3, within the "high" category, consistent with the GEIS categorization.

As described in Section 3.4, the Tri-County (Calvert, St. Mary's, and Charles) area around CCNPP is not subject to growth control measures that limit housing development. In 10 CFR Part 51, Subpart A, Appendix B, Table B-1, the NRC concluded that impacts to housing are expected to be of small significance at plants located in a "high" population area where growth control measures are not in effect. Therefore, because CCNPP is located in a high population area and is not located in an area where growth control measures limit housing development, BGE expects housing impacts (Issue 63) to be small.

This conclusion is supported by the following site-specific housing analysis. The maximum impact to area housing is calculated using the following assumptions: (1) all direct and indirect jobs would be filled by in-migrating residents; (2) the residential distribution of new residents would be similar to current worker distribution; and (3) each new job created (direct and indirect) represents one housing unit. As described in Section 2.1.7, the counties that have the most number of CCNPP employee residences are Calvert, St. Mary's, and Charles which, together, account for approximately 80 percent of CCNPP employees. Therefore, BGE has focused its housing impact analysis on these three counties. Baltimore Gas and Electric Company's conservative estimate of 60 license renewal employees could generate the demand for 192 housing units in the Tri-County area. The Tri-County area has approximately 81,000 housing units[3] with a vacancy rate with a 7 percent (Reference 102), giving approximately 5,700 units available for occupancy. A decrease of 3 percent (192 units) in the number of available units caused by adding 60 personnel to the CCNPP workforce would not be expected to create a discernible change in housing availability, change rental rates and housing values, or spur housing construction or conversion. Given this magnitude of impact, mitigative measures would not be effective or necessary.

4.1.11 Public Services, Public Utilities

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 Part 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." GEIS Section 3.7.4.5

The NRC made public utility impacts a Category 2 issue because an increased problem with water availability may occur in conjunction with plant demand and plant-related population growth as a result of current water shortages in some areas (GEIS Section 4.7.3.5). Local information needed would be a description of water shortages experienced in the area and an assessment of the public water supply system's available capacity.

The NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demand on local groundwater resources. Section 2.1.4 describes the plant's permitted withdrawal rate and the plant's actual use of groundwater from the Aquia Aquifer for process and domestic use purposes. Section 4.1.5 presents an analysis of groundwater use conflicts, concluding that current drawdown would be a few inches per year, with a cumulative impact attributable to the license renewal period of roughly 1.2 feet at the point of maximum offsite impact (site boundary). The Maryland Power Plant Research Program reports that monitoring data shows that decreases in water level around water supply well fields at Lexington Park and Solomons Island south of CCNPP are greater than those observed at the plant. This indicates that withdrawals in these areas have a much greater

3 81,000 housing units equals the sum of available units in Calvert, St. Mary's, and Charles Counties.

effect on the Aquia's potentiometric surface than power plant withdrawals (Reference 101). In light of the small drawdown attributable to the plant, BGE does not expect plant demand to have a direct effect on the groundwater resources in the southern portion of the study area, and need not be considered further in the assessment of impacts to the public water supply system.

As described in Section 3.5, the Solomons Island and Lexington Park areas are starting to experience water supply problems. Therefore, BGE is focusing its groundwater supply analysis on these two areas. As described in Section 2.1.7, BGE's conservative estimate of 60 license renewal employees could generate a population increase of 553 people in Calvert and St. Mary's Counties. To analyze the impact of license renewal on the public water supply systems supporting the Solomons Island/Lexington Park area, only the portion of the population increase expected to live in these communities will be considered. The population distribution of Calvert and St. Mary's Counties indicates that approximately 9 percent of the total population reside in the Solomons Island/Lexington Park communities (References 129, 130). Assuming that the same percentage of the plant-related population growth would live in this area, a population increase of approximately 50 people could be expected in the Solomons Island/Lexington Park communities (9 percent of 548).

The impact to the local water supply systems can be determined by calculating the amount of water that would be needed by these individuals. The average American uses between 50 and 80 gallons per day for personal use (Reference 131). Using this consumption rate, the plant-related population increase would require an additional 4,000 gallons of water per day from local public water supply systems. The Solomons Water Supply System has an average output of 225,000 gallons per day, and Lexington Park Water Supply System has an average output of 1,203,000. The combined output of these two systems is approximately 1,400,000 gallons per day. An additional 50 residents to this area drawing roughly 4,000 gallons per day for personal use represents less than 1 percent of the current daily output. Based on the level of demand that would be placed on these water supply systems, BGE concludes that impacts resulting from plant-related population growth to the public water supply (Issue 65) would be small, requiring no additional capacity.

Potential measures that could be used to mitigate these impacts are given in Section 4.1.5. However, projected CCNPP license renewal-related population growth impacts are so minor that BGE has concluded that they would not warrant mitigation.

4.1.12 Public Services, Education

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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 66)

" . . . small 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 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 enrollment increases greater than 8 percent." GEIS Section 3.7.4.1

The NRC made impacts to education a Category 2 issue because site-specific and project-specific factors determine the significance of impacts (GEIS Section 3.7.4.1). Local factors to be ascertained include: (1) project-related enrollment increases; and (2) status of the student/teacher ratio.

Section 3.5.2 describes CCNPP area schools. As described in Section 2.1.6, BGE has no plans to perform major refurbishment activities; therefore, there would be no impact from refurbishment activities on area public schools' ability to provide educational services, and no additional teaching staff or classroom space would be needed. Due to lack of major plant refurbishment, no analysis of impacts on public schools (Issue 66) is required.

4.1.13 Offsite Land Use, Refurbishment

NRC

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

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

" . . . if 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, (2.6 km^2) and at least one urban area with a population of 100,000 or more within 80 km (50 miles)." GEIS Section 3.7.5

The 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; (3) population density; and (4) proximity to an urban area of at least 100,000.

Section 3.6 describes CCNPP offsite land use. As described in Section 2.1.6, BGE has no plans to perform major refurbishment activities; therefore, there would be no impact from refurbishment activities on land use within the vicinity of CCNPP. Due to lack of major plant refurbishment, no analysis of impacts to offsite land use due to refurbishment (Issue 68) is required.

4.1.14 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 . . . within the vicinity of the plant . . . ." 10 CFR 51.53(c)(3)(ii)(I)

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

" . . . if plant-related population growth is less than five percent of the study area's total population off-site land-use changes would be small . . . " GEIS Section 3.7.5

"If the plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has preestablished patterns of development and has provided adequate public services to support and guide development." GEIS Section 4.7.4.1

The NRC made impacts to offsite land use during the license renewal term a Category 2 issue because land use changes may be perceived to be beneficial by some community members and adverse by others. Therefore, the NRC could not assess the potential significance of site-specific offsite land use impacts (GEIS Section 4.7.4.1). Site-specific factors to consider in an assessment of new tax driven land-use impacts include: (1) the size of plant-related population growth compared to area's total population; (2) the size of 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 (GEIS Section 4.7.4.1). Based on the GEIS case study analysis, NRC concludes that all new population-driven land-use changes during the license renewal term at all nuclear plants would be small, because population growth caused by license renewal would represent a much smaller percentage of the local areas' total population than has operations-related growth (GEIS Section 4.7.4.2).

Population-Related Impacts

As described in Section 2.1.7, BGE estimates that Calvert County would experience the largest increase in population as a result of CCNPP license renewal, with an estimated increase of 433. This would be an increase of less than one percent of the County population.

Since 1970, Calvert County has experienced high growth, and it is expected to be the fastest growing county in the State through the year 2020 (Reference 22). The decline in agricultural land use (Section 3.6) will continue with the growth of the County and the increase in residential development. However, the population increase attributable to CCNPP license renewal would represent less than one percent of the County population. Consistent with NRC's conclusion that population-driven impacts to land use would be small, a significant change in land use in the vicinity of Calvert Cliffs would not be attributable to the CCNPP license renewal population increases.

Tax-Revenue-Related Impacts

This section focuses on Calvert County because it is the only local jurisdiction that receives direct tax revenues as a result of CCNPP's presence. As described in Section 2.1.6, there will be no major refurbishment activities and no new construction associated with the renewal of CCNPP's operating licenses. Therefore, BGE does not anticipate any new tax payments that would influence offsite land use. However, the operation of CCNPP through the license renewal period would result in continued economic benefit, such as direct and indirect salaries and tax contributions to Calvert County. Final Environmental Statement Section XI.C.1 estimated that CCNPP would generate $6.5 million annually in county tax revenues, which at that time (1973) would have represented more than 50 percent of the County tax revenue. Using the gross national product implicit price deflators[4], this would be equivalent to $19 million in 1993 dollars. As shown in Table 4-1, in 1994 BGE paid more than $17 million in property taxes to Calvert County for CCNPP. This payment represents nearly 21 percent of Calvert County's total fiscal year 1994 budget and has a substantial, positive impact on the fiscal condition of Calvert County. Baltimore Gas and Electric Company estimates that property tax payments are likely to increase over the license renewal term, reaching approximately $33 million by the year 2036.

The NRC has determined that the significance of tax payments is moderate if payments are between 10 and 20 percent of a taxing jurisdiction's revenue, and large if the payments are greater than 20 percent of revenue (Reference 5). The NRC further determined that if a plant's tax payments are projected to be medium to large relative to the community's total revenue, license renewal tax-driven land-use changes would most likely be moderate if the community has no pre-established patterns of development (i.e., land use plans or controls), or has not provided adequate public services to support and guide development in the past (Reference 5). The NRC defined the magnitude of land-use changes as follows:

- 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

Using these NRC criteria, CCNPP tax payments, representing approximately 21 percent of the Calvert County budget, are of moderate to large significance. The County's experience with significant population growth (Section 3.8.1) and land use changes (Section 3.6) points to moderate to large land-use changes. However, these changes are due to factors not directly related to the presence of CCNPP. Factors contributing to County growth include proximity to the Washington, DC, and Baltimore metropolitan areas (1- to 1½-hour commute by car); less development and lower taxes than those areas; and less stringent land use, zoning, and development regulations compared to surrounding counties (Section 3.8.1). In addition, the County has strong patterns of development as a result of land use plans (Section 3.6) and has public services in place to support development (Section 3.5). For these reasons,

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4 The U.S. Department of Commerce publishes data that allow comparison of the cost of goods in one year to the cost in another. This is known as the "gross national product implicit price deflator," and it can be used as follows:
1987 constant dollar value for 1973 = 41.3 (Reference 132)
1987 constant dollar value for 1993 = 123.5 (Reference 133)
123.5 divided by 41.3 equals 2.99
This means that for each dollar spent in 1973, $2.99 would have to be spent in 1993 to purchase the same goods. For example, a book that cost $4.00 in 1973 would have cost $11.96 if purchased in 1993 ($4.00 x 2.99 = $11.96).

BGE expects that the tax-revenue-related contribution that CCNPP license renewal would have on Calvert County land use changes would be small and that mitigative measures would be unwarranted.

Calvert County obtains indirect, as well as direct, monetary benefit from CCNPP tax payments. Due, in part, to the presence of such a large, stable source of property tax income, Calvert County enjoys a AAA bond rating, one of the highest bond ratings of any jurisdiction in the state (Reference 107). This rating indicates that there is a minimal risk that Calvert County will default in its timely payment of interest and principal, and it affords the County lower interest rates on borrowed funds. License renewal would continue this indirect benefit. Conversely, plant shutdown and resultant property devaluation would reduce the tax base and could result in a lowering of the County bond rating. Underwriters have already raised the question of whether the CCNPP license would be renewed.

Conclusion

The significance of these figures and their positive impact on Calvert County indicates that renewal would continue to have a positive role in the development of Calvert County, and impacts to offsite land use as a result of operation through the license renewal term (Issue 69) would be small.

4.1.15 Public Services, Transportation

NRC

The environmental report must contain an assessment of " . . . the impact of the proposed project on local transportation during periods of license renewal refurbishment activities." 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 Part 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). GEIS Section 3.7.4.2

The 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, that NRC could not forecast for all plants (GEIS Section 3.7.4.2). Local road conditions to be ascertained are: (1) level of service conditions; and (2) incremental increase in traffic associated with refurbishment activities and license renewal staff.

Section 3.5.3 describes the CCNPP area transportation system. As described in Section 2.1.6, BGE has no plans to perform major refurbishment activities; therefore, there would be no impact to local transportation from refurbishment activities. Due to lack of major plant refurbishment, no analysis of local transportation during periods of license renewal refurbishment activities (Issue 70) is required.

4.1.16 Historic and Archaeological Resources

NRC

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

"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection." 10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 71)

"Sites are considered to have small impacts to historic and archeological resources if (1) the State Historic Preservation Office (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 the character; and (3) if the conditions associated with moderate impacts do not occur." GEIS Section 3.7.7

The NRC made impacts to historic and archeological resource a Category 2 issue because determinations of impacts to historic and archeological resources are site-specific in nature, and the National Historic Preservation Act mandates that determination of impacts must be made through consultation with the SHPO (GEIS Section 4.7.7.3).

Calvert Cliffs is located in an area characterized by many historical, scenic, and cultural resources. The physical structures of the site and BGE's land management practices have allowed the plant to be perceived as well integrated with the surrounding landscape. Over 70 percent of the property at the CCNPP site is maintained in its natural state in keeping with the surrounding environs.

Continued use of transmission lines and rights of way are projected to cause little or no additional impacts beyond those that have already occurred. The historic and prehistoric artifacts found in 1992 during the evaluatory testing phase of the Chalk Point segment did not provide unique information and were dropped from consideration in the National Register of Historic Places. Furthermore, no archeological resources were encountered during the investigation of access road and tower realignments that took place early in 1993. Continued use of these transmission lines would not contribute to additional aesthetic or historical impacts to the area.

No additional impacts to scenic resources have occurred beyond the construction and initial years of CCNPP operation. There are no excessively large structures at CCNPP, such as natural draft cooling towers and associated vapor plumes. The site and nearby environs include forest and farmland that surround the plant and help obscure it from view. Although CCNPP will continue to be visible from the Chesapeake Bay, the combination of natural vegetation and topography would continue to obscure the plant from view from all land areas.

Baltimore Gas and Electric Company is committed to maintaining the historic and cultural resources discussed in Section 3.7. The Visitors Center would continue to be used for public information and education. Baltimore Gas and Electric Company concludes that continued operation would have no adverse impacts to historical resources and therefore, no impacts to mitigate. Baltimore Gas and Electric

Company has initiated consultations with the SHPO regarding CCNPP license renewal. Copies of the consultation request and agency response are provided in Appendix E.

4.1.17 Severe Accident Mitigation Alternatives

NRC

The environmental report must contain a consideration of alternatives to mitigate severe accidents " . . . [i]f the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environmental assessment . . . ." 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 Part 51, Subpart A, Appendix B, Table B-1 (Issue 76)

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

Historically, NRC has not included in its EISs or environmental assessments any analysis of alternative ways to mitigate the environmental impact of severe accidents. A 1989 court decision ruled that, in the absence of an NRC finding that severe accidents are remote and speculative, severe accident mitigation alternatives (SAMAs) should be considered in the NEPA analysis [*Limerick Ecology Action v. NRC*, 869 F.d 719 (3rd Cir. 1989)]. For most plants, including CCNPP, license renewal is the first licensing action that would necessitate consideration of SAMAs.

The NRC concluded in its generic license renewal rulemaking that the unmitigated environmental impacts from severe accidents met the Category 1 criteria, but NRC made consideration of mitigation alternatives a Category 2 issue because ongoing regulatory programs related to mitigation (i.e., Individual Plant Examination [IPE] and Accident Management) have not been completed for all plants. Since these programs have identified plant programmatic and procedural improvements (and in a few cases, minor modifications) as cost-effective in reducing severe accident and risk consequences, NRC thought it premature to draw a generic conclusion as to whether severe accident mitigation would be required for license renewal. Site-specific information to be presented in the environmental report includes: (1) potential SAMAs; (2) benefits, costs, and net value of implementing potential SAMAs; and (3) sensitivity of analysis to changes to key underlying assumptions.

Baltimore Gas and Electric Company continues to define and control plant risk in an aggressive manner. The Company's current approach to modeling plant risk is considered to be one of the most comprehensive in the industry. Several ongoing plant activities are intended to more accurately define plant risk by refining modeling approaches and assumptions, providing alternative approaches to accident prevention and mitigation, and considering the effect on plant risk when evaluating day-to-day plant activities. As a result of refinements to the plant model, BGE expects to see a reduction in the calculated overall plant risk values. Additionally, BGE is implementing Severe Accident Management Guidelines to further improve the plant staff's capability to respond to a postulated severe accident involving core damage. Finally, BGE's aggressive approach to risk-informed plant maintenance will continue to provide a high degree of assurance that planned equipment maintenance will not result in an adverse impact on the overall plant risk profile. The combined effect of all of these activities is expected to result in a plant risk reduction that will be factored into any future assessment of alternatives to mitigating severe accidents.

4.1.17.1 Methodology Overview

The methodology used to perform the CCNPP SAMA analysis was based primarily on the handbook used by the NRC to analyze benefits and costs of its regulatory activities, NUREG/BR-0184 (Reference 134), subject to CCNPP-specific considerations. Baltimore Gas and Electric Company's SAMA requirements, approach, methodology, and exceptions were discussed with NRC staff during a series of public meetings (References 135, 136, 137, 138, 139).

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

Initial input for BGE's SAMA benefits analysis was the Calvert Cliffs Probabilistic Risk Assessment (CCPRA) model. The CCPRA model is the Unit 1 internal and external events risk model. This model is an updated version of the IPE (Reference 140), combined with an updated version of the Individual Plant Examination for External Events (Reference 141). Therefore, the SAMA analysis is based on Unit 1 modeling (with exceptions noted). As noted in Section 4.1.17.2, the estimated risk for Unit 1 is lower than that for Unit 2 due to the two self-cooled EDGs, one of which is dedicated to Unit 1, that were installed subsequent to submittal of the IPE. Baltimore Gas and Electric Company is currently evaluating the effect of this difference on the results of this analysis, but does not expect any change to the final SAMA conclusions.

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

- Establish the Base Case – Use NUREG/BR-0184 to evaluate severe accident impacts:
  - Offsite exposure – Monetary value of consequences (dose) to offsite population;

    Use the CCPRA model to determine total accident frequency (core damage frequency and containment release frequency); Melcor Accident Consequences Code System (MACCS) to convert release input to public dose; and NUREG/BR-0184 methodology to convert dose to present worth dollars (based on valuation of $2,000 per person-rem and present worth discount factor).

  - Offsite economic costs – Monetary value of damage to offsite property;

    Use the CCPRA model to determine total accident frequency (core damage frequency and containment release frequency); MACCS to convert release input to offsite property damage; and NUREG/BR-0184 methodology to convert offsite property damage to present worth dollars.

  - Onsite exposure costs – Monetary value of dose to workers; and

    Use NUREG/BR-0184 best estimate occupational dose values for immediate and long-term dose, then apply NUREG/BR-0184 methodology to convert dose to present worth dollars (based on valuation of $2,000 per person-rem and present worth discount factor).

  - Onsite economic costs – Monetary value of damage to onsite property.

    Use NUREG/BR-0184 best estimate cleanup and decontamination costs, then apply NUREG/BR-0184 methodology to convert onsite property damage estimate to present worth dollars. Onsite property damage covered by insurance and replacement power costs unlikely to be incurred in a deregulated market are not included.

- SAMA Identification – Identify potential SAMAs from the following sources:
  - Severe Accident Mitigation Design Alternative (SAMDA) analyses submitted in support of original licensing activities for other operating nuclear power plants and advanced light water reactor plants;
  - NRC and industry documentation discussing potential plant improvements; and
  - Insight provided by BGE's staff.
- Preliminary Screening – Eliminate obviously non-viable candidates, based upon:
  - SAMA improvements that modify features not applicable to CCNPP;
  - SAMA improvements that have already been implemented at CCNPP; or
  - SAMA improvements could be consolidated with one or more other SAMA improvement(s).
- Final Screening – Eliminate candidates based on preliminary analysis:
  - SAMA re-definition – Redefine general SAMA concepts in terms of CCNPP-specific design and/or process improvements; and
  - Application of feasibility criteria – Eliminate non-viable candidates based upon whether:
    - Implementation of SAMA would require extensive plant reconstruction;
    - Cost of implementing SAMA would exceed maximum benefit for Base Case evaluation; or
    - CCNPP's current design, procedures, and practices already implement the improvement concept proposed by the SAMA.
- Benefit/Cost Evaluation – Calculate net value of implementing each remaining SAMA:
  - Benefit calculation – Estimate benefits of implementing each SAMA individually;
    - NUCAP+™ – Use computer model, NUCAP+, to simplify PRA model sequences and assess SAMA impact on PRA accident frequency results (core damage frequency and/or containment failure frequency). NUCAP+ modeling was validated by comparing sample NUCAP+ results to subset of IPE PRA results.
    - SAMA impacts – Calculate impacts (i.e., on-site/off-site dose and damages) by manipulating the CCPRA model to simulate revised plant risk following implementation of each individual SAMA.

    - Averted SAMA impacts – Calculate benefits for each SAMA in terms of averted consequences. Averted consequences are the arithmetic difference between the calculated impact for the base case and revised impact following implementation of each individual SAMA.
    - SAMA Benefits - Calculate total benefit for each SAMA by summing the averted impacts.
  - Cost of Enhancement (COE) calculation – Estimate the cost of implementing each individual SAMA candidate; and
  - Net Value calculation - Subtract the COE from the benefit of each SAMA to determine the net value of each SAMA candidate.
- Sensitivity Analysis – Determine the effect that changing the discount rate would have on the net value calculation.
- Conclusions – Identify SAMAs having positive net values, if any, and implementation plans or basis for not implementing.

The BGE SAMA analysis for CCNPP is presented in the following sections. These sections provide a detailed discussion of the process presented above.

4.1.17.2 Establishing the Base Case

The purpose of establishing the base case is to provide the baseline for determining the risk reductions that would be attributable to the implementation of potential SAMAs. This severe accident risk, based on the CCPRA model, is calculated through use of the NUCAP+ computer model, based upon site-specific meteorology, population characteristics, and economic information.

The primary source of data relating to the base case is the CCPRA model. The CCPRA model is the latest version of the Calvert Cliffs Unit 1 risk model, and uses PRA techniques to:

- Develop an understanding of severe accident behavior;
- Understand the most likely severe accident consequences;
- Gain a quantitative understanding of the overall probabilities of core damage and fission product releases; and
- Evaluate hardware and procedure changes to assess the overall probabilities of core damage and fission product releases.

The CCPRA model includes both internal events (e.g., loss of feedwater event, loss of coolant accident) and external events (e.g., fire, hurricane, earthquake). It is far more advanced than the IPE submitted to the NRC in December 1993 (Reference 140), and slightly more advanced than the Individual Plant Examination for External Events submitted in August 1997 (Reference 141). Due to this continuous refinement, the CCPRA model is considered a "living" plant risk model. The CCPRA model is periodically updated as a result of:

- Equipment Performance - As data collection progresses, estimated failure rates and system unavailabilities change.
- Plant Configuration Changes - There is a time lag between changes to the plant and incorporation of those changes into the CCPRA model.

- Modeling Changes - The CCPRA model is constantly being refined to incorporate the latest state of knowledge. For example, if a new design calculation indicates that the heat-up rate of various plant areas is not as significant as initially estimated, then this information will be incorporated into the model.

The CCPRA model describes the results of the first two levels of the PRA for CCNPP Unit 1. These levels are defined as follows: Level 1 - determines core damage frequencies based on system analyses and human-factor evaluations; and Level 2 - determines the physical and chemical phenomena that affect the performance of the containment and other radiological release mitigation features to quantify accident behavior and release of fission products to the environment. The scope of plant challenges[5] considered in the CCPRA model includes internal events (e.g., turbine trips, loss of main feedwater, internal floods) and external events (e.g., earthquakes, fires).

Using the results of these analyses, the next step is to perform a Level 3 PRA analysis, which calculates the hypothetical impacts of severe accidents on the surrounding environment and members of the public. The MACCS computer code is used for determining the offsite impacts for the Level 3 analysis, whereas the magnitude of the onsite impacts (in terms of clean-up and decontamination costs and occupational dose) are based on information provided in NUREG/BR-0184 (Reference 134). The principal phenomena analyzed are atmospheric transport of radionuclides, mitigative actions (i.e., evacuation, condemnation of contaminated crops and milk) based on dose projection, dose accumulation by a number of pathways, including food and water ingestion, and economic costs. Input for the Level 3 analysis includes the CCNPP core radionuclide inventory, source terms from the IPE (as applied to the CCPRA model), site meteorological data, projected population distribution (within 50-mile radius) for the year 2030[6], emergency response evacuation modeling, and economic data. Appendix F.1 describes the MACCS input data and assumptions.

The Level 3 analysis looks at five source term[7] categories: two with early containment failure, one with late containment failure, and two with containment bypass as the failure mode. Because the analysis is based on probabilistic risk input, the analytical results relate the frequency of an impact to the magnitude of the impact (i.e., frequency versus risk). In general, severe accidents having the greatest predicted impact have the lowest predicted probability of occurrence.

Calvert Cliffs Units 1 and 2 have many similarities, including nearly identical nuclear steam supply systems, operating procedures, and maintenance practices. However, there is a difference between the Units associated with the EDG configuration. This difference is due to the recent addition of two self-cooled EDGs. As a result of this modification, Unit 1 has one service water (SRW)-cooled EDG and one self-cooled EDG, while Unit 2 has two SRW-cooled EDGs. In addition, a non-safety-related diesel generator with the capability to substitute for any of the EDGs on either Unit was added. The reduced SRW dependency for Unit 1 results in the lower risk for Unit 1 versus Unit 2.

Depending upon the nature of each SAMA, there could be differences in the applicability of the benefit analysis to Unit 2. Those SAMAs that modify the systems that support the EDGs (enhance SRW performance or remove SRW dependency) would have a somewhat larger benefit on Unit 2 than on

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5 The term "plant challenges" refers to events that could initiate a sequence of actions that could lead to unacceptable consequences.

6 Census year (decade) closest to the end of the license period.

7 The term "source term" refers to the amount of radioactivity that could be released to the environment following a severe accident.

Unit 1. Improvements which are not associated with the configuration differences between the Units (e.g., Containment Spray System modifications) will produce nearly identical results.

Offsite Exposure Cost

The Level 3 base case analysis shows an annual offsite exposure risk of 68.63 person-rem. This calculated value is converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem (Reference 142). This monetary equivalent must then be discounted to present value using the NRC standard formula (Reference 134):

$W_{pha} = C \times Z_{pha}$

where W_{pha} = monetary value of public health risk after discounting
$C = [1 - \exp(-rt_f)]/r$

where t_f = years remaining until end of facility life = 20 years
r = real discount rate (as fraction) = 0.07
Z_{pha} = monetary value of public health (accident) risk per year before discounting ($/year)

Using a 20-year period for remaining plant life and a 7 percent discount rate results in a value of approximately 10.76 for C. Therefore, calculating the discounted monetary equivalent of public health risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value, approximately 10.76. The resulting monetary equivalent is presented in Table 4-2.

Offsite Economic Costs

The Level 3 analysis shows an annual offsite economic risk of $69,109. Calculated values for offsite economic costs caused by severe accidents must also be discounted to present value. Discounting is performed in the same manner as for the public health risks discussed above and uses the same C value, approximately 10.76. The resulting monetary equivalent is presented in Table 4-2.

Onsite Exposure Cost

Values for occupational exposure associated with severe accidents are not derived from the CCPRA model, but, instead, are obtained from information published by the NRC (Reference 134). The values for occupational exposure consists of "immediate dose" and "long-term dose." The best estimate values provided by the NRC for immediate occupational dose is 3,300 person-rem, and long-term occupational dose is 20,000 person-rem (over a ten-year clean-up period). The following equations are applied to these values to calculate monetary equivalents.

Immediate Dose

For a currently operating facility, NUREG/BR-0184 recommends calculating the immediate dose present value with the following equation:

Equation (1):

$W_{IO} = R\{(FD_{IO})_S - (FD_{IO})_A\}\ \{[1 - \exp(-rt_f)]/r\}$

where:
- W_{IO} = monetary value of accident risk due to immediate doses, after discounting, ($)
- IO = subscript denoting immediate occupational dose
- R = monetary equivalent of unit dose, ($/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 CCNPP analysis are:

- R = $2,000/person-rem
- r = 0.07
- D_{IO} = 3,300 person-rem/event (best estimate)
- t_f = 20 years (license extension period)
- F = 3.3×10^{-4} events/year (total core damage frequency)

For the basis discount rate, assuming F_A is zero, the monetary value of the immediate dose associated with CCNPP's accident risk is:

$$\begin{aligned} W_{IO} &= R\,(FD_{IO})_S\ \{[1 - \exp(-rt_f)]/r\} \\ &= 2{,}000*3.3\text{x}10^{-4}*3{,}300*\{[1 - \exp(-0.07*20)]/0.07\} \\ &= \$23{,}442 \end{aligned}$$

Long-Term Dose

For a currently operating facility, NUREG/BR-0184 recommends calculating the long-term dose present value with the following equation:

Equation (2):

$W_{LTO} = R\{(FD_{LTO})_S - (FD_{LTO})_A\}\ \{[1 - \exp(-rt_f)]/r\}\ \{[1 - \exp(-rm)]/rm\}$

where:
- W_{LTO} = monetary value of accident risk long-term doses, after discounting, ($)
- LTO = subscript denoting long-term occupational dose
- m = years over which long-term doses accrue

The values used in the CCNPP analysis are:

R = \$2,000/person-rem
r = 0.07
D_{LTO} = 20,000 person-rem/event (best estimate)
m = "as long as 10 years"
t_f = 20 years (license extension period)
F = 3.3×10^{-4} events/year (total core damage frequency)

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

$$W_{LTO} = R\,(FD_{LTO})_S\ \{\,[1 - \exp(-rt_f)]/r\}\ \{[1 - \exp(-rm)]/rm\}$$
$$= 2{,}000 * 3.3\text{x}10^{-4} * 20{,}000 * \{\,[1 - \exp(-0.07*20)]/0.07\}\ \{[1 - \exp(-0.07*10)]/0.07*10\}$$
$$= \$102{,}171$$

Total Occupational Exposures

As shown in Table 4-2, combining Equations (1) and (2) above and using the above numerical values, the long-term accident related onsite (occupational) bounding dose (W_O) is equivalent to:

$W_O = W_{IO} + W_{LTO}$ = (\$23,442 + \$102,171) = \$125,613

Onsite Economic Costs

The net present value for cleanup and decontamination provided in NUREG/BR-0184 is \$1.1 billion (discounted over 10 years). This value must be discounted to present value by multiplying by C (approximately 10.76). To obtain the annual onsite economic risk, this value must then be multiplied by the total core damage frequency of $3.3\text{x}10^{-4}$. The resulting monetary equivalent is \$3.9 million.

Baltimore Gas and Electric Company is already paying for the risk of onsite property damage through insurance premiums reflecting the actuarial value of the damage. This property damage insurance would pay up to \$2.75 billion (in current dollars, with a \$2.5 million deductible), and offsets any loss (any cost) of the insured amount. The insured cost cannot be ignored or dismissed as a "transfer payment" because it is not a free transfer or a benefit. Rather, it is the payment of an accumulated amount provided by the insurance company in return for premiums. Therefore, only the portion of onsite property damage that is above and beyond the coverage provided by BGE's property damage insurance is included in this analysis. As the onsite economic costs for the base case are much less than the \$2.75 billion insurance coverage, this impact is assumed to be zero for this analysis.

With respect to replacement power costs, the rapid transition to energy deregulation makes it extremely remote and speculative that such costs would be incurred. If a nuclear plant were no longer able to sell its power in a deregulated market, one would expect the next marginal producer to replace the power at approximately the same market price. Given this expectation, consumers should not see any significant price impact, and consequently there should be no appreciable public or societal impact. Therefore, no additional valuation for replacement power costs is assumed in this analysis.

4.1.17.3 SAMA Identification and Screening

The NRC and the nuclear industry have documented analyses of methods to mitigate severe accident impacts for existing and new plants designs and for in-system evaluations. Appendix F.2 lists documents from which BGE gathered descriptions of candidate SAMAs. In addition, BGE, in preparing the CCNPP IPE (Reference 140), gained insight into possible CCNPP-specific improvements that could reduce severe accident risks. Table F.2-1 of Appendix F.2 lists the 158 candidate SAMAs that BGE identified for analysis and identifies the source of the information. The first step in the analysis was to eliminate non-viable SAMAs through preliminary screening.

Preliminary Screening

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were obviously not viable for implementation at CCNPP, or could be combined with other similar SAMAs. Screening criteria include:

- Enhancements not applicable to CCNPP (e.g., applicable only to boiling water reactors);
- Enhancements that have already been implemented at CCNPP (e.g., automatic transfer to containment sump recirculation); and
- Similar enhancements that were consolidated.

Table F.2-1 of Appendix F.2 provides a brief discussion of each candidate SAMA and its disposition, whether eliminated from further consideration as unfeasible, combined with another SAMA(s), or designated for further analysis. Based on this preliminary screening, 46 candidate SAMAs were eliminated, 25 conceptual SAMAs were combined into 9 new SAMAs, and 96 of the original SAMAs were designated for further analysis.

Final Screening

The first step in final screening process was to redefine the generic conceptual SAMA description by applying plant-specific information on possible means of implementing the SAMA at CCNPP. This step facilitated further identification of SAMAs that have already been implemented at CCNPP and provided a basis for bounding benefit and cost estimates. The redefined SAMA description provides a more specific description to be compared with the current plant configuration and processes. Based upon this specific SAMA description, a number of potential SAMA candidates were screened out, as they were adequately addressed by existing plant procedures and/or processes.

Baltimore Gas and Electric Company estimated the costs of implementing each SAMA through the application of engineering judgment, estimates from other licensee's submittals, and site-specific cost estimates. To provide common grounds for comparison with the monetized benefits values, implementation cost estimates were calculated based on a single-unit implementation basis. The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. Estimates, based on modifications that were implemented or estimated in the past, were presented in terms of dollar values at the time of implementation (or estimation), and were not adjusted to present-day dollars.

Screening based on level of benefit achieved was carried out in two steps. The first step involved calculating the maximum benefit that could possibly be provided by any one SAMA or combination of SAMAs. This maximum theoretical benefit is based upon the elimination of all plant risk and equates to the previously-calculated base case risk. As shown in Table 4-2, the monetized value of this risk is approximately $2,346,000. Therefore, any SAMA having an estimated single-unit cost of implementation exceeding $2.4 million would not be considered cost-beneficial and was screened from further consideration.

The next step involved performing a benefits analysis on the remaining SAMAs to screen out any hardware SAMAs having an estimated monetized benefit of less than $40,000 (Section 4.1.17.4 discusses benefit calculations in more detail). This step was based on the conclusion that the minimum cost of implementation of a hardware modification at CCNPP would be $40,000. Any SAMA involving a plant modification, therefore, would have to have an estimated benefit of at least $40,000 to be considered cost-beneficial.

In summary, the final screening process eliminated SAMAs having an estimated cost of implementation greater than $2.4 million or an estimated monetized benefit of less than $40,000 (for hardware modifications), as well as those already implemented at CCNPP. Table F.2-2 of Appendix F.2 includes the expanded definition and benefits discussion for the 105 SAMAs subjected to this final screening and provides the specific basis for eliminating 79 from further consideration and subjecting 26 to a more detailed benefit/cost analysis (of which 3 are still being reviewed by BGE).

4.1.17.4 Evaluation of Benefits and Costs

The methodology for determining if a SAMA is beneficial consists of determining the "net value" added by that SAMA. The net value is defined as the sum of the dollar equivalents for each severe accident impact (offsite exposure, offsite economic costs, occupational exposure, and onsite economic costs) minus the cost of implementing the SAMA. If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA, and the SAMA would not be considered cost-beneficial.

The result of implementation of each SAMA would be a change in the CCNPP severe accident risk (i.e., a change in frequency or consequence of severe accidents)[8]. The methodology for calculating the magnitude of these changes is straightforward. First, the CCNPP severe accident risk after implementation of each SAMA is calculated using the same methodology as for the base case. The NUCAP+ model was used to calculate those post-SAMA risks. Appendix F.3 provides a description of the NUCAP+ and presents BGE's validation of the NUCAP+ model relative to the model (RISKMAN) used in the CCPRA model. Some of the SAMAs resulted in a change to both the Level 1 and Level 2 results, while other SAMAs resulted in a change to the Level 1 results only. The NUCAP+ model was used in both of these instances. The results of these analyses for each of the four analytical impacts are subtracted from the base case results presented in Table 4-2 to calculate the difference (i.e., "averted" risk). Additional details regarding calculation of benefits for the SAMAs requiring a detailed cost/benefit analysis are presented in Appendix F.4.

Each SAMA was evaluated in a bounding fashion. Bounding evaluations were performed to address the generic nature of the initial SAMA concepts and to allow each SAMA benefit to be calculated using the saved sequences instead of re-quantifying the plant model.

Evaluating conceptual enhancements can be accomplished in several ways. One approach is to consider many specific enhancements for each of the identified conceptual SAMAs and evaluate each of those

8 Frequency x consequence = risk.

specific enhancements. Although this approach is the most technically accurate, it is also the most time-consuming. Another approach is to bound the problem by assuming that the conceptual SAMA provides the total benefit of each of the specific enhancements. Although this is conservative, if the benefit is screened from a cost perspective, then only a single evaluation is required verses many.

When the plant model is quantified, the results of the quantification are those sequences which lead to core damage. These sequences are called the saved sequences. Producing saved sequences for a single plant model quantification can take in excess of 30 days of computing time as well as several man-days of modeling. Although a full plant model quantification produces the most accurate results for a plant enhancement, the extensive amount of processing time makes this very impractical. However, evaluations may be performed more quickly by processing the saved sequences from the original plant model quantification. Since the same set of sequences are used repeatedly, an evaluation using these original saved sequences may take only a couple of man-hours.

Although using the saved sequences is very time efficient, this approach requires several conservative analysis techniques to achieve bounding results. The most significant of these techniques is to calculate the improvement benefits by setting not only the improved function to success, but by also setting those functions that support the improved function to success, as well. This can best be illustrated by an example. To evaluate the improvement obtained by increasing the capacity of the batteries to 24 hours, the systems which normally provide the batteries with long-term power are set to success, as well the battery chargers themselves. In some cases, such as battery capacity extension, this results in a quite conservative benefit estimate. As a result of these approximations, the benefit may be over-estimated. A detailed evaluation of a specific enhancement may result in a noticeable reduction in the estimated benefit.

As described above for the base case, values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem (Reference 142) and discounted to present value. Values for avoided offsite economic costs were also discounted to present value. The formula for calculating net value for each SAMA is as follows:

Net value = ($APE + $AOC + $AOE + $AOSC) - COE

where $APE = monetized value of averted public exposure ($)
$AOC = monetized value of averted offsite costs ($)
$AOE = monetized value of averted occupational exposure ($)
$AOSC = monetized value of averted onsite costs ($)
COE = cost of enhancement ($)

The projected cost of each SAMA (COE) was derived by utilizing applicable cost estimates published in NRC submittals from other licensees or by preparing CCNPP-specific estimates. The first step in the process was to review previous licensee SAMDA submittals (e.g., the Watts Bar Nuclear Plant SAMDA evaluation). If these previous submittals contained costs for a specific SAMDA, the SAMDA description was reviewed to determine if the cost estimate could reasonably be applied to CCNPP, based on CCNPP's design and licensing bases and knowledge of 20 years of experience associated with implementing plant modifications. If the previous licensee submittals did not contain cost estimates or if these cost estimates could not be applied to CCNPP, one of three sources was then evaluated: similar modifications already implemented at CCNPP, similar modifications implemented at other plants, or previous estimates prepared for CCNPP modifications. If similar modifications had previously been implemented at CCNPP, the costs of these previous modifications were scaled up or down to estimate the

SAMA cost. If none of these three other sources contained usable cost estimates, BGE performed a new detailed cost estimate. Estimates prepared for modifications to safety-related systems were based on ensuring the safety-related aspects of the current plant design are maintained. Specific descriptions of the SAMA cost estimates are provided in Appendix F.4.

Calculated net values for each remaining SAMA are presented in Table 4-3.

4.1.17.5 Sensitivity Analysis

NUREG/BR-0184 recommends using a 7 percent real (i.e., inflation-adjusted) discount rate for value-impact analysis and notes that a 3 percent discount rate should be used for sensitivity analysis to indicate the sensitivity of the results to the choice of discount rate. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. Analyses presented in Section 4.1.17.3 used the 7 percent discount rate in calculating net values for 23 SAMAs. Baltimore Gas and Electric Company also performed a sensitivity analysis by substituting the lower discount rate and recalculating the net value of the strongest candidate SAMAs (10 having highest net values). These values are shown in Table 4-4. As indicated, reducing the discount rate increases the net value of potential SAMAs and reorders their relative ranking.

4.1.17.6 Results

Baltimore Gas and Electric Company analyzed 158 conceptual alternatives for mitigating CCNPP severe accident impacts. Preliminary screening eliminated 46 SAMAs from further consideration, based on inapplicability to CCNPP's design or features that have already been incorporated into CCNPP's current design and/or procedures and programs. Another 25 conceptual SAMAs were combined into 9 new plant-specific SAMAs. During final screening, 79 redefined SAMA candidates were eliminated as a result of disproportionately high implementation costs, low monetized benefits, or design features and/or processes that were already implemented at CCNPP. Due to uncertainties associated with accurately defining the benefits and cost of implementation, three SAMA candidates are still being reviewed under BGE's ongoing efforts to define and control core damage frequency. The remaining 23 SAMA candidates were subjected to a detailed benefit/cost analysis. The averted public exposure, averted offsite cost, averted occupational exposure, averted onsite cost, and implementation cost and net value data for the SAMAs that required a detailed benefit/cost analysis are presented in Table 4-3.

Using the 7 percent real discount rate recommended by NUREG/BR-0184*,* all 155 SAMA candidates for which the evaluation has been completed resulted in negative net values, and are, therefore, determined not to be cost-beneficial. With a 3 percent discount rate, as used in the sensitivity analysis, the magnitude of the negative net values changed, but no additional SAMA candidates were determined to have a positive net value. Furthermore, it was determined that, based on CCNPP's current design and procedures, none of the SAMA enhancements determined to be cost-beneficial for other U.S. nuclear power plants would provide a significant benefit at CCNPP.

In summary, based on the results of this SAMA analysis, BGE has not found any cost-beneficial SAMAs at this time. As described in the introduction to Section 4.1.17, BGE is aggressively pursuing a number of approaches to controlling plant risk and refining the plant risk model. The combined effect of these activities is expected to result in an overall plant risk reduction, which will be factored into any future consideration of alternatives to mitigating severe accidents.

4.1.18 Transportation

NRC

The environmental report must contain an assessment of transportation of fuel and waste " . . . in accordance with § 51.52. The review of impacts shall also discuss the generic and cumulative impacts associated with transportation operation in the vicinity of a high-level waste repository site. The candidate site at Yucca Mountain should be used for the purpose of impact analysis as long as that site is under consideration for licensing." 10 CFR 51.53(c)(3)(ii)(M)

"Table S-4 of this Part contains an assessment of impact parameters to be used in evaluating transportation effects in each case." 10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 85)

"The values shown in Table S-4 are conservative estimates developed on the basis of an average fuel irradiation (burnup) of 33,000 MWd/MTU. Discussions and analyses in NUREG/CR-5009 (PNL-6258) *Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors,* February 1988, show that the burnup level of fuel up to 60,000 MWd/MTU will not result in environmental impacts that are greater than the values currently in Table S-4 . . . ." GEIS Section 6.2.3

"Recent, ongoing efforts by the Department of Energy . . . suggest that there may be unresolved issues regarding the magnitude of cumulative impacts from the use of a single rail line or truck route in the vicinity of the repository to carry all spent fuel from all plants. Accordingly, NRC declines to reach a Category 1 conclusion on this issue at this time." Discussion of Regulatory Requirements, 61 FR 109, June 5, 1996, page 28480.

The NRC made the environmental impacts of transportation of fuel and radioactive waste a Category 2 issue because of a suggestion that there may be unresolved issues regarding the generic and cumulative impacts of transportation infrastructure construction and operation in the vicinity of the Yucca Mountain repository site. In addition, plant-specific information is needed to determine whether a plant fits within the generic envelope of the Table S-4 analysis. Information to be ascertained includes core thermal power level, fuel enrichment, spent fuel average irradiation, shipping of irradiated fuel and radioactive waste, and the packaging of radioactive waste [10 CFR 51.52(a)].

§ 51.52 and Table S-4

Nuclear Regulatory Commission regulation 10 CFR 51.52 presents Table S-4 and indicates that, for a reactor that meets specified criteria, Table S-4 summarizes the environmental effects of transporting fuel (new and spent) and radioactive waste to and from the reactor site on a per-year basis. The table identifies heat and weight per irradiated fuel cask in transit, traffic density, and individual and cumulative dose for workers and the general population under normal conditions. The table also identifies environmental risks from radiological and non-radiological effects under accident conditions. See Table 4-5 for a reprint of Table S-4.

The regulation requires that environmental reports contain either: (a) a statement that the reactor meets specified criteria, in which case its environmental effects would be bound by Table S-4; or (b) further analysis of the environmental effects of transportation of fuel and waste to and from the reactor site. The criteria in Paragraph (a) of 10 CFR 51.52 are not likely to be met by many plants now using higher burnup fuel. The Commission has stated that, in such cases, applicants may incorporate in their analyses the discussion presented in the GEIS in Section 6.2.3, "Sensitivity to Recent Changes in Fuel Cycle," and Section 6.3, "Transportation." (61 FR 66538)

Calvert Cliffs meets all the §51.52(a) criteria but the following two (see Section 2.1.2 for discussion of CCNPP nuclear fuel and radioactive waste):

PLANT PARAMETER	10 CFR 51.52(a) CRITERIA	CURRENT CCNPP AUTHORIZATION
Uranium-235 fuel enrichment, percent	not to exceed 4.0	5.0
Spent fuel average level of irradiation or burnup, MWd/MTU	not to exceed 33,000	60,000

In authorizing BGE to increase CCNPP fuel enrichment to 5 percent uranium-235 and burnup to 60,000 MWd/MTU, NRC also published an environmental assessment and FONSI.[9] The NRC analyzed environmental impacts that the increased fuel enrichment and burnup and a 24-month refueling cycle would have, and decided that the findings of two earlier NRC environmental assessments are applicable to CCNPP.[10] The NRC observed that whatever increased environmental effects are attributable to increases in fuel enrichment and burnup are more than offset by the resultant longer refueling cycle, which results in less-frequent spent fuel handling and fewer shipments. The NRC concluded that CCNPP transportation impacts are either unchanged or reduced from those summarized in Table S-4 and in satisfaction of 10 CFR 51.52(b). Baltimore Gas and Electric Company adopts by reference the NRC analysis and conclusion.

The NRC's CCNPP-specific analysis and conclusion is consistent with the NRC's generic analyses and conclusions found in GEIS Sections 6.2.3, "Sensitivity to Recent Changes in the Fuel Cycle," and 6.3, "Transportation." As NRC provides for in the preamble to its final license renewal environmental report rulemaking,[11] BGE incorporates the GEIS discussion into this environmental report.

In GEIS Section 6.2.3, NRC analyzes the sensitivity of Table S-4's conclusions to increases in fuel enrichment, burnup, and refueling cycle. The NRC noted that while enrichment impacts increase about 5 percent with each 6-month extension of the refueling cycle, the higher burnup of fuel achieved in the longer refueling cycles reduces the average annual output of spent fuel by as much as 45 percent. Analyses show that no revision to Table S-4 would be required as a result of extended burnup up to 60,000 MWd/MTU.

In GEIS Section 6.3, based on Table S-4, NRC discussed the effects of license renewal on low-level waste, mixed waste, and spent fuel transportation. The NRC determined that rail and truck transport corridors should easily accommodate the increase in low-level and mixed waste shipments from license renewal, and that license renewal would result in an additional two to three days of shipments for each reactor's spent fuel under Table S-4 conditions (Table S-4 impacts are presented on the basis of a reference reactor year, so additional years of operation from license renewal do not affect the table's estimates). The environmental impacts from the transportation of fuel and waste attributable to license renewal, based on Table S-4, are found to be small.

In conclusion, NRC and BGE have determined that the 10 CFR 51.52, Table S-4, description of environmental impact of transportation of fuel and radioactive waste to and from one light-water-cooled

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9 54 FR 4352 - 4353, January 30, 1989. Copy included in Appendix G.

10 53 FR 30355 - 30358, August 11, 1988, which references 53 FR 6040 - 6043, February 29, 1988. Copies included in Appendix G.

11 61 FR 66537 - 66554, December 18, 1996, at page 66538, column 3.

nuclear power reactor bounds the environmental impact from such transportation for CCNPP (CCNPP having two reactors, Table S-4 impacts must be doubled). Nuclear Regulatory Commission and BGE conclusions agree that environmental impacts from CCNPP transportation of fuel and radioactive waste attributable to license renewal (Issue 85) would be small.

Generic and Cumulative Impacts

Table S-4 presents bounding estimates of fuel and radioactive waste transportation environmental impacts for a single reactor. At the time of its 1996 rulemaking amending Part 51, the NRC indicated that there was insufficient information and that unresolved issues could exist regarding the magnitude of generic and cumulative impacts of transportation infrastructure construction and operation in the vicinity of a repository site. The NRC, therefore, declined to reach a Category 1 conclusion at that time.

Subsequent to the 1996 rule, the NRC staff performed a supplemental analysis that the NRC believes is sufficient to support a Category 1 conclusion on these issues. Pursuant to the Commission's instructions, the NRC is, therefore, pursuing a generic rulemaking that will categorize the impacts of transportation of high-level radioactive waste as a Category 1 issue (Reference 143). Moreover, the Commission directed that a licensee should only be required to provide a discussion of these issues in the plant-specific environmental report if a license renewal application is received before the rulemaking is completed, and a delay due to the generic rulemaking might affect the licensing process for a license renewal.

The NRC staff has stated that rulemaking would take approximately one year to complete, making spring 1999 a reasonable target date for finalization. The NRC review of the CCNPP license renewal application is expected to extend beyond spring 1999. Therefore, BGE does not expect the generic rulemaking to delay the CCNPP license renewal process and, consistent with the Commission's instructions, the environmental report does not at this juncture need to address generic and cumulative impacts associated with transportation infrastructure construction and operation in the vicinity of a high-level waste repository site.

4.1.19 New and Significant Information

NRC

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

" . . . absent 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 . . . ." Discussion of Regulatory Requirements, 61 FR 109, June 5, 1996, page 28483

Baltimore Gas and Electric Company is not aware of new and significant information regarding the plant's environment or plant operations that would make a generic conclusion codified by the NRC for Category 1 issues not applicable for CCNPP, that would alter regulatory or GEIS statements regarding Category 2 issues, or suggest any other measure of license renewal environmental impact.

4.2 Alternatives

NRC

" . . . the applicant shall discuss in this report the environmental impacts of alternatives . . . ." 10 CFR 51.53(c)(2)

" . . . GEIS contains a discussion of the environmental impacts of alternative energy sources . . . . The information in the GEIS is available for use by the NRC and the licensee in performing the site-specific analysis of alternatives . . . ." Supplementary information to the final rule, 61 FR 28467 - 28497, June 5, 1996, at Section III.B.3, page 28472, column 3.

As discussed in Section 2.2, consistent with the NRC license renewal decision-making standard, Section 4.2 provides sufficient information to clearly indicate whether an alternative would have greater environmental impact than the proposed action (i.e., license renewal), without trying to detail every adverse impact. Providing additional detail or analysis would serve no function if it would only bring to light more adverse impacts of alternatives to license renewal. Baltimore Gas and Electric Company has made effort not to bias the comparison in favor of license renewal by reasonably underestimating, rather than overestimating, the environmental impacts of alternatives to license renewal. For example, BGE assumes maximum reuse of existing facilities and high emissions removal efficiencies.

Sections 4.2.1 and 4.2.2 discuss the following potential environmental impacts: land use, ecology, aesthetics, water quality, air quality, solid waste, human health, socioeconomics, and culture. These are the same impacts, in the same order, that NRC analyzes alternatives to license renewal in the GEIS (GEIS Section 8.1). Sections 4.2.1 and 4.2.2 make frequent reference to the impact significance categories that NRC used (i.e., small, moderate, and large). Section 4.1.1 defines these impact categories.

4.2.1 Coal-Fired Generation

The following discussion includes frequent reference to the analysis that NRC performed on the environmental impacts of coal as an alternative energy source (GEIS Section 8.3.9) and summarized with other alternatives (GEIS Table 8.2).

Land Use

The coal-fired generation alternative would necessitate converting roughly an additional 900 acres of the Calvert Cliffs site to industrial use (plant, coal storage, ash, and scrubber sludge disposal). Currently, some of this land is farmed and the rest is a re-vegetated dredged spoils disposal area known as Lake Davies (Figure 2-3). Additional land use, not at the Calvert Cliffs site, would be attributable to mining necessary to supply 40 years worth of coal and transport coal to the site.

The NRC estimated that constructing a 1,000-MW coal plant at a greenfield[12] site would require approximately 1,700 acres, but that siting where a nuclear plant is located would reduce this impact. The NRC did not expressly characterize the significance of land-use impacts as small, moderate, or large, but did state that construction impacts at a greenfield site could be substantial.

12 "Greenfield" refers to a site not previously developed for power generation purposes. Site could be natural (e.g., wooded) or cultivated.

Using NRC's impact significance categories, the coal-fired generation land-use impact would not be categorized as "small" because converting 900 acres to industrial use would be a detectable change that would noticeably alter the present land-use pattern of agricultural and re-established vegetation. The impact would not be "large" because no important attribute would be destabilized. Although agricultural usage would be eliminated at the site, site agricultural lands are not unique in the region (Section 3.6), and eliminating agriculture at the Calvert Cliffs site should not affect offsite agricultural land use. Finally, almost 1,000 acres of the site's natural habitat would remain unaffected by the construction. Baltimore Gas and Electric Company concludes that the appropriate characterization of coal-fired generation land-use impact is "moderate;" the impact would noticeably alter the current land-use pattern but would not destabilize any important attribute.

A closed-cycle cooling system alternative at the Calvert Cliffs site would impact an additional 25 acres for cooling tower construction. Construction at a new site would impact roughly an additional 150 acres for offices, roads, parking areas, and a switchyard. An additional 424 acres would be needed for transmission lines (assuming plant is sited 10 miles from nearest intertie connection). Depending particularly on transmission line routing, these alternatives could result in moderate to large land-use impacts, consistent with the NRC characterization of land-use impacts at a greenfield site.

Ecology

The NRC concluded that constructing a 1,000-MW coal plant at a greenfield site could have large ecological impact, particularly if it was sited in a rural area with considerable natural habitat. Siting at the existing Calvert Cliffs site, however, should not noticeably alter ecological resources due to the use of previously disturbed areas and the existing intake and discharge system. Important Calvert Cliffs site ecological resources, such as the special-status species discussed in Section 3.1.3, would not be expected to be significantly affected, and approximately 1,000 acres of natural habitat at the site would remain untouched by construction. Impact to Chesapeake Bay ecology would remain unchanged, and 20 years of CCNPP operational monitoring have demonstrated that ecological impacts would not destabilize important attributes of the resource. Baltimore Gas and Electric Company concludes that the appropriate characterization of coal-fired generation ecological impacts would be "small;" that is, ecological effects would not be detectable or would be so minor that they would neither destabilize nor noticeably alter any important attribute of the resource.

The closed-cycle cooling system alternative would further reduce operational aquatic ecology impacts, but would introduce risk to vegetation, particularly tobacco crops, from salt drift. Construction at another site could significantly increase ecological impacts and would have to be reviewed for potential impact to threatened and endangered species. Even at an existing power plant site, adding coal-fired generation would introduce construction impacts and new, albeit incremental, operational impacts. At a greenfield site, an undisturbed area, the impacts would certainly alter the ecology. These ecological impacts could be moderate to large, consistent with the NRC characterization of ecological impacts at a greenfield site.

Aesthetics

The three power plant units, which could be as much as 200-feet tall, would be visible over intervening trees for miles around, particularly in both directions along the reach of the Chesapeake Bay. The three 600-foot tall stacks could be visible as far away as Annapolis, at a distance of 40 miles. This view would contrast strongly with what is otherwise a natural-appearing rural area, with woods and farming areas. Coal-fired generation would also introduce additional mechanical sources of noise (e.g., induced-draft fans and coal handling equipment) that would probably be audible offsite due to their proximity to the Bay.

Baltimore Gas and Electric Company concurs with the NRC conclusion that aesthetic impacts from such a large construction effort in a rural area could be substantial. Adding industrial structures that would be located atop the 100-foot cliffs at the Calvert Cliffs site and that would tower above area vegetation would create a noticeable visual impact for a large area. Given the predominately natural-appearing rural viewscape from the Chesapeake Bay, aesthetics is a significant attribute of the Bay's western shore in the Calvert Cliffs site area. A coal-fired generating station would contrast strongly with the existing resource. Baltimore Gas and Electric Company concludes that the appropriate characterization of coal-fired generation aesthetics impacts would be "large;" the impacts would be clearly noticeable and sufficient to destabilize an important resource.

The closed-cycle cooling system alternative would further increase aesthetic impacts by adding three 520-foot cooling towers and associated plumes. Alternative locations could reduce the aesthetic impact of coal-fired generation if siting was in an area that was already industrialized. In such a case, however, the introduction of such tall stacks and cooling towers would probably still have a moderate incremental impact. Although the environmental report is assuming use of natural draft towers as an alternative technology, mechanical draft towers are also available. Such devices, being only 50- to 100-feet tall, would reduce the visual impact of natural draft towers. Mechanical draft towers, however, introduce another noise source.

Water Quality

Surface Water

The coal-fired generation alternative is assumed to use the existing CCNPP intake and discharge structures and share water flow and temperature characteristics. Surface water quality would be affected by the need for routine maintenance dredging at the existing barge dock to support daily barge traffic.

The NRC did not dwell on water impacts from coal-fired generation, noting that some erosion and sedimentation would be expected from land-clearing activities. Baltimore Gas and Electric Company expects that best management practices required by the County Erosion and Sediment Control Ordinance (Table 5-1) would minimize these impacts. The NRC has determined that surface water quality, hydrology, and use impacts for license renewal would be small.[13] Because the coal-fired generation alternative is assumed to have the same discharge characteristics as CCNPP, and maintenance dredging impacts would be temporary and localized, BGE expects surface water impacts to remain "small;" the impacts would be so minor that they would not noticeably alter any important attribute of the resource.

13 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issues 1 through 12 (Issue 13 addresses cooling towers; therefore, it is not applicable to CCNPP).

Although surface water impacts are expected to remain small, the closed-cycle cooling system alternative would introduce cooling tower blowdown that would be at least two-and-one-half times as saline as the Chesapeake Bay, but, because of the reduced flow, surface water quality impacts should still be small.

Groundwater

The reduced workforce size (1,770 to 400) would reduce groundwater withdrawals for potable water use, but additional withdrawals would be needed for wet-scrubber sulfur oxides emissions control. Maximum groundwater consumption is assumed to be 800 gpm per unit (1,152,000 gallons per day per unit). Leachate from coal storage areas and ash and scrubber waste disposal areas would have to be controlled to avoid groundwater contamination.

The NRC did not address groundwater impacts from coal-fired generation. However, as discussed in Sections 3.2.2, 4.1.5, and 4.1.11, groundwater withdrawals in the Calvert Cliffs site area by public water supply systems, such as Lexington Park, is of some concern in the region. The coal-fired generation alternative would increase the site groundwater use from a current average 225,000 gallons per day to a potential maximum of more than three million gallons per day, an amount three times that of Lexington Park withdrawal. Such an increase would noticeably alter the site's impact on groundwater resources. It might be sufficient to destabilize the resource due to the volume of groundwater available. For these reasons, BGE concludes that the appropriate characterization of coal-fired generation groundwater impacts would be "large;" the impacts would be clearly noticeable and could destabilize this important resource.

Air Quality

Air quality impacts of coal-fired generation due to emissions of sulfur oxides, nitrogen oxides, particulates, and carbon monoxide are discussed below. Discussion of sulfur oxides and nitrogen oxides emission regulatory provisions is taken from the BGE Integrated Resource Plan (Reference 144).

Sulfur oxides emissions - Using current sulfur oxides emissions control technology (Section 2.2.1.1), the total annual stack emissions would include approximately 3,600 tons of sulfur oxides, most of which would be sulfur dioxide. Additional reductions could become necessary. The acid rain provision of the Clean Air Act (Title IV) capped the nation's sulfur dioxide emissions. Under the Act, affected fossil fuel-fired steam units are allocated a number of sulfur dioxide emission allowances. To achieve compliance, each utility must hold enough allowances to cover its sulfur dioxide emissions annually or be subject to certain penalties. If the utility's sulfur dioxide emissions are less than its annually-allocated emission allowances, then the utility may bank the surplus allowances for use in future years. A sulfur dioxide allowances market has been established for the buying and selling of allowances. Baltimore Gas and Electric Company has sulfur dioxide allowances that it anticipates will last until the year 2002 for its existing coal-fired units. To operate a coal-fired generation alternative beginning in the year 2014, however, BGE would have to purchase additional allowances or further reduce sulfur emissions at existing coal-fired plants. Baltimore Gas and Electric Company could achieve further reductions by shutting other plants down or by lowering coal sulfur content (e.g., pre-combustion cleaning), or increasing emissions removal efficiency at existing plants.

Nitrogen oxides emissions - Using currently available control technology (Section 2.2.1.1), the total annual nitrogen oxides emission would be approximately 1,680 tons. Clean Air Act Title IV, however, established an annual nitrogen oxides emissions reduction policy. In addition, Clean Air Act Title I Northeast Ozone Transport Region provisions are more stringent. Current, reasonably available control technology is not expected to achieve the Act's Title I ozone attainment standard, and further regional nitrogen oxides reductions are necessary. In order to implement a coal-fired alternative, BGE would be required to offset its corporate nitrogen oxides emissions through further reductions in nitrogen oxides emissions elsewhere, by shutting other sources down or by back-fitting to reduce nitrogen oxides formation (e.g., installing over-fired air, low nitrogen oxides burners, flue gas re-circulation, and selective non-catalytic and catalytic reduction systems). In the alternative, offsets might be available for purchase on open market.

Particulate emissions - The total annual stack emissions would include 234 tons of filterable particulates and 54 tons of PM_{10} (Section 2.2.1.1). In addition, coal handling equipment would introduce fugitive particulate emissions.

Carbon monoxide emissions - The total carbon monoxide emissions would be approximately 1,170 tons per year (Section 2.2.1.1).

The NRC did not quantify coal-fired emissions but implied that air impacts would be substantial. The NRC noted that adverse human health effects from coal combustion have led to important federal legislation in recent years, and that public health risks, such as cancer and emphysema, have been associated with results of coal combustion. The NRC also mentioned global warming and acid rain as potential impacts. Baltimore Gas and Electric Company concludes that federal legislation and large-scale concerns, such as acid rain and global warming, are indications of concerns about destabilizing important attributes of air resources, and that sulfur oxide emission allowances, nitrogen oxide emission offsets, low nitrogen oxide burners, overfire air, selective catalytic reduction, fabric filters or electrostatic precipitators, and scrubbers are regulatorily-imposed mitigation measures. As such, the appropriate characterization of coal-fired generation air impacts would be "moderate;" the impacts would be clearly noticeable, but would not destabilize this important resource. Due to the effect of emission allowance and offset requirements, overall regional nitrogen oxides emissions would be reduced, the net regional environmental impact would be positive, and additional mitigation would be unwarranted.

While constituent emissions might have to be reduced more than current projections due to Clean Air Act requirements, the overall impact of a coal-fired generation alternative would still be large. Siting the coal-fired generation elsewhere would not significantly change air quality impacts, although it could result in installing more or less stringent pollution control equipment to meet applicable standards.

Waste

Coal combustion generates waste in the form of ash, and air pollution control equipment generates additional ash and scrubber sludge. Approximately 1.5 million tons of this waste would be generated annually for 40 years and disposed of onsite, accounting for 600 of the 900 acres of land-use. While only half of these values are directly attributable to the alternative to a 20-year CCNPP license renewal, the total values are pertinent as a cumulative impact. This impact that could extend well after the 40-year operation life because re-vegetation management and groundwater monitoring for leachate contaminant impacts could be a permanent requirement.

The NRC concluded that large amounts fly ash and scrubber sludge would be produced and would require constant management. Baltimore Gas and Electric Company would agree that disposal of this waste could noticeably affect land use and groundwater quality, but believes that, with appropriate management and monitoring, would not destabilize any resources. After closure and re-vegetation, the land would be available for other uses, and regulatory requirements would ensure groundwater protection. For these reasons, BGE concludes that the appropriate characterization of coal-fired generation waste impacts would be "moderate;" the impacts would be clearly noticeable but would not destabilize any important resource.

Siting elsewhere would not alter waste generation, although other sites might have more constraints on disposal locations.

Human Health

Coal-fired generation introduces worker risks from fuel and lime/limestone mining and worker and public risks from fuel and lime/limestone transportation and stack emissions inhalation. Stack impacts can be very widespread and health risks difficult to quantify. This alternative also introduces the risk of coal-pile fires and attendant inhalation risks.

The NRC noted that there could be human health impacts (cancer and emphysema) from inhalation of toxins and particulates, but did not identify the significance of this impact. Baltimore Gas and Electric Company has no basis for estimating that the significance of these impacts is anything other than small. Regulatory agencies, such as the EPA and the Maryland Department of the Environment, focus on air emissions and revise regulatory requirements, or propose statutory changes, as human health impacts as a whole warrant. Such agencies also impose site-specific emission permit limits as needed to protect human health. Baltimore Gas and Electric Company concludes that the appropriate characterization of coal-fired generation human health impacts would be "small;" that is, human health effects would not be detectable or would be so minor that they would neither destabilize nor noticeably alter any important attribute of the resource.

Socioeconomics

It is assumed that coal-fired construction would take place while CCNPP continues operation, finishing at the time that the nuclear plant would halt operations. Therefore, for the 5-year construction period, the site would have between 1,500 and 2,000 additional workers. During this time, the surrounding communities would experience demands on housing and public services that could have large impacts. After construction, the communities would be impacted by the loss of jobs; construction workers would leave, the nuclear plant workforce (1,770) would decline through a decommissioning period to a minimal maintenance size, and the coal-fired plant would introduce only 220 new jobs.

NRC concluded that socioeconomic impacts at a rural site would be larger than at an urban site because more of the 1,200-2,500 peak construction workforce would need to move to the area to work. The NRC noted that operational impacts could result in moderate socioeconomic benefits in the form of several hundred additional jobs, substantial tax revenues, and plant spending.

Baltimore Gas and Electric Company expects that the size of the coal-fired generation construction workforce and plant-related spending during construction would be noticeable. However, due to the site's proximity to large labor pools in the Washington, DC, and Baltimore areas, BGE would not expect construction workers to move to the Calvert Cliffs area. Operational impacts would include an eventual loss of approximately 1,550 jobs, with a commensurate reduction in demand on socioeconomic resources and contribution to the regional economy. Baltimore Gas and Electric Company would expect that the area's rapid population growth (Section 3.8) would prevent any destabilization of socioeconomic resources. For these reasons, BGE concludes that the appropriate characterization of coal-fired generation socioeconomic impacts would be "moderate;" the impacts would be clearly noticeable but would not destabilize any important resource.

Construction at another site would relocate some socioeconomic impacts but would not eliminate them; the community around CCNPP would still experience the impact of CCNPP operational job loss, and the communities around the new site would have to absorb the impacts of a large, temporary workforce and a moderate, permanent workforce.

Cultural Resources

The NRC concluded that impacts to cultural resources would be relatively small unless important site-specific resources were affected. Baltimore Gas and Electric Company investigated cultural resources at the time of CCNPP construction (Section 3.7) and has an excellent inventory for the site and area. Construction of the coal-fired alternative at the Calvert Cliffs site could be performed without impinging on any cultural resources, and continued BGE conservancy of the site would be expected to provide continued positive benefits to the existing resources in the form of stewardship. Baltimore Gas and Electric Company concludes that the appropriate characterization of coal-fired generation cultural resource impacts would be "small;" that is, cultural resource effects would not be detectable or would be so minor that they would neither destabilize nor noticeably alter any important attribute of the resource. Overall effects are expected to be positive.

Construction at another site could necessitate instituting cultural resource preservation, but impacts can generally be managed and maintained as small.

4.2.2 Gas-Fired Generation

Land Use

Gas-fired generation at the Calvert Cliffs site would require converting an additional 60 acres of the site to industrial use. Currently, some of this land is farmed and the rest is a re-vegetated dredged spoils disposal area. An additional 10 acres would be disturbed during pipeline construction.

The NRC estimated that land-use requirements for a 1,000-MW gas-fired plant at a greenfield site would be small (approximately 110 acres), and that co-locating with a retired nuclear plant would reduce these impacts. Baltimore Gas and Electric Company land-use estimate is less than the NRC estimate and is roughly one-tenth of the BGE estimate for coal-fired generation. The land-use change should not noticeably alter the overall site natural land-use pattern. Baltimore Gas and Electric Company concludes that the appropriate characterization of gas-fired generation land-use impact is "small;" the impact would not be detectable or would be so minor that it would neither destabilize nor noticeably alter any important attribute of the resource.

The closed-cycle cooling system alternative would impact another 25 acres for cooling tower construction. Construction at a new site would impact another approximately 10 acres for offices, roads, parking areas, and a switchyard, and another 424 acres[14] for transmission lines. Depending particularly

[14] See Section 4.2.1, Land Use, footnote for calculation.

on transmission line routing, these alternatives could result in moderate impacts if conversion to industrial use would conflict with local land-use patterns.

Ecology

Siting gas-fired generation at the existing Calvert Cliffs site would have little ecological impact because the facility would be constructed on previously disturbed areas. Additional acreage would include farmland and a dredged spoils disposal area. Ecological impacts would also be minimized by using the existing intake and discharge system. Since this system has been in operation for over 20 years, the aquatic system has adjusted to the initial impacts of the intake and discharge system.

The NRC concluded that land-dependent ecological impacts from construction would be small unless site-specific factors should indicate a particular sensitivity, and that operational impacts would be smaller than for other fossil fuel technologies of equal capacity. Baltimore Gas and Electric Company has identified no site-specific factors that would make gas-fired alternative ecological impacts larger than for the coal-fired alternative or license renewal. Baltimore Gas and Electric Company concludes that the appropriate characterization of gas-fired generation ecological impacts would be "small;" that is, ecological effects would not be detectable or would be so minor that they would neither destabilize nor noticeably alter any important attribute of the resource.

The closed-cycle cooling system alternative would further reduce operational aquatic ecology impacts but would introduce risk to vegetation, particularly tobacco crops, from salt drift. Construction at another site could significantly increase ecological impacts and would have to be reviewed for potential impact to threatened and endangered species. Even at an existing power plant site, adding gas-fired generation would introduce construction impacts and new, albeit incremental, operational impacts. At a greenfield site, an undisturbed area, the impacts would certainly alter the ecology. These ecology impacts could be moderate to large.

Aesthetics

The combustion turbines and heat recovery boilers would be relatively low structures and would be screened from most offsite vantage points by intervening woodlands. The steam turbine building would be taller, approximately 100 feet in height, and together with 230-foot exhaust stacks, would be visible offsite.

The NRC concluded that land-related impacts, such as aesthetic impacts, would be small unless site-specific factors should indicate a particular sensitivity. As in the case of the coal-fired alternative, aesthetic impacts from the gas-fired alternative would be noticeable. However, because the gas-fired structures are shorter than the coal-fired structures and more amenable to screening by vegetation, BGE believes that the aesthetic resources would not be destabilized by the gas-fired alternative. For these reasons, BGE concludes that the appropriate characterization of gas-fired generation aesthetic impacts would be "moderate;" the impacts would be clearly noticeable but would not destabilize this important resource.

The closed-cycle cooling system alternative would further increase aesthetic impacts by adding water vapor plumes from mechanical draft cooling towers. Mechanical draft towers would also introduce a noise source. Alternative locations could reduce the aesthetic impact of gas-fired generation if siting was in an area that was already industrialized. In such a case, however, the introduction of the steam generator building, stacks, and cooling tower plumes would probably still have a moderate incremental impact.

Water Quality

The gas-fired generation alternative is assumed to use the existing intake and discharge structures and share water flow and temperature characteristics; water quality impacts would continue to be small. The reduced workforce size (1,770 to 125) would reduce groundwater withdrawals for potable water use; however, the existing groundwater impact is already small (Section 4.1.5).

Water quality impacts from sedimentation during construction was another land-related impact that NRC categorized as small. The NRC also noted that operational water quality impacts would be similar to, or less than, those from other centralized generating technologies. Baltimore Gas and Electric Company has concluded that water quality impacts from coal-fired generation would be small, and gas-fired alternative water usage would be less than that for coal-fired generation. Baltimore Gas and Electric Company concludes that surface water impacts would remain "small;" the impacts would not be detectable or be so minor that they would not noticeably alter any important attribute of the resource.

The closed-cycle cooling system alternative would introduce cooling tower blowdown that would be at least two and one half times as saline as the Chesapeake Bay but, because of the reduced flow, water quality impacts should not noticeably alter any important water quality attribute and so would remain small.

Air Quality

Natural gas is a relatively clean-burning fuel but, due to the site's location within the Northeast Ozone Transport Region and the area's problem with meeting ozone standards, air quality impacts of gas-fired generation would be of concern. Nitrogen oxides emissions would be 386 tons per year (Section 2.2.1.2). As discussed in Section 4.2.1 for coal-fired generation, Clean Air Act provisions might result in BGE having to further reduce nitrogen oxides by shutting other sources down or by back-fitting to reduce nitrogen oxides formation (e.g., installing over-fired air, low nitrogen oxides burners, flue gas re-circulation, and selective non-catalytic and catalytic reduction systems).

The NRC noted that gas-fired air quality impacts are less than other fossil technologies because fewer pollutants are emitted and sulfur dioxide is not emitted at all. Baltimore Gas and Electric Company emissions calculations (Section 2.2.1.2) confirm that gas-fired alternative emissions would be less than coal-fired alternative emissions. However, the gas-fired alternative would contribute nitrogen oxides emissions to an area that is classified as a serious nonattainment area for ozone (Section 3.3). Because nitrogen oxides contribute to ozone formation, the reduced nitrogen oxides emissions are still of concern, and low nitrogen oxides combusters, water injection, and selective catalytic reduction are regulatorily-imposed mitigation measures. For these reasons, BGE concludes that the appropriate characterization of gas-fired generation air impacts would be "moderate;" the impacts, primarily nitrogen oxides, would be clearly noticeable, but would not be sufficient to destabilize air resources as a whole. Due to the effect of offset requirements, discussed in Section 4.2.1, overall nitrogen oxides emissions would be reduced, the net regional environmental impact would be positive, and further mitigation would be unwarranted.

Waste

The NRC concluded that waste generation from gas-fired technology would be minimal. As indicated in Section 2.2.1.2, gas-firing results in very little combustion byproduct because of the clean nature of the fuel. Waste generation would be limited to typical office wastes. Baltimore Gas and Electric Company concludes that the appropriate characterization of this impact is "small;" waste generation impacts would be so minor that they would not noticeably alter any important resource attribute.

Human Health

The NRC mentions potential gas-fired alternative health risks (cancer and emphysema) without specifying the source of the risk. Presumably, the risk is attributable to nitrogen oxides emissions that contribute to ozone formation, which in turn contributes to health risks. As discussed in Section 4.2.1 for the coal-fired alternative, BGE concludes that legislative and regulatory control of the nation's emissions and air quality are protective of human health, and that the appropriate characterization of gas-fired generation human health impacts would be "small;" that is, human health effects would not be detectable or would be so minor that they would neither destabilize nor noticeably alter any important attribute of the resource.

Socioeconomics

It is assumed that gas-fired construction would take place while the CCNPP continues operation, with completion at the time that the nuclear plant would halt operations. Therefore, for the 3-year construction period, the site would have between 500 and 750 additional workers. During this time, the surrounding communities would experience demands on housing and public services that could have large impacts. After construction, the communities would be impacted by the loss of jobs; construction workers would leave, the nuclear plant workforce (1,770) would decline through a decommissioning period to a minimal maintenance size, and the gas-fired plant would introduce only 125 new jobs.

The NRC concluded that gas-fired construction socioeconomic impacts would not be very noticeable and that the small operational workforce would have the lowest socioeconomic impacts (local purchases and taxes) of any nonrenewable technology. Baltimore Gas and Electric Company estimates that, compared to the coal-fired alternative, the smaller size of the construction workforce, the shorter construction timeframe, and smaller size of the operations workforce all would reduce socioeconomic impacts. For these reasons, BGE concludes that the appropriate characterization of gas-fired generation socioeconomic impacts would be "small;" that is, socioeconomic effects would be so minor that they would neither destabilize nor noticeably alter any important attribute of the resource.

Construction at another site would relocate some socioeconomic impacts but would not eliminate them. The community around the Calvert Cliffs site would still experience the impact of CCNPP operational job loss, and the communities around the new site would have to absorb the impacts of a large, temporary workforce and a moderate, permanent workforce.

Cultural Resources

The NRC concluded, as for the coal-fired alternative, that gas-fired alternative cultural resource impacts would be small unless important site-specific resources were affected. Gas-fired alternative construction at the Calvert Cliffs site would affect a smaller area within the footprint of the coal-fired alternative and, as for that alternative, site knowledge minimizes the possibility of cultural resource impacts. Baltimore Gas and Electric Company concludes that the appropriate characterization of gas-fired generation cultural resource impacts would be "small;" that is, cultural resource effects would not be detectable or would be so minor that they would neither destabilize nor noticeably alter any important attribute of the resource. Overall effects are expected to be positive due to continued stewardship of known resources.

Construction at another site could necessitate instituting cultural resource preservation measures but impacts can generally be managed and maintained as small.

4.2.3 Imported Electrical Power

As discussed in Section 2.2.1.3, imported power would probably be generated by one of the technologies discussed in GEIS Chapter 8. Therefore, BGE is adopting by reference, as representative of the environmental impacts of the imported electrical power alternative to CCNPP license renewal, the GEIS discussion of environmental impacts from generic alternatives. Under the imported power alternative, therefore, environmental impacts would still occur, but would be located elsewhere within the region, nation, or Canada.

4.2.4 No Action

As described in Section 2.2.1.4, the No-Action Alternative refers to a scenario in which NRC would not renew the CCNPP license, and BGE would decommission CCNPP after license expiration. Impacts associated with decommissioning CCNPP would be bounded by the discussion in Chapter 7 of the GEIS and NUREG-0586. The impacts of decommissioning after 40 years of operation would not be significantly different from those occurring after 60 years.

4.3 Committed Resources

4.3.1 Unavoidable Adverse Impacts

NRC

The environmental report shall discuss ". . . [a]ny adverse environmental effects which cannot be avoided should the proposal be implemented." 10 CFR 51.45(b)(2) as referenced in 10 CFR 51.53(c)(2)

Section 4.1.1 adopts by reference the GEIS discussion of Category 1 issues, discussion that addresses adverse environmental effects. For Category 2 issues, BGE has followed NRC regulatory requirements in preparing Section 4.1 and, where required, has addressed adverse effects. For some Category 2 issues, however, the regulation does not require, and Section 4.1 does not present, discussion of environmental impacts. For example, in response to 10 CFR 51.53(c)(3)(ii)(B), Section 4.1.2, Entrainment, explains that CCNPP has a state permit and supporting documentation that is equivalent to a Clean Water Act 316(b) determination. Section 4.1.2 does not discuss adverse environmental effects from entrainment; for that discussion, the reader would be referred to GEIS Section 4.2.2.1.2, although Section 4.1.2 echoes the GEIS conclusion that, given the appropriate documentation, effects are expected to be small. Section 4.1.18 explains that BGE is adopting by reference the NRC approach of revising the regulation to make Issue 85 (transportation of fuel and high-level waste) a Category 1 issue. Section 4.1 does identify the following unavoidable adverse impacts:

- Groundwater - Maximum cumulative drawdown of an offsite well after 20 additional years of CCNPP operations would be approximately 1 foot.
- Socioeconomic - Due to the conservative estimate of 60 additional personnel, a 4 percent increase in demand for housing, less than 1 percent increase in output of local water supply systems, and less than 1 percent increase in traffic.

4.3.2 Irreversible or Irretrievable Resource Commitments

> **NRC**
>
> The environmental report shall discuss ". . . [a]ny 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 referenced in 10 CFR 51.53(c)(2)

Calvert Cliffs generates approximately 88 assemblies (less than 4 canisters) of spent fuel per year. Operation during the CCNPP license renewal period would generate approximately 1,760 assemblies of spent fuel. This spent fuel is destined for disposal at the nation's high-level radioactive waste geologic repository, currently planned for construction at Yucca Mountain, Nevada. This activity is considered to be an irreversible and irretrievable commitment of the material in the spent fuel assemblies and the repository space in which the assemblies would be disposed. The NRC has analyzed the radiological impacts of this disposal activity and concluded that it is a Category 1 issue (10 CFR Part 51, Subpart A, Appendix B, Table B-1).

The NRC evaluated fish and shellfish mortality due to entrainment and impingement and concluded that the issue did not warrant further analysis at plants having a current Clean Water Act 316(b) determination [10 CFR 51.53(c)(3)(ii)(b)]. As discussed in Section 5.1.2, CCNPP has such a determination. While this mortality would be an irreversible and irretrievable commitment of those fish and shellfish, this impact is ongoing during current CCNPP operations and no irreversible or irretrievable impact on the fish or shellfish populations as a whole has been shown.

4.4 Short-Term Use Versus Long-Term Productivity

> **NRC**
>
> The environmental report shall discuss ". . . [t]he 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 referenced in 10 CFR 51.53(c)(2)

Calvert Cliffs operation during the license renewal period would result in the short-term resource uses described in Section 4.1, including in the GEIS descriptions adopted by reference in Section 4.1.1. As a result of normal operations, short-term use of the atmosphere, surface waters, and land surface as receptors for emissions, discharges, and wastes would have an incremental minimal effect on long-term air, water, and land conditions. Baltimore Gas and Electric Company, however, has not identified any clear indication of adverse impacts on long-term productivity. Although not discussed elsewhere because NRC regulatory requirements focus on adverse impacts, BGE and CCNPP ongoing efforts at protecting and enhancing critical habitat for threatened species, the bald eagle and two tiger beetle species, are expected to enhance the long-term productivity of these species.

Table 4-1
CCNPP COUNTY AND STATE PROPERTY TAXES[a]

Year	County (dollars)	State (dollars)	Total (dollars)
1974	418,000	8,360	426,360
1975	6,852,000	137,040	6,989,040
1976	7,431,000	148,620	7,579,620
1977	11,267,000	225,340	11,492,340
1978	11,023,000	220,460	11,243,460
1979	10,825,000	216,500	11,041,500
1980	10,834,000	216,680	11,050,680
1981	10,498,000	209,960	10,707,960
1982	10,622,000	212,440	10,834,440
1983	11,012,000	220,240	11,232,240
1984	11,568,000	231,360	11,799,360
1985	11,743,000	234,860	11,977,860
1986	12,063,000	241,260	12,304,260
1987	13,895,000	277,900	14,172,900
1988	14,632,000	292,640	14,924,640
1989	14,609,570	300,010	14,909,580
1990	14,226,490	291,000	14,517,490
1991	13,918,500	282,630	14,201,130
1992	15,240,820	299,040	15,539,860
1993	15,576,530	307,380	15,883,910
1994	17,323,420	334,870	17,658,290

a. In 1995 dollars.

Table 4-2

ESTIMATED PRESENT DOLLAR VALUE EQUIVALENT FOR SEVERE ACCIDENTS AT CCNPP UNIT 1

Parameter	Present Dollar Value ($)
Offsite population dose	1,477,000
Offsite economic costs	743,000
Onsite dose	126,000
Onsite economic costs	0[a]
Total	2,346,000

a. Insurance offsets all onsite economic costs.

Table 4-3

NET VALUE FOR SAMAs RELATED TO CCNPP UNIT 1

SAMA Number	Objective	Averted Public Exposure	Averted Offsite Costs	Averted Onsite Costs	Averted Occupational Exposure	Total Benefit[a]	Cost of Enhancement	Net Value
01-a	Improve saltwater, SRW, and component cooling pump recovery (post-trip only).	$79,000	$35,000	$0	$5,000	$119,000	$622,000	($503,000)
01-b	Improve saltwater, SRW, and component cooling pump recovery (pre-trip and post-trip).	$92,000	$42,000	$0	$7,000	$141,000	$622,000	($481,000)
05	Hardpipe a Fire Protection (FP) System feed to Component Cooling System to allow an alternate cooling source for the shutdown cooling heat exchangers, safety injection pumps, and reactor coolant pump seals.	$133,000	$59,000	$0	$14,000	$206,000	$565,000	($359,000)
07	Install a redundant AFW pump room ventilation system.	$31,000	$15,000	$0	$2,000	$48,000	$226,000	($178,000)
08	Install containment spray pump header automatic throttle valves.	$8,000	$4,000	$0	$3,000	$15,000	$375,000	($360,000)
15	Create a passive hydrogen ignition system.	$36,000	$18,000	$0	$0	$54,000	$760,000	($706,000)
23	Use the FP System as a back-up source for the Containment Spray System.	$182,000	$86,000	$0	$0	$268,000	$565,000	($297,000)
31	Provide additional direct current battery capability.	$43,000	$23,000	$0	$6,000	$72,000	$1,875,000	($1,803,000)
32	Use fuel cells instead of lead-acid batteries.	$43,000	$23,000	$0	$6,000	$72,000	$2,000,000	($1,928,000)
33-a	Implement automatic cross-tie capability between 4kV Buses 11 and 14.	$89,000	$43,000	$0	$10,000	$142,000	$1,119,000	($977,000)
33-b	Implement automatic cross-tie capability between 4kV Buses 21 and 24.	$25,000	$14,000	$0	$3,000	$42,000	$1,119,000	($1,077,000)

Table 4-3

NET VALUE FOR SAMAs RELATED TO CCNPP UNIT 1

SAMA Number	Objective	Averted Public Exposure	Averted Offsite Costs	Averted Onsite Costs	Averted Occupational Exposure	Total Benefit[a]	Cost of Enhancement	Net Value
34	Incorporate an alternate battery charging capability.	$43,000	$23,000	$0	$6,000	$72,000	$134,000	($62,000)
36	Replace batteries with a more reliable model.	$76,000	$43,000	$0	$11,000	$130,000	$375,000	($245,000)
38-b	Double the capacity of the fuel oil day tanks.	$52,000	$29,000	$0	$7,000	$88,000	$539,000	($451,000)
44	Make the SRW-cooled EDGs air-cooled.	$110,000	$54,000	$0	$12,000	$176,000	$1,700,000	($1,524,000)
45	Use the FP System as a back-up source for diesel cooling.	$110,000	$54,000	$0	$12,000	$176,000	$497,000	($321,000)
48-a	Convert Undervoltage, Auxiliary Feedwater Actuation Signal (AFAS) Block, and Reactor Protective System high pressurizer pressure actuation signals to 3-out-of-4 logic.	$245,000	$133,000	$0	$35,000	$413,000	$593,000	($180,000)
48-b	Operate with the power-operated relief valve block valves shut.	$11,000	$3,000	$0	$2,000	$16,000	$125,000	($109,000)
59	Install additional instrumentation for detecting Inter-System Loss-of-Coolant Accidents.	$38,000	$20,000	$0	$1,000	$59,000	$2,300,000	($2,241,000)
68	Install separate accumulators for the AFW cross-connect and block valves.	$27,000	$15,000	$0	$3,000	$45,000	$214,000	($169,000)
69	Increase the capacity of Condensate Storage Tank 12 to contain a full 24 hours of AFW inventory for both units.	$24,000	$14,000	$0	$3,000	$41,000	$1,000,000	($959,000)

Table 4-3

NET VALUE FOR SAMAs RELATED TO CCNPP UNIT 1

SAMA Number	Objective	Averted Public Exposure	Averted Offsite Costs	Averted Onsite Costs	Averted Occupational Exposure	Total Benefit[a]	Cost of Enhancement	Net Value
70	Provide a means to cool the turbine-driven AFW pumps in a station blackout event.	$31,000	$15,000	$0	$2,000	$48,000	$396,000	($348,000)
74	Automate demineralized water make-up to Condensate Storage Tank 12. This system must have a dedicated diesel generator.	$40,000	$21,000	$0	$7,000	$68,000	$271,000	($203,000)

a. All values in Table 4-3 are rounded to the nearest thousand dollars. Total benefit values presented in this table may differ slightly (by no more than $1,000) from those in the base calculation, due to rounding. In no case will this difference affect the results of this analysis.

Table 4-4

DISCOUNT RATE SENSITIVITY ANALYSIS [a]

SAMA Number	Objective	Cost of Enhancement	Net Value (7% discount rate)[b]	Net Value (3% discount rate)[b]
34	Incorporate an alternate battery charging capability.	$134,000	($62,000)	($33,000)
48-b	Operate with the power-operated relief valve block valves shut.	$125,000	($109,000)	($102,000)
68	Install separate accumulators for the AFW cross-connect and block valves.	$214,000	($169,000)	($149,000)
07	Install a redundant AFW pump room ventilation system.	$226,000	($178,000)	($159,000)
48-a	Convert Undervoltage, AFAS Block, Reactor Protective System high pressurizer pressure actuation signals to 3-out-of-4 logic.	$593,000	($180,000)	($8,000)
74	Automate demineralized water make-up to Condensate Storage Tank 12.	$271,000	($203,000)	($175,000)
36	Replace batteries with a more reliable model.	$375,000	($245,000)	($191,000)
23	Use the FP System as a back-up source for the Containment Spray System.	$565,000	($297,000)	($190,000)
45	Use the FP System as a back-up source for diesel cooling.	$497,000	($321,000)	($248,000)
70	Provide a means to cool the turbine-driven AFW pumps in an station blackout event.	$396,000	($348,000)	($329,000)

a. This table includes the 10 SAMAs with the lowest negative net values. Severe Accident Mitigation Alternative candidates are listed in ascending order, based upon the net value calculated for the 7 percent discount rate.

b. Parenthetical numbers are negative values.

Table 4-5
SUMMARY TABLE S-4 - ENVIRONMENTAL IMPACT OF TRANSPORTATION OF FUEL AND WASTE TO AND FROM ONE LIGHT-WATER-COOLED NUCLEAR POWER REACTOR[a]

Normal Conditions of Transport

	Environmental impact
Heat (per irradiated fuel cask in transit)	250,000 Btu/hr.
Weight (governed by Federal or state restrictions)	73,000 lbs. per truck; 100 tons per cask per rail car
Traffic density:	
Truck	Less than 1 per day
Rail	Less than 3 per month

Exposed population	**Estimated number of persons exposed**	**Range of doses to |exposed individuals[b] (per reactor year)**	**Cumulative does to exposed population (per reactor year)[c]**
Transportation workers	200	0.01 to 300 millirem	4 man-rem
General public:			
Onlookers	1,100	0.003 to 1.3 millirem	3 man-rem
Along route	600,000	0.0001 to 0.06 millirem	

Accidents in Transport

	Environmental risk
Radiological effects	Small[d]
Common (nonradiological) causes	1 fatal injury in 100 reactor years; 1 nonfatal injury in 10 reactor years; $475 property damage per reactor year

a. Data supporting this table are given in the Commission's "Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants," WASH-1238, December 1972, and Supplement 1 NUREG-75/038 April 1975. Both documents are available for inspection and copying at the Commission's Public Document Room, 2120 L Street NW., Washington, DC, and may be obtained from National Technical Information Service, Springfield, VA 22161. WASH-1238 is available from National Technical Information Service at a cost of $5.45 (microfiche, $2.25), and NUREG-75/038 is available at a cost of $3.25 (microfiche, $2.25).

b. The Federal Radiation Council has recommended that the radiation doses from all sources of radiation other than natural background and medical exposures should be limited to 5,000 millirem per year for individuals as a result of occupational exposure, and should be limited to 500 millirem per year for individuals in the general population. The dose to individuals due to average natural background radiation is about 130 millirem per year.

c. Man-rem is an expression for the summation of whole body doses to individuals in a group. Thus, if each member of a population group of 1,000 people were to receive a dose of 0.001 rem (1 millirem), or if 2 people were to receive a does of 0.5 rem (500 millirem), the total man-rem in each case would be 1 man-rem.

d. Although the environmental risk of radiological effects stemming from transportation accidents is currently incapable of being numerically quantified, the risk remains small regardless of whether it is being applied to a single reactor or a multi-reactor site.

5.0 COMPLIANCE STATUS

5.1 Proposed Action

5.1.1 General

Licenses, permits, and other approvals from Federal, State, and local authorities for current CCNPP operations are listed in Table 5-1. Table 5-2 identifies environmental approvals and consultation associated with CCNPP license renewal. As indicated, BGE anticipates that relatively few such approvals are required.

Baltimore Gas and Electric Company has initiated consultation with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service in accordance with Section 7 of the Endangered Species Act (16 USC 1536). Baltimore Gas and Electric Company expects to obtain determination that continued operation of the plant will not jeopardize any Federally threatened or endangered species. Baltimore Gas and Electric Company has included as Appendix D correspondence related to these consultations.

Baltimore Gas and Electric Company has initiated consultation with the Maryland State Historical Preservation Officer regarding potential effects of CCNPP License Renewal on cultural resources, in accordance with Section 106 of the Natural Historic Preservation Act (16 USC 470 et seq.) and has received a favorable determination. Baltimore Gas and Electric Company has included as Appendix E correspondence related to these consultations.

No permits from, or consultations with, states other than Maryland are necessary because CCNPP is at least 20 miles from the nearest Maryland border and BGE expects that the quality of the water or air in neighboring states would not be affected by the proposed action of license renewal.

5.1.2 Clean Water Act Sections 316(a) and 316(b) Documentation

The Federal Clean Water Act establishes a nationwide National Pollutant Discharge Elimination System (NPDES) permit process (33 USC 1342) and authorizes the EPA to establish NPDES permit requirements. An NPDES permit specifies the discharge limits and monitoring requirements that a facility must meet to protect water quality. Associated with the NPDES process are Clean Water Act Sections 316(a) and (b) (33 USC 1326), as discussed below. The Act authorizes EPA to approve state discharge programs to operate in lieu of a Federal program within the states' borders. On September 5, 1974, EPA approved the Maryland permit program.

Clean Water Act Section 316(a)

NRC
" . . . the applicant shall provide a copy of current [if necessary] Clean Water Act . . . 316(a) variance. . . or equivalent State permits and supporting documentation. . . " 10 CFR 51.53(c)(3)(iii)(B)

The following discussion documents that a 316(a) variance was not necessary for CCNPP.

Section 316(a) establishes a process whereby a thermal effluent discharger can demonstrate that thermal discharge limitations are more stringent than necessary and, using a variance, obtain alternative, facility-specific thermal discharge limits (33 USC 1326). Pages B-2 through B-11 (Appendix B) are an excerpt from the COMAR 08.05.04.13 that was in effect during early CCNPP operations. The purpose of the regulation included specifying procedures for determining alternate effluent limits pursuant to Section 316(a) [former COMAR 08.05.04.13B(3); page B-4].[1]

In accordance with the CCNPP operating licenses and original State discharge permit, as well as former COMAR 08.05.04.13C(2)(a) (page B-3), BGE performed a 316(a) study for CCNPP (Reference 145). The study verified CCNPP compliance with State mixing zone requirements. Pages B-12 through B-14 are excerpts from the subsequent CCNPP discharge permit (Permit No. 79-DP-0187, effective February 3, 1982).[2] Section I.E of the permit (page B-14) confirmed that CCNPP met thermal mixing zone requirements and that, therefore, alternate Section 316(a) effluent limits were not necessary. Subsequent (1987 and 1994) CCNPP discharge permits contained no provisions that altered this conclusion.

Clean Water Act Section 316(b)

NRC
" . . . the applicant shall provide a copy of current Clean Water Act 316(b) determinations . . . or equivalent State permits and supporting documentation. . . " 10 CFR 51.53(c)(3)(iii)(B)

The following discussion documents the State 316(b) determination for CCNPP.

Section 316(b) requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact (33 USC 1326). Former COMAR 08.05.04.13B(2) (page B-3) provided the implementing Maryland regulatory purpose.[3] In accordance with the CCNPP operating licenses and original State discharge permit, as well as former COMAR 08.05.04.13C(2)(b) (page B-3), BGE performed a 316(b) study for CCNPP (Reference 145). The subsequent CCNPP discharge permit included the State conclusion that CCNPP would not affect spawning or nursery areas of consequence, would have a modest impingement loss, and was in compliance with COMAR 08.05.04.13 (page B-13).

Subsequent studies and modeling conducted by the Maryland Power Plant Research Program also concluded that entrainment losses have not resulted in depletion of local populations of fish and shellfish (Reference 124). Although BGE completed studies of environmental impacts of the CCNPP cooling water intake structure in 1981,[4] BGE has continued to perform impingement studies in accordance with BGE environmental policy. Re-issuance of the CCNPP discharge permit as recently as 1994 is indication of State acceptance that the plant continues to meet 316(b) requirements.

1 Comparable provisions in the current regulations are located at COMAR 26.08.03.03.

2 1982 NPDES discharge permit issued pursuant to the 1974 edition of COMAR. Copies of the COMAR sections cited in the permit text are included in Appendix B.

3 Comparable provisions in the current regulations are located at COMAR 26.08.03.05.

4 The 1982 and subsequent (1987 and 1994) permits have not required additional impingement or entrainment studies.

5.1.3 Water Quality Certification

Federal Clean Water Act Section 401 requires that applicants for a Federal license to conduct an activity that might result in a discharge into navigable waters must provide the licensing agency a certification from the State that the discharge will comply with applicable Clean Water Act requirements (33 USC 1341). Baltimore Gas and Electric Company is applying to NRC for a license (i.e., license renewal) to continue CCNPP operations and CCNPP operations result in discharges to the Chesapeake Bay, a navigable water, within the State of Maryland. Code of Maryland Regulations Section 26.08.02.10.A.2 indicates that discharges permitted by the Maryland Department of the Environment are certified by the Department. Appendix H (page H-2) provides an excerpt from the COMAR. It is BGE's understanding that, although there would be no reference to Section 401 certification in a discharge permit, discharge permit issuance is indication of the certification. Page H-3 is a copy of the cover sheet for the current Department-issued CCNPP discharge permit. Pursuant to COMAR Section 26.08.02.10.A.2 and conversation with the Maryland Department of the Environment, the CCNPP discharge permit is indication of the State certification required by Clean Water Act Section 401.

5.1.4 Coastal Zone Management

The Federal Coastal Zone Management Act (16 USC 1451 et seq.) requires applicants for a Federal license to conduct an activity that could affect a state's coastal zone to certify to the licensing agency that the proposed activity would be consistent with the state's Federally-approved coastal zone management plan [16 USC 1456(c)(3)(A)]. The National Oceanic and Atmospheric Administration has promulgated implementing regulations that indicate the requirement is applicable to renewal of Federal licenses for activities not previously reviewed by the State [15 CFR 930.51(b)(1)]. The regulation requires license applicants to provide its certification to the Federal licensing agency and a copy to the applicable State agency [15 CFR 930.57(a)]. The Administration has also published documentation of the Maryland program (Reference 146).

The NRC Office of Nuclear Reactor Regulation has issued guidance regarding compliance with the Act (Reference 147, page 5 and Attachments 5, 6, and 7), and the guidance acknowledges that Maryland has an approved coastal zone management program. Calvert Cliffs is located within the Maryland coastal zone, and Appendix H contains BGE coastal zone management program certification for CCNPP license renewal. Baltimore Gas and Electric Company submitted project material and a draft certification to the State. Based on material submitted, the State, in a letter to NRC, concurred with BGE's certification that the proposed activity complies with and will be conducted in a manner consistent with the State's Coastal Zone Management Program (Reference 148). Concurrent with submitting the Applicant's Environmental Report - Operating License Renewal Stage to NRC, BGE has submitted a copy to the State in fulfillment of the regulatory requirement for submitting a copy of the coastal zone consistency certification to the State.

5.2 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 referenced by 10 CFR 51.53(c)(2)

The coal-fired and gas-fired generation alternatives discussed in Sections 2.2.1.1 and 2.2.1.2, respectively, generally could be designed and constructed so as to comply with all applicable environmental quality standards and requirements. It should be noted, however, that increasingly stringent air quality legislative and regulatory provisions, combined with regional air quality concerns, could make construction of a large coal- or gas-fired alternative at the Calvert Cliffs site, or in the region, unfeasible. For example, necessary emission offsets required under the Clean Air Act New Source Review Program could become unavailable.

Although construction and operation details for the imported-power alternative, Section 2.2.1.3, are not known, it is reasonable to assume that any facility offering power for purchase would be in compliance or would be working to achieve compliance.

Table 5-1
FEDERAL, STATE, LOCAL, AND REGIONAL LICENSES, PERMITS, CONSULTATIONS, AND OTHER APPROVALS PERTINENT TO CURRENT CCNPP STATION OPERATION

Agency	Authority	Requirements	CCNPP No.	Issue Date	Expiration Date	Remarks
EPA	Clean Water Act, Section 401	State Water Quality Certification	Not Applicable	June 16, 1994	June 15, 1999	Discharges permitted by MDE under NPDES are considered to have fulfilled this certification requirement (COMAR 26.08.02.10).
NRC	10 CFR Part 50	NRC license, CCNPP Unit 1	DPR-53	July 1974	July 31, 2014	None
NRC	10 CFR Part 50	NRC license, CCNPP Unit 2	DPR-69	August 1976	August 31, 2016	None
NRC	10 CFR Part 72	NRC license, CCNPP Independent Spent Fuel Storage Installation	SNM-2505	November 25, 1993	November 30, 2012	None
MDE	COMAR 26.11.02.03	Construction permits for specified air emissions from Nuclear Security Facility EDG	04-4-0041N	April 21, 1992	None unless project delayed per COMAR 26.11.02.06B	Baltimore Gas and Electric Company would have to obtain additional construction permits before modifying the EDGs. Baltimore Gas and Electric Company has submitted an application for an operating permit for CCNPP sources under the Clean Air Act Title V program administered by MDE under COMAR 26.11.02.
MDE	COMAR 26.11.02.03	Construction permits for specified air emissions from EDGs (4)	04-9-0015, -0016, -0017, -0018N	September 24, 1993	None unless project delayed per COMAR 26.11.02.06B	Baltimore Gas and Electric Company would have to obtain additional construction permits before modifying the EDGs. Baltimore Gas and Electric Company has submitted an application for an operating permit for CCNPP sources under the Clean Air Act Title V program administered by MDE under COMAR 26.11.02.
MDE	COMAR 26.11.02.03	Construction permits for specified air emissions from Sandblast Booth	04-9-0019N	April 24, 1994	None unless project delayed per COMAR 26.11.02.06B	Baltimore Gas and Electric Company would have to obtain additional construction permits before modifying the sandblasting booth. Baltimore Gas and Electric Company has submitted an application for an operating permit for CCNPP sources under the Clean Air Act Title V program administered by MDE under COMAR 26.11.02.

Table 5-1
FEDERAL, STATE, LOCAL, AND REGIONAL LICENSES, PERMITS, CONSULTATIONS, AND OTHER APPROVALS PERTINENT TO CURRENT CCNPP STATION OPERATION

Agency	Authority	Requirements	CCNPP No.	Issue Date	Expiration Date	Remarks
MDE	COMAR 26.11.02.02	Air emission source registration for Auxiliary Steam Generators (2)	04-70-4-00014, -00015	April 21, 1970	None	Baltimore Gas and Electric Company would have to re-register before making source modifications. Baltimore Gas and Electric Company has submitted an application for an operating permit for CCNPP sources under the Clean Air Act Title V program administered by MDE under COMAR 26.11.02.
MDE	COMAR 26.11.02.02	Air emission source registration for EDGs (3) (Auxiliary Building)	04-70-4-00016, -00017, -00018	April 21, 1970	None	Baltimore Gas and Electric Company would have to re-register before making source modifications. Baltimore Gas and Electric Company has submitted an application for an operating permit for CCNPP sources under the Clean Air Act Title V program administered by MDE under COMAR 26.11.02.
MDE	COMAR 26.11.02.02	Air emission source registration for Unit 1 Reactor	04-70-9-00001	November 20, 1970	None	Baltimore Gas and Electric Company would have to re-register before making source modifications. Baltimore Gas and Electric Company has submitted an application for an operating permit for CCNPP sources under the Clean Air Act Title V program administered by MDE under COMAR 26.11.02.
MDE	COMAR 26.11.02.02	Air emission source registration for Unit 2 Reactor	04-70-9-00002	November 20, 1970	None	Baltimore Gas and Electric Company would have to re-register before making source modifications. Baltimore Gas and Electric Company has submitted an application for an operating permit for CCNPP sources under the Clean Air Act Title V program administered by MDE under COMAR 26.11.02.
Calvert County Department of Public Works, Inspections, and Permits Division	Calvert County Erosion and Sediment Control Ordinance	Permit for clearing and grading land	7244, Extended Detention Pond	June 30, 1993	None	Imposes restrictions on additional development within the Protected Area.
Calvert County Department of Public Works, Inspections, and Permits Division	Calvert County Erosion and Sediment Control Ordinance	Permit for clearing and grading land	6936, Lake Davies Sediment Basin	October 23, 1992	None	Imposes restrictions on landfill activities within the Lake Davies Area.

Table 5-1
FEDERAL, STATE, LOCAL, AND REGIONAL LICENSES, PERMITS, CONSULTATIONS, AND OTHER APPROVALS PERTINENT TO CURRENT CCNPP STATION OPERATION

Agency	Authority	Requirements	CCNPP No.	Issue Date	Expiration Date	Remarks
MDE[a]	COMAR 26.17.06[b]	State Water Appropriation Permits for CCNPP groundwater	CA89G007 (01)	April 1, 1989	April 1, 2001	Rifle Range well; renewal applications due by February 14, 2001.
MDE[a]	COMAR 26.17.06[b]	State Water Appropriation Permits for CCNPP groundwater	CA83G008(02)	September 1, 1989	April 1, 2001	Visitors Center well; renewal applications due by February 14, 2001.
MDE[a]	COMAR 26.17.06[b]	State Water Appropriation Permits for CCNPP groundwater	CA63G003(06)	September 1, 1989	April 1, 2001	Recreation Facility (Camp Conoy) wells (4); renewal applications due by February 14, 2001.
MDE[a]	COMAR 26.17.06[b]	State Water Appropriation Permits for CCNPP groundwater	CA69G010(04)	September 1, 1989	April 1, 2001	Protected-area-vicinity wells (5); renewal applications due by February 14, 2001.
MDE	COMAR 26.04.06	Permit for managing sewage sludge	S-93-04-3091-E	January 21, 1993	January 20, 1998	Permit issued to BGE for transporting digested sewage sludge from CCNPP to the Solomons Island Wastewater Treatment Plant.
MDE	COMAR 26.04.06	Permit for managing sewage sludge	S-94-02-3422-E	February 10, 1994	February 9, 1999	Permit issued to Maryland Environmental Service for transporting wet-well sewage from CCNPP to Dorsey Run Wastewater Treatment Plant.
MDE	COMAR 26.04.06	Permit for managing sewage sludge	S-96-30-4172-E	April 25, 1996	April 24, 2001	Permit issued to BGE for transporting sewage sludge to the Virginia State line to be used at permitted sites in Tennessee.
MDE[b]	COMAR 26.17.06[c]	State Water Appropriation Permit for CCNPP use of surface water for cooling	CA71S001(02)	September 1, 1989	April 1, 2001	Renewal application due by February 14, 2001.

Table 5-1
FEDERAL, STATE, LOCAL, AND REGIONAL LICENSES, PERMITS, CONSULTATIONS, AND OTHER APPROVALS PERTINENT TO CURRENT CCNPP STATION OPERATION

Agency	Authority	Requirements	CCNPP No.	Issue Date	Expiration Date	Remarks
MDE	COMAR 26.08.04	Wastewater Discharge Permit	State Discharge Permit Number 92-DP-0187 (NPDES Number MD 0002399)	June 16, 1994	June 15, 1999	This permit covers discharges from Outfalls 001, 002, 003, 004, 005, 006, 007. Calvert Cliffs Nuclear Power Plant Sewage Treatment Plant effluent is permitted for discharge via Outfall 001.
MDE	COMAR 26.10.01.08	Oil Operations Permit	92-OP-0257	NA	May 15, 1997	Tank numbers 396, 400, 412, 573, 575, 536, 578 (lube oil, diesel, waste oil, kerosene); BGE has submitted an application for permit renewal.
MDE	COMAR 26.10	Underground Storage Tank notification	Not applicable	September 24, 1997	None	Tank numbers 413, 641, 580, 579, 581 (waste oil, diesel, gasoline).
MDE	Memorandum of Understanding	Mixed waste management		March 1995	None	Acknowledges lack of commercial disposal capacity and establishes storage management requirements.

MDE = Maryland Department of Environment.

a. Permit issued by Maryland Department of Natural Resources. State transferred permitting authority to MDE July 1, 1995.

b. Permit issued under COMAR 08.05.02, but State re-codified regulation as COMAR 26.17.06 coincident with transferring permitting authority to MDE.

Table 5-2
ENVIRONMENTAL APPROVALS AND CONSULTATIONS FOR CCNPP LICENSE RENEWAL[a]

Agency	Authority	Requirement	Remarks
Federal			
NRC	Atomic Energy Act (42 USC 2011 et seq.) 10 CFR 54.23 10 CFR Part 51	License renewal	Environmental Report submitted in support of license renewal application.
EPA	Clean Water Act Section 401 (33 USC 1341)	Certification	CCNPP NPDES permit constitutes State Certification.
FWS and NMFS	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires Federal agency issuing a license to consult with FWS and NMFS.
State			
Maryland Historic Trust	National Historic Preservation Act Section 106 (16 USC 470f) 36 CFR Part 800	Consultation	Requires Federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Office (Maryland Historic Trust).
MDE Coastal Zone Consistency	Federal Coastal Zone Management Act (16 USC 1451 et seq.) 15 CFR 930.57(a)	Certification	Requires an applicant to provide certification to the Federal agency issuing the license that license renewal would be consistent with the Federally-approved state coastal zone management program. Based on its review of the proposed activity, the State must concur with or object to the applicant's certification.

FWS = U.S. Fish and Wildlife Service
MDE = Maryland Department of the Environment
NMFS = National Marine Fisheries Service
a. No renewal-related requirements identified for local or other agencies.

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A.0 NRC NATIONAL ENVIRONMENTAL POLICY ACT ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS

Baltimore Gas and Electric Company has prepared this Environmental Report - Operating License Renewal Stage for Calvert Cliffs Nuclear Power Plant (CCNPP) in accordance with the requirements of 10 CFR 51.53. Included in the regulation is a list of environmental issues that the U.S. Nuclear Regulatory Commission (NRC) developed from the analysis presented in NRC's Generic Environmental Impact Statement (Reference 1), which examines possible environmental impacts that could occur as a result of renewing licenses of individual nuclear power plants. These 92 issues are listed in Table B-1 of Appendix B to Subpart A of Part 51 and are provided in Table A-1 of this document. For expediency, numbers have been assigned to each issue as it appears in Table B-1 and are referenced throughout this Environmental Report. Table A-1 also provides a cross-reference for each of NRC's environmental issues to the respective environmental report section where that issue is discussed.

Table A-1
CCNPP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NATIONAL ENVIRONMENTAL POLICY ACT ISSUES

	Issue[a]	Category	Section of this Environmental Report
1.	Impacts of refurbishment on surface water quality	1	4.1.1
2.	Impacts of refurbishment on surface water use	1	4.1.1
3.	Altered current patterns at intake and discharge structures	1	4.1.1
4.	Altered salinity gradients	1	4.1.1
5.	Altered thermal stratification of lakes	1	4.1.1
6.	Temperature effects on sediment transport capacity	1	4.1.1
7.	Scouring caused by discharged cooling water	1	4.1.1
8.	Eutrophication	1	4.1.1
9.	Discharge of chlorine or other biocides	1	4.1.1
10.	Discharge of sanitary wastes and minor chemical spills	1	4.1.1
11.	Discharge of other metals in waste water	1	4.1.1
12.	Water use conflicts (plants with once-through cooling systems)	1	4.1.1
13.	Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	NA[b]
14.	Refurbishment impacts to aquatic resources	1	4.1.1
15.	Accumulation of contaminants in sediments or biota	1	4.1.1
16.	Entrainment of phytoplankton and zooplankton	1	4.1.1
17.	Cold shock	1	4.1.1
18.	Thermal plume barrier to migrating fish	1	4.1.1
19.	Distribution of aquatic organisms	1	4.1.1
20.	Premature emergence of aquatic insects	1	4.1.1
21.	Gas supersaturation (gas bubble disease)	1	4.1.1
22.	Low dissolved oxygen in the discharge	1	4.1.1
23.	Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.1.1
24.	Stimulation of nuisance organisms (e.g., shipworms)	1	4.1.1
25.	Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	4.1.2
26.	Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	4.1.3
27.	Heat shock for plants with once-through and cooling pond heat dissipation systems	2	4.1.4
28.	Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	NA[b]
29.	Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	NA[b]
30.	Heat shock for plants with cooling-tower-based heat dissipation systems	1	NA[b]
31.	Impacts of refurbishment on ground-water use and quality	1	4.1.1
32.	Ground-water use conflicts (potable and service water; plants that use < 100 gpm)	1	NA
33.	Ground-water use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	4.1.5

Table A-1
CCNPP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NATIONAL ENVIRONMENTAL POLICY ACT ISSUES

	Issue[a]	Category	Section of this Environmental Report
34.	Ground-water use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	NA[b]
35.	Ground-water use conflicts (Ranney wells)	2	NA[c]
36.	Ground-water quality degradation (Ranney wells)	1	NA[c]
37.	Ground-water quality degradation (saltwater intrusion)	1	4.1.1
38.	Ground-water quality degradation (cooling ponds in salt marshes)	1	NA[b]
39.	Ground-water quality degradation (cooling ponds at inland sites)	2	NA[b]
40.	Refurbishment impacts to terrestrial resources	2	4.1.6
41.	Cooling tower impacts on crops and ornamental vegetation	1	NA[b]
42.	Cooling tower impacts on native plants	1	NA[b]
43.	Bird collisions with cooling towers	1	NA[b]
44.	Cooling ponds impact on terrestrial resources	1	NA[b]
45.	Power line right-of-way management (cutting and herbicide application)	1	4.1.1
46.	Bird collisions with power lines	1	4.1.1
47.	Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.1.1
48.	Floodplains and wetlands on power line right-of-way	1	4.1.1
49.	Threatened or endangered species	2	4.1.7
50.	Air quality during refurbishment (non-attainment and maintenance areas)	2	4.1.8
51.	Air quality effects of transmission lines	1	4.1.1
52.	Onsite land use	1	4.1.1
53.	Power line right-of-way	1	4.1.1
54.	Radiation exposures to the public during refurbishment	1	4.1.1
55.	Occupational radiation exposures during refurbishment	1	4.1.1
56.	Microbiological organisms (occupational health)	1	4.1.1
57.	Microbiological organisms (public health)(plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	NA[b]
58.	Noise	1	4.1.1
59.	Electromagnetic fields, acute effects (electric shock)	2	4.1.9
60.	Electromagnetic fields, chronic effects	NA[d]	NA[d]
61.	Radiation exposures to public (license renewal term)	1	4.1.1
62.	Occupational radiation exposures (license renewal term)	1	4.1.1
63.	Housing impacts	2	4.1.10
64.	Public services: public safety, social services, and tourism and recreation	1	4.1.1
65.	Public services: public utilities	2	4.1.11
66.	Public services, education (refurbishment)	2	4.1.12
67.	Public services, education (license renewal term)	1	4.1.1
68.	Offsite land use (refurbishment)	2	4.1.13

Table A-1
CCNPP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NATIONAL ENVIRONMENTAL POLICY ACT ISSUES

	Issue[a]	Category	Section of this Environmental Report
69.	Offsite land use (license renewal term)	2	4.1.14
70.	Public services, transportation	2	4.1.15
71.	Historic and archaeological resources	2	4.1.16
72.	Aesthetic impacts (refurbishment)	1	4.1.1
73.	Aesthetic impacts (license renewal term)	1	4.1.1
74.	Aesthetic impacts of transmission lines (license renewal term)	1	4.1.1
75.	Design basis accidents	1	4.1.1
76.	Severe accidents	2	4.1.17
77.	Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high level waste)	1	4.1.1
78.	Offsite radiological impacts (collective effects)	1	4.1.1
79.	Offsite radiological impacts (spent fuel and high level waste disposal)	1	4.1.1
80.	Nonradiological impacts of the uranium fuel cycle	1	4.1.1
81.	Low-level waste storage and disposal	1	4.1.1
82.	Mixed waste storage and disposal	1	4.1.1
83.	On-site spent fuel	1	4.1.1
84.	Nonradiological waste	1	4.1.1
85.	Transportation	2	4.1.18
86.	Radiation doses (decommissioning)	1	4.1.1
87.	Waste management (decommissioning)	1	4.1.1
88.	Air quality (decommissioning)	1	4.1.1
89.	Water quality (decommissioning)	1	4.1.1
90.	Ecological resources (decommissioning)	1	4.1.1
91.	Socioeconomic impacts (decommissioning)	1	4.1.1
92.	Environmental justice	NA[d]	NA[d]

a. Source: 10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue numbers added to facilitate discussion.)
b. Not applicable because CCNPP does not use a cooling pond heat or cooling tower dissipation system.
c. Not applicable because CCNPP does not use Ranney Wells.
d. Not applicable because the categorization and impact finding definitions do not apply to these issues.

Reference

1. NUREG-1437, Volume 1, "Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants," December 1996

B.0 CLEAN WATER ACT SECTIONS 316(a) AND 316(b) DOCUMENTATION

Appendix B contains the following items:

- Pages B-2 through B-11 — Excerpt from Code of Maryland Regulations Section 08.05.04 that was in effect from 1978 to 1987. Excerpt addresses cooling water intake structures and thermal effluents
- Pages B-12 through B-14 — Excerpts from Calvert Cliffs Nuclear Power Plant 1982 discharge permit (Permit No. 79-DP-0187)

after the date on which the revocation notice is served. The Administration shall schedule a hearing within 10 days from receipt of the request and give a decision within 10 days from the date of the hearing.

.13 Water Quality Impact Assessment for Thermal Discharges.

Agency note: The meaning of a term with an asterisk (*) is given in Regulation .01 Definitions. The meaning of a term with a number symbol (#) is given in this regulation.

A. Definitions. The following definitions are only applicable to this regulation and are denoted by a number sign (#) the first time the term is used:

(1) "Average ebb tidal excursion" means the average velocity (ft/sec) of the ebb tide passing through the cross-section of the receiving waters at the point of discharge, multiplied by the duration of the tide (slack before ebb to slack before flood). The average velocity will be determined from measurements of transect velocities at three neap tides with low fresh water input and three spring tides with high fresh water input.

(2) "Critical periods" means that time of the year during which sensitive life stages or densities of Representative Important Species (RIS) are present in the plant intake or receiving waters.

(3) "Entrainment" means the incorporation of organisms into the cooling water flow.

(4) "Impingement" means the blocking of larger organisms by a structure in the cooling water intake system.

(5) "Nontidal water" means water above a point where the tide ebbs and flows (generally freshwater).

(6) "Significant" means having an observed effect that is measurable beyond the mixing zone.

(7) "Sufficiently loaded" means any steam electric generating station over 25 megawatts electric net generating capacity that by 1980 will have an annual capacity factor greater than 25, or greater than 40 between June 1 and September 30. Capacity factor is calculated according to the following formula:

$$\text{Capacity factor} = \frac{\text{net electrical energy generated \#}}{\text{period hours} \times \text{MDC net \#}} \times 100$$

(8) "Net electrical energy generated" means gross electrical output of the unit measured at the output terminals of the turbine generator during the reporting period, minus the normal station service electrical energy utilization.

(9) "Maximum dependable capacity net (MDC net) (MWe)" means the dependable main-unit gross capacity less normal station service loads, winter or summer, which ever is smaller.

(10) "Tidal water" means water below a point where the tide ebbs and flows.

B. Purpose. The purpose of this regulation is to specify procedures for determining:

(1) Compliance with Maryland Water Quality Standards for thermal discharges;

(2) Best available technology for intake structures to minimize environmental impacts, to be approved in accordance with §316(b) of the Federal Water Pollution Control Act Amendments of 1972 (FWPCAA of 1972); and

(3) Alternate effluent limitations* pursuant to §316(a) of the FWPCAA of 1972.

C. Requirements.

(1) For discharges of heat equal to or less than a maximum monthly average of 20 × 10⁶ BTU's/day, the mixing zone shall be 50 feet, measured radially from the point of discharge.

(2) Within 180 days of the effective date of these regulations, permittees for discharges of heat greater than 20 × 10⁶ BTU's/day, and other thermal discharges pursuant to the requirements of individual State Discharge Permits* excluding steam electric generating stations not sufficiently loaded #, new sources*, and systems using closed cycle cooling, shall submit a comprehensive plan for:

(a) Studies to determine whether according to the criteria in §E, their facilities' thermal discharge mixing zone complies with State Water Quality Standards;

(b) Studies to determine whether plant cooling water entrainments # affects a spawning or nursery area of consequence for Representative Important Species, (RIS) §D; and

(c) Studies to estimate impingement # loss pursuant to §F (for facilities having surface water intake structures).

(3) Within 2 years of the effective date of these regulations, a summary of the results of the studies in §C (2) will be submitted, and if the Administration determines that a facility meets the criteria specified in §E, best technology available for intake structures will be determined and a new permit issued after notice and hearing. Upon failure to meet these standards the permittee may:

(a) By January 1, 1983 meet the water quality criteria and install best technology available for intake structures;

(b) By January 1, 1983 install closed cycle cooling in accordance with plans approved by the Administration;

(c) Request an opportunity to demonstrate, pursuant to §G, that existing conditions or alternate effluent limitations will assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the receiving water.

(4) These studies shall be conducted in accordance with the following general requirements:

(a) The Administration or its representatives shall be allowed reasonable access to facilities for the purpose of confirmation or conducting parallel studies.

(b) Permittees conducting studies shall submit annual progress reports for review by the Administration. The reports will summarize work completed in the year ending July 30, and will be submitted by October 30. Persons conducting studies also shall submit semi-annual data and sampling summaries to the Administration for review. The Administration may order that a comprehensive plan be modified as a result of its reviews.

(c) Nothing in this regulation may be construed to prevent persons from presenting the results of additional studies regarding impacts. The information requirement of this regulation may be satisfied entirely from existing data provided, in the judgement of the Administration, it is scientifically valid and clearly relevant.

D. Representative Important Species (RIS).

(1) Persons conducting studies shall use selected species from §D(2), below, whenever possible, as a basis for assessing impacts of a discharge on natural water quality. When warranted, the Administration may approve or require additional species not on this list for study at a particular site.

(2) Representative Important Species of Maryland Tidal and Non-Tidal Waters.

REPRESENTATIVE IMPORTANT SPECIES OF MARYLAND TIDAL AND NON-TIDAL WATERS

		Non-Tidal	Estuarine	
		(0) o/oo	(0-5)o/oo	(5-30)o/oo
Class—Birds	Aves			
Mallard	Anas platyrhynchos	r	r	r
Canvasback	Aythya valisineria	r	r	r
Black duck	Anas rubripes	r	r	r
Class—Mammals	Mammalia			
Muskrat	Ondatra zibethica	c	c	c
Phylum—Molluscs	Mollusca			
American oyster	Crassostrea virginica			c
Soft-shelled clam	Mya arenaria			c
Hard clam	Mercenaria mercenaria			c
Brackish-water clam	Rangia cuneata		f	
Fresh water clam	Anadonta spp.	f		
Pulmonate snail	Galba humilis modicella	f		
Gilled snail	Goniobasis virginica	f		
Macoma clam	Macoma balthica		f	
Phylum-Arthropods	Arthropoda			
Blue Crab	Callinectes sapidus		cr	cr

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		Non-Tidal	Estuarine		Marine
		(0) o/oo	(0-5) o/oo	(5-30) o/oo	(30) o/oo
Class—Insects	Insecta				
Caddisflies	Trichoptera	f			
Stoneflies	Plecoptera	f			
Mayflies	Ephemeroptera	f			
Class—Fin Fishes	Osteichthyes				
Striped bass	Morone saxatilis		cr	cr	cr
Croaker	Micropogon undulatus		crf	crf	
White perch	Marone americana	r	cr	cr	
Yellow perch	Perca flavescens	r f	r		
Weakfish	Cynoscion regalis		crf	crf	
Hickory shad	Alosa mediocris	c r	c	c	
American shad	Alosa sapidissima	c r	c	c	
Blueback herring	Alosa aestivalis	c r	c	c	
Alewife	Alosa pseudoharengus	c r	c	c	
Atlantic menhaden	Brevoortia tyrannus		c f	c f	c f
Spot	Leiostomus xanthurus		r f	crf	
Winter flounder	Pseudopleuronectes americanus		c r	c r	
Summer flounder	Paralicthys dentatus		c r	c r	r
Bay anchovy	Anchoa mitchilli		f	f	
Silverside	Menidia spp.		f	f	
	Membras martinica		f	f	

		Non-Tidal	Estuarine		Marine
		(0) o/oo	(0-5) o/oo	(5-30) o/oo	(30) o/oo
Brook trout	Salvelinus fontinalis	r			
Smallmouth bass	Micropterus dolomieui	r			
Largemouth bass	Micropterus salmoides	r			
Pumpkinseed	Lepomis gibbosus	r f	r f		
Redbreast sunfish	Lepomis auritus	r f			
Bluegill	Lepomis macrochirus	r f			
Spottail shiner	Notropis hudsonius	f	f		
Brown bullhead	Ictalurus nebulosus	crf	crf		
White sucker	Catostomus commersoni	rf			
Killifish	Fundulus spp.	c f	c f		
Channel catfish	Ictalurus punctatus	c r	c r	c r	
Naked goby	Gobiosama bosci		f	f	

KEY c = Commercial species
r = Recreational species
f = Forage

List does not include representatives of many marine ecosystems, particularly those in offshore waters.

(3) In order to perform concise, relevant studies, a person conducting studies shall use the following criteria to select a limited number of RIS:

(a) Consider only those listed species normally present in the local salinity regime.

(b) Determine the spatial and temporal distribution of resident and migratory species with respect to their various life stages.

(c) Select at least one fin fish, mollusc, arthropod, and one other species for intensive study, using as selection criteria species abundance, commercial or recreational importance, and sensitivity (per life stage) to facility operations. In fresh water studies one insect species shall also be selected.

E. Determination of Water Quality Compliance. A thermal discharge shall be in compliance with Maryland Water Quality Standards if the following mixing zone criteria are met:

(1) Requirements for Discharges to Tidal Waters#.

(a) The discharge flow may not exceed 20 percent of the annual average net flow past the point of discharge which is available for dilution;

(b) The 24-hour average of the maximum radial dimension measured from the point of discharge to the boundary of the full power 2°C above ambient isotherm (measured during the critical periods#) may not exceed ½ of the average ebb tidal excursion#;

(c) The 24-hour average full power 2°C above ambient thermal barrier* (measured during the critical periods) may not exceed 50 percent of the accessible cross-section of the receiving water* body, both cross-section taken in the same plane; and

(d) The 24-hour average area of the bottom touched by waters heated 2°C or more above ambient at full power (measured during the critical periods may not exceed 5 percent of the bottom below the average ebb tidal excursion.

(2) Requirements for Discharges to Nontidal Waters#.

(a) The design flow may not exceed 20 percent of the average annual stream flow as tabulated in "Flow Characteristics of Maryland Streams", Maryland Geological Survey, 1971, or equivalent publication;

(b) The distance downstream from the point of discharge to the 24-hour average 2°C above ambient isotherm at full power may not exceed the distance traveled in 6 hours by the receiving stream, both distances to be measured during the critical periods;

(c) The 24-hour average full power 2°C above ambient thermal barrier (measured during the critical periods) may not exceed 50 percent of the accessible cross-section of the receiving body, both cross-sections taken in the same plane; and

(d) The area of the bottom touched by waters heated 2°C or more above ambient at full power may not exceed 5 percent of the stream bottom passed over by the stream flowing for 6 hours, both areas to be measured during the critical periods.

F. Determination of Impingement Loss.

(1) The value of the impinged species destroyed by the intake structure shall be determined by estimating the number of each species destroyed and multiplying by the values listed in COMAR 08.02.09.01 Monetary Value of Tidal and Non-Tidal Water Aquatic Animals. These factors will be weighted by multiplying by the following adjustment factor:

Species Function	*Factor*
Recreational only	1.0
Commercial and Recreational	1.0
Commercial only	1.0
Commercial Recreational and Forage	0.8
Commercial and Forage	.75
Recreational and Forage	.75
Forage	.75

(2) The Administration* shall require permittees to install and operate functional modifications to mitigate impingement loss, provided that the additional cost of installation of modifications to intake structures and of operation modifications over a 5-year period, does not exceed 5 times the estimated annual value of impingement loss. These approved modifications shall be defined as "best available technology for intake structures." If a permittee also conducts studies pursuant to §G, the Administration's decision on intake structure modifications shall be made concurrently with the decision on alternate effluent limitations.

G. Requirements for Determining Alternate Effluent Limitations.

(1) Permittees requesting alternate effluent limitations sufficient to assure the protection and propagation of a balanced, indige-

nous population of shellfish, fish, and wildlife in and on the receiving water, shall:

(a) Demonstrate from existing information that the once-through cooling system has had no adverse impact on the existing beneficial uses of the water body over at least a 5-year period; or

(b) Demonstrate that the once—through cooling system has no adverse impacts caused by the following affects (facilities not in compliance with §C(2)(b) need only to consider §G(1)(b)(iv) below:

(i) A significant increase in abundance or distribution of any species considered to be nuisance species by the Administration;

(ii) A significant change in biological productivity;

(iii) A significant elimination or impairment of economic and recreational resources;

(iv) A significant reduction in the successful completion of the life cycle of RIS has occurred.

(2) If the permittee cannot demonstrate that the existing facilities will assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the receiving water, the permittee in requesting alternate effluent limitations shall propose abatement measures to mitigate the impacts in §G(1)(b) caused by any or all of the following:

(a) Intake structures (including embayments) are constructed so as to cause impingement# and entrainment# losses of species resulting from but not limited to:

(i) High intake water velocities;

(ii) Withdrawal of dissolved oxygen depleted waters;

(iii) Withdrawal of ichythyoplankton or larval rich layers;

(iv) Improper screen operations.

(b) Facilities designed to minimize environmental impacts do not have the desired effect or cause other impacts not considered in the design.

(c) Location and configuration of the discharge structure causes impacts resulting from, but not limited to:

(i) Discharge of dissolved oxygen depleted waters;

(ii) Discharge of chemicals;

(iii) Discharge of eroded metals;

(iv) Discharge velocity entrainment.

(3) By January 1, 1983, unless otherwise stipulated in a State Discharge Permit, all permittees subject to this requirement shall meet the applicable standards, operate closed cycle cooling, or meet alternate effluent limitations approved by the Administration.

Administrative History

Effective date: September 1, 1974 (1:1 Md. R. 33)

- Regulation .01B amended effective December 5, 1974 (1:6 Md. R. 278) and April 21, 1978 (5:8 Md. R. 593)
- Regulations .02, .07, and .11 amended effective April 21, 1978 (5:8 Md. R. 593)
- Regulation .02 amended effective July 11, 1980 (7:14 Md. R. 1348)
- Regulation .03 repealed effective July 11, 1980 (7:14 Md. R. 1348)
- Regulation .03B-E amended effective July 28, 1978 (5:15 Md. R. 1187)
- Regulation .06C amended effective May 18, 1979 (6:10 Md. R. 841)
- Regulation .08N adopted effective March 9, 1979 (6:5 Md. R. 444)
- Regulation .09 repealed effective July 11, 1980 (7:14 Md. R. 1348)
- Regulation .11 amended effective July 11, 1980 (7:14 Md. R. 1348)
- Regulation .13 adopted effective May 19, 1978 (5:10 Md. R. 777)

State of Maryland

DEPARTMENT OF HEALTH AND MENTAL HYGIENE

201 WEST PRESTON STREET • BALTIMORE, MARYLAND 21201 • Area Code 301 • 383-

Harry Hughes, Governor

Charles R. Buck, Jr., Sc.D. Secretary

DISCHARGE PERMIT

State Discharge Permit Number	79-DP-0187
NPDES Permit Number	MD0002399
Effective Date	February 3, 1982
Expiration Date	December 31, 1986

Pursuant to the provisions of Title 8 of the Natural Resources Article, Annotated Code of Maryland (1974 Volume) as amended and regulations promulgated thereunder and the provisions of the Federal Water Pollution Control Act Amendments of 1977 (33 U.S.C. Section 466 et. seq.) and implementing regulations 40 C.F.R. Parts 122, 123, 124 and 125, the Department of Health and Mental Hygiene hereinafter referred to as "DHMH" hereby authorizes

Baltimore Gas and Electric Company
P.O. Box 1475
Baltimore, Maryland 21203

TO DISCHARGE FROM
Calvert Cliffs Nuclear Power Plant

LOCATED AT
Lusby, Calvert County, Maryland

VIA OUTFALLS
001, 002, 003, and 004 as identified and described herein

TO
the Chesapeake Bay which is protected for shellfish harvesting

in accordance with the following special and general conditions, and map made a part hereof.

Permit No. 79-DP-0187
Page No. 12

Special Conditions

C. REMOVED SUBSTANCES

1. Within 90 days of the effective date of this permit, the permittee shall submit to DHMH on a form provided, the following information:

   a) Locate, on a suitable map, all areas used for the disposal of any Removed Substances as defined by II. general Conditions B.7;

   b) The physical, chemical and biological characteristics and quantities of any Removed Substances handled, and the method of disposal;

   c) if disposal is handled by other than the permittee identify the contractor or subcontractor, their mailing address, and the Information specified in a and b above.

2. Prior to the use of new or additional disposal areas or contractors or subcontractors the permittee shall notify, in writing DHMH.

D. WASTEWATER OPERATOR CERTIFICATION

Within six months from the date of issuance of this permit, the permittee's facility shall be operated by an industrial wastewater operator duly certified by the Maryland Board of Certification. At no time during the effect of this permit shall the treatment facilities be operated for more than six months without a certified operator.

E. THERMAL COMPLIANCE

The Permittee has conducted studies in accordance with COMAR 08.05.04.13C(2) to determine compliance with thermal discharge mixing zone criteria, to determine whether entrainment affects a spawning or nursery area of consequence, and to estimate impingement losses. The Plant was found to meet thermal mixing zone requirments; not to affect spawning or nursery areas of consequence, and to have a modest impingement loss. The present once-through cooling system is in compliance with COMAR 08.05.04.13 and continued use of the system will be permitted. Therefore, alternate effluent limitations as put forth in Section 316(a) of the Clean Water Act are not necessary.

Permit No. 79-DP-0187
Page No. 25

II. D. NPDES PERMIT

On September 5, 1974 the Administrator of the U.S. Environmental Protection Agency approved the proposal submitted by the State of Maryland for the operation of a permit program for discharges into navigable waters pursuant to Section 402 of the Federal Clean Water Act.

Pursuant to the aforementioned approval, this Discharge Permit is both a State of Maryland Discharge Permit and a NPDES Permit.

This permit and the authorization to discharge shall expire at midnight on December 31, 1986. Permittee shall not discharge after the above date of expiration. In order to receive authorization to discharge after above date of expiration, the permittee shall submit such information, forms, fees as are required by DHMH no later than 180 days prior to the above date of expiration.

William M. Eichbam
Assistant Secretary for
Environmental Programs

C.0 OFFSITE WELL IMPACT CALCULATIONS

C.1 Background Assumptions

This appendix shows how the Baltimore Gas and Electric Company has calculated the potential impact that the Calvert Cliffs Nuclear Power Plant (CCNPP) groundwater withdrawal could have on a hypothetical well located on the site boundary closest to the CCNPP point of withdrawal. Although CCNPP has numerous wells, the Maryland Department of Environment requires Baltimore Gas and Electric Company to monitor withdrawals only from wells that withdraw the most water, the five located in the Protected Area.[1] These monitoring records show that, since beginning operation in 1974, CCNPP has withdrawn an average of approximately 157 gallons per minute of groundwater. For the sake of simplicity of calculation, it is assumed that all withdrawals are from a single point. Drawdown may be expressed as:

$s = [114.6\mathrm{Q} / \mathrm{T}]\mathrm{W}(\mathrm{u})$, where:

s = drawdown in feet

Q = well discharge in gallons per minute

T = transmissivity in gallons per day per foot

W(u) = exponential integral termed "well function." The argument is given by:

$\mathrm{u} = 1.87\mathrm{r}^2 S / \mathrm{T}t$, where:

S = storage coefficient

r^2 = the square of the distance in feet from the pumped well

t = time in days since pumping started

For CCNPP:

Q = 157 gallons per minute

T = 6,500 gallons per day per foot (Reference 1)

r = 5,000 feet

S = 1.8E-04 (Reference 1)

C.2 First-Year Calculation

The calculation for drawdown expected after the first year (365 days) of CCNPP operation is as follows:

$$\mathrm{u} = \frac{(1.87)(5{,}000)^2(0.00018)}{(6{,}500)(365)} = 0.00354 = 3.54 \times 10^{-3}$$

From the table of W(u) and u (Reference 2), if u = 3.54×10^{-3}, W(u) = 5.07

$$s = \frac{(114.6)\ (157)\ (5.07)}{6{,}500} = 14.0 \text{ feet}$$

1 Requirement in groundwater appropriation permit.

C.3 10-Year Calculation

The calculation for drawdown expected after ten years (3,650 days) of CCNPP operation is as follows:

$$u = \frac{(1.87)(5{,}000)^2(0.00018)}{(6{,}500)(3{,}650)} = 0.000355 = 3.55 \times 10^{-4}$$

From the table of W(u) and u, if $u = 3.55 \times 10^{-4}$, $W(u) = 7.37$

$$s = \frac{(114.6)(157)(7.37)}{6{,}500} = 20.4 \text{ feet}$$

References

1. "Ground Water Supply Investigation for the Calvert Cliffs Nuclear Power Plant Near Prince Frederick, Maryland," Bechtel Corporation, January 1969. Transmissivity and the storage coefficient values are averages generated from the aquifer pump test published in this report.

2. Abramowitz, M. and Stegan, I. A., 1972, "Handbook of Mathematical Functions," National Bureau of Standards, Applied Mathematics Series 55, 10th edition, Table W(u) and u.

D.0 SPECIAL-STATUS SPECIES CONSULTATIONS

Appendix D presents letters Baltimore Gas and Electric Company submitted to the U.S. Fish and Wildlife Service and the National Marine Fisheries Service requesting initiation of informal consultation under Section 7 of the Endangered Species Act of 1973. Also provided in this Appendix is the response received from the National Marine Fisheries Service stating that further consultation pursuant to Section 7 is not required. A response from the U.S. Fish and Wildlife has not been received and, therefore, is not presented in this Appendix.

NUCLEAR ENGINEERING

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657
410586-2200

LCM-97-359
October 9, 1997

Ms. Barbara Schroeder
National Marine Fisheries Service
Office of Protected Resources
1315 East-West Highway
Silver Spring, MD 20910

SUBJECT: Request for Informal Consultation under Section 7 of the Endangered Species Act of 1973 in Support of License Renewal Activity

Dear Ms. Schroeder,

Baltimore Gas and Electric Company (BGE) is requesting initiation of informal consultations under Section 7 of the Endangered Species Act of 1973, as amended (16 USC 1531). Baltimore Gas and Electric Company is reviewing the option of license renewal for the Operating Licenses issued by the U.S. Nuclear Regulatory Commission (NRC) for Calvert Cliffs Nuclear Power Plant (CCNPP). Should BGE elect to pursue license renewal, consultation under Section 7 for this action would be needed.

The current Operating Licenses for CCNPP expire in the years 2014 (Unit 1) and 2016 (Unit 2), and BGE is preparing a license renewal application in accordance with NRC regulatory requirements. Nuclear Regulatory Commission guidance directs license applicants to consult with the appropriate agency to determine whether threatened or endangered species are present and whether they would be adversely affected by this action. It is BGE's understanding that NRC uses this process in partial fulfillment of its obligations under the Endangered Species Act. Baltimore Gas and Electric Company is initiating this informal consultation in accordance with NRC guidance and will include a copy of this letter and your response in the environmental report to be submitted as part of the CCNPP license renewal application should we decide to request renewal.

Baltimore Gas and Electric Company has operated CCNPP since 1974. The plant is located in Calvert County, Maryland, on the west bank of the Chesapeake Bay, approximately 40 miles southeast of Washington DC, and 7.5 miles north of Solomons Island, Maryland (see attached figure for details). The plant has two pressurize-water reactors. Each unit has a rating for a net electrical power output of 845 megawatts-electric, and each operates at a maximum core thermal power output level of 2,700 megawatts-thermal. A once-through heat dissipation system transfers heat energy from the plant to the Chesapeake Bay using a shoreline intake and an offshore discharge structure.

One aquatic endangered species, the shortnose sturgeon *(Acipenser brevirostrum)*, is known to inhabit the Chesapeake Bay in this region. Baltimore Gas and Electric Company conducted nearshore trawl surveys of fish in the vicinity of CCNPP from 1969 to 1981 and only collected small numbers of shortnose sturgeon in 1979. Since 1975, CCNPP intake impingement studies have never collected a shortnose sturgeon.

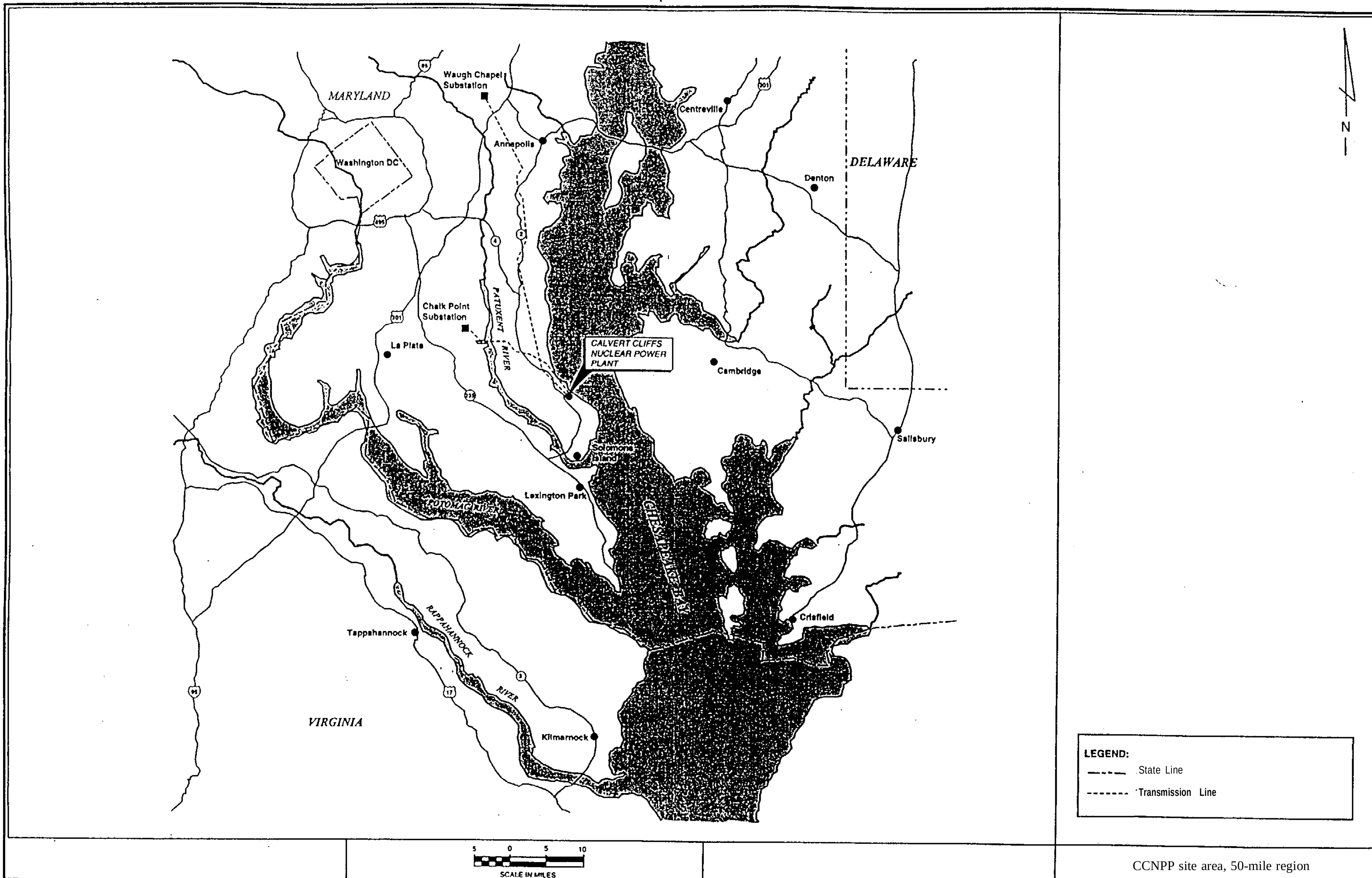
Anticipated activities would take place within existing structures and facilities. Currently, no additional land disturbances or structural modifications have been identified for the purposes or supporting license renewal. Baltimore Gas and Electric Company expects that operation of the plant through the license renewal period (an additional 20 years) would not adversely impact this species and requests your concurrence that formal consultation is not necessary.

We would appreciate your input at this time. If you have any questions, please call me at (410) 495-4803 or our NRC License Renewal Environmental Project Manager, Claudia Craig, at (301) 415-1053.

BWD8K

Barth W. Doroshuk
Principal Engineer
Life Cycle Management Unit

cc: C. H. Cruse (BGE)
T. N. Pritchett (BGE)
J. P. Bennett (BGE)
E. I. Bauereis (BGE)
T. G. Ringger (BGE)
T. E. Benassi (BGE)
R. I. McLean (MDNR)
C. M. Craig (NRC)
Section Office
LCM File (Environmental, LR)



CCNPP site area, 50-mile region

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
Habitat Conservation Division
904 South Morris Street
Oxford, Maryland 21654

12 February 1998

Mr. Barth W. Doroshuk
Principal Engineer
Life Cycle Management Unit
Baltimore Gas and Electric
2650 Calvert Cliffs Parkway
Lusby, Maryland 20657

Dear Mr. Doroshuk:

We have reviewed your request to initiate informal consultation with respect to Section 7 of the Endangered Species Act for those species for which the National Marine Fisheries Service is responsible. After discussing the proposal with Ms. Julia Bradley of your staff, we have concluded that no endangered or threatened species within our purview are found in the project area, and further consultation pursuant to Section 7 is not required.

However, the endangered shortnose sturgeon (Acipenser brevirostrum) and the threatened loggerhead turtle (Caretta caretta) are found in waters adjacent to the project area. Therefore, should project conditions change or new information becomes available which changes the basis of this conclusion, consultation should be reinitiated.

It is stated in your letter that small numbers of shortnose sturgeon were collected in trawl surveys in the vicinity of your plant. Very little information exists for shortnose sturgeon in Chesapeake Bay. Consequently, we would greatly appreciate copies of any records that you have relative to this species.

If you have questions concerning our comments, please call me at (401) 226-5771.

Sincerely,

Timothey E. Goodger
Officer in charge
Oxford Habitat Program

NUCLEAR ENGINEERING

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657
410586-2200

LCM-97-355
October 23, 1997

Mr. John Wolflin
Supervisor - Chesapeake Bay Field Office
U.S. Fish & Wildlife Service
177 Admiral Cochrane Drive
Annapolis, MD 21401

SUBJECT: Request for Informal Consultation under Section 7 of the Endangered Species Act of 1973 in Support of License Renewal Activity

Dear Mr. Wolflin,

Baltimore Gas and Electric Company (BGE) is requesting initiation of informal consultations under Section 7 of the Endangered Species Act of 1973, as amended (16 USC 1531). Baltimore Gas and Electric Company is reviewing the option of license renewal for the Operating Licenses issued by the U.S. Nuclear Regulatory Commission (NRC) for Calvert Cliffs Nuclear Power Plant (CCNPP). Should BGE elect to pursue license renewal, consultation under Section 7 would be needed for this action.

The current Operating Licenses for CCNPP expire in the years 2014 (Unit 1) and 2016 (Unit 2), and BGE is preparing a license renewal application in accordance with NRC regulatory requirements. Nuclear Regulatory Commission guidance directs license applicants to consult with the appropriate agency to determine whether threatened or endangered species are present and whether they would be adversely affected by this action. It is BGE's understanding that NRC uses this process in partial fulfillment of its obligations under the Endangered Species Act. Baltimore Gas and Electric Company is initiating this informal consultation in accordance with NRC guidance and will include a copy of this letter and your response in the environmental report to be submitted as part of the CCNPP license renewal application should we decide to request renewal.

Baltimore Gas and Electric Company has operated CCNPP and its associated transmission lines since 1974, The plant is located near Lusby in Calvert County and the transmission lines are located in Calvert Anne Arundel, and Prince Georges Counties (see attached figure for details). On the CCNPP "site, three federally-listed species presently occur and are listed as follows:

- *Cicindela puritana* - Puritan tiger beetle. This species is currently listed as threatened by the U.S. Fish and Wildlife Service and is listed as endangered by the Maryland Department of Natural Resources. According to The Nature Conservancy, Calvert Cliffs harbors approximately 90 percent of the world's population of this beetle species.
- *Cicindela dorsalis var. dorsalis* - Northeastern beach tiger beetle. This species is currently listed as threatened by the U.S. Fish and Wildlife Service and is listed as endangered by the Maryland Department of Natural Resources. This species can be found along the beach at the base of the cliffs on the CCNPP site.

- *Haliaeetus leucocephaIus* - Bald eagle. This species is currently listed as threatened by the U.S. Fish and Wildlife Service and is listed as endangered by the Maryland Department of Natural Resources. Currently, the CCNPP site has an active nest located on the south side of the site, and 7 offspring have fledged since 1986.

One aquatic endangered species, the shortnose sturgeon *(Acipenser bevirostrum), is known* to inhabit the Chesapeake Bay. Baltimore Gas and Electric Company conducted nearshore trawl surveys of fish in the vicinity of CCNPP from 1969 to 1981 and only collected small numbers of shortnose sturgeon in 1979. Since 1975, CCNPP intake impingement studies have never collected a shortnose sturgeon.

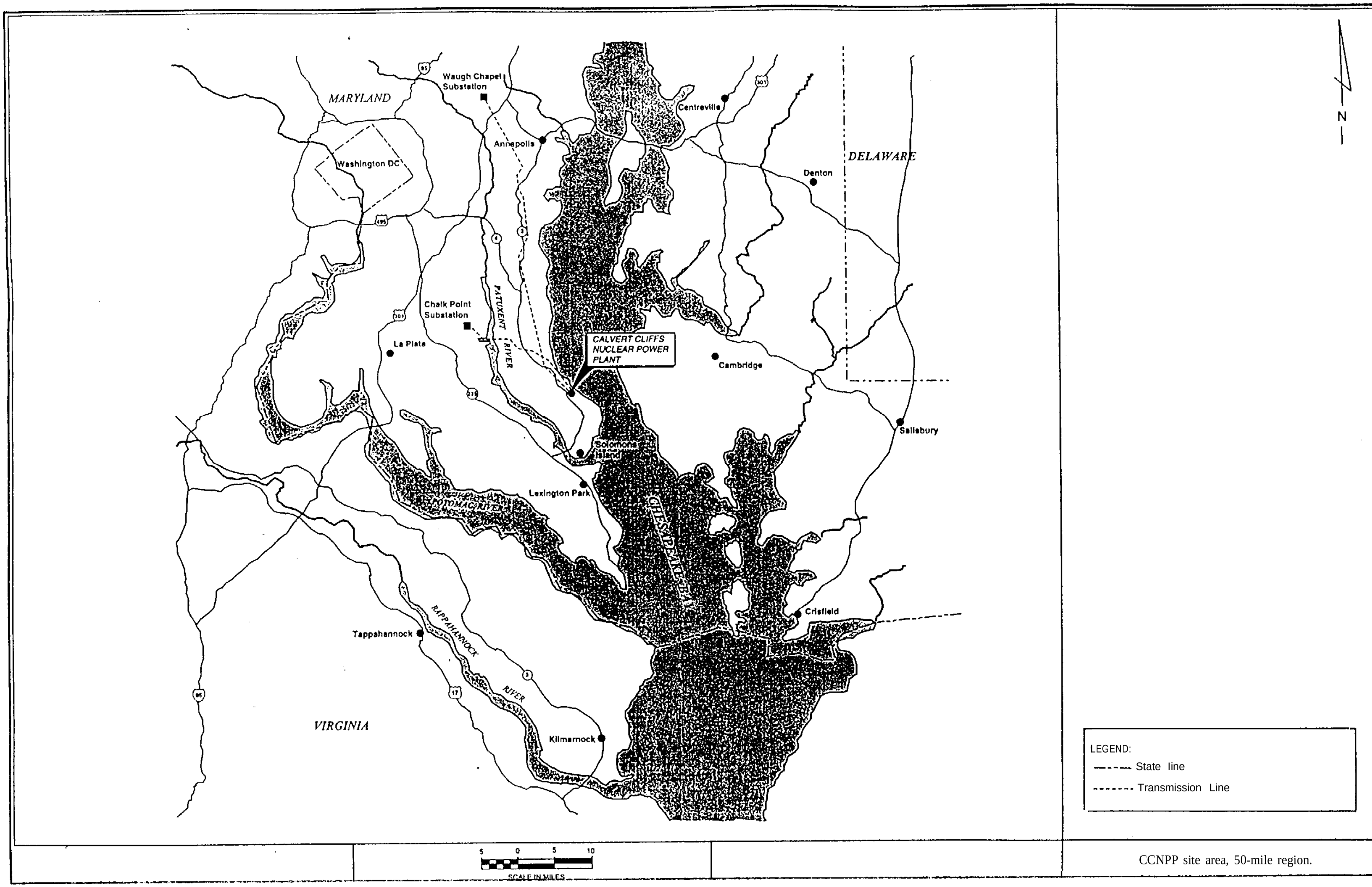
Baltimore Gas and Electric Company believes that through habitat protection and enhancement, the CCNPP effects on listed species have been positive. In 1993, BGE and The Nature Conservancy entered into an agreement giving the Conservancy the right to study and monitor the threatened tiger beetle population on the CCNPP waterfront area. In addition, BGE initiated a legal agreement with the Conservancy to create a Tiger Beetle Habitat Protection Area along approximately 6 miles of beach cliffs. As a result of BGE support of Conservancy efforts, including the CCNPP Agreement, the Conservancy awarded BGE the Conservancy's first Corporate Conservation Award. Baltimore Gas and Electric Company is committed to continuing these programs and expects that operation of the plant through the license renewal period (an additional 20 years) would not adversely impact these species. We therefore request your concurrence that formal consultation is not necessary. Any maintenance activities necessary to support license renewal would be confined within existing structures and facilities. Currently, no additional land disturbances are identified for the purposes of supporting license renewal.

We would appreciate your input at this time. If you have any questions, please call me at (410) 495-4803 or our NRC License Renewal Environmental Project Manager, Claudia Craig, at (301) 415-1053.

Barth W. Doroshuk
Principal Engineer
Life Cycle Management Unit

Attachment

cc: C. H. Cruse (BGE)
T. N. Pritchett (BGE)
J. P. Bennett (BGE)
E. I. Bauereis (BGE)
T. G. Ringger (BGE)
R I. McLean (MDNR)
C. M. Craig (NRC)
Section Office
LCM File (Environmental, LR)



CCNPP site area, 50-mile region.

E.0 CULTURAL RESOURCES CONSULTATION

Appendix E presents Baltimore Gas and Electric Company's request to the Maryland Historic Preservation Officer for of historical and cultural consultations under Section 106 of the National Historic Preservation Act of 1966. Also provided in this Appendix is the agency response stating that the proposed activity is unlikely to affect significant historic and archaeological properties.

NUCLEAR ENGINEERING

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657
410586-2200

LCM-97-374
October 9, 1997

J. Rodney Little
Director-and State Historic Preservation Officer
Maryland Historic Trust
100 Community Place
Brownsville, Maryland 21032

SUBJECT: Request for Historical and Cultural Consultations in Support of License Renewal Activity

REFERENCES:

(1) Letter to D. R Muller (Atomic Energy Commission) from Orlando Ridout (The Maryland Historical Trust), Response to Inquiry Regarding Two Early Dwellings at the Calvert Cliffs Nuclear Plant Site in Maryland, dated June 15, 1972

(2) Goodwin, R and Associates, Inc., *Phase II Archeological Evaluation of Sites 18CV61 and 18CV62, Calvert County, Maryland*, Frederick, Maryland, 1993

(3) Goodwin, R. and Associates, Inc., *Archeological Examination of Structure Relocation and Road Realignments for Baltimore Gas and Electric Company, Calvert Cliffs to Chalk Point 500 kv Transmission Line Corridor - South Circuit, Calvert and Prince George's Counties, Maryland,* Cambridge, Maryland, 1993

Dear Mr. Little,

Baltimore Gas and Electric Company (BGE) is requesting initiation of historical and cultural resources consultations under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470) and Federal Advisory Council on Historic Preservation regulations (40 CFR 800). Baltimore Gas and Electric Company is reviewing the option of license renewal for the Operating Licenses issued by the U.S. Nuclear Regulatory Commission (NRC) for Calvert Cliffs Nuclear Power Plant (CCNPP). Should BGE elect to pursue license renewal, historical and cultural resources consultation for this action would be needed.

The current Operating Licenses for CCNPP expire in the years 2014 (Unit 1) and 2016 (Unit 2), and BGE is preparing a license renewal application in accordance with NRC regulatory requirements. Nuclear Regulatory Commission guidance directs license applicants to consult with the appropriate State Liaison Officer for Historic Preservation. It is BGE's understanding that NRC uses this process in partial fulfillment of its obligations under Section 106 of the National Historic Preservation Act of 1966 and Federal Advisory Council on Historic Preservation regulations. Baltimore Gas and Electric Company is initiating this consultation in accordance with NRC requirements and will include a copy of this letter and your response in the environmental report to be submitted as part of the CCNPP license renewal application, should we decide to request renewal.

Baltimore Gas and Electric Company has operated CCNPP and its associated transmission lines since 1974. The plant is located near Lusby in Calvert County and the transmission lines are located in Calvert Anne Arundel, and Prince Georges Counties (see attached figure for details). In 1971, the Maryland Historical Trust evaluated two historic dwellings located on the site, but found them to be too derelict to be nominated for inclusion on the *National Register*. However, following Maryland Historical Trust direction (Reference 1), BGE took photographs and salvaged some architectural elements of the structures. BGE continues to display these items in the Visitors Center (a remodeled old tobacco barn) on site.

During 1992 and 1993, archeological surveys were conducted along a proposed new transmission line right-of-way in Calvert County (see CCNPP to Chalk Point line on attached figure). As a result two archeological sites were examined extensively during preconstruction surveys. One prehistoric site was found to retain sufficient subsurface integrity to be considered eligible for inclusion on the *National Register of Historic Places* however, the historic and prehistoric artifacts found in 1992 did not provide unique information and the sites were dropped from further consideration. The impact areas of the right-of-way were evaluated extensively, and towers were located in areas that would not affect any intact subsurface artifacts (References 2 and 3).

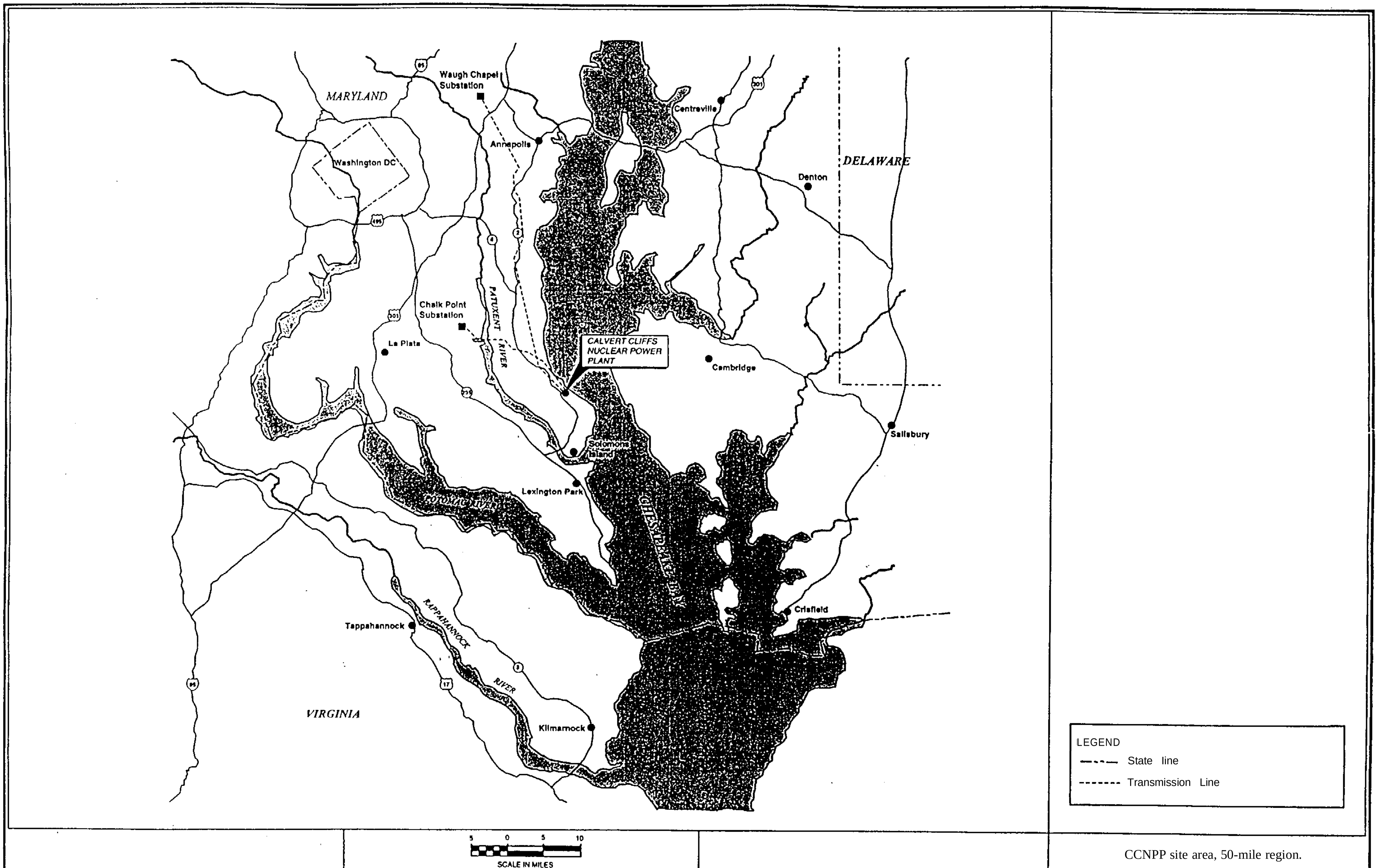
Baltimore Gas and Electric Company is committed to maintaining the historic and cultural resources preserved at the Visitors Center, and this facility would continue to be used for public information and education. Baltimore Gas and Electric Company expects that operation of the plant through the license renewal period (an additional 20 years) would not adversely impact historic or cultural resources. Any maintenance activities that would be necessary to support license renewal would be contained within existing structures and facilities. Currently, no additional land disturbances or structural modifications have been identified for the purposes of supporting license renewal.

In reviewing the option of license renewal for CCNPP, BGE has consulted extensively with Dr. Richard McLean, Maryland Department of Natural Resources, Power Plant Assessment Program. We would appreciate your input at this time. If you have any questions, please call me at (410) 495-4803, Dr. McLean at (410) 260-8662, or our NRC License Renewal Environmental Project Manager, Claudia Craig, at (301) 415-1053.

BWDSK

Barth W. Doroshuk
Principal Engineer
Life Cycle Management Unit

cc: C. H. Cruse (BGE)
T. N. Pritchett (BGE)
E. I. Bauereis (BGE)
T. G. Ringger (BGE)
J. P. Bennett (BGE)
R. I. McLean (MDNR)
C. M. Craig (NRC)
Section Office
LCM File (Environmental, LR)



CCNPP site area, 50-mile region.

F FERC 9703805

NUCLEAR ENGINEERING

GDS/?

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657 "
410586-2200

LCM-97-374
October 9, 1997

J. Rodney Little
Director and State Historic Preservation Officer
Maryland Historic Trust
100 Community Place
Brownsville, Maryland 21032

SUBJECT: Request for Historical and Cultural Consultations in Support of License Renewal Activity

REFERENCES:

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(3) Goodwin, R and Associates Inc., *Archeological Examination of Structure Relocation and Road Realignments for Baltimore Gas and Electric Company, Calvert Cliffs to Chalk Point 500 kv Transmission Line Corridor - South Circuit, Calvert and Prince George's Counties, Maryland,* Cambridge, Maryland, 1993

Dear Mr. Little,

Baltimore Gas and Electric Company (BGE) is requesting initiation of historical and cultural resources consultations 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 (40 CFR 800). Baltimore Gas and Electric Company is reviewing the option of license renewal for the Operating Licenses issued by the U.S. Nuclear Regulatory Commission (NRC) for Calvert Cliffs Nuclear Power Plant (CCNPP). Should BGE elect to pursue license renewal, historical and cultural resources consultation for this action would be needed.

The current Operating Licenses for CCNPP expire in the years 2014 (Unit 1) and 2016 (Unit 2), and BGE is preparing a license renewal application in accordance with NRC regulatory requirements. Nuclear Regulatory Commission guidance directs license applicants to consult with the appropriate State Liaison Officer for Historic Preservation. It is BGE's understanding that NRC uses this process in partial fulfillment of its obligations under Section 106 of the National Historic Preservation Act of 1966 and Federal Advisory Council on Historic Preservation regulations. Baltimore Gas and Electric Company is initiating this consultation in accordance with NRC requirements and will include a copy of this letter and your response in the environmental report to be submitted as part of the CCNPP license renewal application, should we decide to request renewal.

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During 1992 and 1993, archeological surveys were conducted along a proposed new transmission line right-of-way in Calvert County (see CCNPP to Chalk Point line on attached figure). As a result, two archeological sites were examined extensively during preconstruction surveys. One prehistoric site was found to retain sufficient subsurface integrity to be considered eligible for inclusion on the *National Register of Historic Places;* however, the historic and prehistoric artifacts found in 1992 did not provide unique information and the sites were dropped from further consideration. The impact areas of the right-of-way were evaluated extensively, and towers were located in areas that would not affect any intact subsurface artifacts (References 2 and 3).

18 CV 61

2nd site 18CV 62

Baltimore Gas and Electric Company is committed to maintaining the historic and cultural resources preserved at the Visitors Center, and this facility would continue to be used for public information and education. Baltimore Gas and Electric Company expects that operation of the plant through the license renewal period (an additional 20 years) would not adversely impact historic or cultural resources. Any maintenance activities that would be necessary to support license renewal would be contained within existing structures and facilities. Currently, no additional land disturbances or structural modifications have been identified for the purposes of supporting license renewal.

In reviewing the option of license renewal for CCNPP, BGE has consulted extensively with Dr. Richard McLean, Maryland Department of Natural Resources, Power Plant Assessment Program. We would appreciate your input at this time. If you have any questions, please call me at (410) 495-4803, Dr. McLean at (410) 260-8662, or our NRC License Renewal Environmental Project Manager, Claudia Craig, at (301) 415-1053.

Cove Pt.
archeo - no new grnd. disturbance/structure proposed
(IA) [illegible]
10/22/97

BWDSK

Barth W. Doroshuk
Principal Engineer
Life Cycle Management Unit

A review of MHT files and your submittal indicates that this project is unlikely to affect significant historic and archeological properties.

Gary Shaffer 10-22-97
Office of Preservation Services Date
Maryland Historical Trust

cc: C. H. Cruse (BGE)
T. N. Pritchett (BGE)
E. I. Bauereis (BGE)
T. G. Ringger (BGE)
J. P. Bennett (BGE)
R I. McLean (MDNR)
C. M. Craig (NRC)
Section Office
LCM File (Environmental, LR)

F.0 SEVERE ACCIDENT MITIGATION ALTERNATIVES ANALYSIS

Appendix F contains the following sections:

- F.1 -- Melcor Accident Consequences Code System Modeling
- F.2 -- Development of Candidate SAMAs
- F.3 -- Level 2 Modeling
- F.4 -- SAMA Descriptions and Cost Estimates
- F.5 -- List of Acronyms Used in Appendix F

F.1 MELCOR ACCIDENT CONSEQUENCES CODE SYSTEM MODELING

F.1.1 Introduction

The following sections describe the assumptions made and the results of modeling performed to assess the risks and consequences of severe accidents (Nuclear Regulatory Commission [NRC] Class 9) at Calvert Cliffs Nuclear Power Plant (CCNPP) Unit 1.

The severe accident consequence analysis was carried out with the Melcor Accident Consequence Code System (MACCS) code. This code simulates the impact of severe accidents at nuclear power plants on the surrounding environment. The principal phenomena considered in MACCS are atmospheric transport, mitigating actions based on dose projection, dose accumulation by a number of pathways, including food and water ingestion, and economic costs.

F.1.2 Input

The input data required by MACCS are outlined below.

F.1.2.1 Core Inventory

The core inventory (Table F.1-1) is for CCNPP at a power level of 2,700 megawatts-thermal. These values were obtained by adjusting the end-of-cycle values for a 3,412 megawatts-thermal pressurized water reactor (PWR) by a linear scaling factor of 0.791 (Reference 1).

F.1.2.2 Source Terms

The source term input data to MACCS were the severe accident source terms presented in the probabilistic risk assessment (PRA) in the CCNPP Individual Plant Examination (IPE) (Reference 2). This document defines the releases in terms of five source term categories (STCs) and demonstrates the method of calculating releases. Table F.1-2 lists the input release fractions for each MACCS nuclide group, together with the source category frequencies, as calculated in the PRA. The assignment of the radionuclides in Table F.1-2 to these nuclide groups is the same as that given in the standard MACCS input.

There are five STCs — two with early containment failure, one with late containment failure, and two with containment bypass as the failure mode. For MACCS modeling, two of the releases (II and V) were split into two plume segments (with different onset of release times) to represent the time variation in the releases. These are shown in Table F.1-2 as STCs II-1, II-2, and V-1 and V-2. A sixth STC is listed in the PRA to represent the core damage sequences for which containment failure or bypass does not occur and, hence, does not produce severe accident consequences.

The amount (becquerels) of each radionuclide released to the atmosphere for each accident sequence or release category are obtained by multiplying the (adjusted) core inventory at the time of the hypothetical accident (Table F.1-1) by the release fractions (Table F.1-2). Because the accidents are assumed to occur independently, the consequences were summed for all the source term consequences weighted by the annual frequency to obtain the total annual accident risk.

F.1.2.3 Meteorological Data

The MACCS input used a full year of consecutive hourly values of windspeed, wind direction, stability class, and precipitation. These were processed from measurements taken at the site meteorological tower from January 1, 1993 to December 31, 1993.

The MACCS calculations examine a representative subset of the 8,760 hourly observations contained in one year's data set (typically about 150 sequences). The representative subset is selected by sampling the weather sequences after sorting them into weather bins defined by windspeed, atmospheric stability, and rain conditions at various distances from the site.

F.1.2.4 Population Distribution

The predicted permanent resident population around the site for the year 2030 (Table F.1-3) was distributed by location in a grid consisting of sixteen directional sectors, the first of which is centered on due north, the second on 22.5 degrees east of north, and so on (Figure 3-5 in Chapter 3 of this report). The direction sectors are divided into 14 radial intervals extending out to 50 miles. The habitable land fraction for each grid element was calculated from land fraction data within a 50-mile radius of the plant.

F.1.2.5 Emergency Response

As have other U.S. utilities who operate nuclear reactors, BGE has developed a plan for the evacuation of the population within the plume exposure emergency planning zone. This zone is approximately a 10-mile radius centered on the CCNPP site. Site-specific evacuation studies have been carried out by BGE (References 3 and 4), and the evacuation modeling employed for the Severe Accident Mitigation Alternatives (SAMAs) analysis is based on those studies.

Input for the evacuation modeling includes daytime and nightime evacuation times under both normal and adverse conditions for the CCNPP emergency planning zone. For the purposes of the present study, it was assumed that adverse weather would not interfere with the evacuation process, and that only 95 percent of the people within the emergency planning zone would participate in the evacuation. The remaining 5 percent are assumed to be unable or unwilling to evacuate and are assumed to go about their normal activities for 24 hours. For this analysis, it was conservatively assumed that people beyond 10 miles would continue their normal activities unless predictions indicate that specific elevated radiation dose levels would be exceeded.

The long-term phase is assumed to begin after one week and extend for five years. Long-term relocation is assumed to be triggered by a four-rem whole body effective dose equivalent. Long-term protective measures were assumed to be based on generic protective action guideline levels for actions such as decontamination, temporary relocation, contaminated crops and milk condemnation, and farmland production prohibition.

F.1.2.6 Economic Data

Land use statistics including farmland values, farm product values, dairy production, and growing season information were provided on a countywide and statewide basis for distances out to 50 miles (Reference 5).

Economic consequences were estimated by summing the following costs: evacuation costs, temporary relocation costs (food, lodging, lost income), costs of decontaminating land and buildings, lost return-on-investments from properties that are temporarily interdicted to allow contamination to be decreased by decay of nuclides, the cost of repairing temporarily interdicted property, the value of crops destroyed or not grown because they were contaminated by direct deposition or would be contaminated by root uptake, and the value of farmland and of individual, public, and non-farm commercial property that is condemned. Costs associated with damage to the reactor, medical care, life-shortening, and litigation are not calculated by MACCS.

F.1.3 Results

Based on the preceding input data, MACCS was used to estimate the following:

- The downwind transport, dispersion, and deposition of the radioactive materials released to the atmosphere from the failed reactor containment;
- The short- and long-term radiation doses received by exposed populations via direct (cloudshine, plume inhalation, groundshine, and resuspension inhalation) and indirect (ingestion) pathways;
- The mitigation of those doses by protective actions (evacuation, sheltering, and post-accident relocation of people; disposal of milk, meat, and crops; and decontamination, temporary interdiction, or condemnation of land and buildings); and
- The offsite costs of short-term emergency response actions (evacuation, sheltering, and relocation), of crop and milk disposal, and of the decontamination, temporary interdiction, or condemnation of land and buildings.

The MACCS output includes both the frequency (or likelihood of occurrence) of accidents and their impacts (or consequences). A common way in which this combination of factors is used to estimate risk is to multiply the accident frequencies by the consequences. The resultant risk is then expressed as the number, or magnitude, of consequences expected per unit time. Table F.1-4 shows average values of risk associated with population dose and economic costs. These average values were obtained by summing the risk (i.e., frequency multiplied by the consequences) over the entire range of distributions. Because the probabilities are on a per-reactor-year basis, the averages shown are also on a per-reactor-year basis.

F.1.3.1 Dose Impacts

The results of dose impact calculations performed for CCNPP Unit 1 are presented in Table F.1-4. All of the accident sequences and release categories shown in Table F.1-2 contribute to the results, the consequences of each being weighted by the associated frequency.

For perspective, the population doses may be compared with the annual average dose, 5.66×10^5 person-rem, to the population within 50 miles of CCNPP due to natural background radiation. This value was calculated by multiplying the predicted 2030 population within 50 miles of CCNPP (approximately 4,350,000) by the average background radiation dose (130 millirem per year) for that area (Reference 6). This comparison of offsite population exposure risks shows that accident risks are small.

F.1.3.2 Economic Impacts

As noted previously, the various measures for avoidance of offsite dose have an associated cost; these include: (a) evacuation costs; (b) value of crops contaminated and condemned; (c) costs of decontamination; and (d) indirect costs due to loss of property and incomes derived therefrom.
Table F.1-4 provides the annual economic risk from severe accidents at CCNPP Unit 1 for other-than-

plant costs in 1988 dollars. In general, these costs are dominated by evacuation and relocation. The mean risk of $68,000 per year (Table F.1-4) is small compared with the estimated property damage caused by other accidents (e.g., automobile accidents) within 50 miles of the CCNPP site.

Table F.1-1

CCNPP CORE INVENTORY[a]

Nuclide	Core Inventory (becquerels)	Nuclide	Core Inventory (becquerels)
Cobalt-58	2.37E+16	Tellurium-131M	3.70E+17
Cobalt-60	1.95E+16	Tellurium-132	3.69E+18
Krypton-85	1.96E+16	Iodine-131	2.54E+18
Krypton-85M	9.18E+17	Iodine-132	3.74E+18
Krypton-87	1.68E+18	Iodine-133	5.36E+18
Krypton-88	2.26E+18	Iodine-134	5.89E+18
Rubidium-86	1.49E+15	Iodine-135	5.05E+18
Strontium-89	2.84E+18	Xenon-133	5.36E+18
Strontium-90	1.53E+17	Xenon-135	1.00E+18
Strontium-91	3.65E+18	Cesium-134	3.42E+17
Strontium-92	3.80E+18	Cesium-136	1.04E+17
Yttrium-90	1.65E+17	Cesium-137	1.91E+17
Yttrium-91	3.46E+18	Barium-139	4.97E+18
Yttrium-92	3.81E+18	Barium-140	4.92E+18
Yttrium-93	4.31E+18	Lanthanum-140	5.02E+18
Zirconium-95	4.37E+18	Lanthanum-141	4.61E+18
Zirconium-97	4.56E+18	Lanthanum-142	4.45E+18
Niobium-95	4.13E+18	Cerium-141	4.47E+18
Molybdium-99	4.83E+18	Cerium-143	4.34E+18
Technetium-99M	4.16E+18	Cerium-144	2.70E+18
Ruthenium-103	3.59E+18	Praseodymium-143	4.27E+18
Ruthenium-105	2.33E+18	Neodymium-147	1.91E+18
Ruthenium-106	8.15E+17	Neptunium-239	5.11E+19
Rhodium-105	1.62E+18	Plutonium-238	2.90E+15
Antimony-127	2.21E+17	Plutonium-239	6.53E+14
Antimony-129	7.81E+17	Plutonium-240	8.23E+14
Tellurium-127	2.13E+17	Plutonium-241	1.39E+17
Tellurium-127M	2.82E+16	Americium-241	9.18E+13
Tellurium-129	7.33E+17	Curium-242	3.51E+16
Tellurium-129M	1.93E+17	Curium-244	2.06E+15

a. Source: Derived from Reference 1.

Table F.1-2

CCNPP RELEASE FRACTIONS BY NUCLIDE GROUP[a]

STC[b]	Frequency[c]	Xenon/Krypton	Iodine	Cesium	Tellurium	Strontium	Ruthenium	Lanthanum	Cerium	Barium
II-1	8.9E-5	3.0E-2	5.0E-5	5.0E-5	5.0E-4	2.0E-7	1.8E-8	3.0E-9	1.0E-9	1.5E-7
II-2	8.9E-5	2.1E-1	9.0E-4	7.1E-4	6.5E-3	1.3E-6	6.2E-8	1.9E-8	1.0E-8	7.7E-7
III	1.4E-5	1.0E-0	1.3E-1	1.3E-1	5.8E-1	4.8E-4	2.0E-5	2.1E-4	4.0E-8	2.6E-4
IV	5.2E-6	1.0E-0	1.9E-1	2.0E-1	2.3E-2	5.0E-4	2.6E-3	5.0E-4	5.0E-4	5.5E-4
V-1	7.0E-6	5.5E-1	2.4E-3	2.4E-3	1.0E-5	2.1E-6	1.3E-6	3.0E-8	0.2E-9	7.0E-6
V-2	7.0E-6	1.5E-1	4.0E-4	3.0E-4	1.8E-5	1.3E-6	1.6E-6	3.3E-7	1.8E-9	8.0E-6
VI	3.5E-8	1.0E-0	6.9E-1	6.9E-1	3.2E-2	1.0E-3	6.2E-3	7.1E-2	3.9E-4	4.2E-3

a. Source: Reference 2.
b. STC:
II = Late Containment Failure (2 Plume Segments).
III = Small Early Containment Failure.
IV = Large Early Containment Failure.
V = Small Containment Bypass (2 Plume Segments).
VI = Large Containment Bypass.
c. STC frequency per reactor-year.

Table F.1-3

PREDICTED PERMANENT RESIDENT POPULATION AROUND THE CCNPP SITE FOR THE YEAR 2030

	Miles									
Sector	**0-1**	**1-2**	**2-3**	**3-4**	**4-5**	**5-10**	**10-20**	**20-30**	**30-40**	**40-50**
N	0	0	0	0	0	0	0	6,240	133,412	195,396
NNE	0	0	0	0	0	0	251	12,177	38,468	13,005
NE	0	0	0	0	0	2	2,173	17,329	19,543	17,233
ENE	0	0	0	0	0	185	11,471	21,744	10,412	34,639
E	0	0	0	0	0	216	1,051	1,150	7,871	81,735
ESE	0	0	0	0	0	77	396	456	32,496	23,286
SE	6	116	258	399	322	0	1	15	802	16,359
SSE	159	553	922	1,291	1,657	2,712	1,964	986	18,976	624
S	178	550	912	1,260	1,614	24,338	21,530	11,531	17,909	17,717
SSW	178	553	857	1,177	1,303	16,640	21,475	20,757	7,878	16,701
SW	181	537	839	1,017	436	4,138	11,215	31,286	7,796	5,618
WSW	178	537	811	464	651	3,358	15,730	8,486	49,194	10,725
W	178	540	725	669	854	4,034	16,393	30,834	54,070	88,259
WNW	169	521	580	664	854	6,929	16,908	88,320	97,604	456,889
NW	39	209	245	368	608	7,065	26,906	28,973	323,884	1,491,231
NNW	0	0	0	0	0	1,456	40,019	67,748	96,854	325,633

Table F.1-4

ANNUAL RISK FROM SEVERE ACCIDENTS FOR CCNPP UNIT 1

	Late Containment Failure	Small Early Containment Failure	Large Early Containment Failure	Small Containment Bypass	Large Containment Bypass	Total Annual Risk
Population dose (person-rem)						
Within 10 miles	3.28E-01	5.19E+00	2.30E+00	2.91E-01	3.89E-02	8.15E+00
Within 50 miles	7.56E-01	3.93E+01	1.27E+01	1.14E+00	2.10E-01	5.42E+01
Total Economic Costs ($)						
Within 50 miles	6.49E+02	3.25E+04	3.29E+04	2.03E+02	1.80E+03	6.80E+04

F.1 References

1. Chanin, D. I., et al., 1990, Melcor Accident Consequence Code System (MAACS) Vol. I. User's Guide, NUREG/CR-4691, SAN86-1562, Sandia National Laboratories, Albuquerque, New Mexico
2. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated December 30, 1993, "Summary Report of Individual Plant Examination Results (Generic Letter 88-20) (TAC Nos. M74392 & M74393)"
3. "Evacuation Time Estimates Within the Plume Exposure Pathway Emergency Planning Zone for the Calvert Cliffs Nuclear Power Plant," Revision 2, BGE, December 1994
4. "Evacuation Time Estimates Within the Plume Exposure Pathway Emergency Planning Zone for the Calvert Cliffs Nuclear Power Plant," Revision 4, BGE, December 1997
5. "County and City Data Book," Bureau of the Census, U.S. Department of Commerce, 1998
6. Connolly, T. J., "Foundations of Nuclear Engineering," J. Wiley and Sons, 1978

F.2 DEVELOPMENT OF CANDIDATE SAMAs

This section describes the generation of the initial list of potential SAMAs for CCNPP, screening methods, and the analysis of the remaining SAMAs.

F.2.1 SAMA List Compilation

Baltimore Gas and Electric Company generated a list of candidate SAMAs by reviewing industry documents and considering plant-specific enhancements not considered in published industry documents. Industry documents reviewed include the following:

- The Calvert Cliffs IPE submittal (Reference 1);
- The Watts Bar Nuclear Plant Unit 1 IPE submittal (Reference 2);
- The Limerick Severe Accident Mitigation Design Alternative (SAMDA) cost estimate report (Reference 3);
- NUREG-1437 description of Limerick SAMDA (Reference 4);
- NUREG-1437 description of Comanche Peak SAMDA (Reference 5);
- Watts Bar Nuclear Plant SAMDA submittal (Reference 6);
- Tennessee Valley Authority (TVA) response to NRC's Request for Additional Information on the Watts Bar Nuclear Plant SAMDA submittal (Reference 7);
- Westinghouse AP600 SAMDA (Reference 8);
- Safety Assessment Consulting presentation by Wolfgang Werner at the NUREG 1560 conference (Reference 9);
- NRC IPE Workshop - NUREG 1560 presentation (Reference 10);
- NUREG 0498, Supplement 1, Section 7 (Reference 11);
- NUREG/CR-5567, PWR Dry Containment Issue Characterization (Reference 12);
- NUREG-1560, Volume 2, NRC prospective on the IPE program (Reference 13);
- NUREG/CR-5630, PWR Dry Containment Parametric Studies (Reference 14);
- NUREG/CR-5575, Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment (Reference 15);
- Combustion Engineering (CE) System 80+ SAMDA Submittal (Reference 16);
- NUREG 1462, NRC Review of the Asea Brown Boveri, Inc./CE System 80+ Submittal (Reference 17); and
- An ICONE paper by C. W. Forsberg, et. al., on a core melt source reduction system (Reference 18).

Although CCNPP Units 1 and 2 are of CE design, each of the above documents were reviewed for potential SAMAs even if they were not necessarily applicable to a CE plant. Those items not applicable to CCNPP Units 1 and 2 were subsequently screened from this list. The containment performance improvement programs for boiling water reactors and ice condenser plants were not reviewed (and the NUREG-1560 portion of the containment performance improvement for these were not reviewed).

Baltimore Gas and Electric Company assumed that any issues from these documents have been included in the large, dry containment performance improvement program (NUREG/CR-5567). Conceptual enhancements for which no specific details were available (e.g., "improve diesel reliability" or "improve procedures for loss of support systems") were not included on the list, unless they were considered as vulnerabilities in the CCNPP IPE.

F.2.2 Qualitative Screening of SAMAs

The initial list of potential SAMAs are presented in Table F.2-1. Table F.2-1 also presents a qualitative screening of the initial list. Items were eliminated from further evaluation based on one of the following criteria:

- The SAMA is not applicable at CCNPP, either because the enhancement is only for boiling water reactors, the Westinghouse AP600 design or PWR ice condenser containments, or it is a plant-specific enhancement that does not apply at CCNPP; or
- The SAMA has already been implemented at CCNPP; or
- The SAMA is related to reactor coolant pump (RCP) seal injection. Calvert Cliffs, being a CE design plant, does not have an RCP seal injection system; therefore, many of the potential seal injection enhancements identified for other plants do not apply to CCNPP. The SAMAs to replace the existing RCP seal system with a seal injection system are included in the evaluation for SAMA No. 03, "Install improved RCP seals."

In addition to the screening criterion, Table F.2-1 also illustrates how similar items were combined and the assignment of new identification numbers. The new identification numbers will be used throughout the analysis. Nine new SAMAs were created by combining similar items and are described below:

- Improve saltwater (SW), service water (SRW), component cooling (CC) pump recovery: SAMA Nos. 2, 3, 4, 6, 20, and 21 were combined for several reasons: (a) they involve the same accident phenomena (i.e., RCP seal loss-of-coolant accident [LOCA]); and (b) they involve the same groups of plant procedure or hardware changes.
- Improve bus cross-tie ability: SAMA Nos. 61, 62, and 63 were combined because each of the three involve cross-tying of electrical buses.
- Increase frequency of valve leak testing: SAMA No. 97 involved providing leak testing for inter-system loss-of-coolant accident (ISLOCA) valves that are not already tested. Since the CCNPP ISLOCA valves are already tested, SAMA No. 97 was subsumed into SAMA No. 94, which is to increase the testing frequency.
- Create ability for emergency connections of existing or alternate water sources to feedwater/condensate: SAMA No. 116 was subsumed into SAMA No. 115 because Fire Protection (FP) System is one of the options to be considered as an alternate water source in SAMA No. 115.
- Provide an additional high pressure safety injection (HPSI) pump with independent diesel: SAMA No. 125 was subsumed into SAMA No. 124, since they were identical.
- Install motor-generator (MG) set trip breakers in Control Room: SAMA Nos. 142 and 143 were combined because both involved hardware modifications to facilitate rapid removal of power to the control rods in the event of an anticipated transient without scram (ATWS).

- Create/enhance Reactor Coolant System (RCS) depressurization ability: SAMA Nos. 82, 151, and 152 involved changes to enhance RCS depressurization. These enhancements were combined into SAMA No. 87 that involves hardware and/or procedural changes.
- Implement internal flood prevention and mitigation enhancements: SAMA Nos. 103 and 104 were combined because they provide alternative approaches to prevention and mitigation of the same event. Revised SAMA No. 66-a addresses potential procedural changes, and SAMA No. 66-b addresses hardware changes.
- Install improved RCP seals: SAMA Nos. 10, 11, and 14 were combined because they address alternative types of RCP seal systems. An evaluation to determine the overall benefit of improved RCP seals will bound all alternative RCP seal designs.

Based on preliminary screening, 46 improvements were eliminated, 25 conceptual SAMAs were combined into 9 new SAMAs, and 96 original SAMAs were subject to final screening. These improvements are listed in Table F.2-2.

The final screening process involved redefining the generic SAMA descriptions for plant-specific implementation, screening those items whose cost exceeded maximum benefit attainable, and screening those hardware items whose benefit was less than $40,000. Table F.2-2 provides the specific basis for elimination and summarizes the detailed cost-benefit analysis performed on the remaining 23 improvements.

F.2 References

1. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated December 30, 1993, "Summary Report of Individual Plant Examination Results (Generic Letter 88-20) (TAC Nos. M74392 and M74393)"
2. Letter from Mr. M. O. Medford (TVA) to NRC Document Control Desk, dated September 1, 1992, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Generic Letter (GL) 88-20 - Individual Plant Examination (IPE) for Severe Accident Vulnerabilities - Response (TAC M74488)"
3. "Cost Estimate for Severe Accident Mitigation Design Alternatives, Limerick Generating Station for Philadelphia Electric Company," Bechtel Power Corporation, June 22, 1989
4. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, Table 5.35, SAMDAs considered for the Limerick Generating Station, NRC, May 1996
5. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, Table 5.36, Listing of SAMDAs considered for the Comanche Peak Steam Electric Station, NRC, May 1996
6. Letter from Mr. W. J. Museler (TVA) to NRC Document Control Desk, dated June 5, 1993, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDA) - (TAC Nos. M77222 and M77223)"
7. Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk, dated October 7, 1994, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDA) - Response to Request for Additional Information (RAI) - (TAC Nos. M77222 and M77223)"
8. Letter from N. J. Liparulo (Westinghouse Electric Corporation) to NRC Document Control Desk, dated December 15, 1992, "Submittal of Material Pertinent to the AP600 Design Certification Review"
9. Brookhaven National Laboratory, Department of Advanced Technology, Technical Report FIN W-6449, "NRC - IPE Workshop Summary/ Held in Austin, Texas; April 7-9, 1997," dated July 17, 1997/Appendix F - Industry Presentation Material, Contribution by Swedish Nuclear Power Inspectorate (SKI) and Safety Assessment Consulting (SAC): "Insights from PSAs for European Nuclear Power Plants," presented by Wolfgang Werner, SAC
10. Brookhaven National Laboratory, Department of Advanced Technology, Technical Report FIN W-6449, "NRC - IPE Workshop Summary/ Held in Austin, Texas; April 7-9, 1997," dated July 17, 1997/ Appendix D - NRC Presentation Material on Draft NUREG-1560
11. NUREG-0498, "Final Environmental Statement related to the operation of Watts Bar Nuclear Plant, Units 1 and 2," Supplement No. 1, NRC, April 1995
12. NUREG/CR-5567, "PWR Dry Containment Issue Characterization," NRC, August 1990
13. NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," Volume 2, NRC, December 1997
14. NUREG/CR-5630, "PWR Dry Containment Parametric Studies," NRC, April 1991
15. NUREG/CR-5575, "Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment," NRC, August 1990

16. CESSAR Design Certification, Appendix U, Section 19.15.5, Use of PRA in the Design Process, December 31, 1993

17. NUREG-1462, "Final Safety Evaluation Report Related to the Certification of the System 80+ Design," NRC, August 1994

18. Forsberg, C. W., E. C. Beahm, and G. W. Parker, "Core-Melt Source Reduction System (COMSORS) to Terminate LWR Core-Melt Accidents," Second International Conference on Nuclear Engineering (ICONE-2), San Francisco, California, March 21-24, 1993

19. Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk, dated June 30, 1994, "Watts Bar Nuclear Plant (WBN) Unit 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDAs) Evaluation from Updated Individual Plant Evaluation (IPE) (TAC Nos. M77222 and M77223)"

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
Improvements related to RCP seal LOCAs (loss of CC or SW)					
1	Cap downstream piping of normally closed CC drain and vent valves.	This SAMA would reduce the frequency of loss of CC initiating event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.	1, 13		93
2	Enhance loss of CC procedure to facilitate stopping RCPs.	This SAMA would reduce the potential for RCP seal damage due to pump bearing failure.	2, 10, 13	Combined into "Improve SW, SRW, CC pump recovery"	01
3	Enhance loss of CC procedure to present desirability of cooling down RCS prior to seal LOCA.	This SAMA would reduce the potential for RCP seal failure.	2	Combined into "Improve SW, SRW, CC pump recovery"	01
4	Additional training on the loss of CC.	This SAMA would potentially improve the success rate of operator actions after a loss of CC.	2	Combined into "Improve SW, SRW, CC pump recovery"	01
5	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	This SAMA would reduce effect of loss of CC by providing a means to maintain the centrifugal charging pump seal injection after a loss of CC. (Note for Watts Bar Nuclear Plant, this capability was already there for one charging pump at one unit, and the potential enhancement identified was to make it possible for all the charging pumps.)	2, 6, 11, 13	C	N/A
6	On loss of essential raw cooling water, proceduralize shedding CC loads to extend the CC heatup time.	This SAMA would increase time before the loss of CC (and RCP seal failure) in the loss of essential raw cooling water sequences.	2	Combined into "Improve SW, SRW, CC pump recovery"	01

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
7	Increase charging pump lube oil capacity.	This SAMA would lengthen time before centrifugal charging pump failure due to lube oil overheating in loss of CC sequences.	2	C	N/A
8	Eliminate RCP thermal barrier dependence on CC, such that loss of CC does not result directly in core damage.	This SAMA would prevent loss of RCP seal integrity after a loss of CC. Watts Bar Nuclear Plant IPE said they could do this with essential raw cooling water connection to charging pump seals.	2, 13	C	N/A
9	Install an additional SW pump.	This SAMA would decrease core damage frequency (CDF) due to a loss of SW.	5		02
10	Create an independent RCP seal injection system, with dedicated diesel.	This SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of CC or SW, or from a Station Blackout (SBO) Event.	6, 11, 13	Combined into "Install improved RCP seals"	03
11	Create an independent RCP seal injection system, without dedicated diesel.	This SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of CC or SW, but not SBO.	11	Combined into "Install improved RCP seals"	03
12	Use existing hydro test pump for RCP seal injection.	This SAMA would provide an independent seal injection source, without cost of a new system.	7	C	N/A
13	Replace Emergency Core Cooling System (ECCS) pump motors with air-cooled motors.	This SAMA would eliminate ECCS dependency on CC.	10, 13		94
14	Install improved RCP seals.	RCP seal O-rings constructed of improved materials would reduce chances of RCP seal LOCA.	11, 13	Combined into "Install improved RCP seals"	03
15	Install an additional CC pump.	This SAMA would reduce chance of loss of CC leading to RCP seal LOCA.	13		04

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
16	Prevent centrifugal charging pump flow diversion from the relief valves.	If relief valve opening causes a flow diversion large enough to prevent RCP seal injection, then modification would reduce frequency of loss of RCP seal cooling.	13	C	N/A
17	Change procedures to isolate RCP seal letdown flow on loss of CC, and guidance on loss of injection during seal LOCA.	This SAMA would reduce CDF from loss of seal cooling.	13	C	N/A
18	Implement procedures to stagger HPSI pump use after a loss of SW.	This SAMA would allow HPSI to be extended after a loss of SW.	13		96
19	Use FP System pumps as a back-up seal injection and high pressure make-up.	This SAMA would reduce RCP seal LOCA frequency and SBO CDF.	13		97
20	Procedural guidance for use of cross-tied CC or SW pumps.	This SAMA would reduce the frequency of the loss of either of these.	13	Combined into "Improve SW, SRW, CC pump recovery"	01
21	Procedure and operator training enhancements in support system failure sequences, with emphasis on anticipating problems and coping.	This SAMA would potentially improve the success rate of operator actions after support system failures.	2, 13	Combined into "Improve SW, SRW, CC pump recovery"	01

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
22	Improve ability to cool residual heat removal (RHR) heat exchangers.	This SAMA would reduce chance of loss of decay heat removal (DHR) by: (1) implementing procedure and hardware modification to allow manual alignment of FP System to the CC System; or (2) installing a CC header cross-tie.	12, 13	B (for the second option only)	05
Improvements related to Heating, Ventilation and Air Conditioning (HVAC)					
23	Stage back-up fans in switchgear (SWGR) rooms.	This SAMA would provide alternate ventilation in the event of a loss of SWGR Room ventilation.	1, 13	B	N/A
24	Provide a redundant train of ventilation to 480V board room.	This SAMA would improve reliability of 480V HVAC. At Watts Bar Nuclear Plant, only one train of HVAC cools the 480V board room that contains the unit vital inverters, and recovery actions are heavily relied on. The Watts Bar Nuclear Plant IPE said their corrective action program is dealing with this issue. For CCNPP, a site-specific SAMA to "Install a redundant SWGR Room HVAC system" will be evaluated.	2, 13, 18		06
25	Procedures for temporary HVAC.	This SAMA would provide for improved credit to be taken for loss of HVAC sequences.	11, 13	B	N/A
26	Add a SWGR room high temperature alarm.	This SAMA would improve diagnosis of a loss of SWGR HVAC.	13	B	N/A

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
27	Create ability to switch fan power supply to direct current (DC) in an SBO event.	This SAMA would allow continued operation in an SBO event. (This SAMA was created for a boiling water reactor core isolation cooling system room, James A. Fitzpatrick Nuclear Power Plant; but a similar SAMA may be applied to CCNPP's Auxiliary Feedwater [AFW] Pump Room.) Created a CCNPP-specific category, "Install a redundant AFW Pump Room ventilation system."	13		07
Improvements related to ex-vessel accident mitigation/containment phenomena					
28	Delay containment spray (CS) actuation after large LOCA.	When ice remains in the ice condenser at such plants, CS has little impact on containment performance, yet rapidly drain down the refueling water tank (RWT). This SAMA would lengthen time of RWT availability.	2, 6	A	N/A
29	Install CS pump header automatic throttle valves.	This SAMA would extend the time over which water remains in the RWT, when full CS flow is not needed.	11, 12, 13		08
30	Install an independent method of suppression pool cooling.	This SAMA would decrease frequency of loss of containment heat removal.	3, 4	A	N/A
31	Develop an enhanced drywell spray system.	This SAMA would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. This SAMA concept was modified for a PWR to consider the installation of a redundant CS System.	3, 4, 16, 17		09

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
32	Provide a dedicated existing drywell spray system.	Identical to the previous concept, except that one of the existing spray loops would be used instead of developing a new spray system. (This SAMA is similar to PWR CS option in References 5, 6, 11.)	3, 4		10
33	Install a containment vent large enough to remove ATWS decay heat.	Assuming injection is available, this SAMA would provide alternative DHR in an ATWS.	3, 4		11
34	Install a filtered containment vent to remove decay heat.	Assuming injection is available (non-ATWS sequences), this SAMA would provide alternate DHR with the released fission products being scrubbed.	3, 4 (similar options in 5, 6, 8, 11, 12, 16, 17)		12
35	Install an unfiltered hardened containment vent.	This SAMA would provide an alternate DHR method (non-ATWS), which is not filtered.	3, 4, 9, 14		13
36	Create/enhance hydrogen ignitors with independent power supply.	This SAMA would reduce hydrogen detonation at lower cost. Use either a new, independent power supply, a non-safety grade portable generator, existing station batteries, or existing alternating current (AC)/DC independent power supplies such as the security system diesel.	3, 5, 6, 7, 9, 12, 13, 14, 15, 16, 17		14
37	Create a passive hydrogen ignition system.	This SAMA would reduce hydrogen detonation potential without requiring electric power.	7, 11, 16, 17		15
38	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris.	A molten core escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through.	3, 4, 16, 17		16

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
39	Create a water-cooled rubble bed on the pedestal.	This rubble bed would contain a molten core dropping onto the pedestal, and would allow the debris to be cooled.	3, 4, 8, 16, 17		17
40	Provide modification for flooding of the drywell head.	This SAMA would help mitigate accidents that result in leakage through the drywell head seal.	4, 9	A	N/A
41	Enhance FP System and/or Standby Gas Treatment System hardware and procedures.	This SAMA would improve fission product scrubbing in severe accidents.	4		18
42	Create a reactor cavity flooding system.	This SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.	5, 6, 9, 11, 12, 13, 15, 16, 17		19
43	Create other options for reactor cavity flooding.	(a) Use water from dead-ended volumes, the condensed blowdown of the RCS, or secondary system by drilling pathways in the reactor vessel support structure to allow drainage from the steam generator (SG) compartments, refueling canal, sumps, etc., to the reactor cavity. Also (for ice condensers), allow drainage of water from melted ice into the reactor cavity. (b) Flood cavity via systems such as diesel-driven fire pumps.	7, 9, 13	A - the ice condenser portion of this alternative is not applicable to CCNPP	20
44	Enhance air return fans (ice condenser containment).	This SAMA would provide an independent power supply for the air return fans, reducing containment failure in SBO sequences.	6, 11	A	N/A

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
45	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 containment shell.	6, 11		95
46	Create a core melt source reduction system.	Place enough glass underneath the reactor vessel such that a molten core falling on the glass would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur (such benefits are theorized in the reference).	19		21
47	Provide containment inerting capability.	This SAMA would prevent combustion of hydrogen and carbon monoxide gases.	6, 9, 11, 14		22
48	Use the FP System as a back-up source for the CS System.	This SAMA would provide redundant CS method without high cost.	7, 9, 10, 12		23
49	Install a passive CS System.	This SAMA would provide CS benefits at a very high reliability, and without support systems.	8		24
50	Install a secondary containment filtered ventilation.	For plants with a secondary containment, this SAMA would filter fission products released from the primary containment.	8	A	N/A
51	Increase containment design pressure.	This SAMA would reduce chance of containment overpressure.	8		25
52	Increase the depth of the concrete basemat, or use an alternative concrete material to ensure melt-through does not occur.	This SAMA would prevent basemat melt-through.	16, 17		26

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
53	Provide a reactor vessel exterior cooling system.	This SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water.	16, 17		27
54	Construct a building, maintained at a vacuum, to be connected to containment.	In an accident, connecting the new building to containment would depressurize containment and reduce any fission product release.	17		28
55	Add ribbing to the containment shell.	This SAMA would reduce the chance of buckling of containment under reverse pressure loading.	17		29
Improvements related to improvement of AC/DC power reliability/availability					
56	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 causes inadvertent signals.	1, 13	B	N/A
57	Proceduralize alignment of spare diesel to shutdown board after Loss of Offsite Power (LOOP) and failure of the diesel normally supplying it.	This SAMA would reduce SBO frequency.	2	B	N/A
58	Provide an additional diesel generator.	This SAMA would increase onsite emergency AC power reliability and availability (decrease SBO).	5, 6, 10, 13 16, 17		30
59	Provide additional DC battery capability.	This SAMA would ensure longer battery capability during an SBO, reducing frequency of long-term SBO sequences.	5, 6, 13, 16, 17		31

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
60	Use fuel cells instead of lead-acid batteries.	This SAMA would extend DC power availability in an SBO. Fuel cells could effectively extend DC power availability to 24 hours.	16, 17		32
61	Procedure to cross-tie high pressure core spray diesel.	This SAMA would improve core injection availability by providing a more reliable power supply for the high pressure core spray pumps.	10	Combined into "Improve bus cross-tie ability"	33
62	Improve bus cross-tie ability.	This SAMA would improve AC power reliability.	10, 13	Combined into "Improve bus cross-tie ability"	33
63	Incorporate an alternate battery charging capability.	This SAMA would improve DC power reliability by either cross-tying the AC buses, or installing a portable diesel-driven battery charger.	10, 11, 12, 13	The bus cross-tie portion was combined into "Improve bus cross-tie ability"	33/34
64	Increase/improve DC bus load shedding.	This SAMA would improve battery life in SBO.	10, 11, 12, 13		35
65	Replace batteries with a more reliable model	This SAMA would improve DC power reliability.	10		36
66	Create AC power cross-tie capability across units at a multi-unit site.	This SAMA would improve AC power reliability.	11, 12, 13		37
67	Create a cross-unit tie for diesel fuel oil.	For multi-unit sites, this SAMA would add diesel fuel oil redundancy.	13		38
68	Develop procedures to repair or replace failed 4 kV breakers.	This SAMA would offer a recovery path from a failure of breakers that perform transfer of 4.16 kV non-emergency buses from unit station service transformers to system station service transformers, leading to loss of emergency AC power (i.e., in conjunction with failures of the diesel generators).	13		39

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
69	Emphasize steps in recovery of offsite power after an SBO.	This SAMA would reduce human error probability during offsite power recovery.	13		40
70	Develop a severe weather conditions procedure.	For plants that do not already have one, this SAMA would reduce the likelihood of external events CDF.	13		41
71	Develop procedures for replenishing diesel fuel oil.	This SAMA would allow long-term diesel operation.	13		42
72	Install gas turbine generators.	This SAMA would improve onsite AC power reliability.	13		43
73	Install tornado protection on gas turbine generator.	If the unit has a gas turbine, the tornado-induced SBO frequency would be reduced.	16, 17	A	N/A
74	Create a back-up source for diesel cooling.	This SAMA would provide redundant source of diesel cooling.	13		44
75	Use FP System as a back-up source for diesel cooling.	This SAMA would provide redundant diesel support systems.	13		45
76	Provide a connection to alternate offsite power source.	This SAMA would increase offsite power redundancy.	13		46
77	Implement underground offsite power lines.	This SAMA could improve offsite power reliability, particularly during severe weather.	13		47
78	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.	13	B	N/A

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
79	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.	This SAMA would reduce risk of 2/4 inverter failure. The UV and AFAS Block changes should be fairly straight forward, but the High Pressurizer Pressure may be slightly more difficult. If so, then the changes may need to be made to the power-operated relief valve (PORV) circuitry directly. Automatic AFAS Block may be able to be removed completely since it only defends against a rare Main Steam break event. It also might be found that maintaining the PORV block valves normally shut while operating is risk beneficial. Although this would increase the demands on the safeties, the PORVs would be less likely to spuriously open and would still be available for feed and bleed.	18		48
80	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.	The plant is sensitive to the loss of one or more 120V vital AC buses. Recently new inverters were installed, each with a built-in standby unit. However, manual action is required to place the standby unit on-line.	18		49

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
81	Add disconnects at the junction box on the roof of the Auxiliary Building where 4 kV power from the 0C Diesel Generator branches to all four SWGRs. The disconnects would allow the recovery of the 0C Diesel Generator following the loss of any SWGR.	Since the 0C Emergency Diesel Generator (EDG) is designed to back-up any 4 kV bus, it is connected to each bus in each of the SWGRs. However, since the disconnect for each bus is located in the bus's SWGR, a fire in any one of the four SWGRs could result in the loss of the 0C Diesel Generator.	18		50
Improvements in identifying/coping with containment bypass					
82	Proceduralize use of pressurizer vent valves during Steam Generator Tube Rupture (SGTR) sequences.	CCNPP procedures direct the use of pressurizer sprays to reduce RCS pressure after a SGTR. Use of the vent valves would provide a back-up method.	1, 13	Subsumed into "Create/ enhance RCS depressurization ability"	87
83	Install a redundant spray system to depressurize the primary system during a SGTR.	This SAMA would enhance depressurization ability during SGTR.	16, 17		52
84	Improve SGTR coping abilities.	This SAMA would improve instrumentation to detect SGTR, or additional systems to scrub fission product releases.	7, 9, 10, 13, 14, 16, 17		51

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
85	Add other SGTR coping features.	This SAMA would reduce the consequences of a SGTR. Implementation options are: (a) a highly reliable (closed loop) SG shell-side heat removal system that relies on natural circulation and stored water sources; (b) a system which returns the discharge from the SG relief valve back to the primary containment; (c) an increased pressure capability on the SG shell side with corresponding increase in the safety valve setpoints.	7, 8, 17		53
86	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift.	SGTR sequences would not have a direct release pathway.	8, 17		54
87	Replace SGs with new design.	This SAMA would lower frequency of SGTR.	13		55
88	Revise emergency operating procedures (EOPs) to direct that a faulted SG be isolated.	For plants whose EOPs do not already direct this, this SAMA would reduce consequences of a SGTR.	13	B	N/A
89	Direct SG flooding after a SGTR, prior to core damage.	This SAMA would provide for improved scrubbing of SGTR releases.	14, 15		56
90	Implement a maintenance practice that inspects 100% of the tubes in a SG.	This SAMA would reduce the potential for a tube rupture.	16, 17		57
91	Locate RHR inside of containment.	This SAMA would prevent ISLOCA out the RHR pathway.	8		58

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
92	Install self-actuating containment isolation valves.	For plants that do not have this, it would reduce the frequency of isolation failure.	8	A	N/A
93	Install additional instrumentation for ISLOCAs.	Pressure or leak monitoring instruments installed between the first two pressure isolation valves on low-pressure injection lines, RHR suction lines, and HPSI lines would decrease ISLOCA frequency.	5, 6, 11, 13		59
94	Increase frequency of valve leak testing.	This SAMA would decrease ISLOCA frequency.	12		60
95	Improve operator training on ISLOCA coping.	This SAMA would decrease ISLOCA effects.	12, 13		61
96	Install relief valves in the CC System.	This SAMA would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA.	13		62
97	Provide leak testing of valves in ISLOCA paths.	At Kewaunee Nuclear Power Plant, four motor-operated valves (MOVs) isolating RHR from the RCS were not leak tested. This SAMA would help reduce ISLOCA frequency.	13	Subsumed into "Increase frequency of valve leak testing"	60
98	Revise EOPs to improve ISLOCA identification.	Salem Nuclear Power Plant had a scenario in which an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment. Procedure enhancement would ensure LOCA outside containment would be observed.	13		63
99	Ensure all ISLOCA releases are scrubbed.	This SAMA would scrub ISLOCA releases. One suggestion was to plug drains in the break area so the break point would cover with water.	14, 15		64

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
100	Add redundant and diverse limit switch to each containment isolation valve.	Enhanced isolation valve position indication, which would reduce frequency of containment isolation failure and ISLOCAs.	16, 17		65
Improvements in reducing internal flooding frequency					
101	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	For a plant where internal flooding from turbine building to safeguards areas is a concern, this modification could prevent flood propagation.	13	A	N/A
102	Improve inspection of rubber expansion joints on main condenser.	For a plant where internal flooding due to failure of circulating water expansion joint is a concern, this would help reduce the frequency.	13	A	N/A
103	Implement internal flood prevention and mitigation enhancements.	This SAMA would reduce the consequences of a flooding event. Potential enhancements are: (1) submersible MOV operators; and (2) backflow prevention in drain lines.	13	Combined into "Implement internal flood prevention and mitigation enhancements."	66
104	Implement internal flooding improvements at Fort Calhoun Nuclear Power Plant.	This SAMA would reduce flooding risk by preventing or mitigating: (1) a rupture in the RCP seal cooler of the CC System; (2) an ISLOCA in a shutdown cooling line; and (3) an AFW flood involving the need to possibly remove a watertight door.	13	Combined into "Implement internal flood prevention and mitigation enhancements."	66
Improvements related to feedwater/feed and bleed reliability/availability					
105	Install a digital feedwater upgrade.	This SAMA would reduce chance of loss of main feedwater following a plant trip.	1, 13	B	N/A

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
106	Perform surveillances on manual valves used for back-up AFW pump suction.	This SAMA would improve success probability for providing alternate water supply to AFW pumps.	1, 13	B	N/A
107	Install manual isolation valves around AFW turbine-driven steam admission valves.	This SAMA would reduce the dual turbine-driven pump maintenance unavailability.	1, 13	B	N/A
108	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 PORVs. This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP.	11		67
109	Install separate accumulators for the AFW cross-connect and block valves.	This SAMA would enhance the operators' ability to operate the AFW cross-connect and block valves following a loss of air support.	18		68
110	Install a new condensate storage tank (CST).	Either replace old tank with a larger one, or install a back-up tank.	13, 16, 17		69
111	Provide cooling of steam-driven AFW pump in an SBO event.	This SAMA would improve success probability in an SBO by: (1) using FP System to cool pump; or (2) making the pump self-cooled.	13		70
112	Proceduralize local manual operation of AFW when control power is lost.	This SAMA would lengthen AFW availability in SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.	13		71

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
113	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).	16, 17		72
114	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.	13	B	N/A
115	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.	12, 18		73
116	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.	13	Subsumed into "Create ability for emergency connections of existing or alternate water sources to feedwater/condensate"	73
117	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.	13	A	N/A
118	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.	13		74
119	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.	13	A	N/A

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
120	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.	17		75
121	Reduce the support system requirements for low pressure feed.	This SAMA would reduce the dependencies required for successful low pressure feed by performing an analysis that shows that low pressure feed can be achieved with one chain-operated atmospheric dump valve (ADV) (within 30 minutes), one condensate booster pump, one Condensate Pump, one by-pass CV (1105 or 1106), and gravity feed from the CST to the hotwell. If this is possible, then the following plant modifications should be considered: • Making the condensate booster pumps air-cooled; and • Adding accumulators to CVs 1105 and 1106 with a three-way hand valve such that the valves can be maintained full open by aligning the accumulator to the CV. The line could then be throttled using the down stream MOV. Change the plant procedures accordingly.	18		76
122	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.	18		77

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
Improvements in core cooling systems					
123	Provide capability for diesel-driven, low pressure vessel make-up.	This SAMA would provide extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., FP System).	4, 5, 13		78
124	Provide an additional HPSI pump with independent diesel.	This SAMA would reduce frequency of core melt from small LOCA sequences, and from SBO sequences.	6, 16, 17		79
125	Install independent AC HPSI system.	This SAMA would allow make-up and feed and bleed capabilities during an SBO.	11	Subsumed into "Provide an additional high pressure injection safety pump with independent diesel"	79
126	Create the ability to manually align ECCS recirculation.	This SAMA would provide a back-up should automatic or remote operation fail.	12	B	N/A
127	Implement an RWT make-up procedure.	This SAMA would decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR.	12, 13		80
128	Stop low pressure safety injection pumps earlier in medium or large LOCAs.	This SAMA would give more time to perform recirculation swap over.	13		81
129	Emphasize timely recirculation swap over in operator training.	This SAMA would reduce human error probability of recirculation failure.	13	A	N/A
130	Upgrade Chemical and Volume Control System to mitigate small LOCAs.	For a plant like the AP600 where Chemical and Volume Control System cannot mitigate small LOCA, an upgrade would decrease CDF from small LOCA.	8	B	N/A

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
131	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.	8	B	N/A
132	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.	8	A	N/A
133	Replace two of the four safety injection (SI) pumps with diesel-powered pumps.	This SAMA would reduce SI System common cause failure probability. This SAMA was intended for System 80+, which has four trains of SI.	16, 17	A	N/A
134	Align low pressure core injection or core spray to CST on loss of suppression pool cooling.	This SAMA would help ensure low pressure ECCS can be maintained in loss of suppression pool cooling scenarios.	10, 13	A	N/A
135	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.	13	A	N/A
136	Improve the reliability of the automatic depressurization system.	This SAMA would reduce frequency high pressure core damage sequences.	4	A	N/A
137	Disallow automatic vessel depressurization in non-ATWS scenarios.	This SAMA would improve operator control of plant.	13	A	N/A

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
138	Create automatic swap over to recirculation on RWT depletion.	This SAMA would remove human error contribution from recirculation failure.	5, 6, 11	B	N/A
Instrument air (IA)/gas improvements					
139	Modify EOPs for ability to align diesel power to more air compressors.	For plants which do not have diesel power to all normal and back-up air compressors, this change would increase the reliability of IA after a LOOP.	13		82
140	Replace old air compressors with more reliable ones.	This SAMA would improve reliability and increase availability of IA compressors.	13		83
141	Install nitrogen bottles as back-up gas supply for safety relief valves.	This SAMA would extend operation of safety relief valves during SBO and loss of air events (boiling water reactors).	13	A	N/A
Improvements in ATWS coping					
142	Install MG set trip breakers in control room.	This SAMA would provide trip breakers for the MG sets in the control room. Currently, at Watts Bar Nuclear Plant, an ATWS would require an immediate action outside the control room to trip the MG sets. This SAMA would reduce ATWS CDF.	11		84
143	Add capability to remove power from the bus powering the control rods.	This SAMA would decrease time to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	13	Combined into "Install MG set trip breakers in control room"	84
144	Create cross-connect ability for standby liquid control trains.	This SAMA would improve reliability for boron injection during an ATWS event.	13	A	N/A

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
145	Create an alternate boron injection capability (back-up to standby liquid control).	This SAMA would improve reliability for boron injection during an ATWS event.	13	A	N/A
146	Remove or allow override of low pressure core injection during ATWS.	On failure of high pressure core injection and condensate, the Susquehanna units direct reactor depressurization followed by five minutes of automatic low pressure core injection. This SAMA would allow control of low pressure core injection immediately.	13	A	N/A
147	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.	16, 17	B	N/A
148	Create a boron injection system to back-up the mechanical control rods.	This SAMA would provide a redundant means to shut down the reactor.	16, 17	B	N/A
149	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 ATWS frequency.	16, 17		85

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
Other improvements					
150	Provide capability for remote operation of secondary side relief valves in 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.	2		86
151	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.	5, 6, 9, 11, 12, 13, 14, 15, 16, 17		87
152	Make procedural changes only for the RCS depressurization option.	This SAMA would reduce RCS pressure without cost of a new system.	7, 9, 13	Subsumed into "Create/enhance RCS depressurization ability"	87
153	Defeat 100 percent load rejection capability.	This SAMA would eliminate the possibility of a stuck open PORV after a LOOP, since PORV opening would not be needed.	13		88
154	Change control rod drive flow CV failure position.	Change failure position to the 'fail-safest' position.	13	A	N/A

Table F.2-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE CCNPP SAMAs ANALYSIS

Initial SAMA No.	Potential Enhancement	Discussion	Reference Source	Screening Criterion or Combination[a]	Revised SAMA No.
155	Install secondary side guard pipes up to the main steam isolation valves.	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.	16, 17		89
156	Install digital large break LOCA protection.	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (a leak before break).	17		90
157	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.	17		91
158	Enhance the reliability of 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).	18		92

Notes:

a. For the preliminary screening, potential enhancements were combined into other, more general SAMAs (e.g., improve SW, SRW, or CC pump recovery), or eliminated from further consideration for one of the following reasons:

1. The SAMA is not applicable to CCNPP's design (Screening Criterion "A");
2. The SAMA has already been implemented at CCNPP (Screening Criterion "B"); or
3. The SAMA is associated with RCP seal injection, which is not included in CCNPP's design (Screening Criterion "C").

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
01-a	**Improve SW, SRW, and CC pump recovery (post-trip only).** Modify the plant such that, during emergency conditions, the SW, SRW, and CC pumps automatically start when the operating pump fails.	3.17E-04	3.9%	$119,000	$622,000	Based on Cost of Enhancement (COE) ($622K) and $119K benefit, this SAMA has a negative net value (-$503K). For additional details, see Appendix F.4 and Table 4-3.
01-b	**Improve SW, SRW, and CC pump recovery (pre-trip and post-trip).** Modify the plant such that, during normal operating conditions, the SW, SRW, and CC pumps automatically start when the operating pump fails.	3.13E-04	5.2%	$141,000	$622,000	Based on COE ($622K) and $141K benefit, this SAMA has a negative net value (-$481K). For additional details, see Appendix F.4 and Table 4-3.
02	**Install an additional SW pump**. Install a SW swing pump that automatically aligns to the SW header without an operating pump. The pump's motor would still require the same supports as the replaced pump. Ensure that there is no common cause link between the pumps.	3.20E-04	3.0%	$59,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
03	**Install improved RCP seals.** Install RCP seals that do not require cooling.	N/A[c]	N/A	N/A	>$2,500,000	COE exceeds maximum benefit attainable ($2.4M). BGE's estimated COE is based on cost of seals installed in 1989; however, it is doubtful if any seals have been designed which do not require cooling.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
04	**Install an additional CC pump.** Install a fourth CC swing pump that automatically starts on a Safety Injection Actuation Signal (SIAS) given no pumps are operating. The pump should be able to receive power from any source that could supply the existing pumps. Ensure that there is no common cause link between the pumps.	3.29E-04	0.3%	$2,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
05	**Improve ability to cool RHR heat exchangers.** Hard-pipe an FP System feed to CC to allow an alternate cooling source for shutdown cooling heat exchangers, the SI pumps, and RCP seals.	2.93E-04	11.2%	$206,000	$565,000	Based on COE ($565K) and $206K benefit, this SAMA has a negative net value (-$359K). For additional details, see Appendix F.4 and Table 4-3.
06	**Install a redundant SWGR Room HVAC train.** Install a redundant train of SWGR HVAC that automatically starts on high temperature. The system would be diverse (no common cause/mode); protected from missiles and wind; and self-powered.	N/A	N/A	N/A	>$10,000,000	COE exceeds maximum benefit attainable ($2.4M).

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
07	**Install a redundant AFW pump room ventilation system.** Installation of redundant AFW pump room ventilation that automatically starts on high temperature. The system would be diverse (no common cause/mode) and self-powered.	3.25E-04	1.5%	$48,000	$226,000	Based on COE ($226K) and $48K benefit, this SAMA has a negative net value (-$178K). For additional details, see Appendix F.4 and Table 4-3.
08	**Install CS pump header automatic throttle valves**.	3.23E-04	2.1%	$15,000	$375,000	Based on COE ($375K) and $15K benefit, this SAMA has a negative net value (-$360K). For additional details, see Appendix F.4 and Table 4-3.
09	**Develop redundant CS System**.	N/A	N/A	N/A	$5,800,000 (Reference 19)	COE exceeds maximum benefit attainable ($2.4M).
10	**Develop a enhanced CS System**. Install a dedicated CS System that uses the piping from the existing system. The system should automatically start. The system uses the same support systems as the existing CS System.	3.30E-04	0%	$2,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
11	**Install a containment vent large enough to remove ATWS decay heat.** Install a primary containment ventilation system capable of venting the RCS blowdown on an ATWS. The vent should be large enough to allow the inventory released from a large break LOCA to be vented from the primary containment.	N/A	N/A	N/A	N/A	Based on engineering assessment, this SAMA is not applicable to PWRs.
12	**Install a filtered containment vent to remove decay heat.** Install a filtered containment vent to remove containment heat loads after non-ATWS transients.	N/A	N/A	N/A	$5,700,000 (Reference 3)	COE exceeds maximum benefit attainable ($2.4M).
13	**Install an unfiltered hardened containment vent.**	N/A	N/A	N/A	$3,100,000 (Reference 3)	COE exceeds maximum benefit attainable ($2.4M).
14	**Create/enhance hydrogen ignitors with independent power supply.** Modify the hydrogen recombiners so there are self-powered, and effective in eliminating hydrogen burns.	3.30E-04	0%	$53,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
15	**Create a passive hydrogen ignition system.** Install passive hydrogen recombiners that effectively eliminate hydrogen burns.	3.30E-04	0%	$54,000	$760,000 (Reference 16)	Based on COE ($760K) and $54K benefit, this SAMA has a negative net value (-$706). For additional details, see Appendix F.4 and Table 4-3.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
16	**Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris.**	N/A	N/A	N/A	$108,000,000 (Reference 16)	COE exceeds maximum benefit attainable ($2.4M).
17	**Create a water-cooled rubble bed on the pedestal.**	N/A	N/A	N/A	$18,800,000 (Reference 16)	COE exceeds maximum benefit attainable ($2.4M).
18	**Enhance FP System and/or Standby Gas Treatment System hardware and procedures.**	N/A	N/A	N/A	N/A	FP change addressed in SAMA 23. Standby gas treatment system is not applicable for CCNPP.
19	**Create a reactor cavity flooding system.**	N/A	N/A	N/A	$8,750,000 (Reference 19)	COE exceeds maximum benefit attainable ($2.4M).
20	**Create other options for reactor cavity flooding.** Utilize other systems to accomplish reactor cavity flooding.	3.30E-04	0%	$37,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
21	**Create a core melt source reduction system.**	3.30E-04	0%	$5,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
22	**Provide containment inerting capability.**	N/A	N/A	N/A	$10,900,000 (Reference 19)	COE exceeds maximum benefit attainable ($2.4M).

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
23	**Use the FP System as a back-up source for the CS System.** Upgrade the FP System and hard pipe a connection to the CS System. This is assumed to function redundantly to CS. Since the FP System is diesel-backed, CS is available even in an SBO scenario.	3.30E-04	0%	$268,000	$565,000	Based on COE ($565K/EDG), and $268K benefit, this SAMA has a negative net value (-$297K). For additional details, see Appendix F.4 and Table 4-3.
24	**Install a passive CS System.** Install a passive CS System with sufficient inventory to prevent containment failure due to over-pressurization over a 24-hour period.	3.30E-04	0%	$268,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
25	**Increase containment design pressure.**	N/A	N/A	N/A	N/A	This SAMA was identified in the Westinghouse AP600 design submittal. Because of the extensive reconstruction of the containment building that would be considered for an existing plant, this SAMA was not considered further.
26	**Increase the depth of the concrete basemat, or use an alternative concrete material to ensure melt-through does not occur.**	N/A	N/A	N/A	N/A	This SAMA was identified in the CE System 80+ design submittal. Because of the extensive reconstruction of the containment building that would be considered for an existing plant, this SAMA was not considered further.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
27	**Provide a reactor vessel exterior cooling system.** Provide a reactor vessel exterior cooling system that is capable of removing decay heat. This system must be self-powered or passive.	N/A	N/A	N/A	$2,500,000 (Reference 16)	COE exceeds maximum benefit attainable ($2.4M).
28	**Construct a building, maintained at vacuum, to be connected to containment.**	N/A	N/A	N/A	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit attainable ($2.4M). In addition, CE System 80+ judged this would not help against containment bypass.
29	**Add ribbing to the containment shell**. Add ribbing to the containment shell to reduce the chance of buckling under reverse pressure loading.	N/A	N/A	N/A	N/A	This SAMA was identified in the CE System 80+ design submittal. Because of the extensive reconstruction of the containment building that would be considered for an existing plant, this SAMA was not considered further.
30	**Provide an additional diesel generator.** Install a self-sufficient EDG that will automatically align to a de-energized 4 kV bus in the event its dedicated EDG fails or is unavailable.	N/A	N/A	N/A	>>$20,000,000	COE exceeds maximum benefit attainable ($2.4M).

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
31	**Provide additional DC battery capability.** Install additional batteries to extend 125 Volt DC (VDC) battery life to 24 hours.	3.16E-04	4.2%	$72,000 (Similar to SAMA 34)	>$1,875,000	Based on COE ($1.875M), and $72K benefit, this SAMA has a negative net value (-$1.803M). For additional details, see Appendix F.4 and Table 4-3. Note: Involves structural modification, as additional batteries will not fit in rooms; therefore, costs would be much greater.
32	**Use fuel cells instead of lead-acid batteries.** Use fuel cells instead of lead-acid batteries to effectively extend battery life to 24 hours.	3.16E-04	4.2%	$72,000 (Similar to SAMA 34)	$2,000,000 (Reference 16)	Based on COE ($2M) and $72K benefit, this SAMA has a negative net value (-$1.928M). For additional details, see Appendix F.4 and Table 4-3.
33	**General Notes for SAMA No. 33:** For all of the cross-connection options, the automatic alignment logic must be sophisticated enough to prevent cross-connection onto a faulted bus.					
33-a	**Improve bus cross-tie ability**. Implement automatic cross-tie capability between 4 kV Buses 11 and 14.	3.04E-04	7.9%	$142,000	$1,119,000	Based on COE ($1.119M) and $142K benefit, this SAMA has a negative net value (-$977K). For additional details, see Appendix F.4 and Table 4-3.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
33-b	**Improve bus cross-tie ability.** Implement automatic cross-tie capability between 4 kV Buses 21 and 24.	3.21E-04	2.7%	$42,000	$1,119,000	Based on COE ($1.119M) and $42K benefit, this SAMA has a negative net value (-$1.077M). For additional details, see Appendix F.4 and Table 4-3.
33-c	**Improve bus cross-tie ability.** Implement automatic cross-tie capability between 125VDC Buses 11 and 21.	3.04E-04	7.9%	$113,000	Not estimated	The cost of designing a highly reliable automatic bus transfer would greatly exceed the calculated maximum benefit; therefore, this SAMA is not considered further. [d]
34	**Incorporate an alternate battery charging capability.** Reduce the likelihood of battery depletion by modifying the plant such that a portable generator could be used to directly feed each of the four 125 VDC buses. Purchase one or more generators.	3.16E-04	4.2%	$72,000	$134,000 (Reference 19)	Based on COE ($134K) and $72K benefit, this SAMA has a negative net value (-$62K). For additional details, see Appendix F.4 and Table 4-3.
35	**Increase/improve DC bus load shedding.** Improve 125 VDC bus load management to allow the 125 VDC batteries to last for 24 hours.	N/A	N/A	N/A	N/A	In response to SBO Rule, BGE re-analyzed bus load management in 1989. It is not technically feasible to get more than 4 to 5 hours from current batteries. Therefore, this SAMA is not considered further.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
36	**Replace batteries with a more reliable model.**	3.02E-04	8.5%	$130,000	>>$375,000	Based on COE ($375K), and $130K benefit, this SAMA has a negative net value (-$245K). Note: May involve structural work, as larger batteries will not fit in rooms; therefore, costs may be much greater. For additional details, see Appendix F.4 and Table 4-3.
37	**Create AC power cross-tie capability across units at a multi-unit site.**	N/A	N/A	N/A	N/A	Calvert Cliffs' 500 kV grid is already in a ring configuration. This effectively allows the automatic feeding of 500 kV power as long as one of the three high-voltage lines remains available. As this SAMA is already included in Calvert Cliffs' current design, it is not considered further.
38-a	**Create a cross-unit tie for diesel fuel oil.** Create an automatic cross-unit tie for diesel fuel oil by cross-tying the fuel oil storage tanks.	N/A	N/A	N/A	N/A	Calvert Cliffs' EDGs 1B, 2A and 2B are already fed from common fuel oil storage tanks. As this SAMA concept is already included in CCNPP's current design, it is not considered further.
38-b	**Create a cross-unit tie for diesel fuel oil.** Double the capacity of fuel oil day tanks (FODTs) with the additional volume placed between the day tank level switches.	3.12E-04	5.5%	$88,000	$539,000	Based on COE ($539K/EDG) and $88K benefit, this SAMA has a negative net value (-$451K). For additional details, see Appendix F.4 and Table 4-3.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
39	**Develop procedures to repair or replace failed 4 kV breakers.**	N/A	N/A	N/A	N/A	Based on existing functional test procedures, and training, Calvert Cliffs' maintenance staff has consistently demonstrated the ability to diagnose, repair, or replace defective 4 kV breakers in approximately 10 minutes, which is much less than the 2-hour battery depletion time. A new maintenance procedure would not improve this performance; therefore, this SAMA is adequately implemented at CCNPP.
40	**Emphasize steps in recovery of offsite power after an SBO.**	N/A	N/A	N/A	N/A	Calvert Cliffs' EOP-7, "Station Blackout," adequately addresses recovery of offsite power. Therefore, this SAMA is not considered further.
41	**Develop a severe weather conditions procedure.**	N/A	N/A	N/A	N/A	Calvert Cliffs' emergency response procedures and EOPs are maintained to address site-specific activities and include latest site/industry experience. A separate effort to further improve these procedures would provide no value.
42	**Develop procedures for replenishing diesel fuel oil.**	N/A	N/A	N/A	N/A	Actions necessary to initiate fuel oil procurement are provided in the appropriate alarm manual. Therefore, this SAMA is not considered further.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
43	**Install gas turbine generators.** Install a gas turbine generator for a redundant AC power supply.	N/A	N/A	N/A	$3,350,000	COE exceeds maximum benefit attainable ($2.4M).
44	**Create a back-up source for diesel cooling.** Make the SRW-cooled EDGs air-cooled.	2.99E-04	9.4%	$176,000	$1,700,000 per EDG	Based on COE ($1.7M/EDG) and $176K benefit, this SAMA has a negative net value ($1.524M). For additional details, see Appendix F.4 and Table 4-3.
45	**Use FP System as a back-up source for diesel cooling.**	2.99E-04	9.5%	$176,000	$497,000 per EDG	Based on COE ($497K/EDG) and $176K benefit, this SAMA has a negative net value (-$321K). For additional details, see Appendix F.4 and Table 4-3.
46	**Provide a connection to alternate offsite power source.**	N/A	N/A	N/A	>$25,000,000	COE exceeds maximum benefit attainable ($2.4M).
47	**Implement underground offsite power lines.** Install underground offsite power lines.	N/A	N/A	N/A	>>$25,000,000	COE exceeds maximum benefit attainable ($2.4M).
48-a	**Change UV, AFAS Block and High Pressurizer Pressure Actuation Signals to 3-out-of-4 logic, instead of 2-out-of-4.** Convert UV, AFAS Block, and Reactor Protective System High Pressurizer Pressure Actuation Signals to 3-out-of-4 logic.	2.39E-04	27.6%	$413,000	$593,000	Based on COE ($593K) and $413K benefit, this SAMA has a negative net value (-$180K). For additional details, see Appendix F.4 and Table 4-3.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
48-b	**Change UV, AFAS Block, and High Pressurizer Pressure Actuation Signals to 3-out-of-4 logic, instead of 2-out-of-4.** Operate with the PORV block valves shut.	3.26E-04	1.2%	$16,000	$125,000	Based on COE ($125K) and $16K benefit, this SAMA has a negative net value (-$109K). For additional details, see Appendix F.4 and Table 4-3.
49	**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.** Add a feature that would automatically transfer from a failed inverter to a stand-by inverter.	N/A	N/A	N/A	N/A	As part of the efforts initiated under Generic Letter 88-20, BGE is continuing to define and control CCNPP's CDF. Due to uncertainties related to determining the benefits and cost of implementing this enhancement, BGE will continue to evaluate this SAMA in accordance with CCNPP's engineering processes.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
50	**Add disconnects at the junction box on the roof of the Auxiliary Building where 4 kV power from the 0C Diesel Generator branches to all four SWGRs. The disconnects would allow the recovery of the 0C Diesel Generator following the loss of any SWGR.**	N/A	N/A	negligible	N/A	The benefits from this hardware SAMA are negligible (i.e., much less than $40K); therefore, this SAMA is not considered further, as even a simple modification would exceed this amount.
51	**Improve SGTR coping abilities**. Combination of two options: a. Install equipment to automatically isolate the SG in the event of a SGTR. This includes all equipment that is currently required by the EOP to be closed by a manual action. b. Install larger ADVs with dedicated independent support systems capable of preventing primary safety relief valve challenges.	3.27E-04	0.9%	$16,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
52	**Install a redundant spray system to depressurize the primary system during a SGTR.** Install a redundant pressurizer spray system to depressurize the primary system during a SGTR.	N/A	N/A	<$16,000 (Bounded by SAMA 51)	Very high cost	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
53	**Add other SGTR coping features.** Install a highly reliable (closed loop) SG shell-side heat removal system that relies on natural circulation and stored water sources.	N/A	N/A	<$16,000 (Bounded by SAMA 51)	Very high cost	Implementation of any of the modifications proposed by this SAMA for an existing plant would greatly exceed the calculated maximum benefit. Therefore, this SAMA is not considered further.
54	**Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift.**	N/A	N/A	<$16,000 (Bounded by SAMA 51)	Very high cost	For an existing plant, increasing the secondary side pressure capacity is not feasible, as it would require an entirely new secondary system. Therefore, this SAMA is not considered further.
55	**Replace SGs with new design**. Replace the SGs with a more advanced design.	N/A	N/A	N/A	>$100,000,000	COE exceeds maximum benefit attainable ($2.4M).
56	**Direct SG flooding after a SGTR, prior to core damage.** Proceduralize SG flooding after a SGTR, prior to core damage.	N/A	N/A	N/A	N/A	Calvert Cliffs' EOP-6, "Steam Generator Tube Rupture," currently specifies secondary water level to be maintained above top of tubes. Therefore, this SAMA is not considered further.
57	**Implement a maintenance practice that inspects 100 percent of the tubes in a SG.**	N/A	N/A	<$16,000 (Bounded by SAMA 51)	$29,000,000/year for 100% plus point inspections	COE exceeds maximum benefit attainable ($2.4M). In addition, BGE already inspects 100% of tubes using bobbin coil.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
58	**Locate RHR inside of containment.** Locate RHR inside of containment, so that an ISLOCA through RHR would be contained.	N/A	N/A	N/A	N/A	For an existing plant, relocating the RHR inside the containment is not feasible, as it would require an entirely new RHR system. Therefore, this SAMA is not considered further.
59	**Install additional instrumentation for ISLOCAs.** Install additional instrumentation for detecting ISLOCA events. Implement a comprehensive piping inspection program to detect precursors to breaches in RCS integrity. The benefit assumes that the programs are so effective all ISLOCAs are eliminated.	3.28E-04	0.6%	$59,000	$2,300,000 (Reference 19)	Based on COE ($2.3M) and $59K benefit, this SAMA has a negative net value (-$2.241M). For additional details, see Appendix F.4 and Table 4-3.
60	**Increase frequency of valve leak testing.** Additional valve leak testing or non-destructive examinations may be able to identify a potential ISLOCA initiator before the failure occurs.	N/A	N/A	<$59,000 (Bounded by SAMA 59)	Not estimated	The cost of additional valve leak testing or non-destructive examination on the systems providing the highest ISLOCA risk would greatly exceed the calculated maximum benefit. Therefore, this SAMA is not considered further.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
61	**Improve operator training on ISLOCA coping.**	N/A	N/A	N/A	N/A	Current procedures and operator training address ISLOCA coping. These include training on EOPs for LOCA and functional recovery, Abnormal Operating Procedure (AOPs) for excess RCS leakage and abnormal shutdown cooling conditions, as well as various system operational instructions. Therefore, this SAMA is not considered further.[e]
62	**Install relief valves in the CC System.** Install relief valves in the CC System to prevent RCP seal heat exchanger LOCAs from leaving the containment.	3.29E-04	0.3%	$3,000	Not estimated	Hardware SAMAs with benefit values less than $40K were not considered further, as a simple modification would greatly exceed this value.
63	**Revise EOPs to improve ISLOCA identification.**	N/A	N/A	N/A	N/A	Current procedures and operator training address ISLOCA identification. These include training on EOPs for LOCA and functional recovery, AOPs for excess RCS leakage and abnormal shutdown cooling conditions, as well as various system operational instructions. Therefore, this SAMA is not considered further.[e]

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
64	**Ensure all ISLOCA releases are scrubbed.** Develop procedures and install systems such that every possible ISLOCA path will undergo scrubbing.	3.30E-04	0%	$72,000	Not estimated	An evaluation of the most risk-significant ISLOCAs (88% of all ISLOCA risk) has concluded that the these releases would most likely be scrubbed by the existing ventilation filter system and actuation of the FP sprinkler system. The cost of a new filter or spray scrubbing system would greatly exceed the calculated maximum benefit ($72,000). Therefore, this SAMA is not considered further.
65	**Add redundant and diverse limit switch to each containment isolation valve.**	3.30E-04	0%	$2,000	Not estimated	Hardware SAMAs with benefit values less than $40K were rejected from consideration, as a simple modification would greatly exceed this value.
66-a	**Implement internal flood prevention and mitigation enhancements.** Enhance procedures to improve flood mitigation guidance.	N/A	N/A	N/A	N/A	Calvert Cliffs' flood prevention and mitigation strategy was addressed in response to Significant Operating Experience Report 85-05, "Internal Plant Flooding." This strategy includes crediting operator actions to isolate flood sources in response to Control Room annunciation. The effect of diverting existing operator resources to mitigate the relatively low risk flood scenarios would likely have an overall negative impact on the overall plant risk profile. Therefore, this SAMA is not considered further. [e]

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
66-b	**Implement internal flood prevention and mitigation enhancements.** Comprehensive piping inspections or hardware modifications that improve the plant's ability to mitigate a flood.	N/A	N/A	N/A	N/A	As part of the efforts initiated under Generic Letter 88-20, BGE is continuing to define and control CCNPP's CDF. Due to uncertainties in determining the benefits and cost of implementing this enhancement, BGE will continue to evaluate this SAMA in accordance with CCNPP's engineering processes.
67-a	**Install accumulators for turbine-driven AFW pump flow CVs.** Increase the capacity of AFW accumulators that support the AFW flow CVs such that there is sufficient capacity for 24 hours of operation.	3.30E-04	0%	$3,000	Not estimated	Hardware SAMAs with benefit values less than $40K were not considered further, as a simple modification would greatly exceed this value.
67-b	**Install accumulators for turbine-driven AFW pump flow CVs.** Install an accumulator of sufficient capacity to allow ADV operation for 24 hours.	3.30E-04	0%	$1,000	Not estimated	Hardware SAMAs with benefit values less than $40K were not considered further, as a simple modification would greatly exceed this value.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
68	**Install separate accumulators for the AFW cross-connect and block valves.** Install separate accumulators for the AFW cross-connect and AFW block valves to separate this equipment from the constant bleed equipment (e.g., AFW flow CVs).	3.21E-04	2.7%	$45,000	$214,000	Based on COE ($214K) and $45K benefit, this SAMA has a negative net value (-$169K). For additional details, see Appendix F.4 and Table 4-3.
69	**Install a new CST.** Increase the capacity of CST 12 to contain a full 24 hours of AFW inventory for both units.	3.22E-04	2.4%	$41,000	$1,000,000 (Reference 16)	Based on COE ($1M) and $41K benefit, this SAMA has a negative net value (-$959K). For additional details, see Appendix F.4 and Table 4-3.
70	**Provide cooling of steam-driven AFW pump in an SBO event.** Provide a means to cool the turbine-driven AFW pumps in an SBO event.	3.25E-04	1.5%	$48,000	$396,000	Based on COE ($396K), and $48K benefit, this SAMA has a negative net value (-$348K). For additional details, see Appendix F.4 and Table 4-3.
71	**Proceduralize local manual operation of AFW when control power is lost.** Enhance procedures such that local manual operation of AFW is significantly improved. This includes local flow control and pump alignment.	N/A	N/A	N/A	N/A	Local manual operation of AFW is adequately addressed in EOPs (loss of feedwater, SBO, and LOOP) and AOPs (loss of instrument bus power and loss of IA), and is consistent with generic industry guidance on emergency procedures. Therefore, this SAMA is not considered further.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
72	**Provide portable generators to be hooked into the turbine-driven AFW, after battery depletion.** Install a self-sufficient diesel generator capable of driving either the AFW turbine-driven pump or motor-driven pump.	3.17E-04	3.9%	$94,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
73-a	**Create ability for emergency connections of existing or alternate water sources to feedwater/condensate.** Install hardware such that the FP System can be used to directly feed the SG. This option credits manual alignment only.	2.33E-04	29.4%	$740,000	Not estimated	Calvert Cliffs' design already includes the ability to feed the SGs from the FP System through a siamese hose connection on the discharge side of the motor-driven AFW pump. To attain the full benefit of this SAMA concept, an additional hose connection would have to be installed upstream of the Feedwater Control Valve. Also, the FP System would have to meet secondary side pressure requirements. Based on engineering judgment, the implementation costs are expected to greatly exceed the maximum benefit.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
73-b	**Create ability for emergency connections of existing or alternate water sources to feedwater/condensate.** Install hardware such that FP can be used to directly feed the SG. This option considers automatic alignment.	1.77E-04	46.4%	$1,059,000	Not estimated	The modification necessary to achieve the full benefits of this SAMA would involve replacing entire FP System pumps, piping and components with components rated for the much higher secondary side pressure. Based on engineering judgment, the implementation costs are expected to greatly exceed the maximum benefit.
74	**Install an independent diesel generator for the CST make-up pumps.** Automate DW make-up to CST 12. This system must have a dedicated diesel. This option has the added benefit of providing diesel-backed head tank make-up.	3.13E-04	5.2%	$68,000	$271,000	Based on COE ($271K) and $68K benefit, this SAMA has a negative net value (-$203K). For additional details, see Appendix F.4 and Table 4-3.
75	**Create passive secondary side coolers**.	N/A	N/A	N/A	N/A	For an existing plant, design and installation of this SAMA is not considered feasible, as it would involve major changes in plant structures. Therefore, this SAMA is not considered further.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
76	**Reduce the support system requirements for low pressure feed.** Improve Condensate System such that low pressure feed is possible with only 4 kV Bus 12 or 13 available. This is a conservative estimate on the benefit, but would be accurate if 4 kV Bus 12 or 13 could be diesel-backed.	2.33E-04	29.4%	< $740,000 (Bounded by SAMA 73-a)	Not estimated	The Condensate System is dependent upon IA, SRW, and 4 kV power. IA and SRW are both safety-related, but 4 kV Buses 12 and 13 are not. The cost of providing diesel-backing to these buses (either from existing EDG-backed buses or by installing new diesel generators) is expected to exceed the maximum benefit; therefore, this SAMA is not considered further.
77	**Replace current PORVs with larger ones such that only one is required for successful feed and bleed.** Install high capacity PORVs such that a single PORV is capable of providing adequate DHR.	N/A	N/A	N/A	$2,700,000	COE exceeds maximum benefit attainable ($2.4M).
78	**Provide capability for diesel-driven, low pressure vessel make-up.** Provide capability for diesel-driven high capacity low pressure vessel make-up. This would provide redundancy to the safety injection tanks and existing low pressure safety injection pumps.	3.20E-04	3.0%	$22,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
79	**Provide an additional HPSI pump with independent diesel.** Install a high capacity high head HPSI that is supplied by a dedicated diesel.	N/A	N/A	N/A	Between $5,000,000 and $10,000,000	COE exceeds maximum benefit attainable ($2.4M).
80	**Implement an RWT make-up procedure.**	N/A	N/A	N/A	N/A	RWT depletion is prevented by proceduralized accident mitigation strategies in Calvert Cliffs EOPs, and RWT make-up is addressed in the plant's Operating Instructions. Therefore, this improvement is already addressed in Calvert Cliffs procedures, and is not considered further.
81	**Stop low pressure safety injection pumps earlier in medium or large LOCAs**.	N/A	N/A	"minimal"	N/A	The benefits for this SAMA are minimal, as CCNPP has automatic recirculation actuation. The costs associated with revising calculations, accident analyses, and procedures would exceed the minimal benefits. Therefore, this SAMA is not considered further.
82	**Modify EOPs for ability to align diesel power to more air compressors.** Ensure that the plant air compressors are diesel generator backed.	N/A	N/A	N/A	N/A	Calvert Cliffs' plant design and procedures already include the ability to power the plant air compressors from the EDGs. This ability is appropriately addressed in the AOPs. Therefore, this SAMA is not considered further.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
83	**Replace old air compressors with more reliable ones.** Install more reliable plant air, IA, and SW air compressors.	3.27E-04	0.9%	$13,000	Not estimated	Hardware SAMAs with benefit values less than $40K were not considered further, as a simple modification would greatly exceed this value.
84	**Install MG set trip breakers in control room.**	N/A	N/A	"minimal"	N/A	As the ability to perform this function already exists, the benefits are minimal; therefore, this SAMA is not considered further.
85	**Provide an additional instrumentation system for ATWS mitigation (e.g., ATWS mitigation scram actuation circuitry).**	N/A	N/A	"minimal"	N/A	Based on previously-performed operator interviews, it is determined that the current ATWS indication is considered adequate, and additional improvements would not be cost beneficial. Therefore, this SAMA is not considered further.
86	**Provide capability for remote operation of secondary side relief valves in SBO.** Provide capability for remote ADV operation during an SBO.	N/A	N/A	"minimal"	N/A	Based on current plant design, this SAMA would provide little benefit, as the ADVs can already be operated from a remote location during an SBO. Therefore, this SAMA is not considered further.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
87	**Create/enhance RCS depressurization ability.**	N/A	N/A	<$1,059,000 (Bounded by SAMA 73-b)	$500,000 - $4,600,000 (Reference 19)	Enhancements to existing RCS depressurization options were reviewed and considered too costly to justify the benefits of this SAMA. No new RCS depressurization options that would provide cost-effective improvements were identified. Therefore, this SAMA is not considered further.
88	**Defeat 100 percent load rejection capability.** Remove the PORV lift on high pressurizer pressure.	N/A	N/A	<$413,000 (Bounded by SAMA 48-a)	N/A	SAMA 48-b addresses operating with the PORV block valves shut, a procedural change that is less expensive, and would achieve the same benefits as this change. Therefore, this SAMA is not considered further.
89	**Install secondary side guard pipes around the existing piping up to the main steam isolation valves.**	N/A	N/A	N/A	N/A	Calvert Cliffs' current design already includes encapsulated piping up to the main steam isolation valves. Therefore, this SAMA is not considered further.
90	**Install digital large break LOCA protection.** Install digital large break LOCA early detection.	3.25E-04	1.5%	$14,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
91	**Increase seismic capacity of the plant to a High Confidence, Low Pressure Failure of twice the Safe Shutdown Earthquake.**	N/A	N/A	N/A	N/A	This SAMA was considered in the CE System 80+ original design submittal and is not applicable to an existing plant. Therefore, it is not considered further.

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
92	**Enhance the reliability of DW make-up system through the addition of diesel-backed power to one or both of the DW make-up pumps.** Install a dedicated diesel generator for the DW transfer pumps.	N/A	N/A	N/A	N/A	The benefits and cost of an automated diesel generator for the DW transfer pumps is included in SAMA 74. Based on the information presented in SAMA 74, this SAMA is not considered further.
93	**Cap downstream piping of normally closed CC drain and vent valves.**	3.29E-04	0.3%	$3,000	Not estimated	The underlying concept of this SAMA is to provide redundancy for all CC drain and vent lines. However, the majority of drain and vent lines are capped, and implementation of this SAMA for the remaining lines would involve installation of redundant valving. Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
94	**Replace ECCS pump motors with air-cooled motors.**	3.21E-04	2.7%	$19,000	Not estimated	Based on engineering judgment, implementation costs are expected to greatly exceed the maximum benefit.
95	**Provide a core debris control system.**	N/A	N/A	N/A	$45M (Reference 19)	COE exceeds maximum benefit attainable ($2.4M).

Table F.2-2

SUMMARY OF CCNPP SAMAs[a,b]

SAMA No.	Modification/Procedure Enhancement/Training Options	New CDF	CDF Improvement	Maximum Benefit	Cost of Enhancement	Basis for Conclusion
96	**Implement procedures to stagger HPSI pump use after a loss of SW.**	N/A	N/A	N/A	N/A	As part of the efforts initiated under Generic Letter 88-20, BGE is continuing to define and control CCNPP's CDF. Due to uncertainties related to determining the benefits and cost of implementing this enhancement, BGE will continue to evaluate this SAMA in accordance with CCNPP's engineering processes.
97	**Use FP System pumps as a back-up seal injection and high pressure make-up.** Use FP System as a back-up make-up source for the RWTs.	N/A	N/A	N/A	N/A	The FP System takes raw water suction from a non-borated water source, the pretreated water storage tanks. Injection of non-borated water into the RCS following a LOCA would cause reactivity excursions. Therefore, the concept of using the FP System as a source of make-up to the RWTs will not be considered further.

a. Bold text indicates the conceptual enhancement identified in Table F.2-1. Non-bolded text indicates the redefined CCNPP-specific SAMA.
b. All costs and benefits are estimated for a single Unit (i.e., CCNPP Unit 1) only, unless otherwise indicated.
c. Columns are marked not applicable (N/A) for the following categories of SAMAs:
   1. SAMAs in which the COE was estimated to exceed the maximum base case benefit ($2,345,000);
   2. SAMAs that are not applicable to CCNPP's design;
   3. SAMAs for which the conceptual benefits could not reasonably be achieved, based on a review of the current design, procedures or programs;
   4. SAMAs that are still being evaluated by BGE staff;
   5. SAMA for which the conceptual benefits are already achieved through current CCNPP procedures and design; and
   6. Other SAMAs that could not reasonably be expected to be implemented at a fully-constructed plant.

d. Automatically cross-tying 125 VDC buses could result in an overall plant risk reduction. However, numerous design constraints would need to be addressed to ensure the system functions in a beneficial manner:

- The 125 VDC buses must have adequate separation. Ensuring this would be quite expensive or impossible from a design standpoint.
- The 125 VDC buses do not have sufficient capacity to support automatically cross-tying buses. The capacity of each of the buses would need to be dramatically increased. This would also be very expensive.

Beyond the cost of resolving the design constraints described above, the effects of this modification on the 125 VDC buses would also need to be determined. A thorough evaluation of the impact of a cross-connected 125 VDC bus would also be expensive. Therefore, the cost of designing a system that would eliminate all independence concerns (if possible) would greatly exceed the calculated maximum benefit ($113,000). Based on the potential for common-mode failure between facilities following the incorporation of an automatic transfer system, this SAMA will not be considered further.

e. In theory, Operations procedures and training may be improved to reduce plant risk from any particular event (e.g., ISLOCA, flooding). In reality, however, any changes that place a higher degree of operator attention on the mitigation of one event will divert existing operator resources from other, more risk-significant events. Therefore, the benefits derived from improving operator training/procedures on the identification and mitigation of relatively low-risk events are overestimated, as any changes would likely have a negative impact on the overall plant risk profile. Therefore, based on the existing training and procedures on ISLOCA and flooding identification and mitigation, the SAMAs to improve these functions will not be considered further.

F.3 LEVEL 2 MODELING

This section describes the NUCAP+™ model used to perform the Level 2 analyses and provides validation for fitting the CCNPP IPE.

F.3.1 NUCAP+ Model Description

NUCAP+ is a software product developed by SCIENTECH, Inc. for use in preparing Level 2 PRAs for nuclear power plants. Generally, the NUCAP+ model accepts Level 1 (extended) data on plant damage accident sequences and frequencies, and characterizes containment accident processes through the use of containment event trees (CETs). This approach supports the method of Level 2 quantification that uses plant damage sequences (PDSs), CETs, and decomposition event trees (DETs) to calculate STCs. A brief overview of this approach to Level 2 modeling is presented in the following sections.

Data Flow from Accident Sequences to Source Terms

Accident Sequence Input

The data flow in NUCAP+ begins at the Level 1 interface. An extended Level 1 analysis[1] provides data on accident sequences that lead to plant damage (that is, the core melt/damage sequences). The input information for PDS includes designation of the initiator, function failures, function successes, and an estimate of sequence frequency.

PDSs

The number of PDSs identified by a comprehensive Level 1 analysis is potentially large, even though the estimated frequency of most sequences is quite low. In practice, it is neither feasible nor productive to further extend every such sequence individually through a containment accident progression. Instead, those accident sequences that have similar characteristics with respect to probable containment system responses are aggregated into a single PDS.

NUCAP+ provides a means for constructing a decision tree classifying accident sequences into a discrete set of PDSs. The decision criteria are based on the functional events challenged in the accident sequences. Typically, the significantly damaging accident sequences from a Level 1 analysis are classified, or binned, into 15 to 50 distinct PDSs.

CETs

Each PDS becomes the entry point to a CET. A CET is a logical model that delineates possible paths along which an accident sequence may progress. The headings in a CET constitute the major events, with respect to timing and mode of containment failure, that may lead to significantly different outcomes in terms of radionuclide releases to the atmosphere. These key events may, for instance, represent: (1) uncertainties in physical phenomena (such as direct containment heating); (2) operator recovery and mitigation actions; or (3) failure of key systems' consequent on occurrence of specific physical phenomena (such as hydrogen burns) or the general severe accident phenomena.

Timing can be a key factor in the ordering of events included in a CET. The progression can be divided into distinct time periods to which different physical phenomena are important, and for which different

1 The term 'extended Level 1 analysis' refers to the inclusion in the Level 1 sequences of information beyond that required for the determination of core damage. Such information includes the status of containment systems that only come into play after core melt occurs. The end point of such sequences is referred to generically as 'plant damage.'

recovery and mitigation actions may be effective. For example, a simple scheme would divide the progression into four time periods:

- Prior to core uncovery/damage;
- Prior to, at, or near the time of reactor vessel failure; and
- Late - many hours after reactor vessel failure.

The branching paths of a CET define the containment accident sequences. These sequences can then be classified, or binned, into discrete STCs based on similarities in release characteristics.

DETs

A fully detailed CET should be constructed for each PDS, but there would be much redundant information among trees. In principle, one large but fully detailed CET could be constructed for all PDSs, but the graph would be unwieldy and difficult to comprehend and update. To keep the development and maintenance of containment event sequences manageable, NUCAP+ allows the analyst to represent the full theoretical tree as a more compact, high-level tree for each PDS. Each event of the CET is further analyzed as a subordinate tree. The high-level tree is called the CET; its subordinate trees are called DETs. Each heading in the CET represents a factor or event in the accident progression that has substantial effect on either subsequent events or the characteristics of the fission product source terms. The DET for a particular CET event decomposes it into a more detailed set of events or factors that are useful in quantifying the CET event. Decomposition event tree factors often include dependencies on the occurrence (or non-occurrence) of specific prior events, either in the original PDS or in the containment sequence up to that point.

There are three general types of DET headings, based on their interpretation for purposes of sequence quantification:

- Classification Branches, or rule branches, are wholly determined by prior events or characteristics of the PDS. With respect to evaluation of a particular containment accident sequence, they are strictly OFF/ON states. That is, they will have a probability of either zero or one for a given sequence. By capturing prior-path dependencies, rule branches allow one DET to be used for all the nodes under one CET heading. Rule branches in DETs — and all branches in NUCAP+ logic diagrams — use conditional rules to implement the branching logic.
- Subjective Probability Branches from one node are assigned probabilities greater than zero but less than one. They represent situations in which there is in fact a deterministic outcome, but the analyst has insufficient knowledge to specify it. Thus, the assigned probabilities reflect the analyst's degree of belief that one outcome will occur relative to the alternatives. The probabilities of all branches from one node under a subjective probability event must sum to one.
- Stochastic Probability Branches represent outcomes from inherently random underlying processes. The event is considered to be stochastic in nature. As in subjective probability events, the sum of the branch probabilities from a node must be one.

Sequence Quantification

By convention, the last heading in a DET is the same as the CET heading with which it is associated. Quantification of a PDS entails the following operations on its assigned CET.

- At each CET heading, the associated DET is evaluated. Each allowed path through the DET is traced (Classification Branches in the tree will disallow all but one branch at that node for a given PDS). The values of the branch probabilities along each allowed path are multiplied to give a path probability. The values for like paths (those with the same branch attribute at their last heading, that is, at the CET) are added to give the branch probability assigned to the corresponding branch in the CET.
- Probabilities from the CET branches along each containment accident sequence through the CET are multiplied to give a conditional sequence probability relative to the occurrence of the PDS. Of course, the sum of all conditional sequence probabilities from a given PDS is unity.
- Multiplying the PDS frequency by the containment sequence relative probability gives the containment sequence frequency.

STC Binning

The next data flow step after CET frequency quantification is source term binning. In a process analogous to the earlier binning of PDSs, the (typically) large number of containment sequence end points are grouped into a smaller number of STCs. The STCs are defined according to important radionuclide release characteristics, or release-affecting factors: timing, energy content, magnitude, etc. NUCAP+ uses another decision tree, the source term grouping logic diagram, to specify the criteria and rules for assigning each containment sequence to the appropriate STC. The source term grouping logic diagram uses rules that relate PDS characteristics and the CET events of the sequence to the STCs. As the final step in STC binning, the CET frequencies of all sequences assigned to the same STC are summed to yield the source term frequency.

F.3.2 Level 2 Model Validation

Validation of the NUCAP+ Model Against the CCNPP IPE Submittal Model (Level 2)

A CCNPP IPE Level 2 NUCAP+ model has been developed. The original CCNPP Containment Phenomenological Event Trees (CPETs) illustrated in Figure 4.5.2.1 of Reference 1 has 16 top events (including the entry point) and 444 sequences. These sequences are grouped into six Key Release Categories each related to a containment failure category as shown in Table 4.7.4 of Reference 1.

The split fractions for the CCNPP CPET are listed in Table 4.6.3-a of Reference 1. The CPET is implemented as an EXCEL 4.0 Spreadsheet and was quantified using these split fractions. The results are shown in Tables 4.7.2-A and -B of Reference 1, which give the total containment failure category frequencies and the conditional (percentage) contributions from each of the key plant damage states (KPDSs), which are the starting points for the Level 2 quantification.

The NUCAP+ model is limited to 150 sequences; therefore, the CCNPP IPE CPET was fitted to NUCAP+ by deleting low significance branches in a manner judged to best reproduce the IPE containment failure category frequencies. The basis for the installation is that the results are sufficiently accurate for the SAMA analysis purpose. The IPE branch split fractions are used to quantify the NUCAP+ DETs associated with the each CET.

NUCAP+ generates a **C** matrix such that when the KPDS frequencies are arranged into a column vector **p**, then the matrix multiplication of **p** by **C** will produce a column vector **s** of the containment failure category frequencies (i. e. , **C** x **p** = **s)**.

Table F.3-1 is the C matrix that was produced by NUCAP+ with the adapted CCNPP IPE CPET. The columns have been reordered to facilitate direct comparison with Table 4.7.2-B of Reference 1 (shown in Table F.3-2). The values are shown as percentages rather than fractions, and the columns and rows are titled for direct comparison.

Note that the KPDS, HRWF[2], has been added since the IPE was submitted. This KPDS was identified by the subsequent submittal for evaluating external events (Reference 2). Examples of two significant sequences in HRWF are as follows:

- **Earthquake -** A large earthquake (over 1.5 g) causes AFW failure with containment penetration failures with no SI.
- **Panel Fire -** A severe Control Room fire forces the operators to evacuate the Control Room. The operators fail to man the Auxiliary Shutdown Panel, and there is no SI and no DHR.

Both of these sequences are essentially SBO with large early containment failure and are treated as such in the respective CET.

The comparison of Tables F.3-1 and F.3-2 illustrate the agreement between NUCAP+ C matrix and the values generated in the CCNPP IPE submittal. The magnitude of the differences is well within the precision of Level 2 analyses. The close similarity between the matrices is considered sufficient to validate the NUCAP+ model of the CCNPP IPE Level 2 for SAMA analyses.

2 HRWF is an identifier for one particular KPDS and is defined in the CCNPP IPE (Reference 1).

Table F.3-1

NUCAP+ C MATRIX (REARRANGED) IPE BASE CASE MODEL

Containment failure category	KPDS[a]														
	HGIP	**ATWS**	**HBIF**	**HRIF**	**HRSF**	**MBIO**	**LBIO**	**MRIO**	**MCIF**	**MRIF**	**HLBF**	**MCBO**	**MCBF**	**LCVF**	**HRWF**
Intact	90.2%	91.2%				79.0%	82.8%	45.3%							
Late containment failure	4.1%	4.3%	92.5%	95.0%		19.2%	16.7%	54.2%	86.8%	99.6%					
Early small containment failure	1.4%	0.6%	2.0%	1.8%	96.7%	1.4%	0.4%	0.3%	10.3%	0.3%					
Early large containment failure	4.4%	3.9%	5.4%	3.3%	3.3%	0.5%	0.2%	0.2%	2.8%	0.2%					100.0%
Small containment bypass											96.7%	99.9%	99.9%		
Large containment bypass											3.3%	0.1%	0.1%	100.0%	
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

a. The identifier for each KPDS is defined in the CCNPP IPE submittal (Reference 1).

Table F.3-2

PERCENTAGE OF MAJOR CONTAINMENT FAILURE CATEGORIES FOR EACH KPDS[a]

Containment Failure Category	KPDS[b]													
	HGIP	**ATWS**	**HBIF**	**HRIF**	**HRSF**	**MBIO**	**LBIO**	**MRIO**	**MCIF**	**MRIF**	**HLBF**	**MCBO**	**MCBF**	**LCVF**
Intact	90.3%	91.4%				77.3%	82.7%	44.6%						
Late containment failure	4.0%	4.1%	92.5%	95.0%		20.9%	16.7%	54.8%	86.8%	99.6%				
Early small containment failure	1.3%	0.7%	2.0%	1.8%	96.6%	1.2%	0.3%	0.3%	10.3%	0.3%				
Early large containment failure	4.4%	3.8%	5.5%	3.2%	3.4%	0.6%	0.3%	0.2%	2.9%	0.2%				
Small containment bypass											96.7%	99.9%	99.9%	
Large containment bypass											3.3%	0.1%	0.1%	100.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

a. Source: Reference 1, Table 4.7.2-B.
b. The identifier for each KPDS is defined in the CCNPP IPE submittal (Reference 1).

F.3 References

1. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated December 30, 1993, "Summary Report of Individual Plant Examination Results (Generic Letter 88-20) (TAC Nos. M74392 & M74393)"

2. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, , dated August 28, 1997, "Individual Plant Examination of External Events for Severe Accident Vulnerabilities (TAC Nos. M83603 & M83604)"

F.4 SAMA DESCRIPTIONS AND COST ESTIMATES

SAMA No. 01-a - Improve SW, SRW, and CC Pump Recovery (Post-trip only)

Discussion

Probabilistic risk assessment methodology assigns a much lower success likelihood to manual actions than that which may be credited for automatic actions. In an accident scenario, the SW, SRW and CC pumps are started automatically by the Shutdown Sequencer or SIAS. If either of these actuation systems fail, and the operator starts the pump when required, then the likelihood of SW, SRW and CC failure is reduced. However, due to the low likelihood credited for a manual start, the analysis only credits a single SRW or SW pump for each header. With perfect procedures or an enhanced control system, the back-up (or swing) pump will be employed most of the time. This is addressed by reducing the failure likelihood of the appropriate SRW and SW equipment. In addition to improvements involving the pumps, it may be possible for the operators to reduce the load on CC so the RCP seals can be cooled above all else.

Approach to Estimating Bounding SAMA Benefit

Severe Accident Mitigation Alternative No. 01-a considers only the gain if the post-trip procedures and/or design functions are affected. Without re-quantifying the plant model, an evaluation was done to bound the impact of these improvements. The evaluation assumed all actuation channels which feed the CC, SRW, and SW were set to success.

Engineering/Operations Discussion

Two approaches were taken to evaluating this SAMA. Option 1 is a hardware change, which considers modifying the plant to automatically start the back-up pump, if the operating pump fails. Option 2 considered procedure changes only. It should be noted that the benefit of Option 2 is estimated to be approximately 25 percent of Option 1 due to the lower likelihood of operator actions compared to automatic actions. The following discussion addresses these two options:

Option 1

The approach taken to modify these three systems would be to assume that a failed running pump is identified by a drop in discharge header pressure. A corrective modification would be to tie in a pressure switch in each motor start scheme, where the pressure switch would be installed at discharge of each pump before the first check valve, and assume a low pressure setpoint can be reached that represents a stopped pump. The pressure switch would be classified as safety-related (for pressure-boundary function only), but must assume it is installed in a Class 1E circuit. It is assumed that separation between trains can be maintained. A design interface must be included between trains so automatic start signals can be blocked when pumps are intentionally stopped. Handswitch and relay logic modifications are assumed to be included in the scope.

Option 2

This option considered revising CCNPP EOPs to give more importance to cooling water pump recovery. However, in discussions with plant Operations personnel, it was noted that the EOPs were written following guidance provided in CE's generic emergency procedure guidelines, CEN-152 (Reference 1). The strict hierarchy included in CEN-152 ensures plant safety is maintained or restored, based upon their importance to mitigating each event. Unless plant-specific changes were identified and evaluated where CCNPP EOPs could be improved by deviating from the CEN-152 approach, the EOPs typically follow the hierarchy in CEN-152.

In general, the importance of pump recovery is specified based upon the importance of the equipment or systems the pump supports. As an example of a CEN-152 deviation which was made specifically for CCNPP, it was identified that EOP-0, Post-Trip Immediate Actions, requires verification of CC flow to the RCPs early in the procedure (Step C.6), due to the detrimental effect of loss of CC on the RCP seals, and the potential for an ISLOCA if the RCPs are operated without cooling. This change was implemented as a result of insight gained from the CCNPP IPE. On the other hand, other EOPs verify cooling water flow as recommended in the CEN-152 hierarchy. For example, EOP-2, Loss of Offsite Power, requires verification of SRW and SW pumps very early in the procedure (Step E.1) due to the detrimental effects on the EDGs if jacket water is not provided. The EDGs are key to mitigating this event. Procedure EOP-5, Loss of Coolant Accident, does not require verification that the SRW and SW pumps are operating until later in the procedure (Step R.3). The justification for this is that the more important safety functions during a LOCA are those required to prevent core uncovery and to support RCS cooldown and depressurization. As such, verification of cooling water (SRW/SW) flow is provided the appropriate level of importance in this procedure as well. Absent more specific guidance on where cooling water should be given more importance, it is assumed that the existing EOPs, which follow the hierarchy provided in CEN-152, sufficiently address the safety functions necessary to mitigate each event.

This SAMA was intended to reduce plant risk by giving cooling water pump recovery more importance. However, the EOPs are written to specify actions to be taken in a specific order necessary to ensure the safety functions are maintained. Absent more specific guidance on how cooling water should be given more importance, it is assumed that the level of importance provided in CEN-152 adequately addresses the specific safety functions required for each event. Any procedure changes to give cooling water pump recovery more importance would result in reducing the level of importance given to other safety functions. Therefore, the concept of revising the EOPs to give more importance to cooling water pump recovery does not appear to provide any benefit to CCNPP, and this option for SAMA No. 01-a is not reviewed further.

Cost Analysis

Option 1

The cost analysis for Option 1 estimated the modification to all trains of SW, SRW, and CC. The results of the estimate indicated a $622,000 COE, as follows:

Engineering ($50,000 per system x 3 systems = $150,000 + $50,000 general)	$200,000
Parts and material ($50,000 per system x 3 systems)	$150,000
Construction ($50,000 per system x 3 systems)	$150,000
Other	$50,000
Total Direct Costs	**$550,000**
Indirect Supervision Engineering	72,000[1]
Total COE	**$622,000**

Note:

1. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

Option 2

As this SAMA Option does not realistically provide a benefit to CCNPP, a cost analysis is not required.

SAMA No. 01-b - Improve SW, SRW, and CC Pump Recovery (Pre-trip and Post-trip)

Approach to Estimating Bounding SAMA Benefit

If the SW, SRW, and CC pumps are always started by the operators, then the likelihood of SW, SRW, and CC failure is reduced. If the operators are always successful in starting the back-up pump, then the failure of an operating pump will not result in a failure of the SW, SRW, and CC function. Due to the assumed low likelihood of manual pump start, the analysis only credits a single SRW and SW pump for each header; however, with perfect procedures the back-up (or swing) pump can be employed most of the time. This is addressed by reducing the failure likelihood of the SRW and SW pumps. In addition to improvements involving the pumps, it may be possible for the operators to reduce the load on CC so the RCP seals can be cooled above all else.

Severe Accident Mitigation Alternative No. 01-b considers the gain if both pre-trip and post-trip procedures are changed. In addition to the changes made associated with SAMA No. 01-a, this enhancement also evaluates post-trip procedures. This was modeled by reducing the likelihood that SW, SRW, and CC will fail and lead to a plant trip. There are many failure mechanisms by which the cooling water systems could be lost which lead to a plant trip. For this evaluation, all cooling water losses which lead to a plant trip are assumed impossible. This is a bounding evaluation.

Engineering/Operations Discussion

As with SAMA No. 01-a, two approaches were taken to evaluate this SAMA. Option 1 considered modifying the plant to automatically start the back-up pump, if the operating pump failed. Implementation of the conceptual plant modification described for SAMA No. 01-a, Option 1, would provide a benefit for both pre-trip and post-trip pump recovery; therefore, this option was not re-evaluated for the pre-trip benefit alone. Option 2 considered procedure changes only. The following discussion addresses the potential for enhancing plant procedures, per Option 2.

The scope of the procedural option for SAMA No. 01-b is to revise plant operating procedures such that, during normal plant operation, a higher priority is placed on starting the back-up SW, SRW, or CC pump if the operating pump fails. During normal operation, if the operating pump initially starts, then subsequently fails, the Control Room will be alerted of the failed pump by a low header alarm in the Control Room. If the annunciator for low SW, SRW or CC header pressure alarms, operators are directed by the Alarm Manuals to implement the appropriate AOP for the system experiencing the low header pressure condition. Diagnosis of the low pressure alarm, in accordance with the AOPs, ensures the back-up pump will be started prior to plant degradation resulting from the lost pump, and also ensures that the back-up pump will only be started if the low pressure alarm was caused by a pump failure, and not some other system malfunction. Operators are well-trained on the implementation of the AOPs, as well as the Alarm Manuals.

Based on the current proceduralized manual start of the back-up pump on a low header pressure alarm, it is concluded that there are no procedural enhancements which would give more importance to pump recovery. As current operating practice, procedures, and training ensure that the stand-by pump is started shortly following the failure of an operating pump, this option provides no overall benefit and is not applicable to CCNPP.

Cost Analysis

A cost analysis is not required for Option 1, as the modification for SAMA No. 01-a, Option 1 would address the risk of a pump failure during normal plant operations, as well as during a postulated accident condition. Therefore, the estimated COE of $622,000 applies to this option, as well.

As Option 2 is not applicable to CCNPP, a cost analysis is not required.

SAMA No. 05 - Hard-pipe an FP System Feed to the CC System to Allow an Alternate Cooling Source for the Shutdown Cooling Heat Exchangers, the SI Pumps, and the RCP Seals

Approach to Estimating Bounding SAMA Benefit

The FP System has a diesel-driven fire pump which could be used to cool the RCP seals and the SI pumps. All CC functions are considered successful with the exception of cooling to the RCP seals. It is assumed that some form of containment isolation would be required, even with FP cooling to the seals. Additionally, the FP System does not have the capacity to provide enough cool water to support the shutdown cooling heat exchangers. Based on this, the failure likelihood of 11 and 12 CC heat exchangers is not adjusted.

The bounding benefit evaluation considered the following functions successful:

- CC maintains adequate inventory;
- CC flow paths remain open;
- CC pumps operate as required;
- Operator starts/aligns stand-by equipment (pumps, heat exchangers, etc.); and
- RCP seal remains intact.

Engineering/Operations Discussion

The modification to feed the CC System from the FP System would involve the following engineering considerations:

- A 6-inch line from the nearest FP main to the CC header would be used.
- To provide the full benefit of a hard-piped, permanently connected interface, the transfer from the CC System to the FP System would have to be automatic, which would involve a significant amount of Instrumentation and Controls (I&C) engineering. As this transfer would be required during a LOCA, if the CC pumps failed, a SIAS interface would be required. Additionally, the ability to override the transfer would be required, due to the possible need for FP in the event of a fire.
- The interface between the safety-related CC System and the non-safety-related FP System would have to be designed to meet seismic requirements and provide double isolation between the two systems.

Cost Analysis

A conservative estimate of the costs associated with this SAMA is provided, as follows:

Engineering -	$160,000
Mechanical (flow calculations, piping and valve design)	
I&C (controls for automatic transfer, SIAS modifications)	
Civil (seismic analysis, penetrations, if required)	
Parts and Material -	200,000
Mechanical (piping, valves, hangers)	
Electrical and I&C (controls, wiring, control panel instruments)	
Construction	100,000
Documentation (drawings, manuals, etc.)	10,000
Training	10,000
Procedures	10,000
Radwaste Disposal, Health Physics, Monitoring Equipment	10,000
Total Direct Costs	**$500,000**
Indirect Supervision and Engineering	65,000[1]
Total COE	**$565,000**

Note:

1. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

SAMA No. 07 - Install a Redundant AFW Pump Room Ventilation System

Approach to Estimating Bounding SAMA Benefit

The AFW Turbine-Driven Pump Room must be cooled while the turbine-driven pumps are in operation. This can be accomplished by using the non-safety-related air-conditioning unit, the emergency ventilation fans, or by opening the doors to the room. For another cooling option to be effective, it must be automatic and self-powered with a 24-hour power source. Without this, the recovery would be driven by human actions or power availability, which would render the modification ineffective. But, if this option is automatic and self-contained, then the impact can be assessed by assuming AFW Pump Room ventilation function is guaranteed to succeed.

Engineering/Operations Discussion

The system proposed for this SAMA is a diesel-powered electric generator, a 5- to 10-ton chiller unit, and an electric fan coil unit in the AFW Pump Room. This modification would have the following design features:

- Diesel-powered electric generator (230 VDC, 25 Amp) located inside the Turbine Building, including a fuel oil tank capable of maintaining a 24-hour fuel oil capacity. This unit would also produce enough electric power to power the fan coil unit and coolant pump in the AFW Pump Room;
- Chiller unit 5- to 10-ton also located inside Turbine Building;
- Fan coil unit located in the AFW Pump Room; and

- Automatic start with thermostatic controls in the AFW Pump Room capable of automatically starting the generator, chiller, and fan coil units.

Cost Analysis

The minimum cost of this modification, including Engineering (design of new system; effects on other plant systems; turbine building ventilation; Title 10 Code of Federal Regulations (CFR) Part 50, Appendix R, etc.), parts and equipment, construction, is estimated to be approximately $226,000, as follows:

Engineering	$25,000
Mechanical - flow calculations, equipment sizing, drawings, evaluations	
Electrical - power calculations, diesel generator sizing, drawings, evaluations	
Civil - wall penetrations, equipment mounting, etc.	
I&C - electric generator controls, chiller controls, and interfaces	
Appendix R - evaluation of combustible loads (fuel oil)	
Equipment - (diesel-powered electric generator, chiller unit, fan coil unit, piping, controls)	125,000
Construction	25,000
Procedures and training	25,000
Total Direct Costs	**$200,000**
Indirect Supervision and Engineering	26,000[1]
Total COE	**$226,000**

Note:

1. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

SAMA No. 08 - Install CS Pump Header Automatic Throttle Valves

Discussion

Containment spray is designed to ensure the containment pressure does not exceed design limits after a large LOCA. However, full CS flow is not needed in all accidents which result in a Containment Spray Actuation Signal. If the CS can be throttled when full flow is not needed, the RWT draindown time would be extended, thereby allowing more time for a switch to recirculation.

Approach to Estimating Bounding SAMA Benefit

The CS System actuates on high containment pressure. During certain small break LOCAs, CS may deplete the RWT faster than necessary to ensure the proper containment environment is maintained. If the RWT can last 24 hours or longer, then it is more reasonable to consider recovery of the sump recirculation valves. Even if these MOVs cannot be recovered, then it is creditable to assume that the RWT can be refilled. Either of these options can be modeled by assuming that the containment sump recirculation MOVs are guaranteed to succeed.

Engineering/Operations Discussion

At CCNPP, the transfer to recirculation is automatic. Although manual action is credited should the automatic transfer fail, it is judged that providing additional time for the manual back-up would have a minimal benefit.

Cost Analysis

In 1996/1997, automatic throttle valves were installed on the CACs (four per unit). This modification is considered to be approximately equivalent to the modification proposed by this SAMA, except that only two throttle valves would be required per unit (one per CS header). Therefore, it would be logical to assume the cost of installing two throttle valves per unit on the CS headers would be equal to approximately one-half the cost of installing four throttle valves per unit on the CACs. The total cost of the CAC throttle valve modification was approximately $1.5 million, so the estimated COE for this would be $750,000 for two units ($375,000 per unit).

SAMA No. 15 - Create a Passive Hydrogen Ignition System

Discussion

Passive autocatalytic recombiners would allow controlled hydrogen ignition without any power dependencies. As a result, they provide improved hydrogen control, particularly in SBO sequences. They would replace existing hydrogen recombiners to eliminate maintenance and other operational costs. A large number of these would be needed to reduce hydrogen concentrations significantly in the time frames of severe accidents.

Approach to Estimating Bounding SAMA Benefit

This SAMA is conservatively assumed to eliminate hydrogen burns.

Cost Analysis

An estimate of $760,000 was provided for a passive autocatalytic recombiners system in the CE System 80+ SAMDA analysis (Reference 2). This estimate is also considered valid for CCNPP.

SAMA No. 23 - Use the FP System as a Back-up Source for the CS System

Discussion

Increase the capacity of the FP System and hard pipe a connection to CS System.

Approach to Estimating Bounding SAMA Benefit

Due to the redundancy between the CS System and the CAC system, the CS System plays a bigger role in determining the likelihood of containment release/fission product scrubbing than in preventing core damage. From a containment release/fission product scrubbing perspective, the CS System is conservatively assumed to always be available (i.e., does not fail).

Engineering/Operations Discussion

The modification to hard-pipe FP to the CS System would involve the following engineering considerations:

- A 6-inch line from the nearest FP main to the CS header would be used.
- To provide the full benefit of a hard-piped, permanently connected interface, the transfer from the CS System to the FP System would have to be automatic, which would involve a significant amount of I&C engineering. As this transfer would be required during a LOCA, if the CS pumps failed, a SIAS interface would be required. Additionally, the ability to override the transfer would be required, due to the possible need for FP in the event of a fire.
- The interface between the safety-related CS System and the non-safety-related FP System would have to be designed to meet seismic requirements and provide double isolation between the two systems.

Cost Analysis

A conservative estimate of the costs associated with this SAMA is provided, as follows:

Engineering -	$160,000
Mechanical (flow calculations[1], piping and valve design)	
I&C (controls for automatic transfer, SIAS modifications)	
Civil (seismic analysis, penetrations, if required)	
Parts and Material -	200,000
Mechanical (piping, valves, hangers)	
Electrical and I&C (controls, wiring, control panel instruments)	
Construction	100,000
Documentation (drawings, manuals, etc.)	10,000
Training	10,000
Procedures	10,000
Radwaste Disposal, Health Physics, Monitoring Equipment	10,000
Total Direct Costs	**$500,000**
Indirect Supervision and Engineering	65,000[2]
Total COE	**$565,000**

Notes:

1. It has not been determined whether the existing FP pumps will meet the necessary head/flow requirements for the CS System.
2. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

SAMA No. 31 - Provide Additional DC Battery Capability

Discussion

Additional battery capability can extend the life of turbine-driven AFW and I&C systems during an SBO.

Approach to Estimating Bounding SAMA Benefit

The maximum benefit was determined by:

- Assuming that the 125 VDC Bus will be available for 24 hours given the 125 VDC batteries operate in the short-term;
- The likelihood of a LOOP in excess of 4 hours is considered zero; and
- The likelihood of the 480 Volt AC (VAC) buses experiencing common cause is significantly reduced.

Engineering/Operations Discussion

Baltimore Gas and Electric Company replaced all five banks of batteries at CCNPP in 1997 at a cost of approximately $750,000 ($150,000 per battery bank). As the life of the existing batteries is only expected to be 4 hours (using best load management practices), the cost would be expected to increase by at least $750,000 for every additional 4 hours of battery life gained. Therefore, the existing battery capacity would have to be increased by a factor of five to achieve the desired 24-hour capacity. The cost of the additional batteries alone would be $3,750,000 (5 x $750,000) for both units.

It should be noted that the battery rooms are completely filled by the currently installed battery configuration. Therefore, any modifications to increase the current battery capability would necessitate the structural modifications to accommodate the additional batteries.

Cost Analysis

Due to space limitations in the existing battery room, any proposed improvements to install additional batteries would require structural modifications to the battery rooms. Therefore, in addition to the cost of 25 new banks of batteries to extend the battery life to 24 hours ($3,750,000 for both units or $1,875,000 per unit), the total cost of implementing this SAMA would have to include structural modifications to accommodate the additional batteries. However, for the purposes of this analysis, the COE of $1,875,000 per unit will be used.

SAMA No. 32 - Use Fuel Cells Instead of Lead-Acid Batteries

Discussion

This SAMA was proposed by the CE System 80+ SAMDA analysis (Reference 2). The use of fuel cells would extend the duration of DC power availability in an SBO scenario. This SAMA would require extensive modifications to the HVAC System to ensure the system is capable of removing the heat generated by the fuel cells.

Approach to Estimating Bounding SAMA Benefit

Similar to SAMA No. 31, the maximum benefit was determined by:

- Assuming that the 125 VDC bus will be available for 24 hours given the 125 VDC batteries operate in the short-term;
- Assuming the likelihood of a LOOP in excess of 4 hours is zero; and
- Assuming the likelihood of the 480 VAC buses experiencing common cause failure is significantly reduced.

Engineering/Operations Discussion

This enhancement involves replacing the existing lead-acid batteries with fuel cells to extend the DC availability duration. The use of fuel cells would also necessitate modifying the HVAC System for the battery rooms to ensure the system is capable of removing the excess heat generated by the fuel cells.

Cost Analysis

An estimate of $2,000,000 to use fuel cells in lieu of conventional lead-acid batteries was included in the CE System 80+ SAMDA analysis. This estimate was based on enhancements that were being considered during the conceptual design phase, and would be considerably higher for an existing plant, such as CCNPP. However, the $2,000,000 estimate is adequate, considering the bounding nature of this analysis.

SAMA Nos. 33-a and 33-b - Improve Bus Cross-Tie Ability

Discussion (SAMA Nos. 33-a and 33-b)

If all buses had an automatic cross-connect capability, then the theoretical risk from a loss of electrical bus function would be significantly reduced. Although installing automatic cross-connect capability is possible, it is not realistic as it would be very expensive. To bound this problem, the following scenarios will be evaluated:

- 4 kV Buses 11 and 14 can automatically cross-connect: This option should bound most of lower voltage cross-connection options such as 480 VAC Buses 11A, 11B, 14A, and 14B, or 120 VAC Bus 1Y09 to 1Y10.
- 4 kV Buses 21 and 24 can automatically cross-connect: This option should bound most of lower voltage cross-connection options such as 480 VAC Buses 21A, 21B, 24A, and 24B.

SAMA No. 33-a - Implement Automatic Cross-Tie Capability Between 4 kV Buses 11 and 14

Implementation of this SAMA would ensure that if either 4 kV Bus 11 or 14 experiences an undervoltage condition and its dedicated EDG fails, the bus with the failed EDG would be fed automatically from the 4 kV bus with power.

Approach to Estimating Bounding SAMA Benefit

The gain for this option is estimated by setting the 4 kV Bus 14 function and the supports for the bus to success. The following 4 kV Bus 14 support systems are considered successful:

- EDG 1B;

- Diesel Generator 0C;
- SW Header 12; and
- SRW Header 12.

Although the cooling water systems are considered successful for this bounding evaluation, the only dependent piece of equipment also considered successful is EDG 1B. In reality, other plant equipment would also benefit by improving the availability of the cooling water systems. As this other plant equipment is not considered successful for this evaluation, the evaluation is conservative.

Engineering/Operations Discussion

Although cross-tie capability is technically feasible, the benefits may be over-estimated, for the following reasons:

- Automatic transfer switches (ATSs) have a failure frequency that is not considered in the risk analysis;
- Likewise, operator error in the event of an ATS failure is not considered in the analysis;
- Potential for common-mode failure is significantly increased, due to the connection between the safety-related 4 kV facilities;
- Installation of an ATS would require a permanently energized tie between the buses; and
- Installation of an ATS between safety buses would greatly complicate Engineered Safety Features Actuation Signal (ESFAS) logic, and could result in increased risk of Engineered Safety Feature malfunction.

Based on these and other considerations, ATSs were considered undesirable, and their use was minimized during the original plant construction. While BGE still does not believe their use would be beneficial, a rough estimate has been provided to meet the general concept of this SAMA.

Cost Analysis

The following assumptions were made to estimate the cost of implementation for this SAMA:

- Baltimore Gas and Electric Company's estimates for a safety-related 4 kV ATS with logic ($150,000), two cubicles each with one disconnect and one breaker ($100,000 per cubical), associated conduit, cables, etc. ($50,000) total $400,000.
- Due to the modifications impact on ESFAS cabinets, construction could be relatively complicated, and would involve core drilling between the SWGR and cable spreading rooms. Therefore, construction costs are estimated at $250,000.
- Although much of the work could be performed at-power, the actual bus tie-in could render both 4 kV buses inoperable for a period of time, and would, therefore, be performed during a refueling outage. Therefore, the contingency costs are estimated at $500,000. (Note: Although contingency costs are real, for consistency they will not be included in the SAMA cost estimate.)
- Installation of automatic cross-tie capability would involve significant changes to CCNPP's electrical and ESFAS logic. This would involve approximately 2-1/2 man-years of engineering at the current cost of $100,000 per man-year. Therefore, BGE estimates the engineering costs to be at least $250,000.

- Based on operator procedures and training needed to mitigate the effects of a failed ATS, and maintenance procedures and training necessary to ensure that a failed ATS is repaired (without adversely affecting the operable 4 kV bus), the cost of procedures is estimated to be $40,000, and training is also estimated to be $40,000.

Based on the estimates provided above, the minimum cost of implementing this SAMA is $1,119,000, as follows:

Structures	$0
Equipment	400,000
Radwaste Disposal, Health Physics, Monitoring Equipment, etc.	0
Construction	250,000
Engineering[1]	250,000
Procedures	40,000
Calculations	10,000
Training	40,000
Total Direct Costs	**$990,000**
Indirect Supervision and Engineering	129,000[2]
Total COE	**$1,119,000**

Notes:

1. It has not been determined whether the existing FP pumps will meet the necessary head/flow requirements for the CS System.
2. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

SAMA No. 33-b - Implement Automatic Cross-Tie Capability Between 4 kV Buses 21 and 24

Discussion

Implementation of this SAMA would ensure that if either 4 kV Bus 21 or 24 experiences an undervoltage condition and its dedicated EDG fails, the bus with the failed EDG would be fed automatically from the 4 kV bus with power.

Severe Accident Mitigation Alternative No. 33-b is essentially identical to SAMA No. 33-a, except that it considers modifying Unit 2, whereas SAMA No. 33-a modified Unit 1. The benefits would be greater for Unit 1 (SAMA No. 33-a) than for Unit 2 (SAMA No. 33-b), due primarily to the fact that the EDGs for Unit 1 have diverse cooling sources (EDG 1A is self-cooled, EDG 1B is SRW-cooled), while the EDGs for Unit 2 are both cooled by the SRW System. However, the engineering evaluation and cost analysis for SAMA No. 33-b are identical as those for SAMA No. 33-a.

Approach to Estimating Bounding SAMA Benefit

The gain for this option is estimated by setting the 4 kV Bus 21 function and the supports for the bus to success. The following 4 kV Bus 21 support systems are considered successful:

- EDG 2A;
- SW Header 21; and
- SRW Header 21.

Although the cooling water systems are considered successful for this bounding evaluation, the only dependent piece of equipment also considered successful is EDG 2A. In reality, other plant equipment would also benefit by improving the availability of the cooling water systems. As this other plant equipment is not considered successful for this evaluation, the evaluation is conservative.

Engineering/Operations Discussion

The engineering/operations discussion for SAMA No. 33-b is identical to that for SAMA No. 33-a.

Cost Analysis

The estimated cost of implementing SAMA No. 33-b would be the same as that for SAMA No. 33-a. Therefore, the estimated cost of this option is $1,119,000.

SAMA No. 34 - Incorporate an Alternate Battery Charging Capability

Discussion

If the safety-related battery capacity is increased to extend battery life to 24 hours, then all long-term battery functions will always be successful if the short-term functions are successful.

Approach to Estimating Bounding SAMA Benefit

The maximum conceptual benefit was determined by:

- Assuming that the 125 VDC bus will be available for 24 hours, given the 125 VDC batteries operate in the short-term;
- The likelihood of a LOOP in excess of 4 hours is considered zero; and
- The likelihood of the 480 VAC buses experiencing common cause is significantly reduced.

The effectiveness of this enhancement is limited by the requirement for the operators to recognize the failure of the installed battery chargers and to manually connect the portable chargers to the effected bus. To compensate for this reduction in effectiveness, the maximum benefit determined above was reduced by 20 percent.

Engineering/Operations Discussion

This enhancement involves the provision of a portable diesel generator that could be used to provide battery charging during SBO conditions.

The scope of the enhancement is to provide a source of continuous DC power to the instrumentation for the turbine-driven AFW pumps so that in the event of a LOOP and the depletion of the batteries, the AFW pumps can remain functioning. A portable diesel generator set would be connected via the existing permanent plant SWGR for the battery charger via temporary cables, a breaker would be racked-out, the power feed to the battery charger breaker would be disconnected, and the diesel generator connected in its place. This would have to be done early in the SBO scenario so that the batteries would not deplete too far for the trickle charger to continue to provide adequate voltage on the DC bus under use. The enhancement includes all hardware and procedures necessary for connecting the portable diesel.

Cost Analysis

An estimate to provide a portable battery charger was included in TVA's SAMDA analysis for Watts Bar Nuclear Plant. The enhancement would include all hardware and procedures necessary for connecting the portable diesel generator. The similarity between the TVA's portable battery charger SAMDA and BGE's SAMA No. 34 is such that a direct comparison may be made between the two. The estimated COE for a portable battery charger, based on the estimate provided in the TVA SAMDA submittal (Reference 5), is $133,800 (1994 dollars).

SAMA No. 36 - Replace Batteries with a More Reliable Model

Discussion

If all of the 125 VDC batteries were more reliable, then plant risk could be noticeably reduced.

Approach to Estimating Bounding SAMA Benefit

Increased battery reliability would have a notable effect on plant risk, even if the new batteries have the same capacity as the old batteries. The best estimate benefit was determined by assuming that the batteries will not fail in the short-term. Additionally, the 125 VDC buses are not considered to fail at-power. An at-power failure of a 125 VDC bus leads to a plant trip.

Engineering/Operations Discussion

Baltimore Gas and Electric Company replaced all five banks of batteries at CCNPP in 1997 at a cost of approximately $750,000 ($150,000 per battery bank). New batteries which are more reliable than the existing ones (if commercially available) would cost much more than the $750,000 cost of the existing batteries, and would probably require more space. The battery rooms are completely filled by the currently installed battery configuration. Therefore, if more reliable batteries are larger than the existing batteries, it would be necessary to modify the plant structure to accommodate larger batteries.

Cost Analysis

Due to space limitations in the existing battery room, any proposed improvements to install additional batteries would require structural modifications to the battery rooms. Therefore, in addition to the cost of the batteries (greater than $750,000 for five banks of batteries), the total cost of implementing this SAMA would have to include structural modifications to accommodate the additional batteries. However, for the purposes of this analysis, the COE of $375,000 per unit (i.e., $750,000 for both units) will be used.

SAMA No. 38-b - Create a Cross-Unit Tie for Diesel Fuel Oil

Discussion:

If the volume of the FODT is increased (doubled), then diesel generator reliability could be noticeably improved. The increased reliability would be due to the reduced reliance upon the fuel oil transfer pumps. The additional volume must be placed between the day tank level switches.

Approach to Estimating Bounding SAMA Benefit

The bounding benefit is determined by considering that all of the EDGs will be successful in the long-term if the EDGs are successful in the short-term. This is conservative as the EDGs could fail in the long-term due to considerations other than fuel related failures.

Engineering/Operations Discussion

It is assumed that this SAMA would involve either replacing the existing FODTs with tanks with twice the capacity or installing a second tank to supplement the capacity of the existing tank. The engineering has not been performed to determine if either of these alternatives would be feasible, but a conceptual cost analysis was prepared based on replacing the existing tanks with tanks that have twice the capacity.

Cost Analysis

A modification has been planned to replace existing buried underground waste oil storage tanks. These tanks are larger than the FODTs, but can be used as a starting point in estimating the cost of replacing the FODTs. The waste oil storage tanks will cost approximately $200,000 per tank (including Indirect Supervision and Engineering costs).

This estimate has been scaled up, as follows:

Additional engineering required due to safety-related, seismic application	$100,000
Additional construction costs required due to safety-related work with limited space to maneuver	100,000[1]
Licensing activities (exemption necessary to remove tornado missile door)	50,000
Additional tank requirements (safety related, seismic fabrication)	50,000
Total Direct Costs	**$300,000**
Indirect Supervision and Engineering	39,000[2]
Cost of each waste oil storage tank	200,000
Total COE for each FODT	**$539,000**

Notes:

1. The EDGs will be inoperable during the implementation of this modification, due to the tight room conditions. It is expected that implementation would also require at least two days of critical path outage time at $500,000 per day. Although the cost of extended outages due to modification implementation is real, for consistency it will not be included in the SAMA cost/benefit analysis.
2. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

SAMA No. 44 - Create a Back-up Source for Diesel Cooling

Discussion

The three original EDGs (1B, 2A, and 2B) are cooled by the SRW System, which is in turn cooled by the SW System. If these three EDGs were self-cooled (i.e., air-cooling through a radiator or cooling tower), then the plant risk could be noticeably reduced.

Approach to Estimating Bounding SAMA Benefit

The maximum benefit was estimated by considering the EDG cooling water systems are successful. This is conservative as the cooling water supports for the EDGs are also required in LOCA mitigation. These cooling water systems are considered successful:

- SW Header 12;
- SW Header 21;
- SW Header 22;
- SRW Header 12;
- SRW Header 21; and
- SRW Header 22.

Saltwater and SRW Headers 11 are not set to success, since EDG 1A is already self-cooled.

Engineering / Operations Discussion

This enhancement involves the provision of a large air-cooled radiator for each of the three Fairbanks-Morse EDGs. The radiator would replace the SRW cooling for the EDG's jacket water and lube oil systems. The radiators could either be located where the existing missile shield doors are located or on a concrete pad to be constructed outside the existing missile shield doors.

Cost Analysis

A rough estimate to replace the SRW cooling requirement for the three EDGs was provided by the EDG manufacturer in 1997. This rough estimate included:

EDG parts and material	$4,500,000
EDG driveshaft engineering (for radiator fan)	250,000
Other engineering (EDG vendor only)	200,000
EDG upgrade to offset driveshaft losses	250,000
Total Vendor Costs	$5,200,000

The estimate does not include BGE's engineering, materials, and construction costs to modify the existing missile shield door; installation costs, procedures, and training; licensing and design basis changes; or Supervision and Engineering overhead costs. However, based on the total vendor costs, a conservative estimate of $1,700,000 will be used for this analysis ($5,200,000/3 EDGs).

SAMA No. 45 - Use the FP System as a Back-up Source for Diesel Cooling

Discussion

If the FP System could be used as an alternate cooling source for the EDGs, then the plant risk could be noticeably reduced due to the reduced reliance on the SRW System for this function.

Approach to Estimating Bounding SAMA Benefit

The bounding benefit was estimated by setting all of the EDG cooling water supports to success. This is conservative as the cooling supports for the EDGs are also required in LOCA mitigation. The following cooling water functions are considered successful:

- SW Header 12 provides adequate flow;
- SW Header 21 provides adequate flow;
- SW Header 22 provides adequate flow;
- SRW Header 12 provides adequate flow;
- SRW Header 21 provides adequate flow; and
- SRW Header 22 provides adequate flow.

As EDG 1A is self-cooled, SW and SRW Header 11 is not set to success. It should be noted that cooling water system failures which result in a plant trip are not screened, as the likelihood of an EDG being required following a loss of cooling water is fairly small.

Engineering/Operations Discussion

The basis for this SAMA is to provide a back-up means of cooling the Fairbanks-Morse EDG jacket water, intercoolers, and lube oil should a LOOP occur, thereby requiring the service of the EDGs for plant shutdown and accident mitigation. The normal source of EDG cooling is provided by the safety-related SRW System. The heat is transferred from SRW to the Chesapeake Bay by the safety-related SW System.

The 4 kV emergency electrical system includes five diesel generators (two EDGs per unit plus the 100 percent redundant non-safety-related 0C Diesel Generator), any one of which is capable of supplying power to all loads necessary to shut down a unit. In the event of a LOOP, followed by the loss of an EDG, the back-up EDG for that unit will automatically pick-up the shutdown loads. If both EDGs on one unit fail the 0C Diesel Generator can be manually aligned to that unit. The 1A EDG and the 0C Diesel Generator are air-cooled and would not benefit from this SAMA. Therefore, the benefits of this potential improvement would only be realized if the following scenario existed:

- Loss of offsite power involving the unavailability of four independent power sources (i.e., three 500kV transmission lines and the 69kV Southern Maryland Electric Cooperative feeder);
- Failure of the cooling water source to the Unit 2 EDGs. (A temporary loss of SRW or SW [due to a pump failure, for instance] may be mitigated by starting the back-up pump, as required by plant procedures. An irretrievable loss is considered unlikely, due to redundancy in the safety-related SRW and SW Systems.); and
- Unavailability of the 0C Diesel Generator.

Although the combination of failures is considered unlikely (no common-mode failure mechanisms involved, and the EDGs, the SRW and SW Systems are all safety-related systems with redundant equipment requirements), the cost of implementing this enhancement is provided for comparison with the estimated benefits.

Cost Analysis

This SAMA would be involve installing a 6-inch line between the nearest fire main and the SRW System feed to the EDG jacket cooling water, lube oil, and air cooling systems. On the outlet of the EDG heat exchangers, a means of draining the FP System would be required, as FP is not a closed loop system. Alternatively, a return line to the FP System with a heat exchanger would be required. Instrumentation and controls would be similar to those required for the FP feed to the CC System (SAMA No. 05). A conservative estimate of the costs to implement this SAMA on each Fairbanks-Morse EDG is provided, as follows:

Engineering - Mechanical (flow calculations, flooding analysis, piping and valve design); I&C (controls for automatic transfer, SIAS modifications); Civil (seismic analysis, penetrations, if required)	$150,000
Parts and Material - Mechanical (piping, strainers, valves, hangers); Electrical and I&C (controls, wiring, control panel instruments)	100,000
Construction	150,000
Documentation (drawings, manuals, etc.)	10,000
Training	15,000
Procedures	15,000
Radwaste Disposal, Health Physics, Monitoring Equipment	0
Total Direct Costs	**$440,000**
Indirect Supervision and Engineering	57,000[1]
Total COE	**$497,000**

Note:
1. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

SAMA No. 48-a - Convert UV, AFAS Block, and Reactor Protective System High Pressurizer Pressure Actuation Signals to 3-out-of-4 Logic

Discussion

This SAMA is intended to provide a means of mitigating a spurious safety systems actuation, which is one of the most risk-significant contributors in the plant model. Baltimore Gas and Electric Company's risk analysis has demonstrated that the risk benefit to be achieved by preventing this event from occurring exceeds the risk increase to be expected from modifying the actuation logic from 2-out-of-4 logic to 3-out-of-4 logic.

On the failure of two 120V vital AC panels, all ESFAS, AFAS, and Reactor Protective System actuation modules trip. The 120V vital AC panels can fail due to failure of the 125 VDC buses or due to the loss of long-term charging to the 125 VDC buses. The availability of long-term 125 VDC is primarily controlled by the availability of offsite power and 480 VAC transformers. The failure of multiple 480 VAC transformers is largely driven by common cause.

The spurious safety systems actuation impacts include loss of main feedwater, SRW-cooled EDGs, condensate booster pumps, AFW, and SI, as well a PORV spurious opening. If the PORV does not reseat and is not isolated, it is considered a LOCA.

Approach to Estimating Bounding SAMA Benefit

The maximum benefit was determined by setting the following functions to success:

- 120 V vital AC panels (including pre-trip and post-trip failures);
- 125 VDC buses (including pre-trip and post-trip failures); and
- Operator aligns the inverters to the back-up when necessary.

Additionally, the following plant trips are prohibited:

- No LOOPs occur over 4 hours in duration;
- No earthquakes occur (except the largest earthquake that fails everything); and
- No high wind events occur (tornadoes and hurricanes).

Engineering/Operations Discussion

Implementation of the proposed SAMA assumes a major modification of ESFAS, AFAS and Pressurizer Pressure logic modules.

Vitro, the original supplier, is out-of-business but another vendor maintains the old product line (SR-1E). A new design would be required for roughly 20 modules (10 per unit). It is assumed that the vendor can design and build new modules at $10,000 each plus $100,000 vendor engineering. It is further assumed that minimal field work would be required other than post-installation testing. Based on these assumptions, BGE estimates the hardware costs to be $300,000.

The hardware costs do not include the cost of revising the plant risk model, submitting and supporting the associated license amendment, including the 10 CFR 50.92 evaluation. Additionally, the Responsible Design Organization would have to revise numerous design documents and design basis documents, perform 10 CFR 50.59 analysis, critical design reviews, vendor interfacing, project team interfacing, and NRC interfacing. The Responsible Design Organization activities are estimated to be $500,000.

Cost Analysis

The following estimate is provided for a two-unit modification. The estimate is based upon the above engineering estimate, and assumes an NRC submittal would be required to address the Unreviewed Safety Question.

Engineering - Design Engineering (Responsible Design Organization - revise design documents, 50.59, critical design reviews, project team interfacing, NRC interfacing	$500,000
Equipment - (includes parts and vendor engineering)	300,000
Support Organizations (Quality Assurance, Procurement, Systems Engineering, Reliability Engineering, etc.)	60,000
Equipment - (included in vendor engineering)	0
Nuclear Regulatory Matters (NRC submittal)	100,000
Radwaste Disposal, Health Physics, Monitoring Equipment	0
Structures	0
Construction	50,000
Procedures and training	40,000
Total Direct Costs	**$1,050,000**
Indirect Supervision and Engineering	137,000[1]
Total COE	**$1,187,000**

Note:
1. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

Based on the above estimate, the one-unit cost is conservatively estimated at $593,000.

SAMA No. 48-b - Operate with the PORV Block Valves Shut

Discussion

Closing the PORV block valves also achieves a small fraction of this benefit. If the Reactor Protective System channels trip spuriously, then nothing will happen with the block valves closed. This change in operation has the added benefit of virtually eliminating the chance of the spurious opening of a PORV causing a plant trip. This improvement has a negative consequence of increasing the likelihood of an ATWS event not being mitigated.

Approach to Estimating Bounding SAMA Benefit

The best estimate gain can be determined by assuming:

- An inadvertent PORV opening that causes a plant trip cannot occur;
- Both PORVs reclose on low RCS pressure;
- The operator isolates PORVs on low RCS pressure; and
- Both PORVs do not open as required. This is the negative consequence of isolating the PORVs, which reduces the likelihood of ATWS mitigation and increases the likelihood a PORV will stick open.

Note that this assumes that these MOVs can be opened in time to support once-through core cooling operation. Without once-through core cooling, the risk benefit would be much smaller or not a benefit at all.

Engineering/Operations Discussion

Per Technical Specification 3.4.3, the PORVs and the PORV block valves are required to be operable in Modes 1, 2 and 3. Operability of the block valves is demonstrated by Technical Specification 4.4.3.2, which states:

> "Each block valve shall be demonstrated **OPERABLE** at least once per 92 days by demonstrating the valve through one complete cycle of full travel unless the block valve is closed to meet the requirements of Action a, b, or c in Specification 3.4.3."

Based on this specification, the block valves are only allowed to be closed when necessary to meet the Technical Specification actions for excessive PORV leakage. While the safety function of the block valves would not be affected, the ability of the PORVs to perform their safety function would be affected (i.e., to automatically relieve primary system pressure before reaching the pressurizer code safety valve setpoint). Therefore, implementation of this improvement would require a Technical Specification change to allow the block valves to remain shut in Modes 1, 2, or 3.

In support of the Technical Specification change, BGE would have to provide analytical justification for our ability to perform once-through core cooling within a time frame that could allow operators to open the block valves. (It should be noted that Operations has not been asked to provide an estimate on how quickly they would be able to open the block valves. The potential exists that they may not be able to open these valves when needed to support once-through core cooling.) Current analysis requires once-through core cooling prior to the SG boiling dry (possibly as early as ten to fifteen minutes into events involving a loss of feedwater). It is uncertain if it would be possible to support this commitment if manual action was required to open the block valves. However, at a minimum, in addition to changing the Technical Specifications, this change would also involve changing EOPs that credit operation of the PORVs (such as EOP-3, Loss of All Feedwater) and providing training on these changes.

Cost Analysis:

The following cost analysis provides minimum estimates on the analytical, regulatory and procedural work necessary to support closing the PORV block valves during normal operation:

Nuclear Regulatory Matters (Technical Specification change submittal and regulatory support)	$50,000
Nuclear Engineering Unit (engineering analytical support for Technical Specification change and associated procedural changes)	$50,000
Procedure Development	$5,000
Training	$20,000
Total COE	**$125,000**

SAMA No. 59 - Install Additional Instrumentation for ISLOCAs

Discussion

The ISLOCAs involve many containment penetrations. Although not a significant contributor to the CDF, ISLOCAs typically have a more significant Level 2 and Level 3 impact. Five penetrations (3, 4, 5, 6, and 41) are responsible for 87.9% of the total plant risk from ISLOCAs at CCNPP. If pressure or leak monitoring instruments were installed between the first two pressure isolation valves in these five penetrations (four SI lines and one reactor coolant shutdown cooling line), operators would be able to readily identify an ISLOCA before it presented a serious risk increase.

Approach to Estimating Bounding SAMA Benefit

The bounding benefit for this SAMA was estimated by assuming that all ISLOCAs are impossible.

Engineering/Operations Discussion

The enhancement considered by this SAMA is to install pressure instrumentation between the inside-containment and outside-containment isolation valves in the five penetrations (four SI lines and one reactor coolant shutdown cooling line). A pressure alarm in the control room would allow operators to readily identify a potential ISLOCA before it would present a serious risk increase.

Cost Analysis

The cost analysis for SAMA No. 59 is based on a similar SAMDA analysis performed by TVA in support of initial licensing of Watts Bar Nuclear Plant. As discussed in NUREG-0498 (Reference 6), an estimate of $2,300,000 (1993 dollars) was provided for a similar modification at Watts Bar Nuclear Plant. This estimate is also considered valid for CCNPP.

SAMA No. 68 - Install Separate Accumulators for the AFW Cross-Connect and Block Valves

Discussion

On loss of air support, the AFW Unit 1 to Unit 2 cross-connect CVs fail closed while the AFW Block CVs (feed only the good SG) fail open. This degrades the operators' ability to use the cross-connect since the loss of AFW IA will require the Block CVs to be manually closed and the cross-connect CVs to be manually opened.

The AFW flow control CVs constantly bleed air and therefore will deplete the AFW IA within 2 hours if compressors are not available. As long as the accumulators associated with the cross-connect CVs and the Block CVs could survive two strokes for each valve and maintain valve position for 24 hours, then the cross-connect air dependency could be removed.

Approach to Estimating Bounding SAMA Benefit

The bounding benefit is estimated by setting the Unit 2 AFW air-related function to success. With these function successful, air is always available to support the alignment of AFW Pump 23 to Unit 1.

Engineering/Operations Discussion

This improvement will require feeding the following CVs from one or more accumulators:

- 1(2)-CV-4550;
- 1(2)-CV-4520, 4521, 4522 and 4523; and
- 1(2)-CV-4530, 4531, 4532 and 4533.

A total of 18 CVs would require accumulators (9 per unit). The accumulators must be sized to stroke each valve once and to account for leakage from bleeding.

The CVs are normally supplied air at 100-pounds-per-square-inch gauge from Instrument Air Compressors 11(21) and 12(22), or from Plant Air Compressors 11 and 21. The power supply for these compressors is the normal distribution system and can be backed up by an EDG. These air compressors are backed up by safety-related SW Air Compressors 11(21) and 12(22), with boost pressure to 200-pounds-per-square-inch gauge from the AFW air amplifier, stored in the 11A of 11B (21A or 22B) Accumulators, and additionally backed up by a Nitrogen supply line, which is normally isolated. This SAMA would involve installing five additional, four-cubic-foot accumulators per unit (including valves, lines, supports, procurement/engineering and installation). This includes one for cross-connect, one each for AFW Pump 11A and 11B block valves, one for the motor-driven train to each SG (11A and 11B).

Cost Analysis

Much of the work for this modification would have to be performed during a refueling outage (i.e., less than Mode 4 for one week). The work would be performed in the 27-foot Electrical Penetration Room and the SRW Pump Rooms. An estimate of the cost of implementing this modification is as follows:

Engineering	
Design	$70,000
Projects and Systems Engineering	40,000
Materials	
9 non-safety-related, 4-cubic-foot Code vessels - x-ray with certifications, 3/8-inch thick with hydrostatic tests	150,000
Valves, piping, etc.	50,000
Installation (including radiation control, tagging, insulation, scaffolding, painting, in-service testing, etc.)	70,000
Total Direct Costs (2 units)	**$380,000**
Indirect Supervision and Engineering	49,000[1]
Total COE (2 units)	**$429,000**

Note:

1. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

Therefore, the total one-unit cost of implementing this enhancement is estimated to be $214,000.

SAMA No. 69 - Increase the Capacity of CST 12 to Contain a Full 24 Hours of AFW Inventory for Both Units

Discussion

By increasing the capacity of CST 12, the operator will not need to align long-term water for AFW for the first 24 hours.

Approach to Estimating Bounding SAMA Benefit

The maximum gain is estimated by setting the long-term AFW water function to guaranteed success.

Engineering/Operations Discussion

The most feasible means of increasing the capacity of CST 12 is by constructing an additional CST with a cross-tie piping connection to provide make-up to the existing CST.

Cost Analysis

An estimate to install an extended RWT source was provided in the CE System 80+ SAMDA analysis. The SAMDA would include an additional ground-level tank and a pumping device to provide make-up to the existing RWT. The similarity between the CE System 80+ RWT SAMDA and SAMA No. 69 is such that a direct comparison may be made between the two. The estimated COE for an extended RWT source, based on information provided in the CE System 80+ design certification was $1,000,000 (Reference 2). The estimated COE for construction of a new CST is expected to exceed the COE for an extended RWT at CCNPP; therefore, this estimate is considered conservative.

SAMA No. 70 - Provide a Means to Cool the Turbine-Driven AFW Pumps in an SBO Event

Discussion

Similar to SAMA No. 07, "Redundant AFW Pump Room Ventilation," for another cooling option to be effective, it must be automatic and self-powered. Without this, the recovery would be driven by human actions or power availability which would render the modification ineffective. In this case, however, the chilled water will provide cooling to a heat exchanger which will cool the AFW pump seals.

Approach to Estimating Bounding SAMA Benefit

The bounding benefit was estimated by assuming that the AFW Pump Room always has adequate ventilation.

Engineering/Operations Discussion

The approach taken in addressing this SAMA is similar to that taken to address SAMA No. 07, with the following exception:

The chiller will now produce chilled water which will remove the heat from the pump bearing lubricating oil whenever the room temperature exceeds a predetermined value. (Normally, the lubricating oil will still be cooled by the shaft-mounted fan which circulates air past the cooling fins attached to the bearing housing.) Therefore, the new system will require:

- A heat exchanger to transfer heat from the lube oil to the chilled water; and

- Automatic controls to switch to chilled water cooling when the room temperature is too high.

Because this system will be an integrated part of the safety-related AFW System, it will have to be designed to meet the same pedigree of that system. The safety-related boundary will be at the chilled water isolation valves to the heat exchanger. This will increase the cost of designing, procuring, and installing the system.

Cost Analysis

The system proposed for this SAMA is a diesel-powered electric generator sized to power a chiller unit and a safety-related lube oil cooler in the AFW Pump Room, with the following design features:

- AC-powered chiller unit (5- to 10-ton) located inside Turbine Building;
- 230 Volt, 50 Amp diesel generator, including tank for 24 hour fuel oil supply. The diesel will also charge batteries to operate the controls for the system;
- Safety-related piping and lube oil cooler located in the AFW Pump Room; and
- Automatic controls to transfer from air cooling to chilled water cooling for the lube oil.

The estimated cost of this modification is as follows:

Engineering - Mechanical - flow calculations, equipment sizing, drawings, evaluations; Electrical - power calculations, generator sizing, drawings, evaluations; Civil - Wall penetrations, equipment mounting, etc.; I&C - Electric generator controls, chiller controls, and interfaces; Appendix R - Evaluation of combustible loads (fuel oil)	$75,000
Equipment - (diesel-powered electric generator, chiller unit, lube oil coolers [2 per unit], piping, controls)	150,000
Construction	100,000
Procedures and training	25,000
Total Direct Costs	**$350,000**
Indirect Supervision and Engineering	46,000[1]
Total COE	**$396,000**

Note:
1. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

SAMA No. 74 - Automate DW Make-up to CST 12

Discussion

The DW transfer pumps provide make-up to the SRW and CC Systems. By designing the DW make-up to CST 12 line such that it automatically opens on low CST 12 water level, operator actions to align a long-term AFW water supply will not be required. For full benefit, this system must have a dedicated non-safety related electric generator, which would automatically start and supply power to the make-up pump and the CVs. The DW transfer pumps also support make-up to the SRW and CC head tanks. As a result, this modification provides the consequential benefit of increased head tank make-up reliability.

Approach to Estimating Bounding SAMA Benefit

This improvement would not only benefit the long-term AFW water supply function, but head tank make-up (SRW and CC) as well (as the DW transfer pumps would be diesel-backed). To determine the bounding benefit, long-term AFW water supply and head tank make-up (SRW and CC) were set to success.

Engineering/Operations Discussion

Power requirements:

The DW transfer pumps are located in the fire pump house at the tank farm. These pumps are driven by 7.5 horsepower, 460V/230V, 10.5Amp/21Amp motors. Although the motors are normally hooked up to 460V power, it was determined that the cost of a diesel generator capable of providing only 10.5 Amp would be too high, so the option of a 230V/25Amp generator was considered. The generator would be housed outside the fire pump house, with a buried conduit supplying power to the pumps. A fuel storage tank, capable of storing a 24-hour fuel supply, would be housed inside the small generator building, which would necessitate installation of a fire suppression system. The pumps would be hard-wired to the back-up power supply, but they would normally be powered by the existing power supply. The transfer from the normal power supply to the back-up power supply would be automatic. Operation and maintenance of the small generator would require training and procedures.

Control requirements:

The system must be "diesel-backed" to ensure it will be able to cope with SBO, LOOP, or 10 CFR Part 50, Appendix R, event in one form or another. The existing make-up system uses manual valves with no automatic throttling. Valves are opened and pump(s) are started manually. For automatic make-up, a complex control system is needed to detect tank levels and sequence valves and pumps appropriately. A programmable logic controller is well-suited for this application, with motor operators on the valves.

It is assumed that this equipment would remain non-safety-related, and that existing pumps, pump motors, and valves are adequately sized and can be interfaced with new equipment as-is (e.g., a motor operator can be fitted to an existing valve).

It is assumed that existing CST 12 level instrument loops can be modified to add bistables for low and high level. However, CST 12 transmitters can freeze in wintertime and must be freeze-protected. It is assumed that during SBO/LOOP/Appendix R event the back-up diesel provided by this modification will also power existing heat-tracing. Another option might be to install mechanical level switches on side of tank (would require tank modifications).

It is assumed that the diesel generator starts on SBO/LOOP, and that automatic make-up initiates on low level setpoint, controlled via programmable logic controller, with or without SBO/LOOP. Make-up terminates on high-level setpoint. (Initiate sequence = open valve, start pump. Terminate sequence = opposite.) The control system would be located in the fire pump house. It is assumed that remote controls from the Control Room are not needed.

Cost Analysis

The single-unit cost of this enhancement was estimated to be $271,000, based on the following:

Engineering	
Instrumentation and Controls	$150,000
Mechanical (FP)	5,000
Electrical (Generator specifications, hook-up to existing pumps)	13,000
Civil (design of housing)	2,000
Material	
230V/25A Diesel Generator	$170,000
Fuel tank, housing, conduit, cable, sprinkler system, electrical transfer equipment, etc.	
Controls and control cable	
Construction (including engineering oversight and testing)	$125,000
Procedures	$12,000
Training	$5,000
Total Direct Costs (2 units)	**$480,000**
Indirect Supervision and Engineering	62,000[1]
Total COE (2 units)	**$542,000**

Note:

1. Estimate for Supervision and Engineering is based on the typical capital project charges of 13 percent of total direct costs.

F.4 References

1. CEN-152, "Combustion Engineering Emergency Procedure Guidelines," Revision 3, Combustion Engineering Owners Group, May 1987
2. NUREG-1462, "Final Safety Evaluation Report Related to the Certification of the System 80+ Design," NRC, August 1994
3. "Calvert Cliffs Nuclear Power Plant Updated Final Safety Analysis Report," Revision 21, BGE, 1997
4. "Proposed General Design Criteria for Nuclear Power Plants," Criterion 22 - Separation of Protection and Control Instrumentation Systems, Atomic Energy Commission, July 10, 1967
5. Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk, dated June 30, 1994, "Watts Bar Nuclear Plant (WBN) Unit 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDAs) Evaluation from Updated Individual Plant Evaluation (IPE) (TAC Nos. M77222 and M77223)"

F.5 ACRONYMS USED IN APPENDIX F

AC	Alternating Current
ADV	Atmospheric Dump Valve
AFAS	Auxiliary Feedwater Actuation Signal
AOP	Abnormal Operating Procedure
ATS	Automatic Transfer Switch
ATWS	Anticipated Transient Without Scram
BGE	Baltimore Gas and Electric Company
CAC	Containment Air Cooler
CC	Component Cooling
CCNPP	Calvert Cliffs Nuclear Power Plant
CCPRA	Calvert Cliffs Probabilistic Risk Assessment (Model)
CDF	Core Damage Frequency
CE	Combustion Engineering
CET	Containment Event Trees
CFR	Code of Federal Regulations
COE	Cost of Enhancement
CPET	Containment Phenomenological Event Tree
CS	Containment Spray
CST	Condensate Storage Tank
CV	Control Valve
DC	Direct Current
DET	Decomposition Event Tree
DHR	Decay Heat Removal
DW	Demineralized Water
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ESFAS	Engineered Safety Features Actuation Signal
FODT	Fuel Oil Day Tank
FP	Fire Protection
HPSI	High Pressure Safety Injection
HVAC	Heating, Ventilation, and Air Conditioning
I&C	Instrumentation and Controls
IA	Instrument Air
IPE	Individual Plant Examination
ISLOCA	Inter-System Loss-Of-Coolant Accident
KPDS	Key Plant Damage States
LOCA	Loss-Of-Coolant Accident

LOOP	Loss of Offsite Power
MACCS	Melcor Accident Consequences Code System
MG	Motor-Generator
MOV	Motor-Operated Valve
NRC	U.S. Nuclear Regulatory Commission
PDS	Plant Damage Sequence
PORV	Power-Operated Relief Valve
PRA	Probabilistic Risk Assessment
PWR	Pressurized-Water Reactor
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RWT	Refueling Water Tank
SAMA	Severe Accident Mitigation Alternative
SAMDA	Severe Accident Mitigation Design Alternative
SBO	Station Blackout
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIAS	Safety Injection Actuation Signal
SRW	Service Water
STC	Source Term Category
SW	Saltwater
SWGR	Switchgear
TVA	Tennessee Valley Authority
UV	Undervoltage
VAC	Volt AC
VDC	Volt DC

G.0 NRC TRANSPORTATION ASSESSMENTS

Appendix G contains the following items:

- Pages G-2 through G-5 Volume 53, Federal Register, February 29, 1988, pages 6040-6043
- Pages G-6 through G-9 Volume 53, Federal Register, August 11, 1988, pages 30355-30358
- Pages G-10 and G-11 Volume 54, Federal Register, January 30, 1989, pages 4352-4353

The significance of these items is explained below.

In 1984, the U.S. Nuclear Regulatory Commission (NRC) published regulation 10 CFR 51.52, which requires that license applicant environmental reports address environmental effects of fuel and waste transportation. The regulation includes Table S-4, a summary of transportation environmental impacts, and requires: 1) conformance with Table S-4 underlying assumptions of maximum fuel enrichment of 4 percent and maximum fuel irradiation of 33 gigawatt-days per metric ton of uranium (GWd/MTU); or 2) a detailed analysis of transportation impacts.

In 1988, NRC published the environmental assessment and finding of no significant impact included as pages G-2 through G-5 (53 FR 6040-6043, February 29, 1988). The NRC anticipated industry use of increased enrichment and extended burnup. The assessment considered all aspects of the fuel cycle, including transportation, and concluded that the Table S-4 impact summary is conservative and bounds corresponding impacts for enrichment up to 5 percent and burnup to 60 GWd/MTU.

Later in 1988, NRC published the environmental assessment and finding of no significant impact for the Shearon Harris Nuclear Plant that is included as pages G-6 through G-9 (53 FR 30355-30358, August 11, 1988). The NRC stated that it was in the process of revising 10 CFR 51.52 to reflect the earlier (February 29, 1988) environmental assessment and finding of no significant impact, but that in the interim, pursuant to 10 CFR 51.52(b), NRC was accepting "the following analysis of the environmental effects of the transportation of such fuel and waste until such time as the revision to the rule is issued." The analysis is generic (not Shearon Harris-specific) and covers enrichment up to 5 percent and burnup up to 60 GWd/MTU.

In 1989, NRC issued the environmental assessment and finding of no significant impact for Calvert Cliffs Nuclear Power Plant that is included as pages G-10 and G-11 (54 FR 4352-4353, January 30, 1989). The environmental assessment and finding of no significant impact covered Calvert Cliffs' increased enrichment up to 5 percent and burnup up to 60 GWd/MTU, and adopted by reference the Shearon Harris transportation effect findings, stating that the Calvert Cliffs transportation impacts would be "either unchanged or may, in fact, be reduced from those summarized in Table S-4 . . ."

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Assistant Attorney General, Land and Natural Resources Division, Department of Justice, Washington, DC 20530, and should refer to *United States v. B & R Insulation, Inc., and FMC Corporation*, D.J. Ref. 90-5-2-1-1113.

The proposed consent decree may be examined at the office of the United States Attorney, District of Kansas, 412 Federal Building, 812 North Seventh Street, Kansas City, Kansas 66601, and at the Region VII office of the Environmental Protection Agency, Office of Regional Counsel, Attention: Becky Ingrum Dolph, 726 Minnesota Avenue, Kansas City, Kansas 66101. A copy of the proposed consent decree may also be examined at the Environmental Enforcement Section, Land and Natural Resources Division, Department of Justice, Room 1521, Ninth Street and Pennsylvania Avenue NW., Washington, DC 20530. A copy of the proposed consent decree may be obtained in person or by mail from the Environmental Enforcement Section, Land and Natural Resources Division, Department of Justice.

Roger J. Marzulla,

Acting Assistant Attorney General Land and Natural Resources Division, U.S. Department of Justice, 10th and Pennsylvania Avenue NW., Washington, DC 20530.

[FR Doc. 88-4223 Filed 2-26-88; 8:45 am]

BILLING CODE 4410-01-M

NUCLEAR REGULATORY COMMISSION

Availability of Draft Generic Technical Position on "Guidance for Determination of Anticipated Processes and Events and Unanticipated Processes and Events"

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of availability.

SUMMARY: The Nuclear Regulatory Commission (NRC) is announcing the availability of the "Draft Generic Technical Position on Guidance for Determination of Anticipated Processes and Events and Unanticipated Processes and Events."

DATE: The comment period expires April 29, 1988.

ADDRESSES: Send comments to Ronald L. Ballard, Chief, Technical Review Branch, Division of High-Level Waste Management, U.S. Nuclear Regulatory Commission, Mail Stop 1WFN 4-H-3, Washington, DC 20555. Copies of this document may be obtained free of charge upon written request to Cathy Jensen, Technical Review Branch, Division of High-Level Waste Management, U.S. Nuclear Regulatory Commission, Mail Stop 1WFN 4-H-3, Washington, DC 20555, Telephone (301) 492-3455.

FOR FURTHER INFORMATION CONTACT: John Trapp, Technical Review Branch, Division of High-Level Waste Management, U.S. Nuclear Regulatory Commission, Washington, DC 20555, Mail Stop 1WFN 4-H-3, Telephone (301) 492-0509.

SUPPLEMENTARY INFORMATION: The Nuclear Waste Policy Act of 1982 (Pub. L. 97-425) and the Commission regulation 10 CFR Part 60 provide for interactions between the Department of Energy (DOE) and NRC prior to submittal of a license application for a geologic repository. These interactions serve to inform DOE about the information that the NRC staff considers to be necessary in such a license application.

An important mechanism for providing guidance to the DOE is the NRC comments on DOE's Site Characterization Plan, as required by the Nuclear Waste Policy Act. Under 10 CFR Part 60, this takes the form of a Site Characterization Analysis (SCA). Other means of providing guidance to supplement the SCA are staff technical positions on both generic and site-specific issues. Generic Technical Positions (GTP) establish the staff's position on broad technical issues that are applicable to any site; Technical Positions establish the staff's position on a site-specific technical issue. A number of technical positions will be developed by the staff on both generic and site-specific issues. This announcement notices availability and solicits comments on the "Draft Generic Technical Position on Guidance for Determination of Anticipated Processes and Events and Unanticipated Processes and Events."

The purpose of this GTP is to provide guidance concerning the methodologies the NRC staff proposes to utilize in evaluating processes and events which could occur after closure of a high-level radioactive waste repository so that, after significant processes and events have been determined, they can be categorized into anticipated processes and events and unanticipated processes and events. The significance of differentiating between anticipated processes and events and unanticipated processes and events relates to the post-closure performance requirements imposed by the regulations. In particular, for those processes and events categorized as "anticipated," the engineered barrier system must meet the numerical design requirements set forth in 10 CFR 60.113. To conform with the applicable environmental standards as expected to be set forth by the Environmental Protection Agency in 40 CFR Part 191 and implemented in 10 CFR 60.112, consideration must be given to both "anticipated" and "unanticipated" processes and events, including potential human intrusion, to assure that the likelihood of exceeding the EPA environmental standards under these circumstances is low. In arriving at a determination of reasonable assurance that overall performance objectives can be met, additional regulatory requirements may be found to be necessary as they relate to unanticipated processes and events.

In this GTP, the staff provides a basis for categorizing natural processes and events that could occur in the post-closure period into anticipated processes and events and unanticipated processes and events. In addition, the staff provides its view on how human processes and events and repository-induced modifications should be included in the evaluation.

The staff is interested in receiving comments on the utility and practicality of the categorization procedures and potential impacts this draft position would have on the design and analysis required for a high-level waste geologic repository.

Dated at Rockville, Maryland this 22nd day of February, 1988.

For the Nuclear Regulatory Commission.

Ronald L. Ballard,

Chief, Technical Review Branch, Division of High-Level Waste Management, Office of Nuclear Material Safety and Safeguards.

[FR Doc. 88-4230 Filed 2-26-88; 8:45 am]

BILLING CODE 7590-01-M

Extended Burnup Fuel Use in Commercial LWRs; Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission is considering whether or not a generic environmental impact statement (GEIS) is necessary in regard to the anticipated widespread use of extended burnup fuel [1] in commercial light water power reactors (LWRs).

[1] The length of use, or total energy generated, or "burnup" of fuel in a reactor is measured in terms of megawatt days per metric ton of uranium (Mwd/MtU) or Gwd/MtU where 1 Gwd/MtU = 1000 Mwd/MtU. Typically, fuel has been removed from reactors after 3 to 5 years with burnup levels of 28 Gwd/MtU for boiling water reactors and 33 Gwd/MtU for pressurized water reactors. "High" or "Extended" burnup nuclear fuel is considered, for the purpose of this discussion, to be fuel that is left

Continued

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Environmental Assessment

Identification of Proposed Action

No specific licensing action is being identified regarding use of extended burnup fuel in LWRs; however, there have been various requests for the use of extended burnup fuel that have been treated by the Commission on a case-by-case basis. The proposed action being considered by this environmental assessment (EA) is the widespread licensing for use of extended burnup nuclear fuel in commercial LWRs.

The Need for the Proposed Action

There has been an increasing number of applications from licensees in the nuclear industry for license amendments permitting incremental increases in the burnup of fuel. The usage has been cautious at first, but if the fuel continues to perform satisfactorily and if the current economic parameters remain constant, the use of extended burnup fuel is expected to continue. Within the next 10 to 12 years most licensees will probably plan for burnups of 45 Gwd/MtU or more, with refueling cycles of 1.5 to two years instead of the current one year cycle. In view of this trend, it is prudent and timely to evaluate the environmental significance of the potential widespread use of extended burnup fuel and to determine whether a detailed environmental impact statement (EIS) is warranted. The environmental evaluation will also consider the impact on Tables S–3 and S–4 of 10 CFR 51.51 and 51.52, respectively, to determine their applicability for extended burnup fuel.

Environmental Impacts of the Proposed Action

In evaluating the environmental impacts of the use of extended burnup fuel, the Commission relied upon the results of a study conducted for it by Pacific Northwest Laboratories (PNL). The results of the study have been documented in detail in the report entitled, "Assessment of the Use of Extended Burnup Fuels in Light Water Power Reactors," (NUREG/CR–5009, PNL–6258). The overall findings of this study are that no significant adverse effects will be generated by increasing the present batch-average burnup level of 33 Gwd/MtU to 50 Gwd/MtU or above as long as the maximum rod average burnup level of any fuel rod is no greater than 60 Gwd/MtU. Furthermore, based on the above study and the report entitled, "The Environmental Consequences of Higher Fuel Burn-up," (AIF/NESP–032), the NRC staff concludes that the environmental impacts summarized in Table S–3 of 10 CFR 51.51 and in Table S–4 of 10 CFR 51.52 for a burnup level of 33 Gwd/MtU are conservative and bound the corresponding impacts for burnup levels up to 60 Gwd/MtU and uranium-235 enrichments up to 5 percent by weight.

Extensive studies of extended burnup fuels have been conducted under the direction of the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI), with the participation of the fuel vendors nationwide and with the cooperation of several nuclear reactor utilities (see pgs. 1–7 to 1–10 of above mentioned NUREG/CR–5009). These studies have shown that there is no loss in fuel integrity for rod average burnups reaching 60 Gwd/MtU (the maximum level tested), as long as power levels (rate of heat generation) and operating temperatures for the fuel rods remain normal. Activity inventory may increase for long-lived radionuclides of concern; however, for short-lived fission products, the inventories will essentially remain the same. Of the longer lived fission products of concern, only cesium-134, cesium-137, and strontium-90 increase significantly with extended burnup (by factors of 2.5, 1.9, and 1.8, and respectively). The neutron emission rate from transuranic isotopes will increase with extended burnup by a factor of 5.6. At current power levels, the fractions of volatile fission products released into the gap between the fuel and the fuel cladding may increase by a factor of two, but will remain below NRC accident analysis assumptions for noble gases and iodines.

During the study, all aspects of the fuel-cycle were considered; from mining, milling, conversion, enrichment and fabrication through normal reactor operation, transportation, decommissioning, waste disposal and reprocessing. If leakage of radionuclides from a fuel element occurs during operation, the radioactivity is expected to be removed by the plant cooling-water cleanup system. No change in the licensed technical specifications pertaining to allowed cooling-water activity concentrations would be necessary. Thus, with extended burnup, little or no increase in the release of radionuclides to the environment is expected during normal operation. Other parts of the fuel cycle would also not be adversely affected by changing to an extended burnup fuel utilization plan. The impacts on workers and the general population would actually be reduced because at higher burnups, outages for fuel changes will be less frequent, and fuel shipments to and from the reactor sites would be reduced, thus reducing exposure. Although the inventory of long-lived radionuclides in the spent fuel will increase, the amount of spent fuel removed from reactors each year will decrease. In summary, for all aspects considered, except those involving low-level wastes, the radiological impacts were either unchanged or reduced when changing from normal to extended burnup fuel. The low level wastes include various solids collected from the spent fuel storage pool circulating water and reactor cooling water. There would be an increase in the radioactivity of the solids collected from the reactor cooling water as a result of increased fission product inventory and gap-release fraction. The greater activity resulting from the increases in fission product inventory and gap-release fraction, as much as a factor of two, would need to be removed from the reactor cooling water to meet the technical specifications. Overall, there would be less than a 20 percent increase in the radioactivity of the low-level waste.

Accidents that involve the damage or melting of the fuel in the reactor core and spent-fuel handling accidents were also reviewed. It should be noted that since the fuel rod integrity has been shown to be unaffected by the extended burnups considered, the probability of an accident will not be affected. For accidents in which the core remains intact, the release would involve only volatile fission products, and no increase in impacts will occur since the radionuclides contributing most to the dose are short lived and thus do not increase with burnup. For larger (severe) accidents, i.e., those in which an appreciable amount or all of the fuel has melted and fission products and aerosols have been released from the containment system into the biosphere, only a few fission products and the actinides will increase in inventory with extended burnup. The fission products would increase by no more than a factor of two, and the actinides by no more than a factor of six (of those contributing to the dose). However, since these actinides have very small release fractions and biotransfer factors, the risks associated with the actinides would be insignificant compared to those associated with fission products such as cesium-137 and strontium-90. Therefore, the overall accident risk is increased by only a factor of two when changing from 33 Gwd/MtU to 60 Gwd/MtU.

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in a reactor long enough to achieve a burnup of greater than 40 Gwd/MtU. Burnup Levels of up to about 60 Gwd/MtU are being considered.

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For the fuel-handling accident, only the noble gases and iodines escaping the damaged cladding are of significance in the assessment of dose impacts to the population. For a peak rod of an extended burnup fuel design at a burnup level of 60 Gwd/MtU, the release fractions increase by factors of three to four for these radionuclides; however, they remain below those assumed in Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors," with the exception of iodine-131. Note that there is not expected to be any increase in fuel clad perforations. Because the calculated iodine-131 gap-release fraction is 20 percent greater than the Regulatory Guide 1.25 assumed value of 0.10, the calculated thyroid doses resulting from a fuel-handling accident with extended burnup fuel could be 20 percent higher than estimated using the guide. To put this into perspective, it should be noted that Section 15.7.4, Revision 1, "Radiological Consequences of Fuel Handling Accidents," of the NRC's Standard Review Plan indicates that the acceptable dose to an individual "should be well within the 10 CFR Part 100 exposure guidelines of 25 rem." It is indicated that "well within means 25 percent or less than the 10 CFR Part 100 exposure guideline values." Therefore, the 20 percent possible increase in environmental risk of a fuel handling accident is insignificant in view of the staff's conservative interpretation of the dose guidelines.

Spent-fuel transportation accidents were also reviewed. Activity inventory may increase by an overall factor of about three for long-lived radionuclides of concern (assuming a 5-year cooling period) when changing to extended burnup fuel. This increase would be offset by a decrease in the number of shipments, so that the overall change related to spent-fuel transportation accidents would be a 50 percent increase in risk by changing to 60 Gwd/MtU burnup. However, the contribution of the spent-fuel transportation accidents to overall transportation risk is very small. The draft environmental assessment on "The Transportation of Radioactive Material (RAM) to and from U.S. Nuclear Power Plants" (NUREG/CR-2325 prepared by Sandia National Laboratories for the NRC in December 1983) summarizes the normal transportation and transportation accident risks. For spent-fuel transportation during sample years 1985 and 1990, the Summary (Table S-2) shows that these accidents contribute much less than 1 percent to the overall transportation risk. Therefore, a 50 percent increase in such a small contribution will have a negligible effect on overall risk. On balance, the approximatley 45 percent reduction in normal transportation impacts, due to the need for fewer fuel shipments, far outweighs the less than one percent increase in impacts associated with transportation accidents. (e.g., Assume the normal transportation impact is X and the transportation accident impact is 0.01 X. Then for extended burnup, the transportation accident impact would be increased to 0.015 X while the normal transportation impact would be reduced to 0.55 X giving a total impact of 0.565 X; a significant net reduction in overall transportation impact.)

The use of extended burnup fuel would reduce fuel requirements per unit of electricity. This translates directly into reduced requirements for the various materials and operations linked to fuel production (uranium mining, milling, conversion, separation, and fuel fabrication). The result of these reduced production requirements will be a significant reduction in cost, as well as a reduction in environmental impacts from fuel cycle operations required to support one year of reactor operation.

Although the discharged fuel at extended burnup is slightly thermally hotter, has increased neutron emission, and has more long-lived nuclides per unit mass compared to fuel that has not undergone extended burnup, the volume of fuel discharged per unit time will be reduced. Thus, although the waste contains a greater actinide and long-lived fission-product activity, there will be less of it. These opposing characteristics of the waste have an effect on all the back-end stages of the fuel cycle (at-reactor storage, transportation, and repository storage). The net result of these changes would be an increase in transportation shielding requirements, a reduction in the number of fuel shipments, smaller repository waste packages or increased spacing in the underground repository, and a reduction in future at-reactor storage requirements.

As indicated previously, no significant adverse effects were uncovered in the study. On balance, provided that applicable technical specifications and engineering and shielding requirements are adhered to, the study indicated that there should be no net increase in the environmental risk when changing from 33 to 55 Gwd/MtU batch-average burnup level. Likewise, there is no increase in the individual and collective radiation dose to the public or occupational workers during normal operations; in fact, as the study indicated, these doses would actually be reduced. While there is an increase in doses resulting from some postulated accidents, these accidents are extremely low probability events and contribute little to overall risk. Furthermore, though there is an increase, it is generally below what has been assumed in evaluating power plant safety. In summary, the increased accident doses do not significantly affect the risk of any dominant accident scenario and the effect on the overall risk is insignificant.

Alternative to the Proposed Action

The Commission has concluded that there is no significant increase in the environmental impact associated with the proposed action. The principal alternative would be to retain a batch-average burnup level of 33 Gwd/MtU and deny licensee requests to extend the allowed burnup to higher levels. Such action would not reduce environmental impacts and, as indicated above, could result in increased overall environmental impact. In addition, it would deny to the licensees and the public the cost benefits resulting from the use of extended burnup fuel.

Agencies and Persons Consulted

The NRC staff was assisted by Pacific Northwest Laboratories in developing the information needed to perform the environmental assessment. Staff of the Department of Energy (DOE) and the National Environmental Studies Project of the Atomic Industrial Forum were also consulted with regard to results of applicable experimental and analytical studies. The NRC staff did not consult with any other agencies or persons.

Finding of No Significant Impact

The NRC staff has reviewed the anticipated widespread use of extended burnup fuel in commercial LWRs. Based upon the foregoing environmental assessment, the staff concluded that there are no significant adverse radiological or non-radiological impacts associated with the use of extended burnup fuel and that this use will not significantly affect the quality of the human environment. Therefore, pursuant to 10 CFR 51.31, the Commission has determined that an environmental impact statement need not be prepared for this action.

Copies of NUREG/CR-5009 and NUREG/CR-2325 may be purchased through the U.S. Government Printing Office by calling (202) 275-2060 or by writing to the Superintendent of

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Documents, U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20013-7082. Copies may also be purchased from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Road, Springfield, VA 22161. Copies are available for inspection or coping for a fee in the NRC Public Document Room, 1717 H Street, NW., Washington, DC.

Regulatory Guide 1.25 and Section 15.7.4 of the NRC's Standard Review Plan are available for inspection or copying for a fee in the NRC Public Document Room, 1717 H Street, NW., Washington, DC. Copies of the Regulatory Guide may be purchased by calling (202) 275-2060 or by writing to the Superintendent of Documents, U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20013-7082.

Copies of AIF/NESP-032 may be purchased from the USCEA, Publications Office, 7101 Wisconsin Ave., Bethesda, MD 20814, telephone number (301) 654-9260.

Dated at Bethesda, Maryland, this 23rd day of February 1988.

For the Nuclear Regulatory Commission.

Eric S. Beckjord,

Director, Office of Nuclear Regulatory Research.

[FR Doc. 88-4229 Filed 2-26-88; 8:45 am]

BILLING CODE 7590-01-M

Advisory Committee on Reactor Safeguards Subcommittee on Metal Components; Meeting

The ACRS Subcommittee on Metal Components will hold a meeting on March 15, 1988, EPRI NDE Center, 1300 Harris Blvd., Charlotte, NC.

The entire meeting will be open to public attendance.

The agenda for subject meeting shall be as follows:

Tuesday, March 15, 1988—8:30 a.m. until the conclusion of business

The Subcommittee will review the status of the NDE of cast stainless steel piping and other topics related to Subcommittee activities.

Oral statements may be presented by members of the public with the concurrence of the Subcommittee Chairman; written statements will be accepted and made available to the Committee. Recordings will be permitted only during those portions of the meeting when a transcript is being kept, and questions may be asked only by members of the Subcommittee, its consultants, and Staff. Persons desiring to make oral statements should notify the ACRS staff member identified below as far in advance as practicable so that appropriate arrangements can be made.

During the initial portion of the meeting, the Subcommittee, along with any of its consultants who may be present, may exchange preliminary views regarding matters to be considered during the balance of the meeting.

The Subcommittee will then hear presentations by and hold discussions with representatives of the NRC Staff, its consultants, and other interested persons regarding this review.

Further information regarding topics to be discussed, whether the meeting has been cancelled or rescheduled, the Chairman's ruling on requests for the opportunity to present oral statements and the time allotted therefor can be obtained by a prepaid telephone call to the cognizant ACRS staff member, Mr. Elpidio Igne (telephone 202/634-1414) between 8:15 a.m. and 5:00 p.m. Persons planning to attend this meeting are urged to contact the above named individual one or two days before the scheduled meeting to be advised of any changes in schedule, etc., which may have occurred.

Dated: February 24, 1988.

Morton W. Libarkin,

Assistant Executive Director for Project Review.

[FR Doc. 88-4282 Filed 2-26-88; 8:45 am]

BILLING CODE 7590-01-M

[Docket No. 30-13436, ASLBP No. 88-559-01-SC]

Atomic Safety and Licensing Board Panel Hearing; Finlay Testing Laboratories, Inc.

February 22, 1988.

Before Administrative Judges: Robert M. Lazo, Chairman, Glenn O. Bright, Richard F. Cole.

Order (Postponing Hearing)

Please take notice that the evidentiary hearing in this proceeding, scheduled to commence on March 9, 1988, is postponed until further notice.

Dated at Bethesda, Maryland, this 22nd day of February 1988.

It is so *orderd.*

For the Atomic Safety and Licensing Board.

Robert M. Lazo,

Chairman, Administrative Judge.

[FR Doc. 88-4283 Filed 2-26-88; 8:45 am]

BILLING CODE 7590-01-M

OFFICE OF SCIENCE AND TECHNOLOGY POLICY

White House Science Council (WHSC)

The White House Science Council, the purpose of which is to advise the Director, Office of Science and Technology Policy (OSTP), will meet on March 10 and 11, 1988 in Room 5104, New Executive Office Building, Washington, DC. The meeting will begin at 6:00 p.m. on March 10, recess and reconvene at 8:00 a.m. on March 11, 1988. Following is the proposed agenda for the meeting:

(1) Briefing of the council, by the Assistant Directors of OSTP, on the current activities of OSTP.

(2) Briefing of the Council by OSTP personnel and personnel of other agencies on proposed, ongoing, and completed panel studies.

(3) Discussion of composition of panels to conduct studies.

The March 10 session and a portion of the March 11 session will be closed to the public.

The briefing on some of the current activities of OSTP necessarily will involve discussion of material that is formally classified in the interest of national defense or for foreign policy reasons. This is also true for a portion of the briefing on panel studies. As well, a portion of both of these briefings will require discussion of internal personnel procedures of the Executive Office of the President and information which, if prematurely disclosed, would significantly frustrate the implementation of decisions made requiring agency action. These portions of the meeting will be closed to the public pursuant to 5 U.S.C. 552b(c) (1), (2), and (9)(B).

A portion of the discussion of panel composition will necessitate the disclosure of information of a personal nature the disclosure of which would constitute a clearly unwarranted invasion of personal privacy. Accordingly, this portion of the meeting will also be closed to the public, pursuant to 5 U.S.C. 552b(c)(6).

Because of the security in the New Executive Office Building, persons wishing to attend the open portion of the meeting should contact Barbara J. Diering, at (202) 456-7740, prior to 3:00 p.m. on March 9, 1988. Mrs. Diering is also available to provide specific

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Title: Challenge III Grant Application Guidelines for FY 1990.

Frequency of Collection: One-time.

Respondents: State or local governments; Non-profit institutions.

Use: Guideline instructions and applications elicit relevant information from non-profit organizations and State and local arts agencies that apply for funding under specific Challenge III program categories. This information is necessary for the accurate, fair and thorough consideration of competing proposals in the peer review process.

Estimated Number of Respondents: 150.

Average Burden Hours per Response: 80.

Total Estimated Burden: 12,000.

Murray R. Welsh,

Director, Administrative Services Division, National Endowment for the Arts.

[FR Doc. 88-18157 Filed 8-10-88; 8:45 am]

BILLING CODE 7537-01-M

NUCLEAR REGULATORY COMMISSION

[Docket No. 50-400]

Carolina Power & Light Co., et al., Shearon Harris Nuclear Power Plant, Unit 1; Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (NRC or the Commission) is considering issuance of an amendment to Facility Operating License No. NPF-63 to the Carolina Power & Light Company (CP&L or the licensee), for the Shearon Harris Nuclear Power Plant, Unit 1, located in Wake and Chatham Counties, North Carolina.

Environmental Assessment

Identification of Proposed Action

The proposed amendment would revise the provisions in the Technical Specifications (TS) relating to fuel enrichment.

The proposed action is in accordance with the licensee's applications dated February 1 and February 8, 1988, and previous submittals dated May 28, and November 2, 1987.

The Need for the Proposed Action

The proposed changes are needed so that the licensee can use higher enrichment fuel, and provides the flexibility of extending the fuel irradiation and permitting operation of longer fuel cycles.

Environmental Impacts of the Proposed Action

The Commission has completed its evaluation of the proposed revisions to the Technical Specifications. The proposed revisions would permit use of fuel enriched with Uranium 235 in excess of 4 weight percent and up to 4.2 weight percent and the license would expect the fuel to be irradiated to levels above 33 gigwatt days per metric ton (GWD/MT) but not to exceed 60 GWD/MT. The safety considerations associated with reactor operation with higher enrichment and extended irradiation have been evaluated by the NRC staff. The staff has concluded that such changes would not adversely affect plant safety. The proposed changes have no adverse effect on the probability of any accident. The increased burnup may slightly change the mix of fission products that might be released in the event of a serious accident but such small changes would not significantly affect the consequences of serious accidents. No changes are being made in the types or amounts of any radiological effluents that may be released offsite. There is no significant increase in the allowable individual or cumulative occupational radiation exposure.

With regard to potential nonradiological impacts of reactor operation with higher enrichment and extended irradiation, the proposed changes to the TS involve systems located within the restricted area, as defined in 10 CFR Part 20. They do not affect nonradiological plant effluents and have no other environmental impact.

The environmental impacts of transportation resulting from the use of higher enrichment fuel and extended irradiation are discussed in the attached staff assessment entitled, "NRC Assessment of the Environmental Effects of Transportation Resulting from Extended Fuel Enrichment and Irradiation," dated July 7, 1988. As indicated therein, the environmental cost contribution of the proposed increase in the fuel enrichment and irradiation limits are either unchanged or may in fact be reduced from those summarized in Table S-4 as set forth in 10 CFR 51.52(c).

Therefore, the Commission concludes that there are no significant radiological or nonradiological environmental impacts associated with the proposed amendment.

Alternative to the Proposed Action

Since the Commission concluded that there are no significant environmental effects that would result from the proposed action, any alternatives with equal or greater environmental impacts need not be evaluated.

The principal alternative would be to deny the requested amendment. This would not reduce environmental impacts of plant operation and would result in reduced operational flexibility.

Alternative Use of Resources

This action does not involve the use of any resources not previously considered in the "Final Environmental Statement related to the operation of the Shearon Harris Nuclear Power Plant, Units 1 and 2," dated October 1983.

Agencies and Persons Consulted

The NRC staff reviewed the licensee's request and did not consult other agencies or persons.

Finding of No Significant Impact

The Commission has determined not to prepare an environmental impact statement for the proposed license amendment.

Based upon the foregoing environmental assessment, we concluded that the proposed action will not have a significant effect on the quality of the human environment.

For further details with respect to this action, see the application for amendment dated February 1, and February 8, 1988, and submittals May 28 and November 2, 1987, which are available for public inspection at the Commission's Public Document Room, 1717 H Street NW., Washington, DC and at the Richard B. Harrison Library, 1313 New Bern Avenue, Raleigh, North Carolina 27610.

Dated at Rockville, Maryland, this 3rd day of August 1988.

For the Nuclear Regulatory Commission.

Edward A. Reeves,

Acting Director, Project Directorate II-1, Division of Reactor Projects I/II, Office of Nuclear Reactor Regulation.

NRC Assessment of the Environmental Effects of Transportation Resulting From Extended Fuel Enrichment and Irradiation

Introduction

Several Licensees of light water reactors (LWRs) have submitted proposed license amendments to permit use of enriched fuel in excess of four (4) weight-percent uranium-235 and to extend fuel irradiation from the current limit of 33 Gigawatt Days/Metric Ton (GWD/MT) up to 60 GWD/MT. It is anticipated that, in time, almost all licensees of light water reactors will request approval to adopt increases in

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irradiation levels and fuel enrichment. Paragraph (b) of 10 CFR 51.52 states, among other things, that the reactors using fuel enrichment greater than 4 weight-percent uranium-235 or where fuel irradiation exceeds 33 GWD/MT, the licensee shall provide a full description and detailed analysis of the environmental effects to transportation of fuel and wastes to and from the reactor, including values for the environmental impact under normal conditions of transport and for the environmental risk from accidents in transport. The Statement shall indicate that the values determined by the analysis represent the contribution of such effects to the environmental costs of licensing the reactor.

With respect to the issue, the staff published a Notice of Environmental Assessment and Finding of No Significant Impact for extended burnup fuel use in Commercial LWRs in the Federal Register (53 FR 6040), dated February 29, 1988. In the above cited notice, the staff concluded that the environmental impacts summarized in Table S-4 of 10 CFR 51.52 for the burnup level of 33 GWD/MT are conservative and bound the corresponding impacts for burnup level up to 60 GWD/MT and uranium-235 enrichments up to five percent by weight. The staff also concluded that there are no significant adverse radiological or non-radiological impacts associated with the use of extended fuel burnup and/or increased enrichment, and that this use will not significantly affect the quality of the human environment. Moreover, pursuant to 10 CFR 51.31, the Commission determined that an environmental impact statement need not be prepared for this action.

The Staff is in the process of revising the regulations at 10 CFR 51.52 to reflect the findings published in the above cited Federal Register Notice. In the interim, in connection with its review of proposed license amendments to permit use of fuel enriched with uranium 235 in excess of 4 percent and up to 5 percent by weight and irradiated to levels above 33 GWD/MT and up to 60 GWD/MT, and pursuant to 10 CFR 51.52(b), the staff proposes to accept the following analysis of the environmental effects of the transportatio of such fuel and waste until such time as the revision to the rule is issued.

Environmental Impacts of Transportation

In evaluating the environmental impacts of the use of extended irradiation of high enrichment, fuel, the Commission has relied upon the following four studies dealing with the transportation impacts:

(1) Pacific Northwest Laboratories' report NUREG/CR-5009, "Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors," dated February 1988, prepared for the Nuclear Regulatory Commission;

(2) Nuclear Regulatory Commission's report WASH-1238, "Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants, dated December 1972;

(3) Envirosphere Company Report AIF/NE SP-032, "The Environmental Consequences of Higher Fuel Burnup," dated June 1985, prepared for National Environmental Studies Project (NESP) and the Atomic Industrial Forum, Inc.,a with the participation of the Commission's staff; and

(4) Sandia National Laboratories (SNL) Draft Report NUREG/CR-2325, "The Transportation of Radiactive Material (RAM) To and From U.S. Nuclear Power Plants," dated December 1983.

All four studies present the results of evaluation of transportation impacts for postulated traffic models. The results are presented for traffic density, radiological occupational risks, radiological public risks of normal transportation, and risks of transportation accidents. The Pacific Northwest Laboratories (PNL) report and the Envirosphere Company report present the environmental impacts for fuel irradiation levels extending up to 60 GWD/MT and enrichments up to 5 weight percent uranium-235. The PNL results appear to have been derived from the analysis presented in the NESP report.

Table I summarizes the results of traffic densities for transportation of fresh fuel, spent fuel, and other solid waste by truck, rail and barge used in the four studies.

TABLE I.—TRAFFIC DENSITIES SHIPMENTS PER REACTOR YEAR

Transportation mode	NUREG/CR-5009 (PNL)		NESP-032		WASH-1238	SNL [1]
	33 GWD/MT	60 GWD/MT	33 GWD/MT	60 GWD/MT	33 GWD/MT	33 GWD/MT
TRUCK	112	92	112	92	112	122
RAIL	10	6	10	6	10	2.3
BARGE	5	3	5	3		

[1] The report does not clearly state the assumptions regarding fuel enrichment and irradiation levels. However, since Table S-4 in 10 CFR 51.52 is based on 33 GWD/MT, the staff has assumed that SNL analysis must be based on the assumptions contained in 10 CFR 51.52, Table S-4.

The comparison of the results of traffic density analysis shows that there is a reasonable good correlation between the total number of shipments shown in SNL results and that shown in other reports for 33 GWD/MT. Both the PNL study and the NESP study show that there will be a reduction in the total number of shipments (fresh fuel, spent fuel, and low level wastes) when higher levels of irradiation (60 GWD/MT) are assumed. Such high irradiation levels may require that fuel enrichment be increased up to a maximum of 5 weight percent. The reduction in the shipments is due to the fact that there will be fewer outages for fuel reloads resulting in reduced fuel shipments to the reactor and reduced spent fuel shipments from the reactor. However, there will be an increase in the shipment of low level solid wastes. Even when this increase in low level waste shipment is included with the shipment of fresh fuel and spent fuel, the total shipments for higher irradiation (60 GWD/MT) are still somewhat reduced from those at 33 GWD/MT. As a result of the reduction in number of shipments, there should be some reduction in the estimated number of persons exposed. There should also be no significant change in heat generated per irradiated fuel cask and the weight restriction for transporting vehicle.

The discharged spent fuel at higher irradiation (60 GWD/MT) will have more long lived radionuclides per unit mass compared with the spent fuel irradiated at 30 GWD/MT. However, there is a smaller amount of annual spent fuel discharged. Since each spent

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fuel package will meet the surface radiation level limits imposed by the transportation regulations and there are fewer packages being shipped, there will be an overall reduction in the impacts of normal transportation of spent fuel at higher irridiation levels. However, the normal transportation impacts of low level wastes will increase with increased irradiation level. This is due to the fact that slight increases in cooling water activity could occur through increased inventory and gap release fraction. Because this activity would need to be removed to keep cooling water activity within licensed technical specification limits, a small increase in the quantity of low level wastes is estimated to occur. Both NUREG/CR-5009 and NESP-0032 conservatively assume a 20% increase in solid waste at 60 GWD/MT irradiation. Table II summarizes the combined environmental impacts of normal transportation of spent fuel, low level waste and new fuel activities at 33 GWD/MT and 60 GWD/MT as presented in NUREG/CR-5009 and NESP-032.

TABLE II.—NORMAL TRANSPORTATION RADIOLOGICAL EXPOSURE RISK PERSON REM/REACTOR YEAR

Exposure type	NUREG/CR-5009 (PLN)		NESP-032	
	33 GWD/MT	60 GWD/MT	33 GWD/MT	60 GWD/MT
Occupational	4.2[1]	3	4.2	3
General Public	3.2[1]	2.5	3.2	2.0
Total (Normal Transportation Exposures)	7.4	5.5	7.4	5.0

[1] These values are identical to the rounded off values reported in Table S-4 of 10 CFR 51.52, and form the basis of the Commission's determination of no significant adverse environmental impacts of transportation of fuel and wastes to and from nuclear reactor sites.

The above results show that there is in fact an overall reduction in the radiological impacts of normal transportation (the calculated impacts are lower than the values reported in Table S-4).

Environmental impacts also result from transportation accidents. The extended irradiation of fuel will result in an increase in the actinide and fission product inventory in the fuel. Since the spent fuel in transported after an extended storage at the site (5 years), only the long lived fission products and antinides would remain to contribute to the risk. The PNL analysis shows that the overall affect of a higher inventory of antinides and long lived fission products would be to increase the projected dose in the event of an accident involving spent fuel by a factor of about 2.7, when irradiation is increased from 33 GWD/MT to 60 GWD/MT. However, because the increased irradiation will correspondingly decrease the amount of the spent fuel discharged, the probability of a transportation accident will be reduced by an amount roughly equal to the ratio of irradiation levels. The overall effect of the increase in irradiation to 60 GWD/MT would be to increase the radiological risk of spent fuel transportation accidents by about 50%.

As stated earlier, the amount of low level waste is conservatively assumed to increase by about 20% when irradiation levels are increased to 60 GWD/MT. No significant change in composition of low level wastes is expected. Therefore, the transportation accident risks of low level waste shipment would increase by 20%. The transportation risk associated with new fuel shipments would decrease as shipments decreased due to extended burnup.

Although Table S-4 indicates that the radiological risk of accidents is small and not capable of quantification, the radiological risks of transportation accidents were calculated in NUREG/CR-2325. For the 1985 transportation model, the SNL calculated radiological risk of 1.8 person-rem/reactor year. The staff has conservatively assumed from the PNL analyses that the higher irradiation (60 GWD/MT) would result in a 50 percent increase in radiological risks due to transportation of all kinds of radioactive waste (even though for low level waste the increase in expected to be 20% or less and for new fuel the risk would decrease with the assumption). SNL calculated risk of 1.8 person-rem/reactor year could increase to 2.7 person-rem/reactor year at 60 GWD/MT irradiation level. When accident risks at 33 GWD/MT (SNL value) and 60 GWD/MT (Scaled SNL value) are added to normal impacts (PNL and NESP-032 value in Table II), the overall radiological risks at higher irradiation levels are still lower than the risks at 33 GWD/MT irradiation levels. This is shown on Table III.

The analyses presented in NESP-032 show that the radiological environmental impacts of transportation accidents are small at 33 GWD/MT and remain small at 60 GWD/MT. The NESP-032 finding is consistent with finding in WASH-1238 and the results summarized in Table S-4 of 10 CFR 51.52.

TABLE III.—TRANSPORTATION RADIOLOGICAL EXPOSURE RISK PERSON REM/REACTOR YEAR

	NUREG/CR-5009 (PNL)		NESP-032	
	33 GWD/MT	60 GWD/MT	33 GWD/MT	60 GWD/MT
Normal Transportation Exposures	7.4	5.5	7.4	5.0
Accident Exposures (from SNL)	1.8	2.7	1.8	2.7
	9.2	8.2	9.2	7.7

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The non-radiological impacts of transportation accidents are presented in Table S-4 as follows:

(a) 1 fatality in 100 reactor years.

(b) 1 non-fatal injury in 10 reactor years.

(c) $475 property damage per reactor year.

As seen in Table 1, the overall shipments of fresh fuel, spent fuel, and low level waste are slightly reduced. Therefore, the likelihood of an accident would decrease with the decreased number of shipments, while the non-radiological consequences of transportation accidents would remain unchanged.

In summary, the environmental impacts of extended irradiation up to 60 GWD/MT and increased enrichment up to 5 weight percent are bounded by the impacts reproted in Table S-4 of 10 CFR Part 51. Table IV shows the summary of the comparison of impacts. Table IV also supports the staff's conclusions concerning transportation impacts in the Federal Register Notice 53 FR 6040.

TABLE IV.—SUMMARY COMPARISON OF TRANSPORTATION IMPACTS

	Table S-4	60 GWD/MT and up to 5 percent enrichment
Traffic Density		
Truck	Less than 1 per day.	No increase.
Rail	Less than 3 per month.	No increase.
Radiological Risk—Person REM per year:		
Normal Transportation.	7	5.0-5.5
Accidents	1.8	2.7
Total	8.8	7.7-8.2
Non-Radiological Risk.	1 Fatality/100 Reactor Years.	No increase.
	1 Non-Fetal Injury/10 Reactor Yeras.	No increase.
	$475 Property Damage/ Reactor Year.	No increase.

The above evaluation sets forth the changes resulting from increased enrichment (up to 5 weight percent) and extended irradiation (up to 60 GWD/MT), in the environmental impacts of transportation of fuel and wastes to and from the light water reactors set forth in Table S-4, 10 CFR Part 51. The values set forth in this detailed analysis represent the contribution of the environmental effects of transportation of fuel enriched with uranium 235 above 4 weight percent and up to 5 weight percent, and irradiated to levels above 33 GWD/MT and up to 60 GWD/MT to the environmental costs of operating the reactors. As shown above, the environmental cost contributions of the stated increases in fuel enrichment and irradiation limits are either unchanged or may in fact be reduced from those summarized in Table S-4, as set out in 10 CFR 51.52(c).

Dated: July 7, 1988.

[FR Doc. 88-18175 Filed 8-10-88; 8:45 am]
BILLING CODE 7590-01-M

[Docket No. 50-341]

Detroit Edison Co., Wolverine Power Supply Cooperative, Inc.; Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of an amendment to Facility Operating License No. NPF-43, issued to the Detroit Edison Company (DECo) and the Wolverine Power Supply Cooperative, Incorporated (the licensees) for the operation of Fermi-2 located in Monroe County, Michigan.

Environmental Assessment

Identification of Proposed Action

The Proposed amendment would revise provisions in the Fermi-2 Technical Specifications (TSs) relating to the Standby Gas Treatment System (SGTS) Radiation Monitors and the Containment High Range Radiation Monitor.

The Need for the Proposed Action

The proposed changes to the TSs are required in order to remove the potential for an unmonitored release for fission products from the plant and to revise Action Statement 81 to make it consistent with NRC Generic Letter 83-36.

Environmental Impacts of the Proposed Action

The Commission has completed its evaluation of the proposed revision to the TSs. The proposed revision would require a minimum of two channels, instead of one, of the SGTS Radiation Monitors to be operable to ensure that appropriate compensatory actions are taken to preclude conditions which have the potential for allowing unmonitored releases of noble gases. In addition, the proposed amendment would (1) revise the associated Action Statement 81 in Table 3.3.7.5-1 for the SGTS Radiation Monitors and Containment High Range Radiation Monitor to extend the time period before the licensees are required to submit a Special Report to the Commission (pursuant to 6.9.2 of the TSs) as recommended by NRC Generic Letter 83-36; and (2) make appropriate changes in the TS Bases for Accident Monitoring Instrumentation as a result of the changes. Therefore, the proposed changes do not increase the probability or consequences of any accidents, no changes are being made in the types of any effluents that may be released offsite, and there is no significant increase in the allowable individual or cumulative occupational radiation exposure. Accordingly, the Commission concludes that this proposed action would result in no significant radiological impact and could result in the reduction of the radiological impacts.

With regard to potential nonradiological impacts, the proposed changes to the TSs involve systems located within the restricted area as defined in 10 CFR Part 20. They do not affect nonradiological plant effluents and have no other environmental impact. Therefore, the Commission concludes that there are no significant nonradiological environmental impacts associated with the proposed amendment.

The Notice of Consideration of Issuance of Amendment and Opportunity for Hearing in connection with this action was published in the Federal Register on March 10, 1988 (53 FR 7819). No request for hearing or petition for leave to intervene was filed following this notice.

Alternatives to the Proposed Action

Because the Commission has concluded that there is no significant environmental impact associated with the proposed amendment, any alternative would have either no or greater environmental impact. The principal alternative would be to deny the requested amendment. This may increase the environmental impacts attributed to the facility due to allowing the potential for unmonitored releases from the facility.

Alternative Use of Resources

This action involves no use of resources not previously considered in connection with the "Final Environmental Statement Related to

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action are negligible, any alternatives with equal or greater environmental impacts need not be evaluated.

The principal alternative would be to deny the requested action. This would not significantly reduce the environmental impacts of plant operation and would result in reduced operational flexibility.

Alternative Use of Resources

This action does not involve the use of resources not previously considered by the Commission in the "Final Environmental Statement Relating to Operation of Calvert Cliffs Nuclear Power Plant, Units 1 and 2" dated April 1973.

Environmental Impact of the Proposed Amendments

These proposed changes are basically administrative in nature and are provided to facilitate the splitting of the GS-NO's roles between the GS-NO and AGS-NO.

Consequently, these proposed changes pose neither radiological nor non-radiological impacts upon the environment. The day-to-day operation of the plant shall continue to be directly supervised by a manager who holds an SRO license. This constitutes no change in the level of safety exercised in plant operations. Furthermore, the Plant Operations and Safety Review Committee shall continue to include a member with an SRO license which ensures that all nuclear safety matters will continue to be reviewed by a member who has a current detailed level of knowledge of plant operation.

Therefore, the Commission has determined that these proposed amendments pose no significant environmental impact.

Agencies and Persons Consulted

None.

Finding of No Significant Impact

Based on the aforementioned environmental assessment, the Commission has determined that the proposed amendments will not have a significant effect on the quality of the human environment.

For further details with respect to his action see: (1) The applications for license amendments dated March 15, 1988 and December 2, 1988, and (2) the licensee's supplemental letters dated June 2, 1988 and January 13, 1989. These documents are available for public inspection at the Commission's Public Document Room, 2120 L Street NW., Washington, DC, and at the Calvert County Library, Prince Frederick, Maryland.

Dated at Rockville, Maryland, this 25th day of January 1989.

For the Nuclear Regulatory Commission.

Joseph D. Neighbors,

Acting Director, Project Directorate I-1, Division of Reactor Projects I/II.

[FR Doc. 89-2079 Filed 1-27-89; 8:45 am]

BILLING CODE 7590-01-M

[Docket Nos. 50-317 and 50-318]

Baltimore Gas and Electric Co., Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2; Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (NRC or the Commission) is considering issuance of amendments to Facility Operating License Nos. DPR-53 and DPR-69, issued to the Baltimore Gas and Electric Company, (the licensee), for operation of the Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2, respectively, which are located in Calvert County, Maryland. The proposed amendments, submitted via the license application dated June 9, 1988, as supplemented on October 25 and November 17, 1988 would change the Units 1 and 2 Technical Specifications (TS) 5.6.1, "Criticality-Spent Fuel," and 5.6.2, "Criticality-New Fuel," to increase the maximum U-235 fuel enrichment limit from 4.1 to 5.0 weight percent and also, reduce the TS 5.6.2 maximum limit on the effective multiplication factor (K_{eff}) from 0.98 to 0.95. Additional information concerning expected core burnup levels was provided in a December 28, 1988 letter.

This assessment shall also apply to any changes proposed in the reactor core U-235 enrichment limit, up to and including 5.0 weight percent, and to proposed increases in the average level of irradiation of fuel discharged from the reactors up to a batch average discharge burnup limit of 60,000 MWD/MT.

Need for Environmental Impact Statement

The Commission has found that the proposed amendments constitute no additional significant environmental impact and as has, therefore, determined not to prepare an environmental impact statement.

Environmental Assessment

Identification of Proposed Amendments

Currently, the maximum permitted enrichment limit for (1) stored new and spent fuel and (2) fuel in the reactor core at Calvert Cliffs Units 1 and 2 is 4.1 weight percent U-235. The licensee is in the process of shifting its core design to incorporate higher enrichment fuel assemblies to support full 24-month operating cycles. The first Unit 1 24-month cycle commenced in Spring 1988, with a reload planned for April 1990, while the first Unit 2 24-month cycle is nearing its March 1989 completion date. These first 24-month cycle cores were transitional designs provided to economically utilize the lower enrichment fuel (4.0 to 4.85 weight percent U-235) located onsite that had already experience irradiation and burnup during the previous 18-month cycles at each unit. Subsequent to the use of this lower enrichment fuel, the licensee intends to utilize cores with up to 5.0 weight percent U-235 enrichment levels to better support 24 months of continuous power operation without refueling. Consequently, the licensee has proposed changes to increase the U-235 enrichment limits in TS 5.6.1, "Criticality-Spent Fuel," and TS 5.6.2, "Criticality-New Fuel," from 4.1 to 5.0 weight percent.

In addition, the licensee has proposed to restrict the maximum value of K_{eff} to a limit of 0.95, vice the current limit of 0.98, and add the full flood condition to the various densities of unborated water conditions that are assumed in determining K_{eff}. The reduction of the maximum limit for K_{eff} for fully flooded conditions was proposed solely to place the Calvert Cliffs TS limits on new fuel criticality in full accord with the NRC guidance provided in Section 9.1.1, "New Fuel Storage," of the Standard Review Plan (NUREG-0800). This restrictive change would provide more conservative criticality determinations for new fuel storage than those currently required by TS.

Need for the Proposed Amendments

The proposed changes are needed to allow the licensee to support future 24-month full power operating cycles.

Environmental Impact of the Proposed Amendments

The Commission has completed its evaluation of the proposed revisions to the TS and the proposed increase in the burnup limits for the fuel. The staff has concluded that such changes would not adversely affect plant safety. The proposed changes have no significant adverse effects upon the probability of any analyzed accident. The increased burnup may alter slightly the mix of fission products that could be released in the event of a serious accident but such small changes would not significantly affect the consequences of said serious accidents. In addition, no changes would result in the types or amounts of any radiological effluents

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that may be released offsite. Finally, these changes would not contribute to any significant increase in individual or cumulative occupational radiation exposure.

Regarding the potential non-radiological impact of reactor operation with higher enrichment fuel and increased levels of irradiation, the proposed changes involve systems located within the restricted area, as defined in 10 CFR Part 20. They do not affect non-radiological plant effluents and have no other non-radiological environmental impact.

The potential environmental impact resulting from the transportation of higher fuel enrichment and burnup levels is discussed in the staff assessment entitled, "NRC Assessment of the Environmental Effects of Extended Fuel Enrichment and Irradiation," which was published in the Federal Register on August 11, 1988 (53 FR 30355) in connection with the Shearon Harris Nuclear Power Plant, Unit 1, Environmental Assessment and Finding of No Significant Impact. As indicated therein, the environmental cost contribution of the transportation, due to the increases in the fuel enrichment up to 5% and irradiation limits up to 60,000 MWD/MT are either unchanged or may, in fact, be reduced from those summarized in Table S–4 as set forth in 10 CFR 51.52(c). These findings are applicable to these amendments for the Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2.

Therefore, the Commission concludes that the proposed amendments pose no significant radiological or non-radiological environmental impact.

Alternatives to the Proposed Amendments

Since the Commission concluded that there are no significant environmental effects that would result from the proposed changes, any alternatives with equal or greater environmental impacts need not be evaluated.

The principal alternative would be to deny the requested fuel enrichment and burnup increases. This would not reduce environmental impact of plant operation and would result in reduced operational flexibility.

Alternative Use of Resources

This action does not involve the use of any resources not previously considered in the "Final Environmental Statement Related to the Operation of Calvert Cliffs Nuclear Power Plant, Units 1 and 2," dated April 1973.

Agencies and Persons Consulted

The NRC staff reviewed the licensee's request and did not consult with other agencies or persons.

Finding of No Significant Impact

Based upon the foregoing environmental assessment, we conclude that the proposed amendments will not have a significant affect on the quality of the human environment.

For further details with respect to this action, see (1) the application for license amendments dated June 9, 1988, as supplemented on October 25 and November 17, 1988, and (2) the licensee's letter of December 28, 1988, which are available for public inspection at the Commission's Public Document Room, 2120 L Street, NW., Washington, DC and at the Calvert County Library, Prince Frederick, Maryland.

Dated at Rockville, Maryland, this 25th day of January 1989.

For the Nuclear Regulatory Commission.

Joseph D. Neighbors,

Acting Director, Project Directorate I-1, Division of Reactor Projects I/II, Office of Nuclear Reactor Regulation.

[FR Doc. 89–2077 Filed 1–27–89; 8:45 am]

BILLING CODE 7590-01-M

Receipt of U.S. Department of Energy's Site Characterization Plan for Yucca Mountain, Nevada Site

AGENCY: U.S. Nuclear Regulatory Commission.

ACTION: Notice of receipt of the Department of Energy's Site Characterization Plan for Yucca Mountain, Nevada Site.

SUMMARY: The Nuclear Regulatory Commission (NRC) has received for review and comment the Department of Energy's (DOE) Site Characterization Plan (SCP) for the Yucca Mountain, Nevada candidate site for a permanent geologic repository for high-level radioactive waste (HLW). Section 113(b) of the Nuclear Waste Policy Act of 1982 (NWPA) requires that the SCP provide "a general plan for site characterization activities" to be conducted. The purpose of site characterizaton is to collect pertinent geological and other information necessary to evaluate whether the site is suitable for a permanent geologic repository and, if found suitable, to provide DOE with data adequate to prepare and support a license application seeking from the NRC authorization to construct such a repository

As part of the pre-license application phase of the repository licensing process established by NWPA and the Nuclear Waste Policy Amendments Act of 1987 (NWPAA), the NRC is required to review and comment upon DOE's SCP, and in accord with 10 CFR 60.18, "DOE shall defer the sinking of such shafts until such time as there has been an opportunity for Commission comments thereon to have been solicited and considered by DOE." NRC anticipates completion of the review in a seven-month timeframe, culminating in issuance to DOE of a Site Characterization Analysis (SCA) with respect to the SCP, as well as such additional comments as may be warranted.

During its review of the SCP, the NRC will provide an opportunity for the State of Nevada and for affected local governments and Indian Tribes to present their views on the SCP and their suggestions with respect to comments thereon which may be made by the NRC. In addition, NRC staff will be made available to consult with the affected parties upon their written request pursuant to Subpart C of 10 CFR Part 60

At the time of issuance of the SCA, a notice of availability of the SCA and a request for public comment will be published in the Federal Register. Copies of the SCA and of the comments received will be made available at NRC's Public Document Room (PDR) located at 2120 L Street, NW., Lower Level, Washington, DC 20555 and local Public Document Rooms (LPDRs), located at the James R. Dickinson Library, Special Collections Department, University of Nevada-Las Vegas, 4505 Maryland Parkway, Las Vegas, Nevada 89154 and University Library, Government Publications Department, University of Nevada-Reno, Reno, Nevada 89557.

Copies of the SCP may be obtained from DOE by contacting: Stephen H. Kale, Associate Director, Office of Facilities Siting and Development, Office of Civilian Radioactive Waste Management, U.S. Department of Energy, RW–20, 1000 Independence Avenue, SW., Washington, DC 20585 or Carl P. Gertz, Project Manager, Yucca Mountain Project Office, U.S. Department of Energy, Box 98518, Las Vegas, Nevada 89193–8518.

NRC has made copies of the SCP available for public inspection in its PDR and LPDRs.

FOR FURTHER INFORMATION CONTACT: John J. Linehan, Director, Repository Licensing and Quality Assurance Project Directorate, Division of High-Level Waste Management, Office of Nuclear Material Safety and Safeguards, U.S.

H.0 APPROVALS AND CERTIFICATIONS

Appendix H contains the following items:

- Page H-2 Excerpt from current Code of Maryland Regulations. Excerpt addresses water quality certification
- Page H-3 Cover sheet for Calvert Cliffs Nuclear Power Plant discharge permit
- Page H-4 Coastal Zone Management Program Consistency Certification

D. Guidelines for Discharge to Ground Waters.

(1) Land disposal of municipal or similar wastes shall follow the Department of the Environment's "Guidelines for Land Treatment of Municipal Wastewaters" MDE-WMA-001-11/87.

(2) Discharges to a ground water aquifer of specific classification may not result in pollution of an aquifer possessing higher quality criteria.

(3) Discharges to ground water may not result in degradation of ground waters below the criteria established in §C, outside a mixing zone specified in a State discharge permit, general permit, or other permit issued by the Department of the Environment.

(4) Dischargers or potential dischargers to ground waters may be required to monitor ground or surface waters, or both, in a manner and frequency and at locations specified by the Department of the Environment and to periodically submit the results of these activities.

(5) As provided in COMAR 26.13.05.18, the underground injection of hazardous wastes is prohibited.

.10 Water Quality Certification.

A. General.

(1) The Federal Act prohibits the issuance of a federal permit or license to conduct any activity which may result in any discharge to navigable waters unless the applicant provides a certification from this State that the activity does not violate State water quality standards or limitations. This regulation establishes the procedures under which this certification will be issued.

(2) Discharges permitted by the Department under the National Pollutant Discharge Elimination System are certified by the Department.

B. Application for a Water Quality Certification.

(1) An applicant for certification shall submit to the Department an application which includes:

(a) Name and address of the applicant.

(b) A description of the facility or activity.

(c) A description of any discharge which may result from the conduct of any activity including:

(i) Biological, chemical, thermal or other characteristics of the potential discharge; and

MDE
MARYLAND DEPARTMENT OF THE ENVIRONMENT
2500 Broening Highway • Baltimore, Maryland 21224
(410) 631-3000

William Donald Schaefer
Governor

David A.C. Carroll
Secretary

STATE DISCHARGE PERMIT NUMBER	92-DP-0187
NPDES PERMIT NUMBER	MD0002399
EFFECTIVE DATE	June 16, 1994
EXPIRATION DATE	June 15, 1999

Pursuant to the provisions of Title 9 of the Environment Article, Annotated Code of Maryland, and regulations promulgated thereunder, and the provisions of the Clean Water Act, 33 U.S.C. § 1251 et seq and implementing regulations 40 CFR Parts 122, 123, 124, and 125, the Department of the Environment, hereinafter referred to as the "Department", hereby authorizes

Baltimore Gas and Electric Company
P. O. Box 1475
Baltimore, Maryland 21203

TO DISCHARGE FROM

The Calvert Cliffs Nuclear Power Plant

LOCATED

Two miles northeast of Lusby, Calvert County, Maryland

VIA OUTFALLS

001 through 007 as identified and described herein

TO

Chesapeake Bay and Goldstein Branch which are protected for water contact recreation, fishing, shellfish harvesting (Chesapeake Bay only), aquatic life, and wildlife in accordance with the following special and general conditions and map made a part hereof.

COASTAL ZONE MANAGEMENT PROGRAM CONSISTENCY CERTIFICATION

Maryland's Coastal Zone Management Program (CZMP) was developed pursuant to the Federal Coastal Zone Management Act of 1972, as amended. The program was approved by the U.S. Department of Commerce, National Oceanic and Atmospheric Administration, in August 1979. Section 307 of the Act requires that federal activities, including federal licenses and permits, be consistent with a state's federally-approved CZMP. Applicants for federal licenses and permits are required to certify that the proposed activity is consistent with a state's CZMP. Accordingly, Baltimore Gas and Electric Company (BGE) hereby certifies that the proposed Calvert Cliffs Nuclear Power Plant (CCNPP) license renewal complies with and will be conducted in a manner consistent with the Maryland CZMP.[1]

Proposed Activity

Baltimore Gas and Electric Company operates CCNPP Units 1 and 2 in accordance with NRC licenses DPR-53 and DPR-69, respectively. The Unit 1 license will expire on July 31, 2014, and the Unit 2 license on August 13, 2016. Baltimore Gas and Electric Company is applying to NRC for renewal of both licenses, which would enable 20 additional years of operation (i.e., until July 31, 2034 for Unit 1 and August 13, 2036 for Unit 2).

Calvert Cliffs Nuclear Power Plant is in Calvert County, Maryland, on the west bank of the Chesapeake Bay, approximately 40 miles southeast of Washington, DC, and 7.5 miles north of Solomons Island, Maryland (Figure 2-1). Figures 2-3, 2-4, and 2-5 illustrate the site layout, the station layout, and the protected area layout. As shown in Figure 3, the protected area of the plant is located within the 1,000-foot Chesapeake Bay Critical Area Limit.

The CCNPP fuel is uranium dioxide in the form of pellets with an enrichment up to 5-percent by weight uranium-235. The NRC has licensed CCNPP to operate on a 24-month refueling cycle, and a fuel burnup of 60,000 megawatt-days per metric ton of uranium. Baltimore Gas and Electric Company stores CCNPP spent fuel onsite in a spent fuel pool and in dry storage.

Baltimore Gas and Electric Company uses groundwater to supply process and domestic-use water at CCNPP. The State of Maryland has permitted BGE to withdraw no more than 450,000 gallons per day from the Aquia Aquifer. Calvert Cliffs withdraws an average of about 225,000 gallons per day (157 gallons per minute) and has never approached the permit limit. The quantities of groundwater withdrawn for CCNPP have followed a downward trend due primarily to improved technology for the control of water quality chemistry, which has enabled BGE to recirculate water longer before discharge, resulting in less demand for makeup water.

Baltimore Gas and Electric Company currently has a CCNPP workforce of approximately 1,770 (1997) during routine operations. The workforce commutes predominantly from Calvert and St. Mary's Counties. Approximately 60 percent of the employees (1,060) live in Calvert County, 16 percent live in St. Mary's County, and the remaining 24 percent live in other locations. The site workforce increases by as many as 700 temporary workers during refueling outages (one to three months) that occur about once a year.

In compliance with NRC regulations, BGE has analyzed the effects of plant aging and identified activities needed for CCNPP to operate an additional 20 years. Baltimore Gas and Electric Company conservatively assumes that renewal of the CCNPP licenses would require the addition of no more than

[1] This certification is patterned after draft model certification included as Attachment 6 of Reference (3).

60 workers to perform the additional license renewal surveillance, monitoring, inspection, testing, trending, and reporting during the period of extended operations. Calvert Cliffs' license renewal would involve no major plant refurbishment.

Calvert Cliffs supplies more than 12,000,000 megawatt-hours annually (exclusive of plant use), which is approximately 45 percent of the electricity that BGE supplies to its residential, commercial, and industrial customers (Reference 2). In other words, during the license renewal term, CCNPP would supply enough electricity for approximately one million homes for 20 years.

State Program

Maryland's CZMP is referred to as a "networked" program, which means that it is based on a variety of existing State authorities rather than a single law and set of regulations. The Maryland CZMP document (Reference 3) sets forth and discusses these authorities and how the State uses them to assure conformance with Coastal Zone Management Act (16 USC 1451 et seq.) requirements.[2] Tables 5-1 and 5-2 identify licenses, permits, consultations and other approvals necessary for CCNPP license renewal and continued operation.

Probable Effects

The NRC has prepared a generic environmental impact statement (GEIS) on impacts that nuclear power plant operation can have on the environment (Reference 4) and has codified its findings (10 CFR Part 51, Subpart A, Appendix B, Table B-1). The codification identifies 92 potential environmental issues, 68 of which are generically identified as having small impacts and are called "Category 1" issues. In its decision making regarding plant-specific license renewal environmental impacts, absent new and significant information, NRC will rely on its codified findings, as amplified by supporting information in the GEIS, for assessment of environmental impact [40 CFR 51.95(c)(4)]. The codification and 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;
- Socioeconomics;
- Uranium fuel cycle and waste management; and
- Decommissioning.

For plants such as CCNPP that are located within the coastal zone, many of these issues involve impact to the coastal zone. Baltimore Gas and Electric Company has adopted by reference the GEIS analysis for all Category 1 issues.

[2] The Maryland CZMP identifies the key enabling legislation as the Chesapeake Bay Critical Area Protection Act, the Tidal and Nontidal Wetlands Acts, and the Economic Growth, Resource Protection, and Planning Act.

The NRC codification identifies 22 issues as "Category 2," for which license renewal applicants must submit additional, site-specific information.[3] There are 17 Category 2 issues that are applicable to CCNPP.[4] As in the case of Category 1 issues, Category 2 issues can involve impact to the coastal zone at CCNPP. The applicable issues and general conclusions for these issues are as follows:

- Aquatic ecology - 316(a) and (b) approvals obtained, operational history demonstrates small impacts from entrainment, impingement, and heat shock.
- Groundwater use and quality - CCNPP withdrawals average 157 gallons per minute. Baltimore Gas and Electric Company predicts drawdown of Aquia Aquifer to be few inches per year and estimates cumulative drawdown for the license renewal period to be approximately 1.2 feet.
- Terrestrial resources - BGE has no plans to perform major refurbishment activities; therefore, impacts due to refurbishment are not expected.
- Threatened and endangered species - BGE has no plans to perform major refurbishment activities; therefore, impacts due to refurbishment are not expected and impacts to these species through license renewal would be positive due to the continuation of habitat protection and enhancement programs with continued plant operations.
- Air quality - BGE has no plans to perform major refurbishment activities; therefore, impacts due to refurbishment are not expected.
- Human health - CCNPP transmission lines meet the National Electric Safety Code recommendations for preventing electric shock from induced currents; therefore, the impact from electric shock would be small.
- Socioeconomics - BGE has no plans to perform major refurbishment activities; therefore, impacts to the local education system and transportation due to refurbishment are not expected. Baltimore Gas and Electric Company's conservative estimate of 60 additional license renewal personnel would result in a three percent decrease in available housing and less than one percent increase in output of local water system.
- Offsite land use - BGE has no plans to perform major refurbishment activities; therefore, impacts due to refurbishment are not expected. The population-related and tax-related impacts of continued operations would be small.
- Historic and archeological resources - BGE has no plans to perform major refurbishment activities; therefore, impacts due to refurbishment are not expected, and continued operations would have no additional impacts.
- Transportation of fuel and waste - 10 CFR 51.52, Table S-4 bounds the environmental impact from transportation of fuel and waste for CCNPP; therefore, license renewal impacts are expected to be small.

Another source of information about CCNPP impacts on the coastal zone is the biennial reports by the Maryland Power Plant Research Program (e.g., Reference 5). Maryland law requires the Program to

[3] 10 CFR Part 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. BGE 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] Some Category 2 issues are applicable to plants having features that are not present at CCNPP (e.g., cooling towers).

review and evaluate the potential impacts to Maryland's environment from the construction and operation of electric power generating and transmission systems. The Program summarizes these evaluations every other year in a document known as the Cumulative Environmental Impact Report. These reports discuss power plant air, water, terrestrial, radiological, and socioeconomic impacts, as well as various topical issues.

Findings

1. The Nuclear Regulatory Commission has determined that the significance of Category 1 issue impacts are small. A small significance level is defined by NRC as follows:

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

   Baltimore Gas and Electric Company has adopted by reference the NRC findings for Category 1 issues.

2. For applicable Category 2 issues, BGE has determined that the environmental impacts are small, as that term is defined by NRC. Impact to the coastal zone, therefore, would also be small.

3. To the best of its knowledge, BGE is in compliance with Maryland licenses, permits, approvals, and other requirements as they apply to CCNPP impacts on the Maryland coastal zone (see Table 1).

4. Calvert Cliffs' license renewal and continued operation of CCNPP facilities, and their effects, are all consistent with the enforceable policies of the Maryland Coastal Zone Management Program.

State Notification

By this certification that CCNPP license renewal is consistent with the Maryland CZMP, the State of Maryland is notified that, per 15 CFR 930.63(a), it has six months from the receipt of this letter and accompanying information in which to concur or object to the BGE certification. However, pursuant to 15 CFR 930.63(b), if Maryland has not issued a decision within three months following commencement of State agency review, it shall notify the contacts listed below of the status of the matter and the basis for further delay: The State's concurrence, objection, or notification of review status shall be sent to the following contacts:

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References

1. NRR Office Letter No. 906, Revision 1; "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues," NRC Office of Nuclear Reactor Regulation, transmitted to all NRR employees, September 27, 1996
2. "FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others," Baltimore Gas and Electric Company, Baltimore, Maryland, December 31, 1993
3. "State of Maryland Coastal Zone Management Program and Final Environmental Impact Statement," U.S. Department of Commerce, August 1978
4. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," May 1996
5. "Maryland Power Plants and the Environment: A Review of the Impacts of Power Plant and Transmission Lines on Maryland's Natural Resources, Supporting Materials," PPRP-CEIR-9/2, Maryland Power Plant Research Program, Maryland Department of Natural Resources, May 1996