Wolf Creek Generating Station

Applicant's Environmental Report; Operating License Renewal Stage

Docket No. 50-482
License No. NPF-42
License No. ???????

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

List of Attachments

TABLE OF CONTENTS (Continued)

List of Tables

Table **Chapter-Page**

TABLE OF CONTENTS (Continued)

List of Figures

Acronyms and Abbreviations

AQCR	Air Quality Control Region
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
cfs	cubic feet per second
CO	carbon monoxide
CWA	Clean Water Act
DDT	dichloro-diphenyl-trichloroethane
DSM	demand-side management
EPA	U.S. Environmental Protection Agency
FES	Final Environmental Statement
FR	Federal Register
ft^3/year	cubic feet per year
GEIS	Generic Environmental Impact Statement
HEPA	high efficiency particulate air
IPA	integrated plant assessment
KCP&L	Kansas Power & Light
KDHE	Kansas Department of Health and Environment
KDOT	Kansas Department of Transportation
KDWP	Kansas Department of Wildlife and Parks
KEC	Kansas Energy Council
KGCC	Kansas Geospatial Community Commons
KG&E	Kansas Gas & Electric
LOS	Level of service
m^3/year	cubic meters per year
MSA	Metropolitan Statistical Area
MWe	megawatt-electric

NA	not applicable
NAAQS	National Ambient Air Quality Standards
NESC	National Electric Safety Code
NMFS	National Marine Fisheries Service
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
PL	Public Law
$PM_{2.5}$	particulate matter with aerodynamic diameters of 2.5 microns or less
PM_{10}	particulate matter with aerodynamic diameters of 10 microns or less
PWR	pressurized water reactor
SAMA	severe accident mitigation alternatives
SCR	selective catalytic reduction
SHPO	State Historic Preservation Officer
SMITTR	surveillance, monitoring, inspections, testing, trending, and recordkeeping
SNUPPS	Standardized Nuclear Unit Power Plant System
SO_2	sulfur dioxide
SO_x	sulfur oxides
USC	U.S. Code
USCB	U.S. Census Bureau
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
WCGS	Wolf Creek Generating Station
WCNOC	Wolf Creek Nuclear Operating Corporation

1.0 CHAPTER 1 - INTRODUCTION

1.1 PURPOSE OF AND NEED FOR ACTION

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act of 1954, as amended, and NRC implementing regulations. Wolf Creek Nuclear Operating Corporation (WCNOC) operates the Wolf Creek Generating Station (WCGS), near Burlington in Coffey County, Kansas, pursuant to NRC Operating License NPF-42 (Docket No. STN 50-482). The license expires March 11, 2025.

WCNOC has prepared this environmental report in conjunction with its application to NRC to renew the WCGS operating license, in compliance with the following NRC regulations:

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

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

"...The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by State, utility, and, where authorized, Federal (other than NRC) decision makers...." (NRC 1996a)

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

1.2 ENVIRONMENTAL REPORT SCOPE AND METHODOLOGY

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

NRC supplemental information in the *Federal Register* (NRC 1996b; NRC 1996c; NRC 1996d; and NRC 1999a)

Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996a and 1999b)

Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses (NRC 1996e)

Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response (NRC 1996f)

WCNOC has prepared Table 1-1 to verify conformance with regulatory requirements. Table 1-1 indicates where the environmental report responds to each requirement of 10 CFR 51.53(c). In addition, each section of Chapter 4 is prefaced by pertinent regulatory language and applicable supporting document language.

1.3 WOLF CREEK GENERATING STATION LICENSEE AND OWNERSHIP

WCGS is currently owned by Kansas Gas and Electric Company (47 percent), Kansas City Power & Light Company (47 percent), and Kansas Electric Power Cooperative, Inc. (6 percent). WCNOC is the plant operator and is authorized to act as agent for the owners and has exclusive responsibility and control over the physical construction, operation, and maintenance of the facility. The switchyard, including the generator output breakers and the 345-kilovolt transmission lines, are owned by Westar Energy, a corporation formed by the merger of Kansas Gas and Electric and Kansas Power and Light. Kansas Electric Power Cooperative, Inc. owns one of the two 69-kilovolt transmission lines that are connected to the switchyard. The other 69-kilovolt line is owned by Westar Energy.

1.4 TABLES

Table 1-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements.

Regulatory Requirement	Responsive Environmental Report Section(s)
10 CFR 51.53(c)(1)	Entire Document
10 CFR 51.53(c)(2), Sentences 1 and 2	3.0 Proposed Action
10 CFR 51.53(c)(2), Sentence 3	7.2.2 Environmental Impacts of Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3 Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	7.0 Alternatives to the Proposed Action 8.0 Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5 Short-Term Use Versus Long-Term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4 Irreversible or Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions 6.2 Mitigation 7.2.2 Environmental Impacts of Alternatives 8.0 Comparison of Environmental Impact of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0 Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions 6.3 Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.1 Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a Small River with Low Flow) 4.6 Groundwater Use Conflicts (Plants Using Cooling Water Towers or Cooling Ponds that Withdraw Makeup Water from a Small River)

Table 1-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements. (Continue)

Regulatory Requirement	Responsive Environmental Report Section(s)
10 CFR 51.53(c)(3)(ii)(B)	4.2 Entrainment of Fish and Shellfish in Early Life Stages 4.3 Impingement of Fish and Shellfish 4.4 Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.5 Groundwater Use Conflicts (Plants Using >100 gpm of Groundwater) 4.7 Groundwater Use Conflicts (Plants Using Ranney Wells)
10 CFR 51.53(c)(3)(ii)(D)	4.8 Degradation of Groundwater Quality
10 CFR 51.53(c)(3)(ii)(E)	4.9 Impacts of Refurbishment on Terrestrial Resources 4.10 Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.11 Air Quality During Refurbishment (Non-Attainment and Maintenance Areas)
10 CFR 51.53(c)(3)(ii)(G)	4.12 Microbiological Organisms
10 CFR 51.53(c)(3)(ii)(H)	4.13 Electric Shock from Transmission-Line-Induced Current
10 CFR 51.53(c)(3)(ii)(I)	4.14 Housing Impacts 4.15 Public Utilities: Public Water Supply Availability 4.16 Education Impacts from Refurbishment 4.17 Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.18 Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.19 Historic and Archaeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.20 Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions 6.2 Mitigation
10 CFR 51.53(c)(3)(iv)	5.0 Assessment of New and Significant Information
10 CFR 51, Appendix B, Table B-1, Footnote 6	2.6.2 Minority and Low-Income Populations

1.5 REFERENCES

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

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

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

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

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

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

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

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

2.0 CHAPTER 2 - SITE AND ENVIRONMENTAL INTERFACES

2.1 LOCATION AND FEATURES

WCGS is in Coffey County, Kansas, approximately 75 miles southwest of Kansas City. The nearest population center, Emporia, is 28 miles west-northwest of the site (Figure 2-1). WCGS is approximately 3.5 miles east of the Neosho River and the John Redmond Reservoir. Other nearby communities are New Strawn and Burlington (Figure 2-2).

Of the nearly 11,300 acres owned by Kansas Gas and Electric Company, Kansas City Power & Light Company, and Kansas Electric Power Cooperative, 9,818 acres are occupied by WCGS. The acreage beyond the site property is leased as farmland and rangeland. Figure 2-3 depicts the WCGS site boundary. The site buildings and adjacent areas comprise 135 acres, and the WCGS cooling pond (Coffey County Lake) occupies 5,090 acres plus 60 acres for the dam and dikes. The site also includes a 31-acre pond originally constructed primarily to receive lime sludge. Buildings on the property include the reactor containment building, turbine building, auxiliary building, control building, fuel handling facility, switchyard, radioactive waste building, training center, visitor's center (includes Emergency Operations Facility and the simulator), outdoor firing range, and other supporting buildings.

The surrounding area is mostly flat to gently rolling landscape with occasional sedimentary rock outcroppings. Maximum topographic relief is 100 feet or less from the uplands to the valley floors. The land is primarily used for rangeland and farmland, with occasional woodland in river and creek bottoms. The rangeland is mostly native and tame (introduced) grass, brush, and managed pastures. Given the flat nature of the viewscape, the WCGS containment building is a prominent feature of the area.

The Wolf Creek Environmental Education Area is an approximately 500-acre nature area accessible from 17th Road near the north end of the site property (Figure 2-3). It consists of five trails that guide the visitor through a variety of natural Kansas habitats, including native tall grass, woodlands, and wetlands. Added to the natural areas are shelterbelts, planted trees, restored native grasses, developed wetlands, and planted winter food plots for wildlife. The area is the result of a partnership between private citizens, civic organizations, local, state, and federal governments, and the WCGS owners.

Section 3.1 provides a description of the plant and some of its key features.

2.2 AQUATIC ECOLOGICAL COMMUNITIES

Aquatic communities in the vicinity of WCGS are directly influenced by the hydrology of the Neosho River and the transfer of water between John Redmond Reservoir/Neosho River and Coffey County Lake. This section characterizes the hydrology of these waterbodies and the distribution and abundance of aquatic organisms within them.

Description of Neosho River Basin

The Neosho River rises in east-central Kansas (Morris County) and flows southeast some 460 miles across Kansas and Oklahoma to its confluence with the Arkansas River, near Fort Gibson, Oklahoma (Britannica 2005). The Neosho River Basin in Kansas encompasses 6,300 square miles and (all or parts of) 18 counties in southeastern Kansas (Kansas Water Office 2004). Major tributaries are the Cottonwood River, which flows east to join the Neosho River near Emporia, Kansas, and the Spring River, which flows west out of Missouri and then south to join the Neosho River near Wyandotte, Oklahoma (at Grand Lake O' the Cherokees).

There are three U.S. Army Corps of Engineers impoundments in the Neosho River system: Council Grove, Marion, and John Redmond. All three were built as flood control and water supply reservoirs, but they also provide recreational opportunities and important fish and wildlife habitat. Council Grove Reservoir, a 3,280-acre impoundment on the mainstem of the Neosho (KDWP 2005), lies approximately 65 river miles upstream of the Neosho River-Wolf Creek confluence. Marion Reservoir, 6,160-acre impoundment on the Cottonwood River (KDWP 2005), lies approximately 105 river miles upstream of the Neosho River-Wolf Creek confluence. John Redmond Reservoir, a 9,400-acre impoundment on the mainstem of the Neosho River (KDWP 2005) is 3.5 miles west of WCGS and approximately 8 miles upstream of the Neosho River-Wolf Creek confluence.

Coffey County Lake, the 5,090-acre impoundment that serves as the cooling reservoir for WCGS, was created by erecting an earthen dam across Wolf Creek approximately 6 miles upstream from its confluence with the Neosho River (NRC 1975). Filling of Coffey County Lake (then known as Wolf Creek Cooling Lake) began in October 1980 and was completed in June 1982 (EA 1988). It impounds an intermittent stream with a drainage area of 19.5 square miles (Haines 2000). The impoundment was initially filled and subsequently maintained with makeup water pumped from the nearby Neosho River.

The U.S. Geological Survey operates and maintains streamflow gaging stations on the Neosho River up- and downstream of WCGS. Annual mean flow at a Neosho River gaging station (Americus, Kansas) 28 miles upstream of John Redmond Reservoir ranged from 28.2 to 1,106 cubic feet per second over the 1964-2004 period and averaged 322 cubic feet per second (Putnam and Schneider 2005). Annual average flow at a Neosho River gaging station near Burlington, Kansas, approximately 5 miles below the John Redmond Reservoir dam ranged from 190 to 4,982 cubic feet per second and averaged 1,603 cubic feet per second over the 1962-2004 period. Flow at this station has been "completely regulated since 1963 by John Redmond Reservoir" according to the USGS (Putnam and Schneider 2005). Annual mean flow in the Neosho River at a gaging station (Iola, Kansas) approximately 55 river miles downstream of the John Redmond Reservoir dam ranged from 141 to 6,635 cubic feet per second and averaged 1,865 cubic feet per second (Putnam and Schneider 2005). Substantially higher flows at Burlington and Iola reflect the contribution of the Cottonwood River, which essentially quadruples the Neosho's discharge.

Annual precipitation in the Neosho River basin ranges from approximately 30 inches in the western-most part to 42 inches in the southeast (Kansas Water Office 2004). Approximately 70 percent of this precipitation falls between April and September. Flow data at most Neosho River gaging stations reflect this seasonal pattern. Mean monthly stream flows at stations up- and downstream of John Redmond Reservoir are highest over the April-to-July period and lowest over the November-to-February period (Putnam and Schneider 2005).

Studies of Aquatic Biota

WCNOC biologists monitored the macroinvertebrate communities of the Neosho River and Coffey County lake from 1973-1987 to determine spatial and temporal trends and identify possible effects of WCGS construction and operation (EA 1988). Neosho River benthos collections in most years were dominated by oligochaetes, mayflies, stoneflies, net-spinning caddisflies, and midges. No community changes attributable to construction or operation of WCGS were identified. Data were highly variable, due to fluctuating river flows that affected distribution and abundance of organisms and sampling efficiency (EA 1988). The potential for operational impacts was deemed low because of the relatively small amounts of water withdrawn from the John Redmond Reservoir tailwaters for Coffey County Lake makeup and because very little Coffey County Lake water enters the Neosho River via the Coffey County Lake dam spillway (EA 1988).

The Coffey County Lake macroinvertebrate community showed a lower species richness (70 taxa versus 179 taxa)than that found in the Neosho River and it was numerically dominated by aquatic midges (Dipterans) over the 1981-1987 period. Oligochaetes and Tubificids were also important components of the Coffey County Lake benthos community. Mayflies, caddisflies, and dragonflies were relatively less abundant. The numerical dominance of burrowing forms (chironomids and Tubificids) was attributed to the reservoir's "soft ooze-like" substrate, the substrate preferred by these groups. High annual variation from 1981-1987 was attributed to "ecological, climatological, and limnological factors" rather than station operations (EA 1988).

WCNOC biologists conducted pre-operational (1973 - 1984) and operational (1985 - 1987) monitoring studies of Neosho River and Wolf Creek fish populations (EA 1988). These studies were intended to establish baseline conditions with regard to Neosho River and Wolf Creek fish populations and, later, to identify possible changes in these populations associated with construction and operation of WCGS. WCGS received its operating license in March 1985, achieved initial criticality in late-May 1985, and began commercial operation in September 1985.

WCNOC surveys of the Neosho River (from John Redmond Reservoir tailwaters to below Wolf Creek) over the 1973-1987 period yielded 52 fish species, with 13 species appearing in samples in every year (EA 1988). Electrofishing and seine data from a pre-operational period (1977-1982) and an operational period (1985-1987) were pooled to examine species composition and relative abundance. Due to sampling methodology, relatively small number of species dominated samples in all years. Red shiners were most abundant in every year of the study. Gizzard shad and ghost shiners also appeared frequently in samples. These three species comprised 61 to 93 percent of all fish collected in all years but one, 1982 (EA 1988). But 1982 was atypical in that sampling was restricted to the John Redmond Reservoir tailwaters, which resulted in relatively more game fish (white bass and white crappie) and relatively fewer small, schooling fish (minnows and shad) being collected.

In all years, collections were dominated by Cyprinids (minnows and common carp) and Clupeids (gizzard shad). Cyprinids made up 61.2 percent of all fish collected in the 1977-1982 pre-operational period and 73.0 percent of all fish collected in the 1985-1987 operational period (EA

1988). Shad made up 16.4 percent of fish collected in the pre-operational period and 16.8 percent of fish collected in the operational period. Comparisons of other groups (Ictalurids, Catastomids, and Centrarchids) showed relatively small shifts in abundance between pre-operational and operational phases. All species collected were common in the Neosho River system except wiper (striped bass X white bass hybrid) and walleye, both introduced to upstream reservoirs by the Kansas Department of Parks and Wildlife.

Having monitored Neosho River fishes from 1973 to 1987, WCNOC concluded that construction of Coffey County Lake and operation of WCGS had little or no effect on Neosho River fishes (EA 1988). Changes in relative abundance were seen between years, but were relatively small and related to factors entirely outside of WCNOC's control. Weather, in particular, appeared to influence fish populations in the Neosho River downstream of John Redmond Reservoir. Rainfall up-river in the basin determined the volume of water moving into John Redmond Reservoir, which determined the amount of water released downstream into the Neosho River. The amount (and timing) of water released downstream affects macroinvertebrate distribution and abundance and macroinvertebrate drift. It also affects reproductive success of fish that spawn in the river, survival and growth of larval and juvenile fish, age and growth of adult fish, movement of all ages and stages of fish, and predator-prey relationships. Decades of research have shown that weather, specifically seasonal patterns of temperature and rainfall, has a profound effect on the distribution and abundance of benthic macroinvertebrates and fish in both unregulated streams (Larimore et al. 1959; Harvey 1987; Pearsons et al. 1992; Adams and Warren 2005) and tailwaters of flood-control and hydroelectric dams (Jacobs and Swink 1983; Cunningham and Zale 1998; Propst and Gido 2004).

Having established that WCGS was having little or no impact on Neosho River fish populations, WCNOC shifted its focus in 1988 from the Neosho River to Coffey County Lake. Just as significantly, WCNOC biologists transitioned from monitoring fish populations for possible station-related changes to monitoring fish populations in order to more effectively manage them. The primary fishery management goal in the years after the reservoir filled (reached normal operating level in 1982) was gizzard shad control; specifically limiting numbers of young shad in the reservoir because they were vulnerable to cold shock. The concern was that cold-killed and cold-stunned gizzard shad could clog Wolf Creek Generating Station's intake screens.

Before Coffey County Lake reached full pool in 1982, WCGS embarked on an "aggressive" stocking program with the goal of establishing a fishery with a diversity of predators. Species stocked in smaller impoundments within the basin to be flooded included largemouth bass, smallmouth bass, channel catfish, blue catfish, bluegill, black crappie, and walleye. Once filled, more of these species and wipers (striped bass X white bass hybrids) were added. Gizzard shad larvae were unavoidably introduced to the reservoir from the Neosho River when water was pumped to fill the reservoir. White bass and white crappie also appeared after the reservoir filled, and are presumed to have been introduced the same way (Haines 2000). No fishing was allowed in the reservoir in the 1980s, so there was no risk of sport fish populations being overfished. The ultimate goal was a "cropped" prey (gizzard shad) population with a relatively high proportion of larger, older individuals and low reproductive potential and a diverse, fast-growing community of predators with the ability to take different ages and sizes of shad occupying different parts of the reservoir.

After the reservoir was opened to fishing, gamefish populations were managed both to control shad and provide local and regional anglers with high-quality fishing. In June 1998, Coffey County assumed responsibility for managing public use of the WCGS cooling reservoir and changed the name of the reservoir to Coffey County Lake (Coffey County 2005). At that time, the Coffey County Sheriff's Office assumed responsibility for controlling public access to the reservoir. The reservoir is open for public use (fishing) seven days a week from sunrise to sunset, weather and reservoir levels permitting.

Coffey County Lake, with its thriving populations of channel catfish, white crappie, smallmouth bass, walleye and wipers, has become a popular destination for Kansas anglers. Kansas Department of Wildlife and Parks (KDWP) issues annual Fishing Forecasts for public waters in Kansas, which are in effect ratings of public fishing areas. Coffey County Lake received biologists' rating of Excellent for walleye (the only state reservoir to receive this ranking for walleye) and smallmouth bass (the only state reservoir to receive this ranking for smallmouth bass) (KDWP 2004). Channel catfish, white crappie, white bass, and wiper fishing were all rated Good.

WCNOC closely monitors fish populations in Coffey County Lake in order to draft annual fisheries management plans that will satisfy the complementary goals of controlling gizzard shad numbers and maintaining healthy populations of gamefish. WCNOC biologists use a variety of gear types (e.g., electrofishing, fyke netting, gill netting, and seining) and sample Coffey County Lake in systematic fashion to ensure that species of interest are effectively sampled and sampling results are amenable to statistical analysis. Fish are collected in spring, summer, or fall, depending on the species and its seasonal habitat preferences. Sampling is intended to gather information on gizzard shad reproduction, survival, and abundance and predator (largemouth bass, smallmouth bass, white bass, wiper, and walleye) age and growth, condition, and abundance.

Having established population characteristics (size and age distribution, year class strength, actual and relative abundance) and compared population data to previous years, WCNOC biologists submit annual fisheries monitoring reports and management recommendations to Wolf Creek Generating Station's Manager of Regulatory Affairs. These findings are also discussed with KDWP fishery biologists, who then draft regulations for Coffey County Lake for WCNOC review. When both organizations are satisfied with the proposed regulations, KDWP biologists submit these regulations to the Kansas Wildlife and Parks Commission, which typically approves them. Regulations approved by the Commission are adopted and made enforceable by order of the Secretary of Wildlife and Parks.

2.3 GROUNDWATER RESOURCES

WCGS is located in the Central Lowland physiographic province. The land surface is gently rolling in the Central Lowland province except where major rivers and their tributaries are deeply incised. Kansas, Missouri, and Nebraska are in part of the North American craton, an area that has been tectonically stable throughout most of geologic time. The area has undergone some deformation, as demonstrated by the Nemaha Uplift, located approximately 50 miles west of WCGS. Pennsylvanian strata are present in the area of WCGS, consisting of shale, sandstone, limestone, and some coal beds. Quarternary and tertiary deposits, consisting primarily of unconsolidated sand and gravel, exist along the Neosho River (USGS 1997).

WCGS makes no groundwater withdrawals for plant consumptive use. Only small quantities of groundwater are available within a 50-mile radius of WCGS. The groundwater is produced from three types of aquifers: the alluvial deposits in the river valleys, the weathered bedrock including the shallow soil, and the unweathered bedrock (WCNOC 2004).

The regional alluvial aquifer along the Neosho River is composed of sands, silts, and gravel. The width of the alluvium in the valley ranges from 1 to 10 miles, but is less than 20 feet thick in Coffey, Woodson, and Allen counties. Yields from wells in the alluvial aquifer are less than 100 gallons per minute (WCGS 1980). Recharge occurs from precipitation and from the Neosho River during periods of high flow (WCNOC 2004). The level in the aquifer is, therefore, closely related to the river level. The chemical quality of the water in regional alluvial aquifers generally is suitable for most uses. Typically, the water is hard and a calcium biocarbonate type. Dissolved solids concentrations are generally less than 500 milligrams per liter and high iron concentrations are common (USGS 1997).

The weathered bedrock aquifer consists of weathered shales, siltstones, sandstones, and limestones (WCNOC 2004). The weathered zone may be up to 40 feet thick (NRC 1975). Pressure tests indicate that this aquifer is sufficiently permeable to yield up to 10 gallons per minute. Recharge occurs from precipitation and locally from downward percolation through the overlying alluvium. Discharge occurs into both alluvium and streams (WCNOC 2004).

The consolidated bedrock aquifers are composed of sandstones and limestones which are limited to yields ranging from about 1 to 10 gallons per minute. Recharge occurs by precipitation and infiltration of surface water at the outcrops. Where overlain by shales and siltstones, which act as aquitards and aquicludes, vertical recharge to the limestones and sandstones is minimal (WCNOC 2004). Test holes installed at WCGS suggest the presence of an aquiclude at a depth of about 40 feet (NRC 1975).

Groundwater movement is in a southwesterly direction from the plant site towards the Neosho River. The water table contour is a muted image of the surface topography. The piezometric surface of the deeper aquifers reflects the gradient of the parent formation. In all cases, the gradient is generally from the site toward the Neosho River (NRC 1975).

2.4 CRITICAL AND IMPORTANT TERRESTRIAL HABITATS

WCGS is located in Coffey County, Kansas, approximately 3.5 miles east of the Neosho River and the John Redmond Reservoir, and 28 miles east-southeast of Emporia, Kansas. The WCGS site encompasses approximately 9,818 acres. The site includes the 5,090-acre Coffey County Lake, which was formed by the construction of an earth dam across Wolf Creek, and a 31-acre pond originally constructed primarily to receive lime sludge. The power plant and associated buildings and areas comprise 135 acres.

Land management activities on property outside the WCGS site is designed to achieve a balance between agricultural productionand conservation. In 2004, approximately 1,420 acres were leased for grazing, 540 acres were leased for hay production, and 1,270 acres were leased for crops such as soybeans, milo, corn, and wheat (WCNOC 2005a). WCNOC's agricultural leases require conservation practices such as contour plowing and construction and/or maintenance of terraces to reduce soil erosion. At harvest, crops around field edges are left in the fields for wildlife (WCNOC 2005b).

Grazing restrictions, pasture rotation, and controlled burning are used to ensure continued rangeland health at WCGS (WCNOC 2005b). Fire has always been an integral part of prairie habitats, and prescribed burning is used on grasslands at WCGS to control woody brush invasion, control less desirable cool-season grasses or weeds, increase wildlife value, and to increase prairie vigor and production. Prescribed burning was completed on approximately 1,150 acres during 2004 (WCNOC 2005a). Most grassland units at WCGS are scheduled to be burned once every third year.

Native prairie at WCGS is categorized as "bluestem prairie" and is typically composed of tall grasses and many species of forbs (NRC 1975). Most forested areas at WCGS are in lowlands, and consist of trees such as hackberry (*Celtis occidentalis*), black walnut (*Juglans nigra*), American elm (*Ulmus americana*), bur oak (Quercus macrocarpa), and white bitternut hickory (*Carya cordiformis*) (WCGS 1980).

A 200- to 400-foot wide area adjacent to the Coffey County Lake shoreline has been managed since 1980 as a natural area buffer between the lake and agricultural areas. Agricultural activities are not allowed in this area, and previously cultivated lands have been allowed to advance through natural succession stages. Native grasses have been re-established in some portions of the lakeside buffer zone, and land management activities here include controlled burning (WCNOC 2005a).

The 31-acre Lime Sludge Pond (Figure 2-3) discussed in Section 3.1.5 was originally constructed to receive lime sludge, but it was never used for that purpose. It is an unlined pond north of the switchyard and adjacent to Coffey County Lake, and like Coffey County Lake, it provides habitat for numerous aquatic species (plants, invertebrates, and fish) and semi-aquatic species (waterfowl, wading birds, reptiles, amphibians, and mammals).

A wildlife monitoring program was initiated in 1982 to monitor and assess waterfowl, water bird, and bald eagle usage of Coffey County Lake and the Lime Sludge Pond. This program included transmission-line collision surveys to assess avian collision mortality and determine potential mitigation needs. Upon completion of monitoring in 1986, sufficient data had been collected to determine that avian collisions with transmission lines were minimal, and no endangered or threatened species were found. Consequently, the scope of the wildlife monitoring program was reduced (WCNOC 1988).

The current program consists of annually reviewing waterfowl and bald eagle survey data collected by the KDWP and then determining if changes to the wildlife monitoring program are warranted (WCNOC 2005a).

The Wolf Creek Environmental Education Area is an approximately 500-acre nature area near the north end of the site property. It consists of five trails that guide visitors through a variety of habitats, including native tall grass prairie, native and planted forests, wetlands, and wildlife food plots.

The Wolf Creek Environmental Education Area is the result of a partnership between private citizens, civic organizations, local, state, and federal governments, and WCGS.

The area surrounding WCGS consists mainly of rangeland and farmland, with occasional forested areas along the Neosho River and various creeks. The rangeland is mostly native grass, mixed grass-brush, and managed pastures. There is no federally designated or proposed critical habitat for threatened or endangered terrestrial species in the vicinity of WCGS or its associated transmission lines.

Section 3.1.3 describes the transmission lines that were built to connect WCGS to the transmission grid system. The corridors pass through land that is primarily agricultural and open range. The corridors do not cross any state or federal parks, wildlife refuges, or wildlife management areas. State and federal land in the vicinity of WCGS is associated with the John Redmond Reservoir west of the WCGS site. The John Redmond Wildlife Area, managed by KDWP, lies approximately one mile west of the pre-existing WCGS-to-Benton corridor where the corridor passes west of Coffey County Lake. Flint Hills National Wildlife Refuge, managed by the U.S. Fish and Wildlife Service (USFWS), is an 18,500-acre area located on the upstream portion of John Redmond Reservoir on land owned by the U.S. Army Corps of Engineers.

Biologists at WCGS work closely with the USFWS and KDWP on wildlife and habitat management at WCGS. For example, four ospreys (*Pandion haliaetus*) were released each year from 1996 to 2001 at the Wolf Creek Environmental Education Area in cooperation with KDWP in an attempt to establish a nesting population. In addition, five juvenile American peregrine falcons (*Falco peregrinus anatum*) were released at WCGS in 2004, and five more peregrine falcons were released in 2005, in an attempt to establish a nesting population (Haines 2005).

2.5 ENDANGERED AND THREATENED SPECIES

Table 2-1 presents animal and plant species that are federally or state-listed as endangered or threatened, or are proposed or candidates for listing, in counties within which WCGS and associated transmission lines are located. The transmission lines are located in Butler, Coffey, and Greenwood Counties. The species included in Table 2-1 are those that meet one of the following conditions:

- Records maintained by U.S. Fish and Wildlife Service Region 6 (USFWS 2005a) indicate the species has been recorded in at least one of the counties crossed by transmission line.

- Records maintained by KDWP (2005) indicate that at least one county crossed by transmission lines is within the known historic range[1] of the species, or the county includes state-designated critical habitat for the species.

Federally listed and state-listed species recorded in Coffey, Butler, and Greenwood Counties consist of six birds, one mammal, two fish, six mussels, and one plant (Table 2-1). The federally listed species (and the one species that is a candidate for federal listing) in Table 2-1 are discussed below.

Bald eagle

The bald eagle (*Haliaeetus leucocephalus*) is federally and state-listed as threatened. Bald eagles occur in a wide variety of habitats, but proximity to water is important. Preferred habitat includes a high amount of water-to-land edge where prey is concentrated. Thus, bald eagles are generally restricted to coastal areas, lakes, and rivers. Bald eagles prey on fish near the surface but will eat dead fish or other carrion, as well as birds and mammals. Bald eagle populations declined in the early 20th century due to loss of habitat, shooting, and trapping. During the 1950s and 1960s, the use of organochlorine pesticides such as DDT contributed to poor nesting success through bioaccumulation and subsequent eggshell thinning. Most organochlorine pesticides are now banned in the United States, and bald eagle populations are increasing. Some bald eagles migrate while others stay in the same area year round. Migratory eagles concentrate near open water in the winter (USFWS 2005b). A pair of bald eagles has nested at WCGS in the northern portion of Coffey County Lake since 1994. The nest is monitored by USFWS in cooperation with WCNOC. Numerous transient bald eagles sometimes congregate in winter along Coffey County Lake and John Redmond Reservoir.

Least tern

The least tern (*Sterna antillarum*) is state-listed as endangered, and interior populations of the species are federally-listed as endangered. The "interior" populations are those more than 50 miles from coasts. Least terns winter in Central and South America and are found in Kansas only during migration or during summer nesting. Nesting habitats for the interior least tern are

1 The KDWP (2005) website includes a link to county lists of threatened and endangered species. However, the KDWP county lists include not only species recorded in the county of interest, but also species whose "probable historic range" encompass that county. This is not readily apparent when viewing the county lists. The "species information" and "range maps" links at the KDWP website provide information on the known historic range and state-designated critical habitat for the species in question.

sparsely vegetated sand and gravel bars within wide unobstructed river channels. They occasionally nest in sand and gravel pits, dredge islands, or along lake shorelines. Least terns feed by hovering and diving for small fish. The interior population of the least tern has declined primarily due to loss of habitat from dam construction and river channelization on major rivers throughout the Mississippi, Missouri, and Rio Grande River systems (USFWS 2005b). Because of dams, river flows are often not conducive to the creation and maintenance of sandbars with sparse vegetation. Other disturbances, such as housing construction and development, and recreational activities that disturb nest sites, continue to threaten least tern populations (USFWS 2005b). The Final Environmental Statement (FES) related to the operation of WCGS stated that the least tern was observed at John Redmond Reservoir in 1977, but the FES did not specify whether the occurrence referred to migratory or nesting terns (NRC 1982). One to six least terns were observed on a few occasions at Coffey County Lake during the mid 1980s but the terns were presumed to be transients, and there has been no known nesting of least terns at Coffey County Lake (Haines 2005). The USFWS Region 6 website indicates no current records of the least tern in Butler, Coffey, or Greenwood Counties (USFWS 2005a), but the KDWP website shows Coffey County as within the known historic range of the least tern (KDWP 2005).

Piping plover

The piping plover (*Charadrius melodus)* is state-listed as threatened. Piping plovers breed in North America in three geographic regions: the Atlantic Coast, the Northern Great Plains, and the Great Lakes. The Northern Great Plains population is federally listed as threatened. Piping plovers return to their breeding grounds in March or April, and depart by September to winter along the Gulf Coast. Northern Great Plains piping plovers nest on wide, sparsely vegetated sand or gravel beaches along alkali lakes, rivers, or dredge islands. They forage near water and prey on invertebrates (USFWS 2005b). Critical habitat has been designated by the USFWS for piping plover breeding habitat in Minnesota, Montana, North Dakota, South Dakota, and Nebraska, but not Kansas. Current threats to the piping plover consist primarily of destruction of sandbars for flood control and navigation, and water level regulation policies (USFWS 2005b). The USFWS Region 6 website indicates no current records of the piping plover in Butler, Coffey, or Greenwood Counties (USFWS 2005a), but the KDWP website shows Coffey County as within the known historic range of the piping plover (KDWP 2005).

Whooping crane

The whooping crane (*Grus americana*) is federally and state-listed as endangered. The historical breeding range of the whooping crane included the northern Great Plains, and the birds historically wintered along the Gulf of Mexico. Currently, most whooping cranes breed in the Northwest Territories (Canada) and winter at the Aransas National Wildlife Refuge on the coast of Texas (USFWS 2005b). Birds from this population migrate through central Kansas during the spring and fall. Whooping cranes feed and roost in wetlands and upland grain fields, and nest in marshy areas among cattails, bulrushes, and sedges. Whooping cranes feed on crabs, clams, crayfish, frogs, and other small aquatic life, as well as rodents, small birds, and berries. Loss of habitat is the main reason for the whooping crane's decline. Cheyenne Bottoms State Waterfowl Management Area and Quivira National Wildlife Refuge have been designated as Critical Habitat for migrating whooping cranes under the Endangered Species Act (USFWS 2005b). These two areas are approximately 150 miles west of WCGS and more than 80 miles northwest of the western terminus of the WCGS-Rose Hill transmission line. The USFWS Region 6 website indicates no current records of whooping cranes in Butler, Coffey, or Greenwood Counties (USFWS 2005a), but the KDWP website shows Coffey and Greenwood Counties as within the known historic range of the whooping crane (KDWP 2005).

Mead's milkweed

Mead's milkweed (*Asclepias meadii*) is federally listed as threatened. The State of Kansas does not include plant species in its list of endangered and threatened species. Mead's milkweed is a perennial herb. Its greenish-white flowers are borne in a single cluster atop a two-foot stalk in May and early June. It requires five to eight years to reach maturity from seed. Plants appear to be long-lived and may live for more than a century (NatureServe 2005). Mead's milkweed is a species of dry-mesic to mesic tallgrass prairies, but has also been recorded from chert glades and sandstone rock-ledges. Plants seem to prefer full sun, occupying slopes that grade between 0 and 18 percent. The species was formerly widespread over much of the native tallgrass prairie region of the Midwest. It is currently known from 27 counties in eastern Kansas, west-central Missouri, south-central Iowa and eastern Illinois. Mead's milkweed is threatened by factors such as loss of habitat due to urbanization and agricultural land conversion, loss of pollinators, loss of fire regime, mowing prior to seed set, pesticide application or drift from adjacent land, and a lack of adequate prairie management (NatureServe 2005). The USFWS Region 6 website indicates current records of this species in Coffey County (USFWS 2005a). The KDWP county occurrence website does not include plants.

Topeka shiner

The Topeka shiner (*Notropis topeka*) was listed by the USFWS as endangered in 1998 (63 FR 69008-69021) and is currently listed as threatened by the state of Kansas. Once common in small prairie streams in the midwest, the species is now restricted to a few headwater tributaries of the Missouri and Mississippi Rivers in portions of Minnesota, Iowa, Missouri, South Dakota, Nebraska, and Kansas (Lee et al. 1980; USFWS 1997; USFWS 2005). Many populations have disappeared over the last 30 years, particularly in Iowa, Kansas, and Missouri where the species was once relatively common (USFWS 1997; USFWS 2005a). The USFWS attributed this decline to habitat loss and degradation, with the decline possibly exacerbated by the introduction of non-native fishes (63 FR 69008-69021).

In Kansas, the Topeka shiner is found mainly in small headwater streams in the Flint Hills, in the east-central part of the state. These include a number of tributaries of the Cottonwood River, the Big Blue River, and the Smoky Hill River (KDWP 2004a). The Cottonwood River is a tributary of the Neosho River, which is the source of WCGS's makeup (cooling) water. Topeka shiner populations in the Cottonwood/Neosho drainage in Butler, Chase, and Greenwood Counties are more than 40 miles upstream of WCGS in small streams that are unaffected by WCGS operations. The KDWP has designated several dozen streams (and stream segments) in Kansas as critical habitat for the Topeka shiner (KDWP 2004a), indicating that they are essential for the conservation of the species. None of these streams or stream segments could be affected by operation of WCGS, because WCGS is downstream from these segments.

Neosho madtom

The Neosho madtom (*Noturus placidus*) is currently listed as threatened by both the USFWS and the KDWP. The Neosho madtom is a small (less than 3 inches long) catfish that is native to the Arkansas River Basin of Kansas, Oklahoma, and Missouri. Neosho madtoms are found in rocky riffles and along sloping gravel bars in relatively clear rivers of moderate size. The most important populations are believed to be those of the Cottonwood, Neosho, and Spring Rivers of Kansas (Wenke and Eberle 1991). Smaller populations are found in adjacent areas of Oklahoma (Ottawa and Craig Counties) and Missouri (Jasper County). Within this limited range, the Neosho madtom has experienced population declines as the result of drought-related habitat degradation, removal of gravel bars, and water pollution from feedlot runoff (Wenke and

Eberle 1991). Habitat loss has also followed the construction of mainstream impoundments in Kansas and Oklahoma that inundated Neosho madtom habitat. KDWP has designated the Cottonwood, Neosho, and Spring Rivers as critical habitat for the Neosho madtom, including the main stem of the Neosho River from its point of discharge from the John Redmond Reservoir to the Kansas-Oklahoma border (KDWP 2004b).

USFWS and USGS researchers compared densities of several catfish species up- and downstream of John Redmond Reservoir over an 8 year (1991-1998) period to determine if flow, habitat, and water quality alteration associated with the creation and operation of the flood control reservoir and dam had affected downstream ictalurid populations, in particular the threatened Neosho madtom (Wildhaber et al. 2000). They found that Neosho madtom densities were significantly higher above John Redmond Reservoir than below John Redmond Dam and determined that higher upstream densities were associated with higher levels of turbidity and smaller-sized gravel in the substrate. These up- and downstream differences in turbidity and substrate composition were attributed to operation of the dam and flood control reservoir. The presence of John Redmond Dam and Reservoir also changed annual flow regimes below the dam, resulting in lower minimum flows, lower short-term (1-day and 3-day) maximum flows, reduced variation in flow rates, increased winter flows, increased long-term (30-day and 90-day) maximum flows, increased length and variability in length of high-flow events, and later date of maximum annual flow below the dam. In essence, the Neosho River below John Redmond Reservoir has become a river with lower minimum flows, lower short-term (e.g., daily) flows, and higher long-term (e.g., monthly) flows, all of which stem from management of the reservoir to maintain water levels in the reservoir and minimize downstream flooding. Certain minimum flows in spring are necessary to ensure successful Neosho madtom reproduction; certain minimum flows in late-summer and fall improve overwinter survival of young-of-the-year madtoms. Based on these findings, the USFWS and USGS researchers recommended that additional data be obtained on habitat requirements of Neosho River madtoms and that flows below the John Redmond Dam be increased during critical periods to “assess if fish populations and habitat respond to changes in flow as predicted by this study” (Wildhaber et al. 2000).

Neosho madtoms were occasionally collected in the 1970s in kick-seine samples from the Neosho River up- and downstream of the Wolf Creek-Neosho River confluence by biologists conducting baseline surveys for WCGS (WCGS 1980). Neosho madtoms continued to appear in Neosho River kick-seine samples after the Station became operational, in 1985 (EA 1988). A total of 110 Neosho madtoms were collected (and released unharmed) from Neosho River monitoring stations over the 1985-1991 period (EA 1988, Maynard 1990a,b; Rhodes 1991; Rhodes 1992). Flooding hindered seining in 1992 and no Neosho madtoms were collected (Hagan 1992). WCGS discontinued its monitoring of Neosho River fishes in 1993, turning its focus to the fish community of Coffey County Lake.

Neosho mucket mussel

The Neosho mucket mussel (Lampsilis rafinesqueana)is a riverine Unionid that is associated with shallow, unpolluted streams with fine to medium gravel substrates (KDWP 2004c). The Neosho mucket is found in the Illinois, Neosho, and Verdigris River systems of Kansas, Oklahoma, Missouri, and Arkansas. Once relatively widespread, it has disappeared from approximately 70 percent of its range, with Kansas and Oklahoma portions of its range experiencing the worst losses (Center for Biological Diversity 2004). Neosho mucket habitat has been degraded by pollutants, impaired by gravel mining, and inundated by impoundments.

The Neosho mucket mussel has been designated an endangered species by the state of Kansas and has been a candidate for federal listing since 1984 (KDWP 2004c; Center for Biological Diversity 2004). This freshwater mussel was once found in streams across eastern Kansas, but is now largely restricted to the Neosho and Verdigris Rivers and their tributaries and a short segment of the Spring River in Cherokee County in the southeastern corner of Kansas (KDWP 2004c; Obermeyer 2000). KDWP has designated sections of these rivers as critical habitat for the species, including the main stem of the Neosho River from State Highway 58 (Coffey County) to the Kansas/Oklahoma border (KDWP 2004c), which includes portions of the Neosho River downstream of its confluence with Wolf Creek.

Summary

Of the seven federally listed species and one federal candidate species in Table 2-1, only four species (bald eagle, least tern, Neosho madtom, and Neosho mucket mussel) have been confirmed in the vicinity of WCGS or along the associated transmission corridors. A pair of bald eagles has nested at Coffey County Lake since 1994. Least terns were observed at Coffey County Lake as recently as the 1980s, but there has been no known nesting of least terns at the lake. The Neosho madtom and the Neosho mucket mussel occur in the Neosho River up-and downstream of its confluence with Wolf Creek. As discussed in Section 2.4, peregrine falcons, a state-listed species, have been released in the vicinity of Coffey County Lake. With the exception of these five species, no state- or federally listed species is known to occur in the vicinity of the WCGS site or along the associated transmission corridors.

2.6 DEMOGRAPHY

2.6.1 Regional Demography

The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) presents a population characterization method that is based on two factors: "sparseness" and "proximity" (NRC 1996). "Sparseness" measures population density and city size within 20 miles of a site and categorizes the demographic information as follows:

Demographic Categories Based on Sparseness

		Category
Most sparse	1.	Less than 40 persons per square mile and no community with 25,000 or more persons within 20 miles
	2.	40 to 60 persons per square mile and no community with 25,000 or more persons within 20 miles
	3.	60 to 120 persons per square mile or less than 60 persons per square mile with at least one community with 25,000 or more persons within 20 miles
Least sparse	4.	Greater than or equal to 120 persons per square mile within 20 miles
Source: NRC 1996.		

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

Demographic Categories Based on Proximity

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

Demographic Categories Based on Proximity (Continue)

		Category
In close proximity	4.	Greater than or equal to 190 persons per square mile within 50 miles
Source: NRC 1996.		

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

GEIS Sparseness and Proximity Matrix

Proximity

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

Low Population Area

Medium Population Area

High Population Area

Source: NRC 1996.

WCNOC used 2000 census data from the U.S. Census Bureau (USCB 2000a) and the Kansas Geospatial Community Commons (KGCC 2000) with geographic information system software (ArcView®) to determine most demographic characteristics in the WCGS vicinity. The calculations (TtNUS 2005a) determined that 13,095 people live within 20 miles of WCGS, producing a population density of 10 persons per square mile. Applying the GEIS sparseness measures results in the most sparse category, Category 1 (less than 40 persons per square mile and no community with 25,000 or more persons within 20 miles).

To calculate the proximity measure, WCNOC determined that 176,301 people live within 50 miles of WCGS, which equates to a population density of 23 persons per square mile (TtNUS 2005a). Applying the GEIS proximity measures, WCGS is classified as Category 1 (no city with 100,000 or more persons and less than 50 persons per square mile within 50 miles). Therefore, according to the GEIS sparseness and proximity matrix, WCGS ranks of sparseness, Category 1, and proximity, Category 1, result in the conclusion that WCGS is located in a low population area.

The nearest major metropolitan area is Kansas City, Kansas (75 miles northeast), with a 2000 population of 146,866 (USCB 2000b). The population distribution within a 50-mile radius of

WCGS is generally considered rural. Minor exceptions to this are Emporia (28 miles northwest) and Ottawa (35 miles northeast) where the 2000 populations were 26,760 and 11,921, respectively. The municipality nearest the WCGS is the City of Burlington (3.5 miles southwest) with a 2000 population of 2,790 (USCB 2000c).

All or parts of 21 counties, Emporia, Ottawa, and sections of three Metropolitan Statistical Areas (MSAs) and one Micropolitan Statistical Area are located within 50 miles of WCGS (Figure 2-1). The MSAs are (1) Kansas City, Missouri-Kansas, (2) Topeka, Kansas, and (3) Lawrence, Kansas, and the Micropolitan Statistical Area is Emporia, Kansas (USCB 2003).

From 1990 to 2000, the population of the Kansas City MSA increased from 1,636,528 to 1,836,038, an increase of 12.2 percent. The population of the Topeka MSA increased from 210,257 to 224,551, an increase of 6.8 percent. The population of the Lawrence MSA increased from 81,798 to 99,962, an increase of 22.2 percent. And, the population of the Emporia Micropolitan Statistical Area increased from 37,753 to 38,965, an increase of 3.2 percent (USCB 2003).

Because approximately 70 percent of employees at WCGS reside in Coffey and Lyon Counties, they are the counties with the greatest potential to be socioeconomically affected by license renewal at WCGS (see Section 3.4). Table 2-2 shows population estimates and decennial growth rates for these two counties. Values for the State of Kansas are provided for comparison. The table is based on U.S. Census Bureau (USCB) data for 1980, 1990, and 2000, University of Kansas Policy Research Institute projections through 2010, and a WCNOC projection to 2050 that is based on linear regression techniques.

Over the last several decades, Coffey and Lyon Counties have fluctuated between positive and negative growth rates. From 1970 to 1980, Coffey and Lyon Counties' growth rates were relatively large, outpacing the state of Kansas as a whole. From 1980 to 1990, population growth slowed for the entire state of Kansas and Coffey and Lyon Counties' population growth rates were negative. From 1990 to 2000, Kansas' population growth rate was 8.5 percent, while Coffey County increased by 5.4 percent and Lyon County increased by 3.5 percent (TtNUS 2005b).

2.6.2 Minority and Low-Income Populations

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

WCNOC used ArcView® geographic information system software to determine the minority characteristics by block group. WCNOC included all block groups if any part of their area lay within 50 miles of WCGS. The 50-mile radius includes 196 block groups (Table 2-3).

2.6.2.1 Minority Populations

The NRC Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues defines a "minority" population as: American Indian or Alaskan Native; Asian; Native Hawaiian or other Pacific Islander; Black Races, and Hispanic Ethnicity (NRC 2001). Additionally, NRC's guidance requires that (1) all other single minorities are to be treated as one population and analyzed, and (2) the aggregate of all minority populations are to be treated as one population and analyzed. The guidance indicates that a minority population exists if either of the following two conditions exists:

- The minority population in the census block group or environmental impact site exceeds 50 percent.
- The minority population percentage of the environmental impact area is significantly greater (typically at least 20 percentage points) than the minority population percentage in the geographic area chosen for comparative analysis.

For each of the 196 block groups within the 50-mile radius, WCNOC calculated the percent of the block group's population represented by each minority. If any block group minority percentage exceeded 50 percent, then the block group was identified as containing a minority population. WCNOC selected the entire State of Kansas as the geographic area for comparative analysis, and calculated the percentages of each minority category in the State. If any block group percentage exceeded the corresponding State percentage by more than 20 percent, then a minority population was determined to exist (TtNUS 2005a).

Census data for Kansas (USCB 2000d) characterizes 0.9 percent of the population as American Indian or Alaskan Native; 1.7 percent Asian; 0.0 percent Native Hawaiian or other Pacific Islander; 5.7 percent Black races; 3.4 percent all other single minorities; 2.1 percent multi-racial; 13.9 percent aggregate of minority races; and 7.0 percent Hispanic ethnicity.

Table 2-3 presents the numbers of block groups in each county in the 50-mile radius that exceed the threshold for minority populations. Figures 2-4 through 2-6 locate the minority block groups within the 50-mile radius.

Five census block groups within the 50-mile radius have All Other Single Minority populations that exceed the state average by 20 percent or more. They are all located in Lyon County.

Five census block groups within the 50-mile radius have Aggregate Minority populations that exceed the state average by 20 percent or more. Of those five block groups, one has Aggregate Minority populations of 50 percent or more.

Nine census block groups within the 50-mile radius have Hispanic Ethnicity populations that exceed the state average by 20 percent or more. Of those nine block groups, one has Hispanic Ethnicity populations of 50 percent or more.

2.6.2.2 Low-Income Populations

NRC guidance defines low-income population based on statistical poverty thresholds (NRC 2001) if either of the following two conditions are met:

- The low-income population in the census block group or the environmental impact site exceeds 50 percent.
- The percentage of households below the poverty level in an environmental impact area is significantly greater (typically at least 20 percentage points) than the low-income population percentage in the geographic area chosen for comparative analysis.

WCNOC divided USCB low-income households in each census block group by the total households for that block group to obtain the percentage of low-income households per block group. Using the State of Kansas as the geographical area chosen for comparative analysis, WCNOC determined that 10.1 percent of Kansas as low-income households (TtNUS 2005a). Table 2-3 identifies the low-income block groups in the region of interest, based on NRC's two criteria. Figure 2-7 locates the low-income block groups.

Seven census block groups within the 50-mile radius have low-income households that exceed the state average by 20 percent or more. Of those seven block groups, one has 50 percent or more low-income households.

2.7 TAXES

The owners of WCGS pay annual property taxes to Coffey County, so the focus of this analysis will be on Coffey County.

From 2000 through 2004, Coffey County collected between $28.7 and $31.3 million annually in tax revenues (see Table 2-4). Each year, Coffey County collects these taxes, retains a portion for county operations (which include libraries, hospitals, roads, etc.), and disburses the remainder to school districts, fire districts, and the county's municipalities to fund their respective operating budgets (Raaf 2005). For the years 2000 through 2004, WCGS's property taxes have represented 80 to 85 percent of Coffey County's total tax revenues (Table 2-4). Over the past five years, 38 to 46 percent of the WCGS property tax payment has been received by Unified School District #244 (WCNOC 2005).

WCGS's annual property taxes are expected to remain relatively constant through the license renewal period. With respect to deregulation, the State of Kansas has taken no action. Therefore, the potential effects of deregulation would be unknown at this time. Should deregulation ever be enacted in Kansas, this could affect utilities' tax payments to counties. However, any changes to WCGS property tax rates due to deregulation would be independent of license renewal.

2.8 LAND USE PLANNING

This section focuses on Coffey and Lyon Counties because the majority (approximately 70 percent) of the permanent WCGS workforce lives in these counties (see Section 3.4) and because WCNOC pays property taxes in Coffey County.

From 1990 to 2000, Coffey County's population growth rate was 5.4 percent and Lyon County's population growth rate was 3.5 percent, while the population of the state of Kansas grew 8.5 percent (Section 2.6). Over the same period, 1990 to 2000, the number of housing units in Coffey County increased by 4.4 percent and the number of housing units in Lyon County increased by 2.9 percent, while the total number of units in the state increased by 8.3 percent (USCB 1990; USCB 2000).

Coffey County does not have a comprehensive land use plan, but uses zoning and subdivision regulations to control development. Lyon County uses a comprehensive land use plan and zoning and subdivision regulations to guide development. Both counties encourage growth in areas where public facilities, such as water and sewer systems, exist or are scheduled to be built in the future. Both counties promote the preservation of the communities' natural resources and neither county has growth control measures.

Coffey County

Coffey County covers 630 square miles of land area (USCB 2005), which is predominantly rural. Land in the WCGS' immediate vicinity is used for agriculture and livestock grazing (Hotaling 2005). WCGS and its cooling lake are built on a 9,818-acre tract of land near Burlington (NRC 1996). The cooling lake inundated approximately 5,090 acres of land, and the actual plant facilities, including the lake's dam and dikes, cover approximately 200 acres.

Since WCGS's construction, industries have located in Burlington, Gridley, Waverly, Lebo, and Le Roy. However, most of the industries are small (under 100 employees) (Hotaling 2005). The County has a revolving loan program that provides loans to businesses at relatively low interest rates, making company relocation to Coffey County more appealing (Hotaling 2005). Burlington, a town that had only two small rural industries when WCGS's operation began, now has two industrial parks and one commercial park. Additionally, the intersection of I-35 and U.S. 75 is host to a concentration of commercial and industrial land users (Casper 2005).

Most residential development is concentrated in or near the County's incorporated towns and cities. However, there has been a recent trend involving residential movement to more rural areas of the County. People are purchasing individual tracts of land in rural areas, constructing homes, and commuting to urban centers for work. However, there have been no major residential developments in these rural areas (Casper 2005).

Because Coffey County is primarily rural, many workers commute into the county from other places such as Emporia, Ottawa, Topeka, and Kansas City. They prefer to live near larger metropolitan areas and commute to jobs in the county (Casper 2005).

Lyon County

Existing Land Use

Lyon County covers 851 square miles of land area (USCB 2005). Land use planning in Lyon County is guided by the Lyon County Planning and Zoning Boards. They have developed a land use plan, the *Comprehensive Plan for Lyon County, Kansas* (Lyon County 2001), to assess current land use trends and guide future land use decision-making. A review of land use plan indicates that there are approximately 2,000 home sites within Lyon County, with well over 300 tracts having an area of 3 acres or less. Many uses are currently non-conforming, with respect to size, and local planning officials project that there will continue to be new housing units developed within the unincorporated areas of Lyon County. U.S. Census Bureau (USCB) data indicate that from 1990 to 2000, the population of Lyon County has increased 3.5 percent. However, local planning officials have projected that the County's population will decline modestly thereafter (as shown in Table 2-2). They also state that there has been an increase in population within the City of Emporia, but an overall decrease in the rural population (Lyon County 2001).

The Lyon County Zoning Board and staff have identified development trends in the following areas located outside of their metropolitan planning area (Lyon County 2001):

1) Along Old Highway 50 between Emporia and the Lyon-Coffey county line
2) East of Emporia, between Highway 50 and Interstate 35
3) Along Burlingame Road North, from Road 190 (old Rinker school house) to the junction of Highway 99
4) Along Americus Road, between Emporia and Americus
5) Along Highway 50, west of Emporia
6) Along Road E, west of Emporia, from Road 180 to Road 210
7) Along Road 130, from Highway 99, south of Emporia, west to Lockerman Road
8) Along Road 110, from Highway 99, south of Emporia, west to Lockerman Road
9) From Highway 99, north of Emporia, to the Burlingame Road intersection

As observed by the Planning Board, rural residential growth has followed the water lines improved by the Water Districts in Lyon County. Current land use data indicate that a large percentage of the rural residential development has occurred within one mile of the Emporia-Lyon County metropolitan planning area and also along the above-designated areas. The goals and objectives, adopted as a part of the County comprehensive plan, amendments of the zoning and subdivision regulations, are designed to promote orderly development as the County and cities respond to growth pressures in the unincorporated areas (Lyon County 2001).

Lyon County Planning Goals

The Lyon County planning goals are as follows (Lyon County 2001):

1) To preserve and enhance utilization of rural land for agricultural purposes, while ensuring sufficient amounts of developable land suitable for future urban growth.

2) To provide ample opportunity for continued commercial and industrial development logically distributed at locations with suitable access, adequate public facilities, and within an orderly, efficient, and environmentally safe planning framework.

3) To provide affordable housing for present and future populations of Lyon County, while preserving existing residential areas.

Because of the limited water and sewer infrastructure throughout the rural areas of the County, the pattern of development near the Emporia-Lyon County metropolitan areas and along the defined development areas is projected to continue. Local planning decision-making is administered so that residential, non-farm growth continues within the metropolitan planning areas, within one mile of these areas, and along designed urban corridors (Lyon County 2001).

2.9 SOCIAL SERVICES AND PUBLIC FACILITIES

2.9.1 Public Water Supply

Because WCGS is located near the town of Burlington (in Coffey County) and most of the WCGS employees reside in Coffey and Lyon Counties, the discussion of public water supply systems will be limited to Coffey and Lyon Counties. On average, WCGS obtains 600,000 to 700,000 gallons of potable water per month from Rural Water District 3, which purchases water from the City of Burlington and from Public Wholesale District 12. There are no drinking water wells on the WCGS site.

The *Kansas Water Plan* is one of the primary tools used by the State of Kansas to coordinate the management, conservation, and development of the water resources of the state. It contains recommendations on how the state can best achieve the proper utilization and control of the water resources of the state. The Kansas Water Office is the water planning agency for the state, responsible for compiling the Plan. The Plan is organized into three main sections: Policy Recommendations, Basin Sections, and Background Information. Coffey and Lyon Counties are primarily contained within the Neosho Basin (see Section 2.2) and are, therefore, addressed in the Neosho Basin Section of the Kansas Water Plan (State of Kansas 2004).

There were an estimated 174,000 residents in the basin in the year 2000, and the population is projected to grow to nearly 195,000 by the year 2040. Nearly 80 percent of water used in the basin is from surface sources (2000 water use). Over 48 percent of water is consumed for municipal use, followed by 32 percent for industrial use, 12 percent for recreation, and seven percent for irrigation. Significant water management entities in the basin include conservation districts throughout the basin, the See-Kan, Flint Hills, and Lake Region Resource Conservation and Development areas and 15 active watershed districts. The Corps of Engineers is responsible for management of the three major reservoirs (State of Kansas 2004).

The Plan addresses water quality and supply issues occurring in selected areas throughout the basin. The State is addressing these issues through the use of monitoring and mitigation programs. At this time, drinking water supplies are adequate and will continue to be for the foreseeable future.

Tables 2-5 and 2-6 provide details of Coffey and Lyon Counties' respective water suppliers and capacities. It should be noted that all municipal water suppliers either pump and treat or purchase surface water to fulfill potable water needs within the County. Often, the municipal water suppliers that purchase water, purchase it from the local suppliers that pump and treat water.

2.9.2 Transportation

Coffey County covers approximately 630 square miles (USCB 2005). The City of Burlington, the county seat, is located on US 75, 16 miles south of Interstate 35 in east-central Kansas. Interstate 70 can be accessed 55 miles north in Topeka, Kansas. US 169 is 18 miles east of Burlington, and US 54 intersects US 75, 20 miles south of Burlington (Coffey County 1999). See Figures 2-1 and 2-2 for locations.

Airports serving the county are the Coffey County Airport, 8 miles north of Burlington on US 75, Forbes Field and Phillip Billard Airport, 50 miles north of Coffey County in Topeka, and the Kansas City International Airport, 1.5 hours northeast (Coffey County 1999).

Railroads serving the county are Union Pacific in LeRoy, Kansas and Burlington-Northern-Santa Fe in Lebo, Kansas. The nearest inter-modal terminal is 45 miles away (Coffey County 1999).

Road access to WCGS is via 16th Road, from the east, and 17th Road, from the west. The plant access road, Oxen Lane, intersects with 16th and 17th Roads (Figure 2-3). Approximately six miles northwest of WCGS, 17th Road intersects with US 75, which travels in a north-south direction. Employees traveling from the north, northwest, west, southwest, and south of WCGS would use 17th Road and/or US 75 to reach the station. Employees traveling from the north, northeast, east, southeast, and south would use 16th Road. During shift changes, there is some congestion near the intersection of 17th Road and US 75. However, the intersection remains clear at all other times.

In determining the significance levels of transportation impacts for license renewal, NRC uses the Transportation Research Board's level of service (LOS) definitions (NRC 1996). The Kansas Department of Transportation makes LOS determinations for roadways involved in specific projects. However, there are no current LOS determinations for the roadways analyzed in this document (Peterson 2005; Casper 2005). As LOS data is unavailable, annual average daily traffic volumes are substituted. Table 2-7 lists roadways in the vicinity of WCGS and the annual average number of vehicles per day, as determined by the Kansas Department of Transportation.

2.10 METEOROLOGY AND AIR QUALITY

WCGS is located in Coffey County Kansas, which is part of the Southeast Kansas Intrastate Air Quality Control Region (AQCR) (40 CFR 81.254). The climate of southeastern Kansas is continental, characterized by rapid changes in temperature and marked extremes, resulting in hot summers and cold winters. The prevailing winds are from the south to southeast except during the winter when north to northwest winds prevail. The site vicinity is subject to occasional severe thunderstorms and the possibility of a tornado from early spring until autumn. However, precipitation is generally moderate throughout the year and snowfall ranges from very little during some winters to substantial during others. The topography of the general area is undulating terrain and there are no meteorologically significant terrain features or bodies of water in the site vicinity (WCNOC 2004). Meteorological information, as it relates to analysis of severe accidents, is included in Attachment F.

Under the Clean Air Act, the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS), which specify maximum concentrations for carbon monoxide (CO), particulate matter with aerodynamic diameters of 10 microns or less (PM_{10}), particulate matter with aerodynamic diameters of 2.5 microns or less ($PM_{2.5}$), ozone, sulfur dioxide (SO_2), lead, and nitrogen dioxide (NO_2). Areas of the United States having air quality as good as or better than the NAAQS are designated by EPA as attainment areas. Areas having air quality that is worse than the NAAQS are designated by EPA as non-attainment areas. Those areas that were previously designated nonattainment and subsequently redesignated to attainment due to meeting the NAAQS are maintenance areas. States with maintenance areas are required to develop an air quality maintenance plan as an element of the State Implementation Plan.

Coffey County is in attainment for all air quality standards as are all counties in the State of Kansas (40 CFR 81.317, 70 FR 974, and 70 FR 7070). In Kansas, Johnson County and Wyandotte County, approximately 49 miles and 67 miles from WCGS, respectively, were designated as maintenance areas under the 1-hour ozone standard (40 CFR 81.317). On April 15, 2004, the EPA Administrator implemented designations, classifications, and boundaries for areas of the country with respect to the 8-hour ozone NAAQS (69 FR 23858). Designations under the 1-hour ozone NAAQS were revoked one year after designations under the 8-hour standard were implemented. However, the EPA rule for implementing the 8-hour ozone NAAQS calls for areas that were maintenance areas under the 1-hour standard and are attainment areas for the 8-hour standard to put in place a plan to maintain the 8-hour ozone standard for a ten-year period. Thus, Kansas is required to develop a plan to maintain the 8-hour ozone standard in Johnson and Wyandotte Counties, essentially classifying these counties as maintenance areas under the 8-hour ozone standard. The nearest non-attainment area is the Metropolitan St. Louis (Missouri-Illinois) Interstate AQCR, approximately 235 miles east of WCGS, which is designated as a non-attainment area under the $PM_{2.5}$ NAAQS (70 FR 974) and a non-attainment area under the 8-hour ozone NAAQS (40 CFR 81.326).

2.11 CULTURAL RESOURCES

Area History in Brief

Prehistory

The prehistory of Kansas may be broadly subdivided into five general stages. Paleo-Indian big-game hunters preyed upon Pleistocene megafauna between 11,000 and 6,000 B.C. using darts tipped with distinctive fluted- and parallel-flaked lanceolate stone points. Between 6,000 and 200 B.C., Archaic peoples subsisted by gathering wild plant foods and hunting smaller game. Characteristic tools included stemmed and notched dart points, grinding stones, chipped stone drills, ground axeheads, but no ceramics. The appearance of thick pointed-bottom pottery vessels together with an increased reliance on food resources from the gallery forests along streams ushered in the Plains Woodland period which lasted until 1000 A.D. Remains of houses may be found along with distinctive dart points and other stone tools. The Central Plains cultures from 1000 A.D. to 1500 practiced a simple horticulture and hunted buffalo with the bow and arrow. They often lived in villages, fashioned globular cord-roughened pottery vessels, and used a wide variety of stone and bone tools. During the European Contact period, the ancestors of several historically identified Plains Indian tribes occupied Kansas. They ranged from sedentary farmers to largely nomadic bison hunters (KG&E and KCP&L 1974). (Today, four recognized tribes maintain reservations in Kansas—the Prairie Band Potawatomi, Kickapoo, Iowa, and Sac and Fox. However, dozens of tribes are represented by the thousands of Native Americans residing in the state. The rich Indian heritage of Kansas can be seen in the many place names of Indian origin.)

History

The State of Kansas is named after the Kansa Indians. Kansa means “People of the South Wind.” In 1541, the Spanish explorer Francisco Vasquez de Coronado arrived, lured by tales of wealth. Coronado found no gold, only rich land. By the late 18th century, France claimed all of the Louisiana territory, which included most of Kansas and 12 other future states. In 1803, the United States purchased the territory from France, completing the largest acquisition of land added to the U.S. at one time. Meriwether Lewis and William Clark camped on the Kansas side of the Missouri River while exploring the new purchase in 1804 (State of Kansas 2002).

In 1821, Missouri trader William Becknell traveled west and the Santa Fe Trail was developed. The Oregon Trail, used by emigrants during the middle decades of the 1800s, crossed the northeastern section of the state (State of Kansas 2002).

Passage of the Kansas-Nebraska Act in 1854 opened these territories to European settlement, also giving rise to the struggle between proslavery and free-state forces. As these forces came into conflict, acts of terrorism were committed on both sides, coining the term “Bloody Kansas”. At the same time, the federal government began the forced removal of Native American tribes from Kansas. Although most tribes were removed by 1871, European settlement on the Western frontier resulted in periodic violence that continued until 1878 (State of Kansas 2002).

In 1857, gold fever struck as word spread of rich deposits in Kansa Territory in present-day Colorado, known as Pike’s Peak gold rush. In response to the need for better forms of communication, the Leavenworth freighting firm of Russell, Majors and Waddell established the Pony Express in 1860. The route led across the northeastern corner of Kansas. The Pony

Express became obsolete in October 1861 with the completion of the transcontinental telegraph (State of Kansas 2002).

In July 1859, a free-state constitution was drafted that fixed the present boundaries of the state. Following the election of Abraham Lincoln and the secession of Southern states from the Union, the Kansas bill was passed on January 29, 1861, making Kansas the 34th state of what at the time was a rapidly disintegrating Union. More than 20,000 Kansans served in the Civil War, including 2,080 African-American troops (State of Kansas 2002).

When the Union Pacific Railroad reached Abilene in 1867, long-horned cattle were driven to Kansas where they were fed native buffalo grass before being shipped to market. The next two decades saw the rise of the notorious cow towns, including Abilene and Dodge City. With the passage of the Homestead Law in 1862, Congress encouraged a large increase in European settlement (State of Kansas 2002).

In 1874, Mennonite immigrants from Russia introduced "Turkey Red" wheat, which would provide the basis for Kansas as a wheat-producing state. Social, industrial and political progress opened the 20th century (State of Kansas 2002).

WCGS Area History

When first reported historically, the Osage Indians of Missouri had been using the lower stretches of the Neosho River as a hunting ground. Osage village locations are vague, but it is speculated that they had existed on the Osage River just east of the Kansas-Missouri border since 1673 (KG&E and KCP&L 1974). From 1811 to 1820, groups of Osage Indians began to settle along the Neosho River. As a result of public pressure for relocation of the remains of many eastern tribes, the Osage, in 1825, relinquished much of the land they claimed in Missouri, Arkansas, Oklahoma, and Kansas. The consolidated population settled in a strip of land, 50 miles wide by 75 miles long, which paralleled the southern border of Kansas from a point 25 miles west of the Missouri border. Villages were located along the Neosho River from present-day Oswego in Labette County to Erie in Neosho County. From this reserve they continued summer tribal buffalo hunts to western Kansas. Steadily increasing encroachment from European settlers and the diminishing herds of bison in the Western Plains caused the relocated Indians to relinquish their land in the Neosho River drainage in 1865 and, subsequently, the remainder of their land in Kansas in 1872 (KG&E and KCP&L 1974).

Following the Osage, groups of Sac and Fox, Pottawatomie, and Kickapoo moved into eastern Kansas, including Coffey County. Historic accounts locate Sac and Fox reserves just north of the WCGS area (KG&E and KCP&L 1974).

Coffey County has been isolated from most historically important events in Kansas (KG&E and KCP&L 1974). The County lies some distance south and east of the Santa Fe and Oregon Trails. It is far east of the famous cattle drive trails, however, a minor cattle trail paralleled the Neosho River. The County was not affected by the violence of the "Bloody Kansas" era that occurred before and during the Civil War (KG&E and KCP&L 1974). It was named for Colonel A. M. Coffey, a member of the first territorial legislature.

The first known settlement within the County was made in the Neosho valley in 1854 by Frederick Troxel, who built a log cabin three-fourths of a mile south of the present town of Le Roy and moved there with his family. The City of Burlington was declared the county seat in 1866. The first postoffice was established at Le Roy (Ward 2002).

The history of the railroads of Coffey County includes the construction of the Neosho division of the Missouri, Kansas & Texas, in 1870, the Missouri Pacific, built in 1880, and the Atchison, Topeka & Santa Fe, built in 1878. (Ward 2002).

Initial Operation

In the Final Environmental Statement (FES) for the operation of WCGS (NRC 1982), NRC staff stated that the FES for construction of WCGS indicated that there were no natural or historic landmarks, sites, or places within 5 miles of the WCGS area listed on the National Register of Historic Places or the National Registry of Natural Landmarks. The FES for operation also indicated that none had been added or identified as being eligible for inclusion since that time.

Additionally, in the FES for operation, NRC staff referenced an archaeological survey, funded by KG&E and KCP&L that identified cultural resources in the area that might be impacted by construction of the WCGS. The survey identified 17 archaeological sites, with five defined as having the potential for scientific knowledge. Subsequently, additional surveying was performed and eight additional sites were discovered. Of the 25 total sites, 20 were selected for testing. The analysis of the tests indicated that none of the sites were significant enough to warrant nomination to the National Register (NRC 1982).

The FES for operation indicated that transmission line corridors were selected to avoid archaeologically sensitive areas and that no significant cultural resource sites had been identified. At that time, the nearest listed or eligible for listing in the National Register properties to the transmission lines were the Columbia Bridge in Peoria, Kansas, and the C. N. James Cabin in Augusta, Kansas (NRC 1982).

A railroad spur built to facilitate construction at the WCGS site threatened an archaeological site. The site was subsequently excavated (NRC 1982).

In the FES for operation, NRC staff concluded that operation of the station would not result in any significant impact on historical and archaeological sites in the area. The State Historic Preservation Officer stated that no historic sites or buildings would be affected by the construction or operation of the WCGS (NRC 1982).

Current Status

As of 2005, the National Register of Historic Places lists five locations in Coffey County (U.S. Department of the Interior 2005). Of these five locations, two fall within a 6-mile radius of WCGS boundaries. Table 2-8 lists the National Register of Historic Places sites within the 6-mile radius of WCGS.

2.12 OTHER PROJECTS AND ACTIVITIES

As indicated on Figure 2-2, there are few urban areas and little industrial development within the 6-mile radius of WCGS. The only federal project nearby is the John Redmond Reservoir, for which construction was completed in 1965. Operated by the Tulsa District of the U.S. Army Corps of Engineers, the Reservoir is on the Neosho River approximately 3.5 miles west of WCGS. The purpose of this 9,400-acre Reservoir is to provide flood control, water supply, water quality, and recreation. As described in Section 3.1.2, the Reservoir provides a source of makeup water for the Wolf Creek cooling lake (Coffey County Lake). WCGS purchases the water, which is owned by the Kansas Water Resources Board, under a water contract, which will expire 2017.

On June 25, 2002, Kansas Electric Power Cooperative, one of the WCGS owners, began commercial operation of a diesel generator peaking station approximately three miles north of WCGS. The Sharpe Generating Station consists of ten 2-megawatt diesel generators. WCNOC contributed to the funding of this project, because the Sharpe plant provides a redundant source of offsite power for WCGS. WCGS supplies a 69-kilovolt line to the Sharpe plant. This line terminates at the Sharpe substation, which is further connected to the local Lyon-Coffey Electric Cooperative 12-kilovolt system.

WCNOC is not aware of any other existing or reasonably foreseeable projects.

2.13 TABLES AND FIGURES

Table 2-1. Endangered and Threatened Species Recorded in Butler, Coffey, and Greenwood Counties.

Common Name	Scientific Name	Federal Status	State Status
Birds			
Bald eagle	*Haliaeetus leucocephalus*	Threatened	Threatened
Least tern	*Sterna antillarum*	Endangered	Endangered
Peregrine falcon	*Falco peregrinus*	-	Endangered
Piping plover	*Charadrius melodus*	Threatened	Threatened
Snowy plover	*Charadrius alexandrinus*	-	Threatened
Whooping crane	*Grus americana*	Endangered	Endangered
Mammals			
Eastern spotted skunk	*Spilogale putorius*	-	Threatened
Mussels			
Flutedshell mussel	*Lasmigona costata*	-	Threatened
Neosho mucket mussel	*Lampsilis rafinesqueana*	Candidate	Endangered
Ouachita kidneyshell mussel	*Ptychobranchus occidentalis*	-	Threatened
Rabbitsfoot mussel	*Quadrula cylindrica*	-	Endangered
Sharp hornsnail	*Pleurocera acuta*	-	Threatened
Western fanshell mussel	*Cyprogenia aberti*	-	Endangered
Fish			
Neosho madtom	*Noturus placidus*	Threatened	Threatened
Topeka shiner	*Notropis topeka*	Endangered	Threatened
Plants			
Mead's milkweed	*Asclepias meadii*	Threatened	-

Source: USFWS (2005a); KDWP (2005)
- = Not listed.

Table 2-2. Estimated Populations and Decennial Growth Rates.

Population and Decennial Growth Rate						
	Coffey County		**Lyon County**		**Kansas**	
Year	Number	Percent	Number	Percent	Number	Percent
1980[a]	9,730	31.5%	35,108	9.5%	2,363,679	5.2%
1990[a]	8,408	-13.6%	34,732	-1.1%	2,477,574	4.8%
2000[b]	8,865	5.4%	35,935	3.5%	2,688,418	8.5%
2010[c]	8,939	0.8%	35,263	-1.9%	2,818,880	4.9%
2020[d]	9,010	0.8%	35,800	1.6%	2,950,000	4.6%
2030[d]	9,090	0.8%	36,100	0.7%	3,080,000	4.4%
2040[d]	9,160	0.8%	36,400	0.7%	3,210,000	4.2%
2050[d]	9,240	0.8%	36,600	0.7%	3,340,000	4.1%

a. USCB (1995)
b. USCB (2005)
c. University of Kansas (2004)
d. TtNUS (2005b)

Table 2-3. Minority and Low-Income Population Census Blocks within 50-Mile Radius of WCGS.

County	Total Block Groups within 50 miles	AI or AN	Asian	NH or PI	Black	Other	Multi-Racial	Aggregate	Hispanic	Low-Income (Households)	2000 Population within 50 miles
Allen*	13	0	0	0	0	0	0	0	0	0	14,385
Anderson*	7	0	0	0	0	0	0	0	0	0	8,110
Bourbon	4	0	0	0	0	0	0	0	0	0	1,844
Butler	1	0	0	0	0	0	0	0	0	0	77
Chase	4	0	0	0	0	0	0	0	0	0	2,280
Coffey*	8	0	0	0	0	0	0	0	0	0	8,865
Douglas	8	0	0	0	0	0	0	0	0	0	8,426
Elk	1	0	0	0	0	0	0	0	0	0	38
Franklin*	23	0	0	0	0	0	0	0	0	0	24,784
Greenwood	9	0	0	0	0	0	0	0	0	0	6,729
Johnson	1	0	0	0	0	0	0	0	0	0	26
Linn	9	0	0	0	0	0	0	0	0	0	4,085
Lyon*	32	0	0	0	0	5	0	5	9	5	35,935
Miami	19	0	0	0	0	0	0	0	0	1	12,353
Morris	2	0	0	0	0	0	0	0	0	0	322
Neosho	16	0	0	0	0	0	0	0	0	1	11,935
Osage*	15	0	0	0	0	0	0	0	0	0	16,712
Shawnee	8	0	0	0	0	0	0	0	0	0	9,371
Wabaunsee	3	0	0	0	0	0	0	0	0	0	1,401
Wilson	8	0	0	0	0	0	0	0	0	0	4,836
Woodson*	5	0	0	0	0	0	0	0	0	0	3,788
Totals:	196					5		5	9	7	176,301

Table 2-3. Minority and Low-Income Population Census Blocks within 50-Mile Radius of WCGS. (Continued)

County	Total Block Groups within 50 miles	AI or AN	Asian	NH or PI	Black	Other	Multi-Racial	Aggregate	Hispanic	Low-Income (Households)	2000 Population within 50 miles
Block Groups where minorities or low-income populations exceed 50 percent.											
Lyon*	32	0	0	0	0	0	0	1	1	1	35,935
State Percentages											
Kansas		0.9	1.7	0	5.7	3.4	2.1	13.9	7	10.1	

AI = American Indian
AN = Alaskan Native
NH = Native Hawaiian
PI = Pacific Islander
* = Counties completely within the 50-mile radius.
Source: TtNUS (2005a)

Table 2-4. Wolf Creek Generating Station Tax Information 2000-2004.

Year	Coffey County Tax Revenues[a]	Property Tax Paid by WCGS Owners	Percent of Coffey County Revenues
2000	$28,738,820	$24,298,703	85
2001	$29,551,325	$23,923,320	81
2002	$29,441,799	$24,477,745	83
2003	$30,563,511	$24,639,242	81
2004	$31,292,371	$25,019,784	80

a. Raaf (2005).

Table 2-5. Major Coffey County Public Water Suppliers.

Water Supplier[a]	Water Source[a]	Average Daily Use (MGD)	Maximum Daily Capacity (MGD)
City of Burlington	Pumped Surface Water	0.6 to 0.7[b]	1.8[b]
Coffey County Rural Water District 2	Purchased Surface Water	Not Applicable	Not Applicable
Coffey County Rural Water District 2E	Purchased Surface Water	Not Applicable	Not Applicable
Coffey County Rural Water District 3	Purchased Surface Water	Not Applicable	Not Applicable
City of Gridley	Purchased Surface Water	Not Applicable	Not Applicable
City of Lebo	Purchased Surface Water	Not Applicable	Not Applicable
City of Le Roy	Purchased Surface Water	Not Applicable	Not Applicable
City of New Strawn	Purchased Surface Water	Not Applicable	Not Applicable
City of Waverly	Purchased Surface Water	Not Applicable	Not Applicable

MGD = Million Gallons Daily
a. EPA (2005)
b. Sowder (2005)

Table 2-6. Major Lyon County Public Water Suppliers.

Water Supplier[a]	Water Source[a]	Average Daily Use (MGD)	Maximum Daily Capacity (MGD)
City of Admire	Purchased Surface Water	Not Applicable	Not Applicable
City of Allen	Purchased Surface Water	Not Applicable	Not Applicable
City of Emporia	Pumped Surface Water	9.4[b]	12.5[b] (15 MGD – Total Design Capacity)[b]
Green Acres Mobile Home Park	Purchased Surface Water	Not Applicable	Not Applicable
City of Hartford	Purchased Surface Water	Not Applicable	Not Applicable
Lyon County Rural Water District 1	Purchased Surface Water	Not Applicable	Not Applicable
Lyon County Rural Water District 2	Purchased Surface Water	Not Applicable	Not Applicable
Lyon County Rural Water District 3	Purchased Surface Water	Not Applicable	Not Applicable
Lyon County Rural Water District 4	Purchased Surface Water	Not Applicable	Not Applicable
Lyon County Rural Water District 5	Purchased Surface Water	Not Applicable	Not Applicable
City of Olpe	Purchased Surface Water	Not Applicable	Not Applicable
City of Reading	Purchased Surface Water	Not Applicable	Not Applicable

MGD = Million Gallons Daily
a. EPA (2005)
b. Kelsey (2005)

Table 2-7. Traffic Counts for Roads in the Vicinity of WCGS for 2004.

Roadway and Location	Annual Average Daily Traffic (AADT)
17th Road, 2 mi. west of US 75	509
17th Road, 3 mi. east of US 75	1,155
Oxen Lane	1,082
16th Road, at intersection with Trefoil Road	825
US 75, near intersection with 17th Road	5,190
Source: KDOT (2004) Note: All AADTs represent traffic volume during the average 24-hour day during the year indicated.	

Table 2-8. Sites Listed in the National Register of Historic Places that fall within a 6-Mile Radius of WCGS.

Site Name	Location
Burlington Carnegie Free Library	201 North Third, Burlington
U. S. Post Office - Burlington	107 South Fourth Street, Burlington
Source: U.S. Department of the Interior (2005)	

FIGURE 2-1
50-Mile Vicinity Map

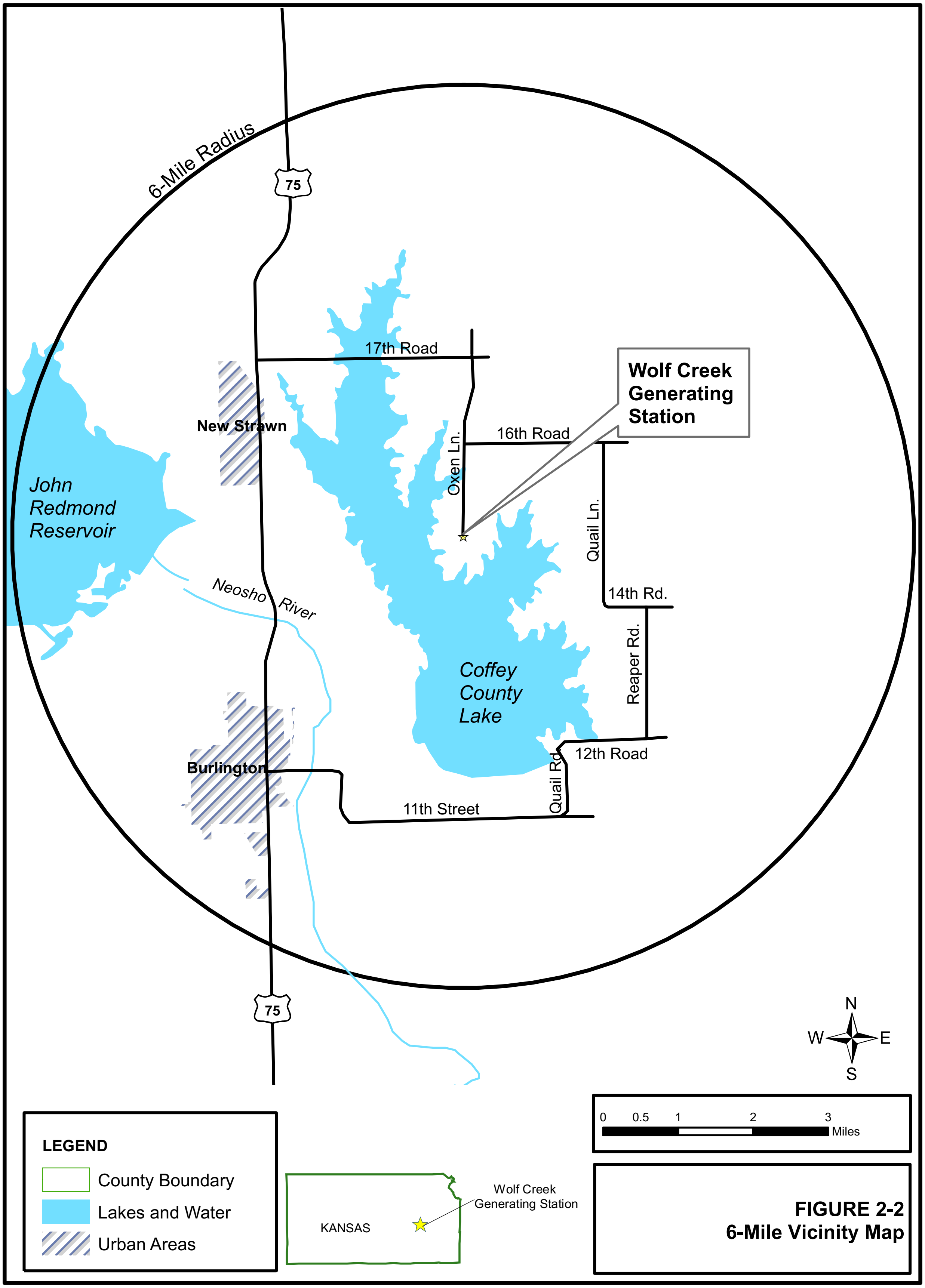


FIGURE 2-2
6-Mile Vicinity Map

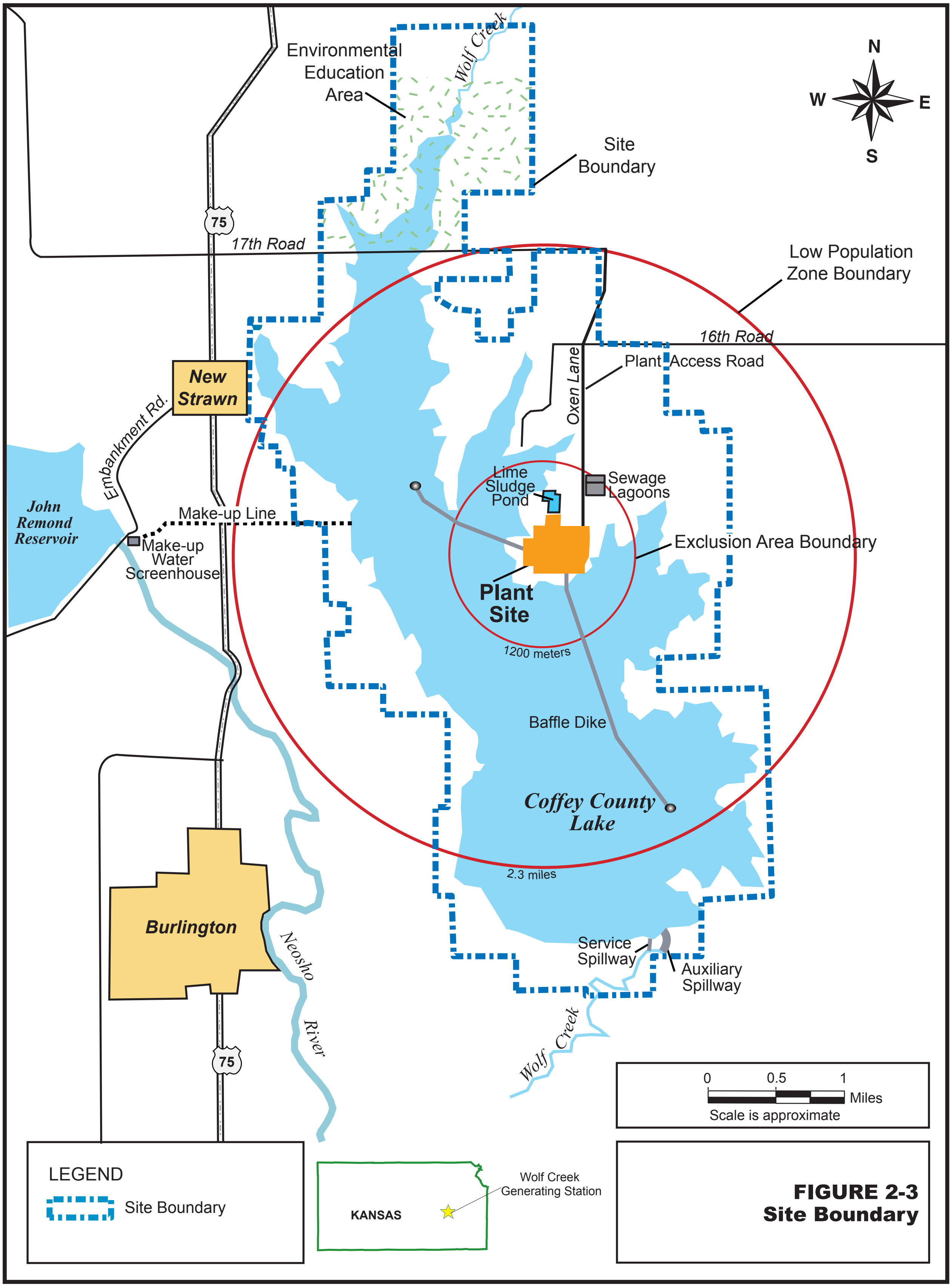


FIGURE 2-3
Site Boundary

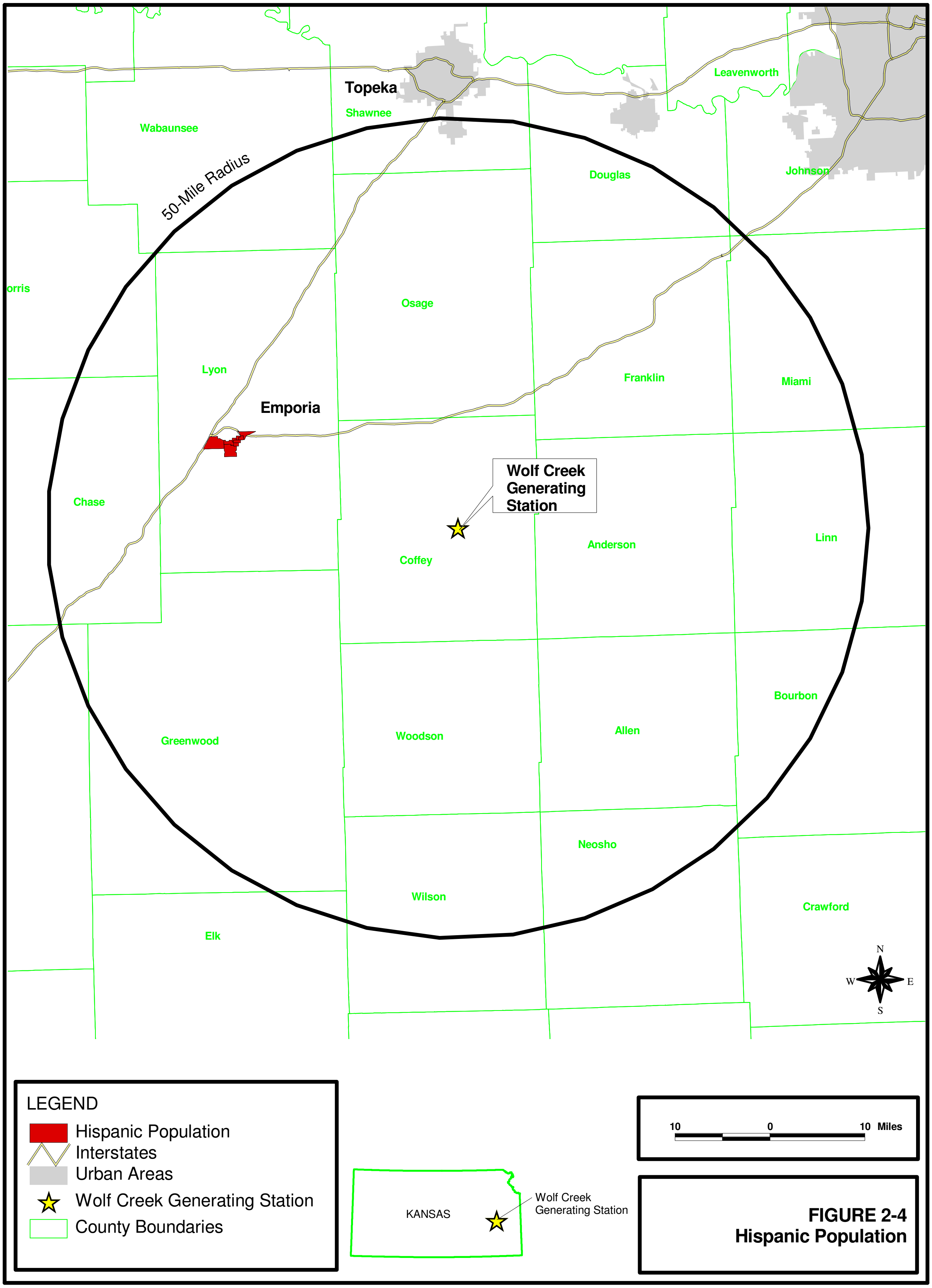


FIGURE 2-4
Hispanic Population

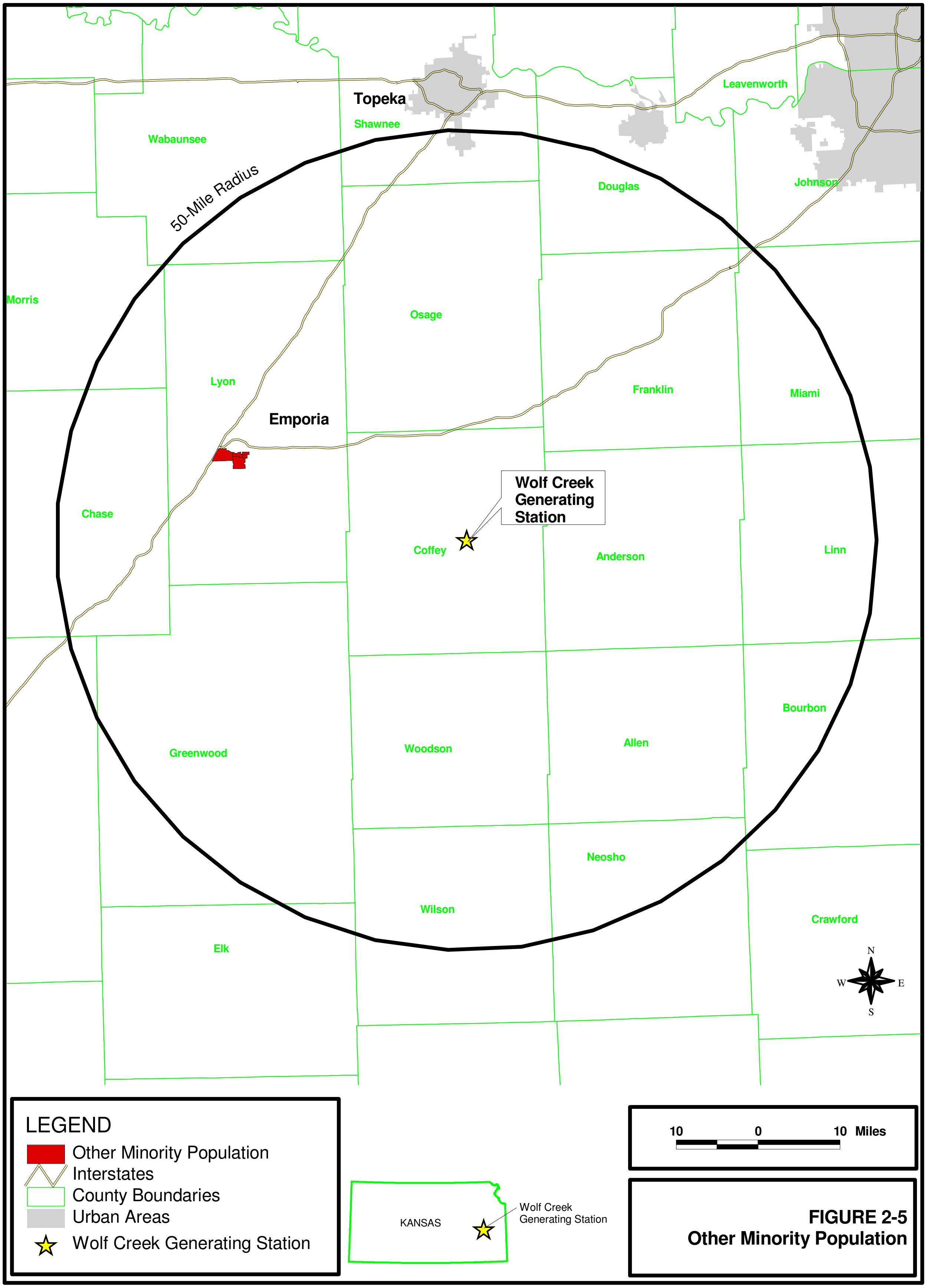


FIGURE 2-5
Other Minority Population

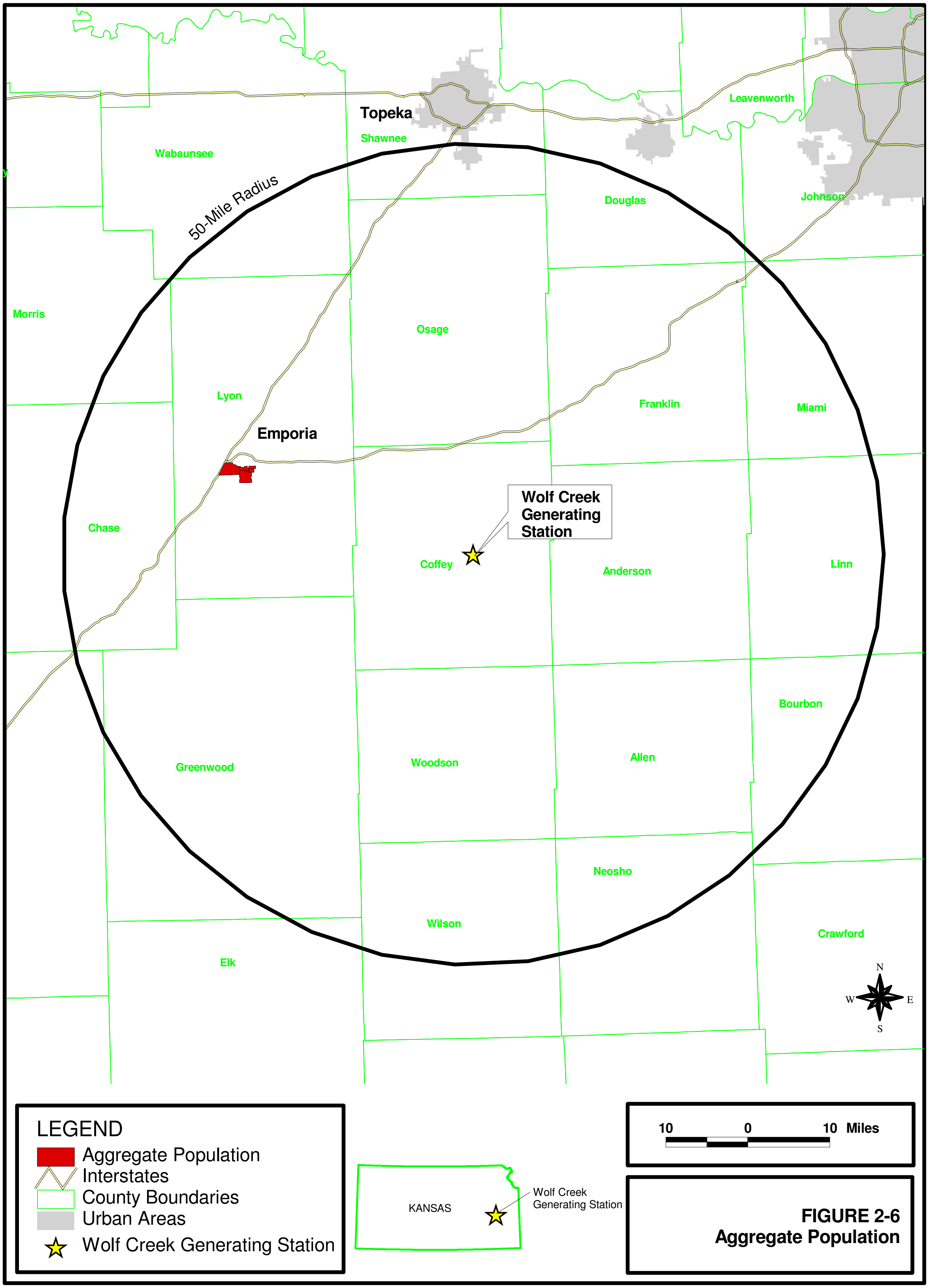


FIGURE 2-6
Aggregate Population

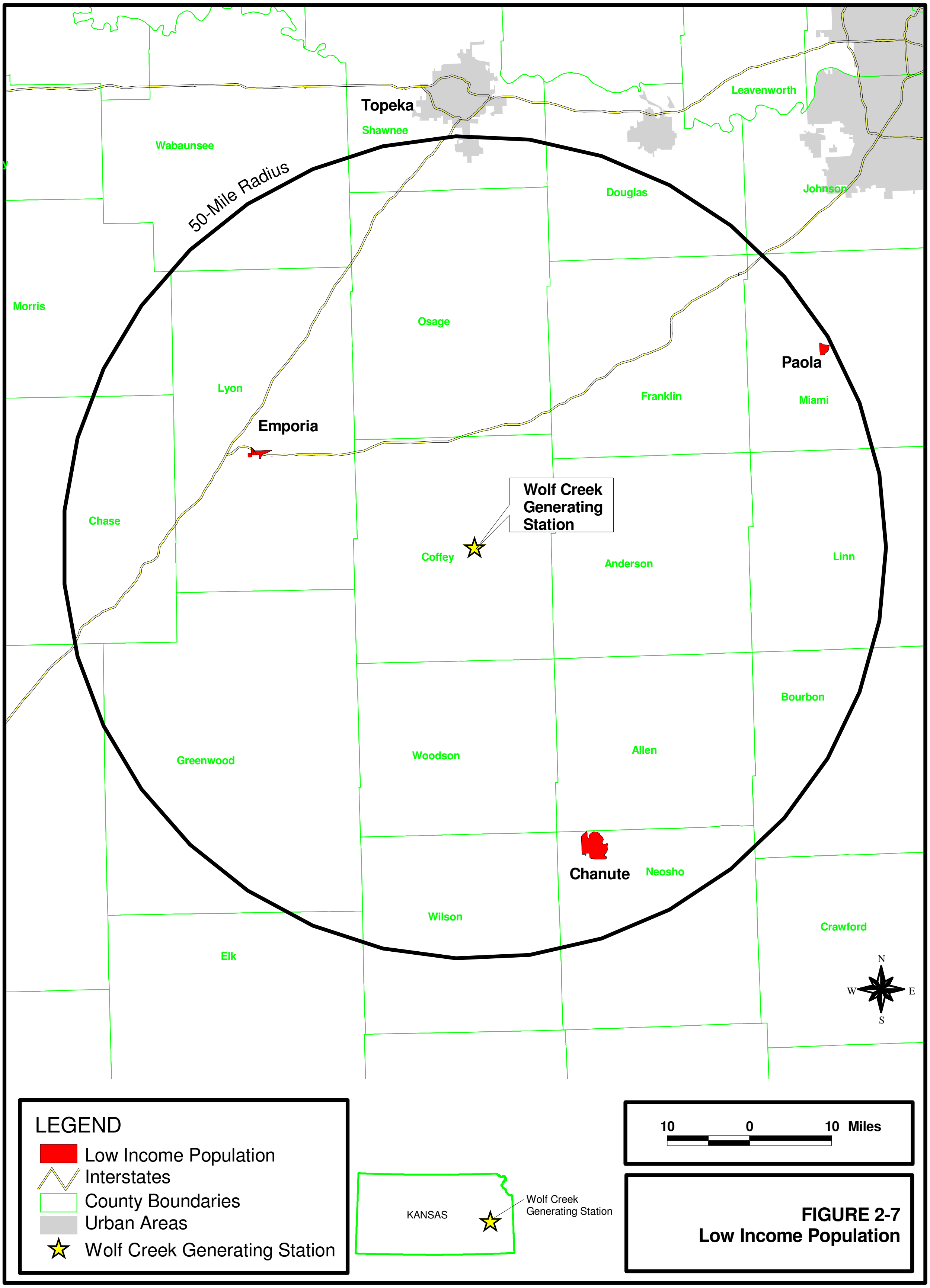


FIGURE 2-7
Low Income Population

2.14 REFERENCES

Section 2.2

Adams, S. B. and M. L. Warren. 2005. "Recolonization by warmwater fishes and crayfishes after severe drought in upper Coastal Plain streams." *Transactions of the American Fisheries Society* 134: 1173-1192.

Britannica (Britannica Concise Encyclopedia Online). 2005. Neosho River. Available on line at http://concise.britannica.com/.

Coffey County. 2005. "Coffey County Lake." Available on line at http://www.coffeycountyks.org/sheriff18.html. Accessed on June 14, 2005.

Cunningham, K. W. and A. V. Zale. 1998. "Dynamics of white crappie exploitation in an Oklahoma tailwater fishery." *Proceedings Oklahoma Academy of Science* 78: 35-40.

EA (EA Engineering, Science, and Technology). 1988. Wolf Creek Generating Station Operational Phase Environmental Monitoring Program, Final Report. Prepared for WCNOC by EA Engineering, Science, and Technology, Great Plains Regional Office.

Haines, D. E. 2000. "Biological control of gizzard shad impingement at a nuclear power plant." Environmental Science & Policy 3: S275-S281.

Harvey, B. C. 1987. "Susceptibility of young-of-the-year fishes to downstream displacement by flooding." *Transactions of the American Fisheries Society* 116: 851-855.

Jacobs, K. E. and W. D. Swink. 1983. "Fish abundance and population stability in a reservoir tailwater and an unregulated headwater stream." *North American Journal of Fisheries Management* 3: 395-402.

KDWP (Kansas Department of Wildlife and Parks). 2004. Kansas Fishing Forecast. Available on line at http://www.kdwp.state.ks.us/news/content/view/full/849.

KDWP (Kansas Department of Wildlife and Parks). 2005. Where to fish in Kansas: public waters. Available on line at http://www.kdwp.state.ks.us/news/fishing/where_to_fish_in_kansas/fishing_locations_public_waters.

Kansas Water Office. 2004. Kansas Water Plan: Neosho Basin Section. Available on line athttp://www.kwo.org/KWP/NEO_basin_111804.pdf.

Larimore, R. W., W.F. Childers, and C. Heckrotte. 1959. "Destruction and re-establishment of stream fish and invertebrates affected by drought." *Transactions of the American Fisheries Society* 88: 261-285.

NRC (U.S. Nuclear Regulatory Commission). 1975. *Final Environmental Statement related to construction of Wolf Creek Generating Station Unit 1. NUREG-75/096.* Office of Nuclear Reactor Regulation. Washington, DC.

Pearsons, T. N., H. W. Li, and G. A. Lamberti. 1992. "Influence of habitat complexity on resistance to flooding and resilience of stream fish assemblages." *Transactions of the American Fisheries Society* 121: 427-436.

Propst, D. L. and K. B. Gido. 2004. "Responses of native and non-native fishes to natural flow regime mimicry in the San Juan River." *Transactions of the American Fisheries Society* 133: 922-931.

Putnam and Schneider. 2005. Water Resources Data, Kansas: Water Year 2004, Water-Data Report Kansas-04-1. U.S. Department of the Interior, U.S. Geological Survey.

Section 2.3

NRC (U.S. Nuclear Regulatory Commission). 1975. *Final Environmental Statement related to construction of Wolf Creek Generating Station Unit 1.* Office of Nuclear Reactor Regulation. NUREG-75/096. October. pp. 2-10 – 2-11.

USGS (U.S. Geological Survey). 1997. Ground Water Atlas of the United States: Kansas, Missouri, and Nebraska, HA 730-D. Available online at http://capp.water.usgs.gov/gwa/ch_d/index.html.

WCGS (Wolf Creek Generating Station). 1980. Wolf Creek Generating Station Unit. No. 1 – Environmental Report, Operating License Stage.

WCNOC (Wolf Creek Nuclear Operating Corporation). 2004. *Wolf Creek Updated Safety Analysis Report*, Revision 18. March.

Section 2.4

Haines, D. (Wolf Creek Nuclear Operating Corporation, Burlington, Kansas). 2005. Personal Communication with M.L. Whitten, (Tetra Tech NUS, Aiken, South Carolina), May 11.

NRC (U.S. Nuclear Regulatory Commission). 1975. *Final Environmental Statement related to construction of Wolf Creek Generating Station, Unit 1*, NUREG-175/096, Office of Nuclear Reactor Regulation, Washington, DC.

WCGS (Wolf Creek Generating Station). 1980. Wolf Creek Generating Station Unit No. 1, Environmental Report, Operating License Stage - Volume 1.

WCNOC (Wolf Creek Nuclear Operating Corporation). 1988. "Wolf Creek Generating Station 1987-1988 Operational Wildlife Monitoring Report". Environmental Management Section, Burlington, Kansas, November.

WCNOC (Wolf Creek Nuclear Operating Corporation). 2005a. "Wolf Creek Generating Station, Annual Environmental Operating Report 2004". Environmental Management Organization, Burlington, Kansas, April.

WCNOC (Wolf Creek Nuclear Operating Corporation). 2005b. "The Environment". Available at http://www.wcnoc.com/environment.cfm. Accessed May 17, 2005.

Section 2.5

Center for Biological Diversity. 2004. Candidate Petition Project: Mollusks. Available on line at http://www.sw-center.org/swcbd/Programs/bdes/cp/index.html.

EA (EA Engineering, Science, and Technology, Inc.). 1988. *Wolf Creek Generating Station Operational Phase Environmental Monitoring Program, Final Report.* Prepared for Wolf Creek Nuclear Operating Corporation by EA Engineering, Science, and Technology, Inc., Great Plains Regional Office.

Hagan, R. C. 1992. Letter to USFWS regarding 1992 fish and wildlife sampling activities and renewal of WCNOC's Neosho madtom sub-permit 91-27. R.C. Hagan, WCNOC, Burlington, Kansas. December 22.

Haines, D. (Wolf Creek Nuclear Operating Corporation, Burlington, Kansas). 2005. Personal Communication with M.L. Whitten, (Tetra Tech NUS, Aiken, South Carolina), May 11.

KDWP (Kansas Department of Wildlife and Parks). 2004a Species Information: Topeka Shiner (*Notropis topeka*). Available online at http://www.kdwp.state.ks.us/news/other_services/threatened_and_endangered_species/threatened_and_endangered_species/species_information.

KDWP (Kansas Department of Wildlife and Parks). 2004b Species Information: Neosho madtom (*Noturus placidus*). Available online at http://www.kdwp.state.ks.us/news/other_services/threatened_and_endangered_species/threatened_and_endangered_species/species_information.

KDWP (Kansas Department of Wildlife and Parks). 2004c Species Information: Neosho Mucket Mussel (*Lampsilis rafinesqueana*). Available online at http://www.kdwp.state.ks.us/news/other_services/threatened_and_endangered_species/threatened_and_endangered_species/species_information.

KDWP (Kansas Department of Wildlife and Parks). 2005. Threatened and Endangered Species. T&E statewide and county lists and species information. Available at http://www.kdwp.state.ks.us/news/other_services/threatened_and_endangered_species. Accessed May 15, 2005.

Lee, D. S., C. R. Gilbert, C. H. Hocutt, R. E. Jenkins, D. E. McAllister, and J. R. Stauffer. 1980. *Atlas of North American Freshwater Fishes.* North Carolina State Museum of Natural History, Raleigh, NC.

Maynard, O.L. 1990a. Letter to Kansas Dept. of Wildlife and Parks with 1989 Conditional Wildlife Permit Activities Report. O.L. Maynard, WCNOC, Burlington, Kansas. January 19.

Maynard, O.L. 1990b. Letter to Kansas Dept. of Wildlife and Parks with information on 1988 and 1989 Neosho madtom sampling. O.L. Maynard, WCNOC, Burlington, Kansas. January 23.

NatureServe. 2005. Nature Serve Explorer, an Online Encyclopedia of Life. Available at http://www.natureserve.org/explorer/index.htm. Data last updated February 2005. Accessed May 10-15, 2005.

NRC (U.S. Nuclear Regulatory Commission). 1982. *Final Environmental Statement Related to Operation of Wolf Creek Generating Station, Unit 1*, NUREG-0878, Office of Nuclear Reactor Regulation, Washington, D.C., June.

Obermeyer, Brian K. 2000. Recovery Plan for Four Freshwater Mussels in Southeast Kansas: Neosho Mucket, Ouachita Kidneyshell, Rabbitsfoot, Western Fanshell. Kansas Department of Wildlife & Parks, Pratt, Kansas. November.

Rhodes, F. T. 1991. Letter to Kansas Dept. of Wildlife and Parks with 1990 Conditional Wildlife Permit Activities Report and 1991 Renewal Application. F. T. Rhodes, WCNOC, Burlington, Kansas. January 15.

Rhodes, F. T. 1992. Letter to Kansas Dept. of Wildlife and Parks with 1991 Conditional Wildlife Permit Activities Report and 1992 Renewal Application. F. T. Rhodes, WCNOC, Burlington, Kansas. January 30.

USFWS (U.S. Fish & Wildlife Service). 1997. Topeka Shiner Fact Sheet. Prepared by Region 6 (Mountain - Prairie Region) of the USFWS. Available at http://mountain-prairie.fws.gov/species/fish/shiner/facts.htm.

USFWS (U.S. Fish & Wildlife Service). 2005a. Mountain-Prairie Region, Endangered Species Program. Available at http://www.r6.fws.gov/endspp/. Accessed May 15, 2005.

USFWS (U.S. Fish & Wildlife Service). 2005b. Species Information, Threatened and Endangered Animals and Plants. Available at http://endangered.fws.gov/wildlife.html. Accessed May 13-15, 2005.

USFWS (U.S. Fish & Wildlife Service). 2005c. "Questions and Answers about the Topeka Shiner," prepared by Region 3 of the USFWS. Available online at http://www.fws.gov/midwest/endangered /fishes/tosh-qas.html.

WCGS (Wolf Creek Generating Station). 1980. Wolf Creek Station Unit No. 1 – Environmental Report, Operating License Stage.

Wenke, T.L. and M. E. Eberle. 1991. "Neosho Madtom Recovery Plan." Prepared by Natural Science Research Associates for Region 6 U.S. Fish and Wildlife Service, Denver.

Wildhaber, M.L., V. M. Tabor, J. E. Whitaker, A. L. Allert, D. W. Mulhern, P. L. Lamberson, and K. L. Powell. 2000. "Ictalurid populations in relation to the presence of a main-stem reservoir in a Midwestern warmwater stream with emphasis on the threatened Neosho madtom." *Transactions of the American Fisheries Society* 129: 1264-1280.

Section 2.6

KGCC (Kansas Geospatial Community Commons). 2000. TIGER 2000 Census Block Groups. Available online at http://gisdasc.kgs.ku.edu/kgcc/catalog/coredata.ctm. Accessed April 11, 2005.

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

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

TtNUS (Tetra Tech NUS). 2005a. "Calculation Package for Wolf Creek Regional Demography." Aiken, South Carolina. May 31.

TtNUS (Tetra Tech NUS). 2005b. "Wolf Creek Population Projections for Section 2.6". Aiken, South Carolina. April.

University of Kansas. Policy Research Institute. 2004. Kansas Statistical Abstract. Enhanced Online Edition. Section 17: Population. Available at http://www.ku.edu/pri/ksdata/ksah/population/. Accessed April 28, 2005.

USCB (U.S. Census Bureau). 1995*. Kansas. Population of Counties by Decennial Census: 1900 to 1990.* Available online at http://www.census.gov/population/cencounts/ks190090.txt. Accessed April 27, 2005.

USCB (U.S. Census Bureau). 2000a. *Summary File 3: Census 2000.* Available online at http://www.census.gov/. Accessed April 28, 2005.

USCB (U.S. Census Bureau). 2000b. *P1. Total Population [1] – Universe: Total population. Kansas City, Kansas.* Available online at http://www.census.gov/. Accessed April 27, 2005.

USCB (U.S. Census Bureau). 2000c. *GCT-PH1. Population, Housing Units, Area, and Density: 2000.* Available online at http://www.census.gov/. Accessed April 27,

USCB (U.S. Census Bureau). 2000d. *Summary File 1: Census 2000.* Available online at http://www.census.gov/. Accessed April 26, 2005.

USCB (U.S. Census Bureau). 2003. *Table 3b. Population in Metropolitan and Micropolitan Statistical Areas Ranked Separately by 2000 Population for the United States and Puerto Rico: 1990 and 2000.* Available online at http://www.census.gov/. Accessed April 28, 2005.

USCB (U.S. Census Bureau). 2005. *Kansas Quickfacts. Coffey and Lyon Counties, Kansas* Available online at http://www.census.gov/. Accessed April 27, 2005.

Section 2.7

Raaf, J. (Coffey County Treasurer's Office). 2005. Electronic mail to E. N. Hill (Tetra Tech NUS). "Property Tax Revenue Information for Coffey County." Coffey County Treasurer's Office, Coffey County, Kansas. May 18.

WCNOC (Wolf Creek Nuclear Operating Company). 2005. Response to request for information from Tetra Tech NUS. Property Tax Payments to Coffey County.

Section 2.8

Casper, H. (Coffey County Zoning Department). 2005. Personal communication with E. N. Hill (Tetra Tech NUS, Inc.). "Land Use Information." Coffey County Zoning Department, Coffey County, Kansas. May 31.

Hotaling, J. (Coffey County Economic Development). 2005. Personal communication with E. N. Hill (Tetra Tech NUS, Inc.). "Land Use Information." Coffey County Economic Development, Coffey County, Kansas. June 1.

Lyon County. 2001. *Comprehensive Plan for Lyon County, Kansas.* Available online at http://www.lyoncounty.org/LYON%20COUNTY%20COMPREHENSIVE%20PLAN.pdf. Accessed May 30, 2005.

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

USCB (U.S. Census Bureau). 1990. H001. Housing Units – Universe: Housing Units. Data Set: 1990 Summary Tape File 1 (STF 1) – 100-Percent Data. Available online at http://factfinder.census.gov/. Accessed June 1, 2005.

USCB (U.S. Census Bureau). 2000. H1. Housing Units [1] - Universe: Housing Units. Data Set: Census 2000 Summary File 1 (SF 1) – 100-Percent Data. Available online at http://factfinder.census.gov/. Accessed June 1, 2005.

USCB (U.S. Census Bureau). 2005. *Kansas Quickfacts. Coffey and Lyon Counties, Kansas* Available online at http://www.census.gov/. Accessed April 27, 2005.

Section 2.9

Casper, H. 2005. Personal communication with E. N. Hill (Tetra Tech NUS, Inc.). Land Use Information. Coffey County Zoning Department. May 31.

Coffey County. 1999. *Coffey County Economic Development. Transportation/Location.* Available online at http://www.coffeycountyks.org/ecodevo/trans.html. Accessed May 18, 2005.

EPA (United States Environmental Protection Agency). 2005. U. S. Environmental Protection Agency Local Drinking Water Information. Kansas Drinking Water. List of Water Systems in Safe Drinking Water Information System database for Coffey and Lyon Counties. Available online at http://www.epa.gov/enviro/html/sdwis/sdwis_query.html. Accessed April 21.

KDOT (Kansas Department of Transportation). 2004. KDOT Traffic Count Maps. Available online at http://www.ksdot.org/. Accessed May 6, 2005.

Kelsey, K. (Kansas Department of Health and Environment, Enforcement and Regulation Development, Public Water Supply Section). 2005. "Water supply data for the City of Emporia Water Supply Facility." April 21, 2005. Personal communication with E. N. Hill (Tetra Tech NUS, Inc.).

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

Peterson, P. (Kansas Department of Transportation District 4). 2005. Electronic mail to E. N. Hill (Tetra Tech NUS). "Level of Service Request for Coffey County." May 27.

Sowder, Jack. City of Burlington Water Superintendent. 2005. “Water supply data for the City of Burlington Water Supply Facility.” May 5, 2005. Personal communication with E. N. Hill (Tetra Tech NUS, Inc.).

State of Kansas. 2004. *Kansas Water Plan. Neosho Basin Section.* Kansas Water Office. Topeka, Kansas. November 18.

USCB (U.S. Census Bureau). 2005. *Kansas Quickfacts. Coffey and Lyon Counties, Kansa.* Available online at http://www.census.gov/. Accessed April 27, 2005.

Section 2.10

WCNOC (Wolf Creek Nuclear Operating Corporation). 2004. *Wolf Creek Updated Safety Analysis Report*, Revision 18, Wolf Creek Generating Station, Burlington, Kansas, March 3.

Section 2.11

KG&E and KCP&L (Kansas Gas and Electric Company and Kansas Power and Light Company). 1974. *Environmental Report Volume I, Wolf Creek Generating Station*. July 22.

NRC (U.S. Nuclear Regulatory Commission). 1982. *Final Environmental Statement related to the operation of Wolf Creek Generating Station, Unit No. 1.* Kansas Gas and Electric Company, et al. NUREG-0878. June.

State of Kansas. 2002. accessKansas. Kansas Facts and History. Kansas at a Glance. Available online at http://www.accesskansas.org/facts-history/basic-facts.html. Accessed May 26, 2002.

U.S. Department of the Interior. 2005. National Register of Historic Places. Available online at http://www.nationalregisterofhistoricplaces.com/KS/coffey/state.html. Accessed May 24, 2005.

Ward, Carolyn. 2002. "Coffey County." Available online at http://skyways.lib.ks.us/genweb/archives/1912/c/coffey_county.html. Accessed May 25, 2005.

3.0 CHAPTER 3 – PROPOSED ACTION

NRC

"The report must contain a description of the proposed action..." 10 CFR 51.53(c)(2)

WCNOC proposes that NRC renew the operating license for WCGS for an additional 20 years beyond the current license expiration date of March 11, 2025. Renewal of the operating license would give WCNOC and the State of Kansas the option of relying on WCGS to meet future electricity needs. Section 3.1 discusses the major features of the plant and the operation and maintenance practices directly related to the license renewal period. Sections 3.2 through 3.4 address potential changes that could occur as a result of license renewal.

3.1 GENERAL PLANT INFORMATION

WCGS is a nuclear-powered steam electric generating facility that began commercial operation on September 3, 1985. The nuclear reactor is a Westinghouse pressurized water reactor (PWR) producing a reactor core power of 3,565 megawatts-thermal. The design net electrical capacity is 1,165 megawatts-electric. Figure 3-1 depicts the site layout.

The following subsections provide information on the reactor and containment systems, the cooling and auxiliary water systems, the electrical transmission system, and two wastewater systems of interest. Additional information about WCGS is available in the final environmental statement for operation of the plant (NRC 1982), the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996), and the WCGS Updated Final Safety Analysis Report (WCNOC 2004).

3.1.1 Reactor and Containment Systems

The nuclear steam supply system at WCGS is a four-loop Westinghouse pressurized water reactor. The reactor core heats water to approximately 590 degrees Fahrenheit. Because the pressure exceeds 2,000 pounds per square inch, the water does not boil. The heated water is pumped to four U-tube heat exchangers known as steam generators where the heat boils the water on the shell-side into steam. After drying, the steam is routed to the turbines. The steam yields its energy to turn the turbines, which are connected to the electrical generator. The nuclear fuel is low-enriched uranium dioxide with enrichments 5 percent by weight uranium-235 or less and fuel burnup levels of a batch average of approximately 48,000 megawatt-days per metric ton uranium. WCGS operates on an 18-month refueling cycle.

The reactor, steam generators, and related systems are enclosed in a containment building that is designed to prevent leakage of radioactivity to the environment in the improbable event of a rupture of the reactor coolant piping. The containment building is a reinforced concrete cylinder with a slab base and a hemispherical dome. A welded steel liner is attached to the inside face of the concrete shell to insure a high degree of leak tightness. In addition, the 4-foot thick concrete walls serve as a radiation shield for both normal and accident conditions.

The containment building is ventilated to maintain pressure and temperatures within acceptable limits. The containment ventilation system also can purge the containment prior to entry. Exhaust from the ventilation system is monitored for radioactivity before being released to the plant vent. High efficiency particulate air (HEPA) filters can be used when needed to filter the air before releasing it. The containment can be isolated if needed.

The WCNOC plant is a Standardized Nuclear Unit Power Plant System (SNUPPS) design.

3.1.2 Cooling and Auxiliary Water Systems

The water systems most pertinent to license renewal are those that draw from surface water bodies. The Circulating Water System, Service Water System, and the Essential Service Water System all draw from and discharge to Coffey County Lake, formerly known as the Wolf Creek Cooling Lake. The Neosho River is the source of makeup water for Coffey County Lake. Drinking water is supplied by Rural Water District 3, which obtains water from the City of Burlington (which draws from the Neosho River) and from Public Wholesale District 12 (which draws from Melvern Lake). The plant does not use Ranney wells or use any groundwater, which would bring it within the scope of 10 CFR 51.53(c)(3)(ii)(C).

Coffey County Lake

The 5,090-acre Coffey County Lake is designed to provide adequate cooling water to the plant during a one-in-fifty-year drought. The water level in the Lake is normally maintained by the watershed; however, during dry months, it is sometimes necessary to pump water to the Lake from the Neosho River, just below the John Redmond Reservoir dam. During times of flooding, service and auxiliary spillways provide for controlled release of the water to prevent overtopping of the Coffey County Lake dam. Although the dam has provisions for releasing water to Wolf Creek (blowdown for chemistry control), such release is infrequently performed. As indicated in Section 4.4.1.1 of the GEIS (NRC 1996), Coffey County Lake is a cooling pond. Figure 2-3 depicts the Coffey County Lake and its location relative to the John Redmond Reservoir (including the water makeup line).

Lake Makeup Water System

Makeup water for Coffey County Lake is drawn from the Neosho River immediately downstream of the John Redmond Reservoir. WCNOC has a valve in the dam piping that is opened during pumping to maintain flow to the pumps. A makeup water screenhouse, situated on the east bank of the river, contains a bar grill, 3/8-inch traveling screens, and three makeup water pumps. Two auxiliary raw water pumps are also available to supply the demineralizer system when service water is not operating. When the river is at flood stage, the three pumps together can pump up to 1,280 gallons per minute to Coffey County Lake. The 54-inch diameter supply line to the Lake discharges at the makeup water discharge structure on the western shore of the lake (see Figure 2-3).

Circulating Water System

Condenser cooling water is withdrawn from Coffey County Lake through the circulating water intake structure (Figure 3-1). This structure has trash racks to remove larger debris and 3/8-inch traveling screens to remove smaller debris. Although the intake structure has four pumps, only three are needed to provide the design flow rate of approximately 500,000 gallons per minute. After passing through the condenser, the warmed water is returned to Coffey County

Lake at the circulating water discharge structure (Figure 3-1). This structure has a discharge well which overflows into a 40-foot wide apron and then onto the surface of the Lake. During the winter, operators may align the circulating water system to direct a fraction of the warmed discharge back to the circulating water intake structure to prevent freezing. Baffle dikes (Figure 2-3) prevent short-circuiting of the discharge water to the intake.

WCNOC injects anti-scalants and dispersants, biocides, and corrosion inhibitors into the Circulating Water System to maintain the system and prevent fouling by corrosion and biological organisms (WCNOC 2005). The Kansas Department of Health and Environment has not restricted the discharge of heat into Coffey County Lake by WCGS (see Attachment B).

Station Service Water Systems

There are two independent station service water systems: the Service Water System and the Essential Service Water System. Both systems provide screened water from Coffey County Lake for cooling several closed cooling water systems. The Service Water System takes suction from the circulating water intake structure and returns the warmed water to the circulating water discharge pipe. During normal operation, it also provides water to the Essential Service Water System. The flow rate is variable, but flow rates could be as high as 50,000 gallons per minute.

The Essential Service Water System cools several safety-class systems and provides cooling for safe shutdown during an accident. During accident conditions, the Essential Service Water System takes suction from the Ultimate Heat Sink, a specially designed impoundment contiguous with Coffey County Lake, at the Essential Service Water intake structure. Discharge goes to a separate discharge structure on the Ultimate Heat Sink. The Ultimate Heat Sink is part of Coffey County Lake; however, an underwater dam prevents draining of the Ultimate Heat Sink in the event of failure of the Lake dam.

3.1.3 Transmission Facilities

The Final Environmental Statement (FES) (NRC 1982) identifies three 345-kilovolt and two 69-kilovolt transmission lines that would be built to connect WCGS to the electric grid. The pre-existing LaCygne-Benton transmission line was rerouted around the cooling lake and connected to the WCGS switchyard with one connection going to Benton and the other going to LaCygne. Two new lines, one to the West Gardner substation and one to the Rose Hill substation would be constructed. In addition, a four-mile long tap into the Athens-Burlington 69-kilovolt line (which had already been relocated to accommodate the cooling lake) was constructed to provide construction power, and a three-mile long radial line (not a supply line for the 69-kilovolt system) to a substation in Sharpe was also constructed. This substation just north of WCGS powered a gas compressor station.

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

- The 345-kilovolt line to West Gardner was not constructed.

- In 2002, Kansas Electric Power Cooperative, Inc. constructed a 20-megawatt power plant (ten 2-megawatt diesel generators) in Sharpe to which the WCGS 69-kilovolt Sharpe line was connected.

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

- WCGS-Rose Hill – This 345-kilovolt line owned by Westar Energy extends southwestward for 98 miles in a 150-foot wide corridor to the Rose Hill Substation southeast of Wichita.

- Rerouting of WCGS-Benton – Operating at 345 kilovolts, this Westar circuit segment wraps around the north end of the cooling lake for approximately 7 miles and then connects to the preexisting line to Benton. Nearly all of this rerouting occurs on WCGS property in a 150-foot wide corridor.

- Rerouting of WCGS-LaCygne – This 0.7-mile Westar segment connects the preexisting LaCygne line to the WCGS switchyard. All of this rerouting occurs on WCGS property in a 150-foot wide corridor.

The 69-kilovolt Sharpe line and the 69-kilovolt tap to the Athens-Burlington line are specifically not within the scope of the analysis presented in Section 4.13, because the analysis applies only to lines 98 kilovolts and above.

In total, the transmission lines of interest to Section 4.13 are contained in approximately 105 miles of corridor that occupy approximately 1,900 acres. The corridors pass through land that is primarily agricultural and open range. The areas are mostly remote, with low population densities. The lines cross numerous county, state and U.S. highways after leaving the switchyard. Corridors that pass through farmlands generally continue to be used as farmland. Westar Energy plans to maintain these transmission lines, which are integral to the larger transmission system, indefinitely. These transmission lines will remain a permanent part of the transmission system after WCGS is decommissioned.

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

3.1.4 Sewage Lagoons

Plant sewage is collected in gas-tight and vented concrete sumps and pumped to the sanitary sewage system where a lift station sends it to a nondischarging, two-cell, wastewater stabilization lagoon (Figure 2-3). The lagoon is designed to handle 10,000 gallons per day during normal operation. The lagoon collects sludge in the bottom, and the water is disposed by evaporation. This technology for sewage disposal is common in Kansas and was adopted by WCGS in 1995 to eliminate direct discharges to Coffey County Lake. Although not intended for discharge, the capability exists to discharge the sewage lagoon into a slough of Coffey County Lake using National Pollutant Discharge and Elimination System outfall 001A (see Attachment B). Under the proposed action, the sewage lagoon would continue to perform its design function.

3.1.5 Lime Sludge Pond

This 31-acre pond (Figure 2-3) was originally constructed in 1979 to receive blowdown from lime water softeners, backwash from sand and carbon filters, and regeneration wastes from ion exchange. It is an unlined pond north of the switchyard and adjacent to the cooling lake near the circulating water discharge. Although constructed and permitted primarily to receive lime sludge, it was never used for that purpose. Over the years it has received demineralizer regeneration wastes, sand and carbon filter backwash, and precipitator blowdown. Today the pond is designated as National Pollutant Discharge and Elimination System outfall 005 (see Attachment B) but it does not normally receive any plant wastewater. Approximately once per year, when there is a Circulating Water System outage, the pond could receive wastewater from the Wastewater Treatment Facility, which would consist of miscellaneous leaks and draindown from the powerblock sumps in the turbine building. Normally, the Wastewater Treatment Facility discharges to Coffey County Lake. The Lime Sludge Pond can discharge to Coffey County Lake through a sluice gate.

Section 2.4 discusses the ecological significance of the Lime Sludge Pond. Under the proposed action, the Lime Sludge Pond would continue to receive the wastes for which it is permitted.

3.2 REFURBISHMENT ACTIVITIES

NRC

> "The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures...This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)
>
> "…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories…(2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item...." (NRC 1996)

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

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

The WCGS IPA conducted by WCNOC under 10 CFR 54 (included as part of license renewal application) has not identified the need to undertake any major refurbishment or replacement actions to maintain the functionality of important systems, structures, and components during the WCGS license renewal period. Accordingly, WCNOC has determined that license renewal regulations in 10 CFR 51.53(c)(3)(ii) do not require WCNOC to assess the impact of refurbishment on plant and animal habitats, estimated vehicle exhaust emissions, housing availability, land use, public schools, or highway traffic on local highways. (See 10 CFR 51.53(c)(3)(ii)(E), (F), (I), (J), respectively.)

3.3 PROGRAMS AND ACTIVITIES FOR MANAGING THE EFFECTS OF AGING

NRC

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

"…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item." NRC 1996, Section 2.6.3.1, pg. 2-41. ("SMITTR" is defined in NRC 1996 as surveillance, monitoring, inspections, testing, trending, and recordkeeping.)

The IPA required by 10 CFR 54.21 identifies the programs and inspections for managing aging effects at WCGS. These programs are described in Appendix B of the *License Renewal Application, Wolf Creek Generating Station* to which this Environmental Report is appended.

3.4 EMPLOYMENT

Current Workforce

WCNOC employs approximately 1,100 permanent employees and 425 long-term contract employees at WCGS, a one-unit facility. The permanent staff at a nuclear plant with one reactor normally ranges between 600 and 800 employees (NRC 1996). However, WCNOC employs, not only the plant-related employees, but also its corporate employees at the site. At many other nuclear plants, corporate employees are located off-site. Approximately 70 percent of the employees live in Coffey and Lyon Counties, Kansas. The remaining employees are distributed across 19 counties in Kansas, with numbers ranging from 1 to 68 employees per county. One individual lives outside of Kansas.

WCGS is on an 18-month refueling cycle. During refueling outages, site employment increases above the permanent workforce by as many as 700 to 960 workers for approximately 40 days of temporary duty. This number of outage workers generally falls within the range (200 to 900 workers per reactor unit) reported in the GEIS for additional maintenance workers (NRC 1996).

License Renewal Increment

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

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

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

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

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

3.5 FIGURES

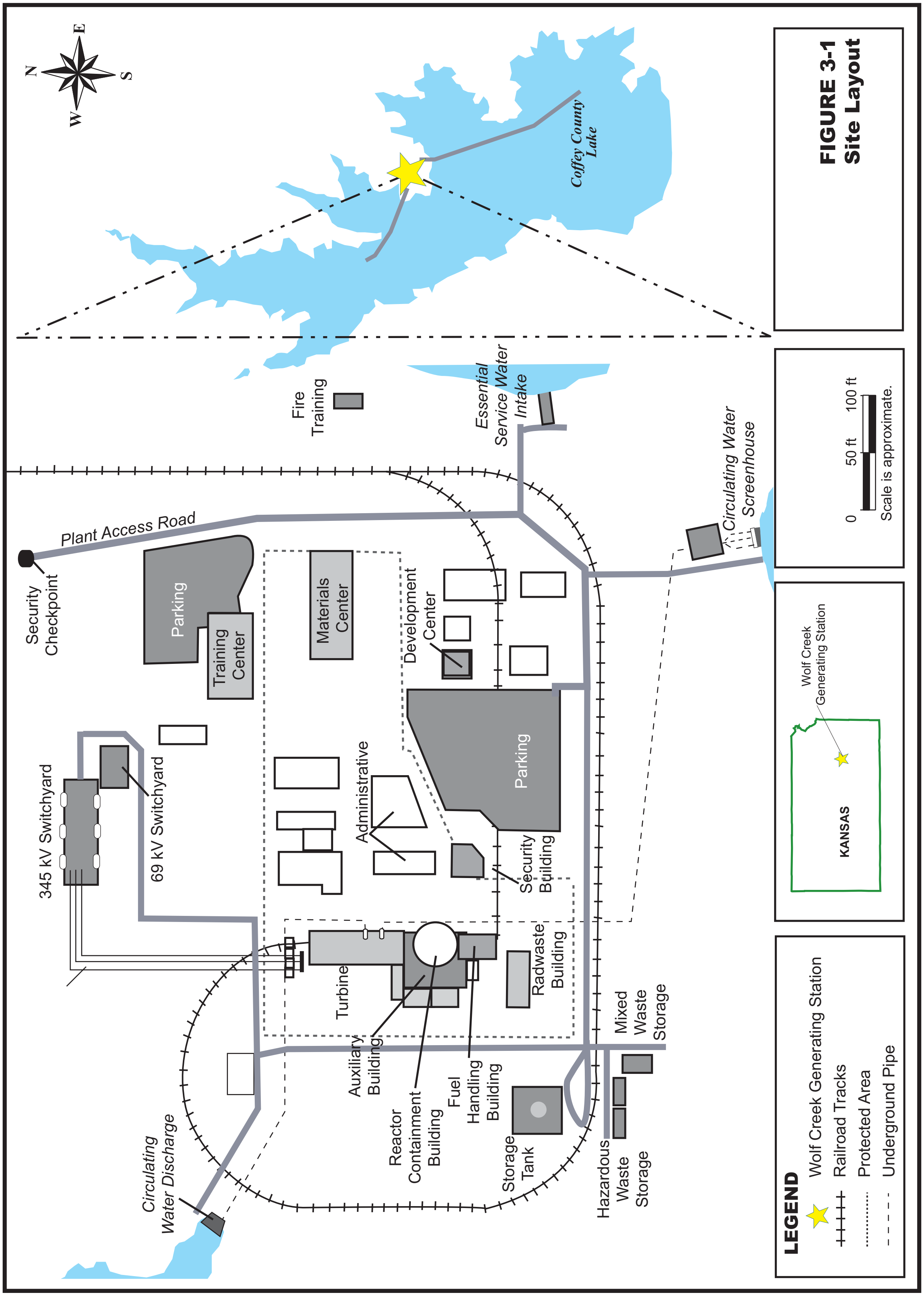


FIGURE 3-1
Site Layout

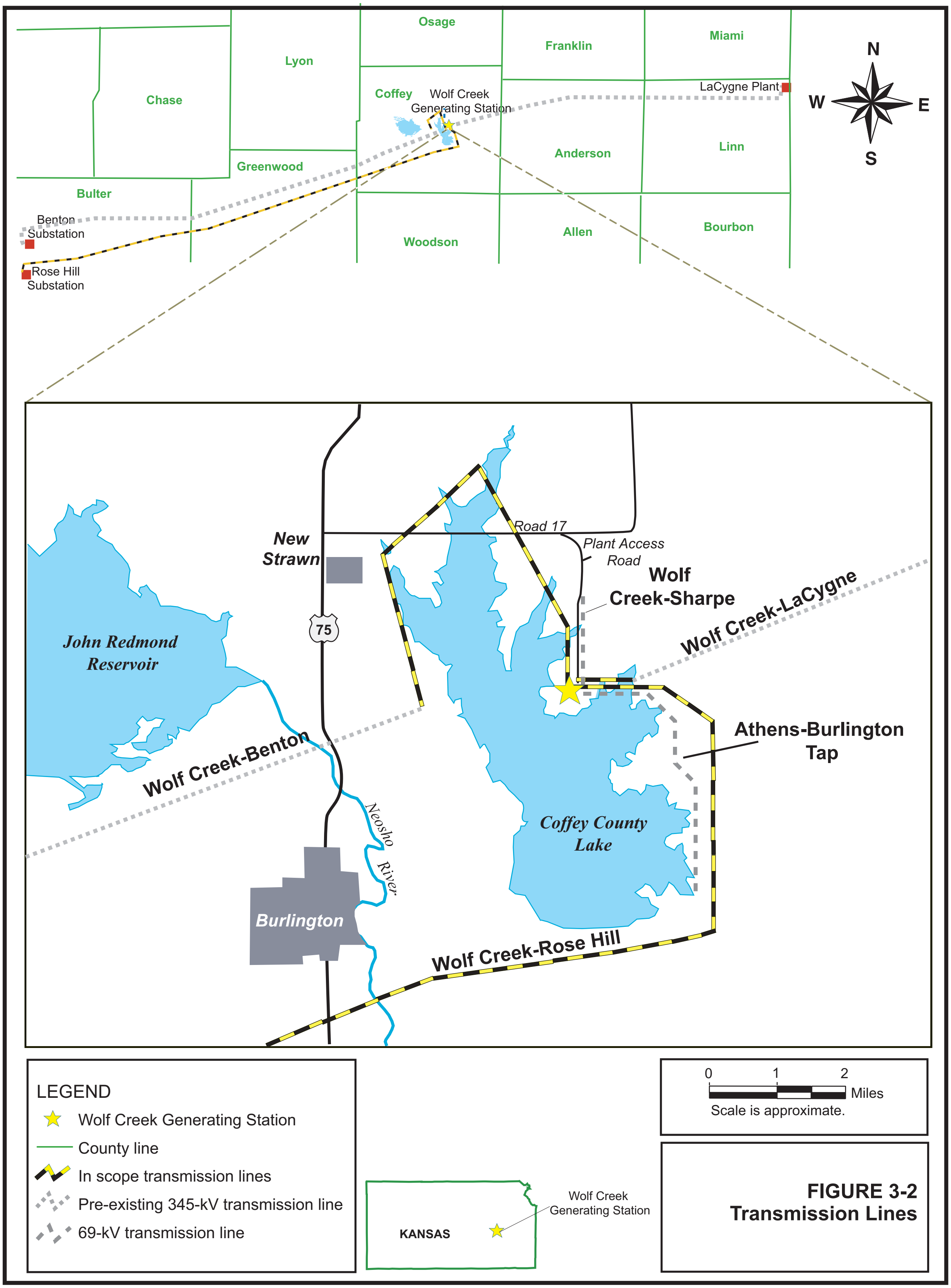


FIGURE 3-2
Transmission Lines

3.6 REFERENCES

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

NRC (U.S. Nuclear Regulatory Commission). 1982. *Final Environmental Statement Related to Operation of Wolf Creek Generating Station, Unit 1*, NUREG-0878, Office of Nuclear Reactor Regulation, Washington, D.C., June.

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

WCNOC (Wolf Creek Nuclear Operating Corporation). 2004. *Wolf Creek Updated Safety Analysis Report*, Revision 17, Wolf Creek Generating Station, Burlington, Kansas, March 3.

WCNOC (Wolf Creek Nuclear Operating Corporation). 2005. “Circulating/Service Water Treatment Chemicals and Limits,” Form APF 07A-002-01, Rev. 0, submitted in email from R. L. Logsdon (WCNOC) to S. Connor (Tetra Tech NUS) April 5.

4.0 CHAPTER 4 - ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION AND MITIGATING ACTIONS

NRC

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

"…The environmental report shall include an analysis that considers…the environmental effects of the proposed action…and alternatives available for reducing or avoiding adverse environmental effects.…" 10 CFR 51.45(c) as adopted by 10 CFR 51.53(c)(2) and 10 CFR 51.53(c)(3)(iii)

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

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

Chapter 4 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of the WCGS operating license. NRC has prepared a *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996a), which identifies and analyzes 92 environmental issues that NRC considers to be associated with nuclear power plant license renewal. In its analysis, NRC designated each of the 92 issues as Category 1, Category 2, or NA (not applicable) and required plant-specific analysis of only the Category 2 issues.

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

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

Absent new and significant information (Chapter 5), NRC rules do not require analyses of Category 1 issues, because NRC resolved them using generic findings presented in 10 CFR 51, Appendix B, Table B-1. An applicant may reference the generic findings or GEIS analyses for Category 1 issues.

If the NRC analysis concluded that one or more of the Category 1 criteria could not be met, the issue was assigned as Category 2. NRC requires plant-specific analyses for Category 2 issues. NRC designated two issues as "NA" (Issues 60 and 92), signifying that the categorization and impact definitions do not apply to these issues. Attachment A of this report lists the 92 issues and identifies the environmental report section that addresses each issue and, where appropriate, references supporting analyses in the GEIS.

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)
>
> "…[A]bsent 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…." (NRC 1996b)

WCNOC has determined that, of the 69 Category 1 issues, 12 do not apply to WCGS because they apply to design or operational features that do not exist at the facility. In addition, because WCNOC does not plan to conduct any refurbishment activities, the NRC findings for the seven Category 1 issues that pertain only to refurbishment do not apply to this application. WCNOC has reviewed the NRC Category 1 findings and has identified no new and significant information that would make the NRC findings inapplicable to WCGS. Therefore, WCNOC adopts by reference the NRC findings for these 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)

NRC designated 21 issues as Category 2. Sections 4.1 through 4.20 address each of these issues (Section 4.17 addresses two issues), beginning with a statement of the issue. As is the case with Category 1 issues, two Category 2 issues apply to operational features that WCGS does not have. In addition, four Category 2 issues apply only to refurbishment activities or to scenarios involving additional employment for managing plant aging. WCNOC does not plan any refurbishment or additional employment. If an issue does not apply to WCGS, the section explains the basis for inapplicability.

For the 15 Category 2 issues that WCNOC has determined to be applicable to WCGS, analyses are provided. These analyses include conclusions regarding the significance of the impacts relative to the renewal of the operating license for WCGS and, when applicable, discuss potential mitigative alternatives. WCNOC has identified the significance of the impacts associated with each issue as either Small, Moderate, or Large, consistent with the criteria that NRC established in 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

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

MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.

LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

In accordance with National Environmental Policy Act practice, WCNOC considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are small receive less mitigative consideration than impacts that are large).

"NA" License Renewal Issues

NRC determined that its categorization and impact-finding definitions did not apply to two issues (Issues 60 and 92); however, WCNOC included these issues in Attachment A. Applicants currently do not need to submit information on chronic effects from electromagnetic fields (10 CFR 51, Appendix B, Table B-1, Footnote 5). For environmental justice, NRC does not require information from applicants, but noted that it will be addressed in individual license renewal reviews (10 CFR 51, Appendix B, Table B-1, Footnote 6). WCNOC has included minority and low-income demographic information in Section 2.6.2.

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

NRC

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided…" 10 CFR 51.53(c)(3)(ii)(A)

"…The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on instream and riparian communities near these plants could be of moderate significance in some situations…" 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 13

The water-use issue associated with operation of cooling ponds is the availability of adequate streamflows to provide makeup water, particularly during droughts or in the context of increasing in-stream or off-stream uses (NRC 1996). For this reason, NRC made surface water use conflicts a Category 2 issue.

Surface water-use conflicts must be addressed because Coffey County Lake receives its makeup water from the Neosho River (John Redmond Reservoir tailwaters). John Redmond Reservoir serves as the primary flood control project for the Neosho River from John Redmond Dam to the headwaters of Grand Lake O' the Cherokees, located more than 100 miles downstream of John Redmond Dam. From 1962 through 2004, the average annual flow of the Neosho River at Burlington, Kansas (USGS Station 07182510) was 1,603 cubic feet per second or 5.06×10^{10} cubic feet per year (Putnam and Schneider 2005). Therefore, the Neosho River meets the NRC definition of a small river.

WCNOC has secured long-term rights to 9.672 billion gallons of water per calendar year from John Redmond Reservoir, which represents approximately 85 percent of the reservoir's water supply storage and 58 percent of its conservation storage (USACE 1996). Most of the remaining 1.5 billion gallons per year of the reservoir's water supply storage are reserved by downstream municipalities. Water for WCGS leaves John Redmond Reservoir via a 30-inch supply pipe and flows into the Neosho River (John Redmond Reservoir tailwaters). The maximum design flow through this pipe is approximately 130 cubic feet per second/58,000 gallons per minute (USACE 1996). The pipe's flow is diverted into a channel on the east side of the river, where the WCGS's makeup water screenhouse is located. The screenhouse contains three makeup water pumps, each rated at 40 to 60 cubic feet per second/18,000 to 27,000 gallons per minute, and two small auxiliary (raw) water pumps, each rated at 400 gallons per minute.

WCGS withdraws water from the Neosho River (John Redmond Reservoir tailwaters) intermittently throughout the year as makeup water for Coffey County Lake and for station use as auxiliary raw water. Although WCNOC's contract with the Kansas Water Resources Board allows WCGS to withdraw up to 9.672 billion gallons of water per calendar year, in recent years the total volume withdrawn has ranged from 3.94 to 4.81 billion gallons, which represents 41 to 51 percent of the allotment (WCNOC 2001, 2002, 2003a, 2004, 2005). Concurrently with pumping from the tailwaters, WCGS operators open the pipe to the Reservoir's conservation pool. Based on measurements of streamflow taken at the Burlington, Kansas, U.S. Geological Survey gaging station 3.5 miles downstream of the makeup water intake, withdrawals of this magnitude do not reduce flow in the Neosho River (WCNOC 2001, 2002, 2003a, 2004, 2005).

In the *Final Environmental Statement related to operation of WCGS, Unit No. 1*, the NRC concluded that withdrawal of water for makeup would not cause unacceptable effects on Neosho River biota under normal hydrological conditions (NRC 1982). The NRC evidenced concern, however, about instream flows in the Neosho River during severe and prolonged droughts, indicating that makeup water withdrawals during such droughts would stress aquatic communities, including fish populations. The Kansas Water Resources Board reserves the right to limit withdrawals at these times to protect downstream users and aquatic communities. Specifically, the contract (State of Kansas 1976) stipulates that:

"If the total amount of water contracted for withdrawal from the John Redmond Reservoir in the next 12-month period is greater than the supply available from that reservoir which is deemed to be 9,672 million gallons per year due to a prolonged drought, the Board will apportion the available waters among the purchasers having contracts therefore as may best provide for the health, safety, and general welfare of the people of this state as determined by the Board."

and

"If, because of an emergency, the Board deems it necessary for the health, safety, or general welfare of the people of Kansas to reduce or terminate the withdrawal of water from John Redmond Reservoir, the Board will apportion any available water among persons having contracts therefore as may best provide for the health, safety, or general welfare of the people of Kansas…"

(from Article 11, "Continuity of Water Service")

The contract also contains a requirement that:

"Whenever the elevation of water in the reservoir is below 1,039 feet above mean sea level, the amount of water taken at the point of withdrawal from the reservoir will not exceed a running average rate of 26,499 million gallons per day. The running average rate to be calculated on a quarterly basis…"

(from Article 16, "Rate of Withdrawal")

The water supply contract, therefore, makes clear that the state is not obligated to supply 9,672 million gallons of water per annum if drought reduces the conservation pool. The contract further stipulates that withdrawals from the reservoir's tailwaters will be limited when the reservoir is below the top of the conservation pool (1,039 feet above mean sea level).

In addition to these controls, which are focused on the available supply of John Redmond Reservoir water, the Certificate of Appropriation issued by the state of Kansas contains additional restrictions that are tied to Neosho River flows below the John Redmond Reservoir dam. The Certificate of Appropriation limits "use of natural flows in the Neosho River" to 76,300 gallons per minute (170 cubic feet per second) and 35,120.24 acre-feet per calendar year. The Certificate of Appropriation also prohibits withdrawals for industrial (WCGS) use when the natural flows in the river immediately downstream from the point of diversion (the makeup screen house) are 250 cubic feet per second or less unless the Chief Engineer-Director of the

Kansas Water Office determines that such withdrawals are in the public interest. Finally, should the level of Coffey County Lake fall below 1,080 feet, and water from John Redmond Reservoir/Neosho River is not available for pumping due to drought conditions, WCGS would implement plant procedure, OFN SG-003, "Natural Events" (WCNOC 2003b). Should the lake level fall to 1,075 feet, WCGS would be shut down.

Because instream flows are not affected by WCGS withdrawals under normal circumstances and because the state of Kansas can limit withdrawal of Neosho River water during extreme droughts, any impacts of WCGS operations on instream and riparian communities in the Neosho River over the license renewal term would be SMALL and would not warrant mitigation.

4.2 ENTRAINMENT OF FISH AND SHELLFISH IN EARLY LIFE STAGES

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…entrainment." 10 CFR 51.53(c)(3)(ii)(B)

"…The impacts of entrainment are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 25

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

As Section 3.1.2 describes, WCGS withdraws condenser cooling water from, and discharges heated effluent to, Coffey County Lake, a manmade impoundment. NRC has categorized WCGS as having a cooling pond heat dissipation system.

The State of Kansas issued the first National Pollutant Discharge Elimination System (NPDES) permit for WCGS in 1977 and has issued 7 renewals since that time (Attachment B). The state has never required WCNOC to conduct a 316(b) study for WCGS but has made no explicit 316(b) determination for the station. The lack of an explicit determination is not unusual, though, and WCNOC concludes that State issuance of the WCGS NPDES permit constitutes an implicit determination that the WCGS cooling water intake structure reflects the best technology available for minimizing adverse environmental impact such as entrainment of fish and shellfish. As WCNOC has no indication of such impact being an issue at WCGS, WCNOC concludes that the impact of entrainment of fish and shellfish is SMALL and that mitigative measures are not warranted.

4.3 IMPINGEMENT OF FISH AND SHELLFISH

NRC

> "If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…impingement…." 10 CFR 51.53(c)(3)(ii)(B)
>
> "…The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 26

NRC made impacts on fish and shellfish resources resulting from impingement a Category 2 issue, because it could not assign a single significance level to the issue. Impingement impacts are small at many facilities, but might be moderate or large at other plants (NRC 1996). 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.

See Section 4.2's description of WCGS NPDES 316(b) determination. As WCNOC has no indication of impingement of fish and shellfish being an issue at WCGS, WCNOC concludes that the impact is SMALL and that mitigative measures are not warranted.

4.4 HEAT SHOCK

NRC

> "If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act…316(a) variance in accordance with 40 CFR 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock…" 10 CFR 51.53(c)(3)(ii)(B)
>
> "…Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 27

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

As Section 3.1.2 describes, WCGS has a once-through heat dissipation system, but withdraws from and discharges to a cooling pond, Coffey County Lake. As discussed below, WCGS received Permit No. I-NE07-P002 to discharge under the NPDES, which has been approved by the Administrator of the U.S. Environmental Protection Agency pursuant to Section 402(b) of the Federal Water Pollution Control Act Amendments of 1972 [33 USC 1342 (b)].

Section 316(a) of the Clean Water Act establishes a process whereby a thermal effluent discharger can demonstrate that thermal discharge limitations are more stringent than necessary to protect a balanced indigenous population of fish and wildlife and obtain facility-specific thermal discharge limits (33 USC 1326).

In a letter to Kansas Gas & Electric Company dated December 13, 1974, the Kansas Department of Health and Environment granted WCGS an exemption from the requirements of Section 316(a) of the Clean Water Act based on the fact that the station began construction (as defined in Section 306 of PL 92-500) of its cooling impoundment prior to the effective date of the regulation (40 CFR 423). The KDHE letter asserts, however, that the station is still responsible for complying with state water quality standards, then known as "Water Quality Criteria for Interstate and Intrastate Waters of Kansas" (and incorporated in Kansas Administrative Regulations 28-16-28) and currently referred to as "Kansas Surface Water Quality Standards."

The current WCGS NPDES Permit (No. I-NE07-P002) (see Attachment B) does not contain thermal effluent limitations to assure the protection and propagation of a balanced indigenous community of shellfish, fish, and wildlife in Coffey County Lake. Therefore, WCNOC concludes that the current NPDES permit reflects continued acceptance of the exemption from thermal standards.

WCNOC concludes that impacts to fish and shellfish from heat shock are SMALL and that mitigative measures are not warranted.

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

NRC

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

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

NRC made this groundwater use conflict a Category 2 issue because at a withdrawal rate of more than 100 gallons per minute (gpm), a cone of depression could extend offsite. This could deplete the groundwater supply available to offsite users, creating an impact that could warrant mitigation. Information needed to address this issue includes the WCGS groundwater withdrawal rate (whether greater than 100 gpm), offsite drawdown, and impact on neighboring wells.

This issue does not apply to WCGS because, as indicated in Section 3.1.2, WCGS does not use any groundwater.

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

NRC

> "If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year…[t]he applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(3)(ii)(A)

> "…Water use conflicts may result from surface water withdrawals from small water bodies during low flow conditions which may affect aquifer recharge, especially if other groundwater or upstream surface water users come on line before the time of license renewal…" 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 34

NRC made groundwater use conflicts a Category 2 issue because consumptive use of withdrawals from small rivers could adversely impact aquatic life, downstream users, and aquifer recharge. This is a particular concern during low flow conditions and could create a cumulative impact due to upstream consumptive use. From 1962 through 2004, the average annual flow of the Neosho River at Burlington, Kansas (U.S. Geological Survey Station 07182510) was 5.06×10^{10} cubic feet per year (1,603 cfs) (Putnam and Schneider 2005). Therefore, the Neosho River meets the NRC definition of a small river. WCGS withdraws its condenser cooling water from a cooling pond (Coffey County Lake) that receives its makeup water from the Neosho River directly below John Redmond Reservoir Dam. Coffey County Lake provides continuous recharge to the rock and soil underneath the site. Groundwater levels were predicted to rise 45.8 feet within 100 feet of the cooling lake 50 years after filling (NRC 1975). Two miles from WCGS, the rise in groundwater was predicted to be less than 0.4 feet (NRC 1975).

As discussed in Section 2.3, a regional alluvial aquifer occurs along the Neosho River (WCGS 1980). The amount of groundwater used within a 20-mile radius of WCGS is small. No groundwater is used for the operation of WCGS (NRC 1982). There are no municipalities in the vicinity of WCGS that use groundwater (EPA 2005). The only known groundwater supply being used for industrial purposes within a 20-mile radius of the site is from one well owned by the Atchison Topeka and Santa Fe Railway located 15 miles west-northwest of WCGS (WCNOC 2004), and therefore upstream of WCGS's withdrawal point from the Neosho River.

A well inventory conducted in 1973 identified 198 wells within five miles of the plant site. These local wells are used for domestic and livestock purposes. They supply small quantities of water from the weathered bedrock and larger quantities from the alluvium. Most wells in the area intercept groundwater in the weathered bedrock zone where the permeability has been increased by weathering. Information obtained during the well inventory indicated a trend away from domestic groundwater usage and toward the use of treated surface water (WCNOC 2004).

In the final environmental statement (FES) for construction, NRC conducted an analysis of Neosho River flow rates immediately downstream of the John Redmond dam with and without the water being diverted to Coffey County Lake. The results showed that there would be a reduction of flow during some portions of the period-of-record drought. However, there would be no change in the downriver flow during the worst part of the drought because the water surface in John Redmond Reservoir would be below the conservation level. In this case, water would be released downstream only for the previous water rights and for water quality purposes, which are the same with or without the presence of WCGS (NRC 1975).

In addition, a water purchase contract between the State of Kansas, Kansas Water Resources Board, Kansas Gas and Electric (KG&E), and Kansas City Power and Light Company (KCP&L) limits the amount of water that WCGS can withdraw from John Redmond Reservoir to 9,672 million gallons of water per year. KG&E and KCP&L own WCGS. The contract states that “If the total amount of waters contracted for withdrawal from the John Redmond Reservoir in the next 12-month period is greater than the supply available from that reservoir which is deemed to be 9,672 million gallons per year due to a prolonged drought, the Board will apportion the available waters among the purchasers having contracts therefore as may best provide for the health, safety, and general welfare of the people of this state as determined by the Board” (State of Kansas 1976). Should the State of Kansas determine that an insufficient amount of water is available to maintain flows in the Neosho River, the state will apportion available waters to best benefit the people of Kansas.

WCGS does not use groundwater for operation of the plant but does withdraw water from the Neosho River, which could affect recharge of the alluvial aquifer during low flows. However, during the worst drought conditions and lowest flows in the Neosho River, WCGS would not withdraw water from the Neosho River because the water level in John Redmond Reservoir would be below the conservation stage. The State of Kansas may also limit the amount of water that WCGS can withdraw from John Redmond Reservoir if a prolonged drought is experienced. Although recharge to the alluvial aquifer could, in theory, be affected by low flows in the Neosho River, impacts caused by WCGS would be minimal because lower water levels in John Redmond Reservoir would ultimately preclude or reduce releases at the dam and thus withdrawal of makeup water for Coffey County Lake. Therefore, continued operation of WCGS would have SMALL impacts on groundwater use conflicts and no mitigation is warranted.

4.7 GROUNDWATER USE CONFLICTS (PLANTS USING RANNEY WELLS)

NRC

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

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

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

This issue does not apply to WCGS because, as indicated in Section 3.1.2, WCGS does not use Ranney wells.

4.8 DEGRADATION OF GROUNDWATER QUALITY

NRC

"If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided." 10 CFR 51.53(c)(3)(ii)(D)

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

The issue of groundwater degradation applies to WCGS because the station uses a cooling pond (Coffey County Lake). As Section 3.1.2 describes, the Circulating Water System, Service Water System, and the Essential Service Water System all draw from and discharge to Coffey County Lake, a 5,090-acre impoundment.

The Coffey County Lake dam has a spillway that empties into Wolf Creek, a tributary of the Neosho River. Makeup water for Coffey County Lake is supplied from the Neosho River immediately downstream of John Redmond Reservoir. Water exits the John Redmond Reservoir through a 30-inch supply pipe, controlled by WCGS, directly into the outlet channel below the dam. A makeup water screenhouse with three pumps is located on the east bank of the Neosho River below the outlet to pump the water to Coffey County Lake, which is located approximately 3 miles east of John Redmond dam.

WCNOC conducted a study of groundwater quality in the vicinity of the site over the 1973-1987 period. Groundwater samples were collected from as many as eight wells in a given study year. A total of 12 different wells were used in the program (EA 1988).The wells were located within five miles of WCGS, in multiple directions from the plant (WCNOC 2004). The quality of groundwater samples collected near WCGS from 1973 through 1987 varied considerably among wells. Concentrations of total dissolved solids appeared greatest in a well located directly south of the site, as did calcium and chloride (EA 1988). Data collected during 1987 (the last year of the study) indicated water quality parameters in groundwater were within the concentration ranges observed in previous studies, with a few exceptions; some dissolved constituents (chloride, magnesium, and iron) were lower in one or more wells in 1987 than in previous years. Well water at the monitoring sites was typically very hard with high levels of dissolved constituents. These observations did not change after dam closure for Coffey County Lake (formerly Wolf Creek Cooling Lake) or after WCGS began operation (EA 1988). The study concluded that there appeared to be no effects on groundwater quality due to WCGS in the areas covered by the study (EA 1988).

Based on this study, there appears to be no negative impact on groundwater quality as a result of operation of WCGS. Impacts of continued operation would be SMALL and would not warrant mitigation.

4.9 IMPACTS OF REFURBISHMENT ON 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 51, Subpart A, Table B-1, Issue 40
>
> "…If no important resource would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant…." (NRC 1996)

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

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

4.10 THREATENED AND ENDANGERED SPECIES

NRC

> "Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act." 10 CFR 51.53(c)(3)(ii)(E)
>
> "Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 49

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

Section 2.2 of this Environmental Report describes the aquatic communities of the Neosho River, which supplies makeup water for Coffey County Lake, and Coffey County Lake, the station's cooling reservoir. Section 2.4 describes important terrestrial habitats at WCGS and along the associated transmission corridors. Section 2.5 discusses threatened or endangered species that occur or may occur at WCGS and along associated transmission corridors.

Two federally-listed species and one candidate species occur in the vicinity of WCGS. A pair of bald eagles, federally- and state-listed as threatened, has nested on Coffey County Lake since 1994. The nest is monitored by the U.S. Fish and Wildlife Service and WCNOC biologists. The Neosho mucket mussel, a candidate for federal listing, is found in the mainstem of the Neosho River from Coffey County to the Kansas-Oklahoma line and may be present in small numbers in the vicinity of WCGS. The Neosho madtom, federally- and state-listed as threatened, was regularly collected in the 1980s and early 1990s in the Neosho River up- and downstream of the Neosho River-Wolf Creek confluence.

The Neosho Madtom Recovery Plan (Wenke and Eberle 1991) lists WCGS as one of eight potential threats to the Neosho madtom. The Recovery Plan notes that under normal circumstances, operation of WCGS would not have a significant impact on the Neosho River and its fish populations but suggests that during a severe drought operation of the station could reduce (by as much as 50 percent) the volume of water passed downstream from John Redmond Reservoir to the Neosho River. As discussed in some detail in Section 4.1, WCNOC believes there are adequate controls and safeguards in place to minimize the impact of WCGS operation on Neosho River flows and fish populations during severe droughts. The state of Kansas reserves the right to limit the amount of water that can be withdrawn for industrial use during droughts and would have the option of curtailing WCGS diversion of Neosho River flow if deemed in the best interest of the citizens of Kansas.

With the exception of the species identified in Section 2.5, WCNOC is not aware of any threatened or endangered terrestrial species that could occur at WCGS or along the associated transmission corridors. Current operations of WCGS and WCNOC vegetation management practices along transmission line rights-of-way are not believed to affect any listed terrestrial or aquatic species or their habitat. Furthermore, plant operations and transmission line maintenance practices are not expected to change significantly during the license renewal term. Therefore, no adverse impacts to threatened or endangered species from current or future operations are anticipated.

WCNOC wrote to the Kansas Department of Wildlife and Parks and the U.S. Fish and Wildlife Service requesting information on any listed species or ecologically significant habitats that might occur on the WCGS site or along the associated transmission corridors. Agency responses are provided in Attachment C and indicate that license renewal will not impact listed species or important habitats.

As discussed in Section 3.2, WCNOC has no plans to conduct refurbishment or construction activities at WCGS during the license renewal term. Therefore, there would be no refurbishment-related impacts to special-status species and no further analysis of refurbishment-related impacts is applicable. Furthermore, because WCNOC has no plans to alter current operations and resource agencies contacted by WCNOC evidenced no serious concerns about license renewal impacts, WCNOC concludes that impacts to threatened or endangered species from license renewal would be SMALL and do not warrant mitigation.

4.11 AIR QUALITY DURING REFURBISHMENT (NON-ATTAINMENT AREAS)

NRC

> "If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended." 10 CFR 51.53(c)(3)(ii)(F)
>
> "…Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage…." 10 CFR 51, Subpart A, Table B-1, Issue 50

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

The issue of air quality during refurbishment is not applicable to WCGS because, as discussed in Section 3.2, WCNOC has no plans for refurbishment or other license-renewal-related construction activities at WCGS.

4.12 MICROBIOLOGICAL ORGANISMS

NRC

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

"These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 57

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

This issue is applicable to WCGS because the plant uses a cooling pond, Coffey County Lake. It is also relevant because the Coffey County Lake is used by the public for fishing (but not swimming). Organisms of concern include the enteric pathogens Salmonella and Shigella, the *Pseudomonas aeruginosa* bacterium, thermophilic Actinomycetes ("fungi"), the many species of Legionella bacteria, and pathogenic strains of the free-living Naegleria amoeba. Humans are generally resistant to infections of *Naegleria fowleri*, but once infected, death is generally the end result.

Thermophilic bacteria can exist at temperatures from 77°F to 176°F, with maximum growth at 122°F to 140°F (Joklik and Smith 1972). Accordingly, these bacteria are able to survive in the human digestive tract, which has a temperature around 99°F (Joklik and Smith 1972). Many of the pathogenic microorganisms (e.g., Pseudomonas, Salmonella, and Shigella) are ubiquitous in nature, occurring in the digestive tracts of wild mammals and birds (and thus in natural waters), but are usually only a problem when the host is immunologically compromised.

WCGS uses the 5,090-acre Coffey County Lake to transfer waste heat from the condensers to the atmosphere (see Section 3.1.2 for a description of the circulating water system). Baffle dikes built in the lake create a longer path between the heated discharge and the cooler intake waters. The baffle dikes create a discharge cove area of approximately 290 acres (Figure 2-3). During the summer months, water temperatures in the discharge cove, including areas adjacent to the discharge structure, can range from 90°F to 110°F. Water temperature at the intake structure is in the range of 77°F to 81°F (WCNOC 1987), a range in which, in theory, could allow limited survival of thermophilic microorganisms but which is well below the optimal temperatures for growth and reproduction.

In 1987, WCNOC commissioned a study of *Naegleria fowleri* in the cooling lake. The study did not identify any of the pathogenic species of Naegleria, but did find large populations of the nonpathogenic species in the discharge cove. No Naegleria were found at the intake structure. It is possible that the nonpathogenic population masked the presence of the pathogenic species. Fishermen are not allowed in the discharge cove as far as the discharge structure and, thus, are not exposed to the warmest water.

As a result of concerns about pathogenic microorganisms, WCNOC distributed information to its workers regarding possible health effects of thermophilic pathogens in cooling water systems and instituted a number of requirements and procedures related to safe practices in areas that could harbor pathogens such as the condenser bays during outages. In approximately 20 years of station operation, no WCGS employee has been diagnosed with a disease associated with a thermophilic pathogen.

WCNOC has written the Kansas Department of Health and Environment (KDHE) requesting information on any studies that may have been conducted on thermophilic microorganisms in the WCGS region and any concerns KDHE may have relative to these organisms in Coffey County Lake. The KDHE response (Attachment E) states that there have been no reports of illnesses from thermophilic pathogens associated with Coffey County Lake and there is no likely threat from the public's use of the lake. Given that there have been no incidents of infection by thermophilic organisms and that the 1987 study failed to identify *Naegleria fowleri*, WCNOC concludes that the impact of thermophilic organisms on the public is SMALL and does not warrant mitigation.

4.13 ELECTRIC SHOCK FROM TRANSMISSION-LINE INDUCED CURRENTS

NRC

The environmental report must contain an assessment of the impact of the proposed action on the potential shock hazard from transmission lines ". ...[i]f the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced current…" 10 CFR 51.53(c)(3)(ii)(H)

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

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

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

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

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

As described in Section 3.1.3, there are two 345-kilovolt lines that were specifically constructed to distribute power from WCGS to the electric grid (Wolf Creek-Rose Hill and re-routed segments of LaCygne-Benton). WCNOC's analysis of these transmission lines began by identifying the limiting case for each line. The limiting case is the configuration along each line where the potential for current-induced shock would be greatest. Once the limiting case was identified, WCNOC calculated the electric field strength for each transmission line, then calculated the induced current.

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

The analysis determined that Wolf Creek-Rose Hill and re-routed segments of LaCygne-Benton transmission lines has the capacity to induce 4.3 and 1.5 milliamperes in a vehicle parked beneath the lines, respectively. Therefore, since neither transmission line had the capacity to induce as much as five milliamperes, the WCGS transmission lines conform to the NESC provisions for preventing electric shock from induced current. Details of the analysis, including the input parameters for each line's limiting case, can be found in TtNUS (2005).

Westar Energy, the lines' owner, has surveillance and maintenance procedures that provide assurance that design ground clearances will not change. These procedures include routine aerial inspection nine times per year, which include checks for encroachments, broken conductors, broken or leaning structures, and signs of trees burning, any of which would be evidence of clearance problems. Ground inspections conducted once every ten years include examination for clearance at questionable locations, integrity of structures, and surveillance for dead or diseased trees that might fall on the transmission lines. Problems noted during any inspection are brought to the attention of the appropriate organization(s) for corrective action.

WCNOC's assessment under 10 CFR 51 concludes that electric shock is of SMALL significance for the WCGS transmission lines. Due to the small significance of the issue, mitigation measures, such as installing warning signs at road crossings or increasing clearances, are not warranted.

1 Part 2, Rules 232C1c and 232D3c.

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

4.14 HOUSING IMPACTS

NRC

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

"…Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or areas with growth control measures that limit housing development…." 10 CFR 51, Subpart A, Table B-1, Issue 63

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

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

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

Sections 2.6 and 2.8 indicate that WCGS is located in a low population area that is not subject to growth control measures that limit housing development. NRC regulatory criteria at 10 CFR 51, Subpart A, Table B-1, Issue 63, indicates that moderate or large housing impacts of the workforce may be associated with plants located in sparsely populated areas or areas with growth control measures that limit housing development. However, because WCNOC anticipates that existing "surge" capabilities for routine activities, such as outages, will enable WCNOC to perform the increased surveillance, monitoring, inspections, testing, trending, and recordkeeping (SMITTR) workload without increasing WCGS staff (Section 3.4), WCGS license renewal housing impacts would be expected to be small. WCNOC concludes that since there would be no increase in staffing, no housing impacts would be experienced and, therefore, the appropriate characterization of WCGS license renewal housing impacts is SMALL.

4.15 PUBLIC UTILITIES: PUBLIC WATER SUPPLY AVAILABILITY

NRC

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

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

"Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (NRC 1996)

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

NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. As Section 3.4 indicates, WCNOC anticipates no increase in WCGS employment attributable to license renewal. Section 2.6 describes the WCGS regional demography. Section 2.9.1 describes the public water supply systems in the area, their permitted capacities, and current demands. As discussed in Section 3.2, no refurbishment is planned for WCGS and no refurbishment impacts are therefore expected. Accordingly, the following discussion focuses on impacts of continued operations on local public utilities.

NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. At this time, WCGS purchases water from Rural Water District 3 which purchases water from the City of Burlington and Public Wholesale District 12. WCGS uses approximately one to two percent of the total treated water production capacity of the City of Burlington's municipal water supply and three to four percent of actual production. Usage does not stress system capacity and is not currently an issue. As discussed in Section 4.14, WCNOC has no plans to increase WCGS staffing due to refurbishment or plant aging management activities. WCNOC has identified no operational changes during the WCGS license renewal term that would increase plant water use.

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

4.16 EDUCATION IMPACTS FROM REFURBISHMENT

NRC

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

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

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

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

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

4.17 OFFSITE LAND USE

4.17.1 Offsite Land Use - Refurbishment

NRC

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

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

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

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

This issue is not applicable to WCGS because, as Section 3.2 discusses, WCNOC has no plans for refurbishment at WCGS.

4.17.2 Offsite Land Use – License Renewal Term

NRC

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

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

"…[I]f plant-related population growth is less than five percent of the study area's total population, off-site land-use changes would be small…" (NRC 1996)

"If the plant's tax payments are projected to be a dominant source of the community's total revenue, new tax-driven land-use changes would be large. This would be especially true where the community has no pre-established pattern of development or has not provided adequate public services to support and guide development in the past." (NRC 1996)

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

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

Population-Driven Impacts

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

Tax-Driven Impacts

Determining tax-revenue-related land use impacts is a two-step process. First, the significance of the plant's tax payments on taxing jurisdictions' tax revenues is evaluated. Then, the impact of the tax contribution on land use within the taxing jurisdiction's boundaries is assessed.

Tax Payment Significance

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

Land Use Significance

NRC defined the magnitude of land-use changes as follows (NRC 1996):

Small - very little new development and minimal changes to an area's land-use pattern.

Moderate - considerable new development and some changes to land-use pattern.

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

NRC further determined that, if the plant's tax payments are projected to be a dominant source of the community's total revenue, new tax-driven land-use changes would be large. This would be especially true where the community has no pre-established pattern of development or has not provided adequate public services to support and guide development in the past (NRC 1996).

WCGS Tax Impacts

Table 2-4 provides a comparison of total tax payments made by WCGS to Coffey County and Coffey County's annual property tax revenues. For the years 2000 through 2004, WCGS's property taxes have represented 80 to 85 percent of Coffey County's total tax revenues. Over the past five years, 38 to 46 percent of the WCGS property tax payments have been received by Unified School District #244. Using NRC's criteria, WCGS's tax payments are of large significance to Coffey County and Unified School District #244.

WCGS Land Use Impacts

As stated in Section 2.8, Coffey County does not have a comprehensive land use plan. WCGS's construction and operation have had large indirect impacts on the economy in Coffey County. The plant's property tax payments have allowed the county to lower its property tax rates while upgrading its provision of municipal services (Hotaling 2005). Until recently, the County offered a lease-purchase program to businesses. The County used much of its tax revenue from WCGS to purchase industrial buildings and machinery to lease, at a discount, to companies on a lease-purchase basis. The program is no longer in effect, however. The majority of leases have ended and the facilities and machinery have been purchased. Presently, Coffey County uses much of its tax revenue from WCGS to provide a revolving loan program to businesses seeking low-cost loans for property, facilities, and equipment (Hotaling 2005). Companies benefit by paying less for loans for facilities and equipment, and the county benefits by attracting industrial development. According to local economic development officials, the combination of low property taxes, above-average municipal services, and relatively low plant and equipment loan costs has been successful in attracting some small and medium-sized industries to Coffey County (Hotaling 2005).

WCGS's positive contributions to the county's overall quality of life also serve as a tool in recruiting industries. The tax base, employment, and salaries that WCGS provides have encouraged commercial development, particularly in the incorporated towns in Coffey County, and have helped make the region's economy more stable. Local economic development officials feel that the plant's tax payments have been responsible for improving the county's hospital, roads, sewers, schools, and recreation facilities and that these improvements are a selling point to industrial prospects. Also, they feel that WCGS has brought a more highly educated, technical work force to the County and that the workers would continue to support the types of community improvements that would be attractive to industries (Hotaling 2005).

Since WCGS's construction, industries have begun to locate in Burlington, Gridley, Waverly, Lebo, and Le Roy (Hotaling 2005; Casper 2005). Although most of the industries are small, their presence does create changes in the county's land-use and development patterns. Burlington, a town that had only two small rural industries when WCGS's operation began, now has two industrial parks. Local planning and economic development officials state that infrastructure for the industrial parks has been largely funded by the county tax revenues provided by WCGS (Hotaling 2005). Although Coffey County is still rural, with agriculture as its primary land use, WCGS's tax payments and overall positive contributions to the community's quality of life have enabled the county to attract some industrial development.

Conclusion

WCGS’s property taxes account for over 80 percent of Coffey County's property tax revenues, well above the highest NRC significance level of 20 percent for taxes. As such, WCGS has been and would likely continue to be the dominant source of tax revenue for Coffey County. However, despite having this income source, with concomitant improvements in public services (Hotaling 2005; Casper 2005), Coffey County is still predominantly rural, and land in the plant's immediate vicinity will likely continue to be used for agriculture and livestock grazing into the license renewal term.

Although local officials expect some small-scale industrial and commercial growth in the county's incorporated towns, the nuclear plant's presence is not expected to directly attract support industries and commercial development or to encourage or deter residential development (NRC 1996; Hotaling 2005). License renewal would not generate additional tax revenues, beyond those currently generated during the original operating term, but would continue the beneficial impact of the plant on the county. Therefore, the land-use impacts of WCGS' license renewal term are expected to be SMALL, with very little new development and minimal changes to the area’s land-use pattern.

4.18 TRANSPORTATION

NRC

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

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

Small impacts would be associated with U.S. Transportation Research Board Level of Service A, having the following condition: "…Free flow of the traffic stream; users are unaffected by the presence of others." and Level of Service B, having the following condition: "…Stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished…." (NRC 1996)

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

As described in Section 3.2, no refurbishment is planned and no refurbishment impacts to local transportation are therefore anticipated. As described in Section 3.4, no additional license renewal employment increment is expected. Therefore, WCNOC expects license-renewal impacts to transportation to be SMALL and believes no mitigation would be necessary.

4.19 HISTORIC AND ARCHAEOLOGICAL RESOURCES

NRC

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

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

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

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

As a result of the cultural resources investigations for the construction and operation Final Environmental Statements for WCGS (NRC 1975; NRC 1982), NRC staff ultimately concluded that WCGS would have no impacts on cultural resources (See Section 2.11).

As discussed in Section 3.2, WCNOC has no refurbishment plans and no refurbishment-related impacts are anticipated. WCNOC is not aware of any historic or archaeological resources that have been affected to date by WCGS operations, including operation and maintenance of transmission lines. WCNOC is aware, however, that the site vicinity and the surrounding environs have potential for containing cultural resources. Therefore, WCNOC has developed a cultural resources procedure to protect those resources. Because WCNOC has no plans to construct additional facilities at WCGS during the license renewal term and the new procedure should protect resources that may be discovered, WCNOC concludes that operation of generation and transmission facilities over the license renewal term would have SMALL impacts to cultural resources; hence, no mitigation would be warranted. As Appendix D demonstrates, the Kansas State Historical Society has concurred with this conclusion.

4.20 SEVERE ACCIDENT MITIGATION ALTERNATIVES

NRC

> The environmental report must contain a consideration of alternatives to mitigate severe accidents "…if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment..." 10 CFR 51.53(c)(3)(ii)(L)
>
> "…The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76

Section 4.20 summarizes WCNOC's analysis of alternative ways to mitigate the impacts of severe accidents. Attachment F provides a detailed description of the severe accident mitigation alternatives (SAMA) analysis.

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

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

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

WCNOC used industry, NRC, and WCGS-specific information to create a list of 17 SAMAs for consideration. WCNOC analyzed this list and screened out SAMAs that would not apply to the

WCGS design, that WCNOC had already implemented, or that would achieve results that WCNOC had already achieved by other means. WCNOC prepared preliminary cost estimates for the remaining SAMAs and used the base risk value to screen out SAMAs that would not be cost-beneficial.

WCNOC calculated the risk reduction that would be attributable to each candidate SAMA (assuming SAMA implementation) and re-quantified the risk value. The difference between the base risk value and the SAMA-reduced risk value became the averted risk, or the value of implementing the SAMA. WCNOC prepared more detailed cost estimates for implementing each SAMA and repeated the cost/benefit comparison.

WCNOC performed six sensitivity studies to evaluate how the SAMA results would change if certain key parameters were changed. These sensitivity studies are discussed in Section F.7 of Attachment F.

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

4.21 REFERENCES

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

NRC (U.S. Nuclear Regulatory Commission), 1996b. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." *Federal Register*, Volume 61, Number 109, page 28483. June 5.

Section 4.1

NRC (U.S. Regulatory Commission). 1982. *Final Environmental Statement related to the operation of Wolf Creek Generating Station, Unit 1,* NUREG-0878, Office of Nuclear Reactor Regulation, Washington, D.C., June.

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

Putnam and Schneider. 2005. "Water Resources Data, Kansas, Water Year 2004, Water-Data Report KS-04-1." U.S. Department of the Interior, U.S. Geological Survey.

State of Kansas. 1976. Kansas Water Resources Board, Water Purchase Contract No. 76-2.

USACE (U.S. Army Corp of Engineers). 1996. John Redmond Dam and Reservoir, Neosho River, Kansas, *Water Control Manual, Appendix O Part III to Water Control Master. Manual Arkansas River Basin*. Department of the Army Tulsa District, Corps of Engineers. Oklahoma. April

WCNOC (Wolf Creek Nuclear Operating Corporation). 2001. "2000 Annual Environmental Operating Report."

WCNOC (Wolf Creek Nuclear Operating Corporation). 2002. "2001 Annual Environmental Operating Report."

WCNOC (Wolf Creek Nuclear Operating Corporation). 2003a. "2002 Annual Environmental Operating Report."

WCNOC (Wolf Creek Nuclear Operating Corporation). 2003b. Natural Events, Rev. 12. OFN5G-003. December 16.

WCNOC (Wolf Creek Nuclear Operating Corporation). 2004. "2003 Annual Environmental Operating Report."

WCNOC (Wolf Creek Nuclear Operating Corporation), 2005. "2004 Annual Environmental Operating Report." April.

Section 4.2

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

Section 4.3

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

Section 4.4

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

Section 4.6

EPA (United States Environmental Protection Agency). 2005. U. S. Environmental Protection Agency Local Drinking Water Information. Kansas Drinking Water. List of Water Systems in Safe Drinking Water Information System database for Coffey and Lyon Counties. Available online at http://www.epa.gov/enviro/html/sdwis/sdwis_query.html. Accessed April 21.

NRC (U.S. Nuclear Regulatory Commission). 1975. *Final Environmental Statement related to construction of Wolf Creek Generating Station Unit 1*. Office of Nuclear Reactor Regulation. NUREG-75/096. October.

NRC (U.S. Nuclear Regulatory Commission). 1982. *Final Environmental Statement Related to Operation of Wolf Creek Generating Station, Unit 1*, NUREG-0878, Office of Nuclear Reactor Regulation, Washington, D.C., June.

Putnam and Schneider. 2005. “Water Resources Data, Kansas, Water Year 2004, Water-Data Report KS-04-1.” U.S. Department of the Interior, U.S. Geological Survey.

State of Kansas. 1976. Kansas Water Resources Board, Water Purchase Contract No. 76-2.

WCGS (Wolf Creek Generating Station). 1980. *Wolf Creek Generating Station Unit. No. 1 – Environmental Report, Operating License Stage*.

WCNOC (Wolf Creek Nuclear Operating Corporation). 2004. *Wolf Creek Updated Safety Analysis Report,* Revision 18. March 11.

Section 4.8

EA (Engineering, Science, and Technology, Inc.). 1988. *Wolf Creek Generating Station Operational Phase Environmental Monitoring Program, Final Report*. Prepared for Wolf Creek Nuclear Operating Corporation. Great Plains Regional Office, September.

WCNOC (Wolf Creek Nuclear Operating Corporation). 2004. *Wolf Creek Updated Safety Analysis Report*, Revision 18. March 11.

Section 4.9

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

Section 4.10

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

Wenke, T.L. and M. E. Eberle. 1991. "Neosho Madtom Recovery Plan." Prepared by Natural Science Research Associates for Region 6 U.S. Fish and Wildlife Service, Denver. Available on http://ecos.fws.gov/docs/recovery_plans/1991/910930e.pdf

Section 4.11

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

Section 4.12

Joklik, W. K. and D. T. Smith. 1972. *Microbiology.* 15th Edition. Meredith Corporation. New York.

WCNOC (Wolf Creek Nuclear Operating Corporation). 1987. "*Naegleria fowleri* Test Results," LI 87-0627, interoffice correspondence from Gregg Wedd to Distribution, October 16.

Section 4.13

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

TtNUS (Tetra Tech NUS). 2005. "Calculation Package for Wolf Creek Transmission Lines Induced Current Analysis." Aiken, South Carolina. May 19.

Section 4.14

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

Section 4.15

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

Section 4.16

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

Section 4.17

Casper, H. (Coffey County Zoning Department). 2005. Personal communication with E. N. Hill (Tetra Tech NUS, Inc.). "Land Use Information." May 31.

Hotaling, J. (Coffey County Economic Development). 2005. Personal communication with E. N. Hill (Tetra Tech NUS, Inc.). "Land Use Information." June 1.

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

Section 4.18

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

Section 4.19

NRC (U.S. Nuclear Regulatory Commission). 1975. *Final Environmental Statement related to construction of Wolf Creek Generating Station Unit 1*. Office of Nuclear Reactor Regulation. NUREG-75/096. October.

NRC (U.S. Nuclear Regulatory Commission). 1982. *Final Environmental Statement Related to Operation of Wolf Creek Generating Station, Unit 1*, NUREG-0878, Office of Nuclear Reactor Regulation, Washington, D.C., June.

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

5.0 CHAPTER 5 - ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

5.1 DISCUSSION

NRC

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

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants and provides for license renewal. License renewal applications must include an environmental report (10 CFR 54.23) with the content as prescribed in 10 CFR 51. In an effort to streamline the environmental review, NRC has resolved most of the environmental issues generically and only requires an applicant's analysis of the remaining issues.

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware [10 CFR 51.53(c)(3)(iv)]. The purpose of this requirement is to alert NRC staff to such information so the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) conclusions (NRC 1996).

WCNOC expects that new and significant information would include:

- Information that identifies a significant environmental issue not covered in the GEIS and codified in the regulation, or

- Information that was not covered in the GEIS analyses and that leads to an impact finding different from that codified in the regulation.

NRC does not specifically define the term "significant." For the purpose of its review, WCNOC used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act authorizes CEQ to establish implementing regulations for federal agency use. NRC requires license renewal applicants to provide NRC with input, in the form of an environmental report, that NRC will use to meet National Environmental Policy Act requirements as they apply to license renewal (10 CFR 51.10). CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), focus on significant environmental issues (40 CFR 1502.1), and eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). WCNOC expects that moderate or large impacts, as defined by NRC, would be significant. Chapter 4 presents the NRC definitions of "moderate" and "large" impacts.

The new and significant assessment process that WCNOC used during preparation of this license renewal application included: (1) interviews with WCNOC subject experts on the validity of the conclusions in the GEIS as they relate to WCGS, (2) an extensive review of documents related to environmental issues at WCGS, (3) correspondence with state and federal agencies to determine if the agencies had concerns not addressed in the GEIS, (4) a review of reports submitted to NRC in accordance with Section 5.4.2 of the Environmental Protection Plan, (5) a review of other license renewal applications for pertinent issues, (6) credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies, and (7) interfaces with allied nuclear plants under the Strategic Teaming and Resource Sharing alliance.

As a result of this review, WCNOC is aware of no new and significant information regarding the environmental impacts of WCGS license renewal.

5.2 REFERENCES

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

6.0 CHAPTER 6 - SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

WCNOC has reviewed the environmental impacts of renewing the WCGS operating license and has concluded that all impacts would be SMALL and would not require additional mitigation. This environmental report documents the basis for WCNOC's conclusion. Chapter 4 incorporates by reference the NRC findings for the 50 Category 1 issues that apply to WCGS, all of which have impacts that are SMALL (Attachment A, Table A-1). Chapter 4 also analyzes Category 2 issues, all of which are either not applicable or have impacts that would be SMALL. Table 6-1 identifies the impacts that WCGS license renewal would have on resources associated with Category 2 issues.

6.2 MITIGATION

NRC

"The report must contain a consideration of alternatives for reducing adverse impacts…for all Category 2 license renewal issues…"

10 CFR 51.53(c)(3)(iii)

"…The environmental report shall include an analysis that considers and balances…alternatives available for reducing or avoiding adverse environmental effects.…" 10 CFR 51.45(c) as incorporated by 10 CFR 51.53(c)(2) and 10 CFR 51.53(c)(3)(iii)

All impacts of license renewal are SMALL and would not require mitigation. Current operations include mitigation and monitoring activities that would continue during the term of the license renewal. WCNOC performs routine mitigation and monitoring activities to ensure the safety of workers, the public, and the environment. These activities include:

- The Radiological Environmental Monitoring Program
- Emissions monitoring
- Effluent chemistry monitoring
- Monitoring the water quality and fishery of Coffey County Lake
- Environmental Protection Plan implementing procedure reporting requirements

These monitoring programs and activities ensure that the plant's permitted emissions and discharges are within regulatory limits and any unusual or off-normal emissions or discharges would be quickly detected, thus, mitigating potential impacts. In addition, limitations on water withdrawn from the Neosho River during drought conditions mitigate the potential for loss of habitat in the river, and, therefore, impacts to sensitive species.

6.3 UNAVOIDABLE ADVERSE IMPACTS

NRC

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

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

- Waste heat from operation of WCGS is discharged to Coffey County Lake and would continue to affect the distribution and abundance of plankton, benthos, and fish in the lake, especially the immediate vicinity of the discharge. The waste heat also slightly increases the consumption of lake water, due to increased evaporation accompanying the added heat load.
- Some juvenile and adult fish would continue to be impinged on the intake traveling screens.
- Some larval fish and shellfish would continue to be entrained at the intake structure.
- Water would continue to be withdrawn from the Neosho River.
- Small amounts of radioactivity will continue to be released to the air and Coffey County Lake and the very low probability risk of accidental radiation exposure continues to exist.
- The containment building continues to be a prominent feature in the viewscape around the site.

6.4 IRREVERSIBLE AND IRRETRIEVABLE RESOURCE COMMITMENTS

NRC

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

The continued operation of WCGS for the license renewal term will result in irreversible and irretrievable resource commitments, including the following:

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

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

NRC

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

The current balance between short-term use and long-term productivity at WCGS was established when the plant began operating in 1985. The WCGS Final Environmental Statement (NRC 1982) evaluated the impacts of constructing and operating WCGS in Coffey County, Kansas. Approximately 9,800 acres were acquired for the plant and buffer areas, in addition to that needed for transmission line corridors. The greatest impact was the loss of terrestrial resources to Coffey County Lake, a 5,090-acre reservoir constructed to provided cooling for circulating water. The loss of productivity of rangeland and farmland covered by the reservoir could be long-term if the reservoir remains after the plant ceases operations; however, this long-term loss would likely be offset by the recreational opportunities created by the lake.

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

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

6.6 TABLES

Table 6-1. Category 2 Environmental Impacts Related to License Renewal at WCGS.

No.	Issue	Environmental Impact
Surface Water Quality, Hydrology, and Use (for all plants)		
13	Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	**SMALL**. Surface water for makeup to Coffey County Lake is held in the conservation pool at John Redmond Reservoir for use by WCGS under a contact with the State of Kansas.
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)		
25	Entrainment of fish and shellfish in early life stages	**SMALL**. WCGS has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements.
26	Impingement of fish and shellfish in early life stages	**SMALL**. WCGS has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements.
27	Heat shock	**SMALL**. WCGS has a current NPDES permit which constitutes compliance with CWA Section 316(a) requirements.
Groundwater Use and Quality		
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	**None**. WCGS does not withdraw any groundwater. Therefore, this issue does not apply.
34	Groundwater use conflicts (plants using cooling towers or cooling ponds that withdraw make-up water from a small river)	**SMALL**. WCGS withdraws water from the Neosho River, but flow is not diminished because of concurrent releases from the John Redmond Reservoir.
35	Groundwater use conflicts (Ranney wells)	**None**. WCGS does not use Ranney wells. Therefore, this issue does not apply.
39	Groundwater quality degradation (cooling ponds at inland sites)	**SMALL**. There is no evidence suggesting groundwater quality has been affected by Coffey County Lake.
Terrestrial Resources		
40	Refurbishment impacts	**None**. No impacts are expected because WCGS will not undertake refurbishment.
Threatened or Endangered Species		
49	Threatened or endangered species	**SMALL**. WCNOC does not plan to alter current operations over the license renewal period. Neither WCNOC nor natural resource agencies have identified any concerns about impacts of current operations. The Kansas Department of Health and Environment and the U.S. Fish and Wildlife Service concur.
Air Quality		
50	Air quality during refurbishment (nonattainment and maintenance areas)	**None**. No impacts are expected because WCGS will not undertake refurbishment.

Table 6-1. Category 2 Environmental Impacts Related to License Renewal at WCGS. (Continued)

No.	Issue	Environmental Impact
Human Health		
57	Microbiological organisms (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	**SMALL**. Studies have not detected Naegleria fowleri and no incidents of infection have been reported. The Kansas Department of Health and Environment concurs.
59	Electric shock from transmission line-induced currents	**SMALL.** The largest modeled induced current under the WCGS transmission lines is 4.3 milliamperes, which is less than the National Electric Safety Code standard of 5 milliamperes for preventing electric shock from induced current.
Socioeconomics		
63	Housing impacts	**SMALL.** For the purpose of license renewal, WCNOC does not plan on any refurbishment and does not plan to add employees. Therefore, there will be no increased demand on housing because of license renewal.
65	Public services: public utilities	**SMALL.** For the purpose of license renewal, WCNOC does not plan on any refurbishment and does not plan to add employees. Therefore, there will be no increased demand on public utilities because of license renewal.
66	Public services: education (refurbishment)	**None.** No impacts are expected because WCGS will not undertake refurbishment.
68	Offsite land use (refurbishment)	**None.** No impacts are expected because WCGS will not undertake refurbishment.
69	Offsite land use (license renewal term)	**SMALL.** Although taxes paid by the plant constitute a large fraction of the county tax revenue, the county has not shown significant offsite land use change since WCGS construction. Therefore, continued operation is expected to continue to have a SMALL impact on local land use.
70	Public services: transportation	**SMALL.** For the purpose of license renewal, WCNOC does not plan on any refurbishment and does not plan to add employees. Therefore, there will be no increased demand on the local transportation infrastructure because of license renewal.
71	Historic and archaeological resources	**SMALL.** WCNOC does not plan on any refurbishment or transmission-line corridor changes during the license renewal term. Continued plant site operations are not expected to impact cultural resources. The State Historic Preservation Office concurs.
Postulated Accidents		
76	Severe accidents	**SMALL.** The benefit/cost analysis did not identify any cost-effective aging-related severe accident mitigation alternatives **(to be verified)**.

6.7 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1982. *Final Environmental Statement Related to Operation of Wolf Creek Generating Station, Unit 1*, NUREG-0878, Office of Nuclear Reactor Regulation, Washington, D.C., June.

7.0 CHAPTER 7 - ALTERNATIVES TO THE PROPOSED ACTION

NRC

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

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

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

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

Chapter 7 evaluates alternatives to WCGS license renewal. The chapter identifies actions that the owners of WCGS (i.e., Kansas Gas and Electric Company, Kansas City Power & Light Company, and Kansas Electric Power Cooperative, Inc.) might take, and associated environmental impacts, if NRC chooses not to renew the plant’s operating license. The chapter also addresses WCGS actions that the owners of WCGS have considered, but would not take, and identifies bases for determining that such actions would be unreasonable.

WCNOC divided its alternatives discussion into two categories, “no-action” and “alternatives that meet system generating needs.” In considering the level of detail and analysis that it should provide for each category, WCNOC 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)]

WCNOC has determined that the analysis of alternatives should focus on comparative impacts, specifically whether an alternative’s impacts would be greater, smaller or similar to the proposed action.

Providing additional detail or analysis serves no function if it only brings to light additional adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which provide that the consideration of alternatives (including the proposed action) should enable reviewers to evaluate their comparative merits

(40 CFR 1500-1508). WCNOC considers Chapter 7 sufficient with regard to providing detail about alternatives to establish the basis for necessary comparisons to the Chapter 4 discussion of impacts from the proposed action.

In characterizing environmental impacts from alternatives, WCNOC has used the same definitions of SMALL, MODERATE, and LARGE that are presented in the introduction to Chapter 4.

7.1 NO-ACTION ALTERNATIVE

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

WCGS provides approximately 1,165 megawatts of electricity to WCNOC's customers. WCNOC thinks that any alternative would be unreasonable if it did not include replacing the capacity of WCGS. Replacement could be accomplished by (1) building new generating capacity, (2) purchasing power from the wholesale market, or (3) reducing power requirements through demand reduction. Section 7.2.1 describes each of these possibilities in detail, and Section 7.2.2 describes environmental impacts from feasible alternatives.

The Generic Environmental Impact Statement (GEIS) (NRC 1996a) defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. NRC-evaluated decommissioning options include immediate decontamination and dismantlement and safe storage of the stabilized and defueled facility for a period of time, followed by additional decontamination and dismantlement. Regardless of the option chosen, decommissioning must be completed within a 60-year period. Under the no-action alternative, WCNOC would continue operating WCGS until the existing license expires, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of a larger reactor (the "reference" pressurized-water reactor is the 1,175-megawatt-electric [MWe] Trojan Nuclear Plant). This description is applicable to decommissioning activities that WCNOC would conduct at WCGS.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include impacts of occupational and public radiation dose; impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated in the *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities; Supplement 1* (NRC 2002a) that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. WCNOC adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

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

WCNOC concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those occurring following license renewal, as identified in the GEIS (NRC 1996a) and in the decommissioning generic environmental impact statement (NRC

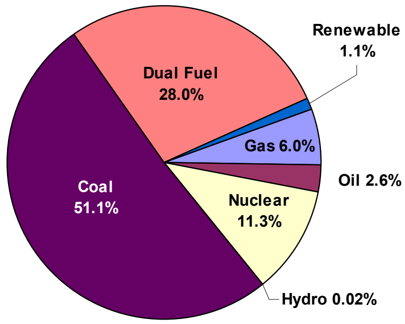
2002a). These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

7.2 ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

WCGS has a net capacity of 1,165 MWe and in 2003 generated approximately 8.9 terawatt-hours of electricity (EIA 2004a). This power, equivalent to the energy used by approximately 800,000 residential customers, would be unavailable to WCNOC's customers if the WCGS operating license was not renewed. If the WCGS operating license was not renewed, the owners of WCGS would need to build new generating capacity, purchase power, or reduce power requirements through demand reduction to ensure they meet the electric power requirements of their customers.

The current mix of power generation options in Kansas is one indicator of what the owners of WCGS consider to be feasible alternatives. In 2002, electric generators in Kansas had a total generating capacity of 10,396 MWe. This capacity includes units fueled by coal (51.1 percent), dual-fired (i.e., gas and oil; 28.0 percent), nuclear (11.3 percent), gas (6.0 percent), oil (2.6 percent), non-hydroelectric renewables (1.1 percent), and hydroelectric (0.02 percent). In 2002, the electric industry in Kansas provided approximately 47.2 terawatt-hours of electricity. Actual utilization of generating capacity in Kansas was dominated by coal (75.0 percent), followed by nuclear (19.2 percent), gas (3.8 percent), oil (1.1 percent), non-hydroelectric renewables (1.0 percent) and hydroelectric (0.03 percent) (EIA 2004b). Figures 7-1 and 7-2 illustrate Kansas's electric industry generating capacity and utilization, respectively.

Comparison of generating capacity with actual utilization of this capacity indicates that coal and nuclear are used by electric generators in Kansas substantially more relative to their capacity than either oil-fired or gas-fired generation. This condition reflects the relatively low fuel cost and baseload suitability for nuclear power and coal-fired plants, and relatively higher use of oil and gas-fired units to meet peak loads. Comparison of capability and utilization for oil and gas-fired facilities indicates a strong preference of gas firing over oil firing, indicative of higher cost and greater air emissions associated with oil firing. Energy production from renewable sources is similarly preferred from a cost standpoint, but capacity is limited and utilization can vary substantially depending on resource availability.



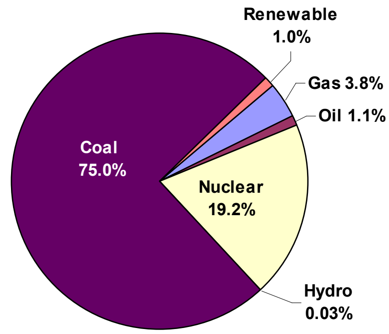


Figure 7-1. Kansas Generating Capacity by Fuel Type, 2002

Figure 7-2. Kansas Generation by Fuel Type, 2002

7.2.1 Alternatives Considered

Technology Choices

For the purposes of this environmental report, WCNOC conducted evaluations of alternative generating technologies to identify candidate technologies that would be capable of replacing the net base-load capacity of the nuclear unit at WCGS.

Based on these evaluations, it was determined that feasible new plant systems to replace the capacity of the WCGS nuclear unit are limited to pulverized-coal, gas-fired combined-cycle, and new nuclear units for base-load operation. This conclusion is supported by the generation utilization information presented above that identifies coal as the most heavily utilized non-nuclear generating technology in the state. WCNOC would use gas as the primary fuel in its combined-cycle turbines because of the economic and environmental advantages of gas over oil. Manufacturers now have large standard sizes of combined-cycle gas turbines that are economically attractive and suitable for high-capacity base-load operation. For the purposes of the WCGS license renewal environmental report, WCNOC has limited its analysis of new generating capacity alternatives to the technologies it considers feasible: pulverized coal-fired, gas-fired and advanced nuclearunits. WCNOC chose to evaluate combined-cycle turbines in lieu of simple-cycle turbines because the combined-cycle option is more economical. The benefits of lower operating costs for the combined-cycle option outweigh its higher capital costs.

Mixture

NRC indicated in the GEIS that, while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, it would be impractical to analyze all the combinations. Therefore, NRC determined that alternatives evaluation should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically reasonable and commercially viable

(NRC 1996a). Consistent with the NRC determination, WCNOC has not evaluated mixes of generating sources. The impacts from coal- and gas-fired generation presented in this chapter would bound the impacts from any combination of the two technologies.

Effects of Restructuring

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

In 1997, the Kansas Corporation Commission commissioned a study on the possible outcomes of deregulating the electric industry in Kansas. The results of the study indicate that over the long-term retail electric competition should produce positive benefits for the State. During the 1999 legislative session several bills were introduced to restructure the industry, but no bill was acted on before the session adjourned. No new legislation has been introduced since the 1999 session. The state is continuing to monitor restructuring efforts in other jurisdictions, but is not currently pursuing further action (FEMP 2005).

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

Alternatives

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

7.2.1.1 Construct and Operate Fossil-Fuel-Fired Generation

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

For comparability, WCNOC selected gas- and coal-fired units of equal electric power capacity. One unit with a net capacity of 1,165 MWe could be assumed to replace the 1,165-MWe WCGS net capacity. However, industry experience indicates that, although custom size units can be built, using standardized sizes is more economical. For example, standard-sized units include a gas-fired combined-cycle plant of 562.5 MWe net capacity (Chase and Kehoe 2000). Two of these standard-sized units would have 1,125 MWe net capacity. For comparability, WCNOC set the net power of the coal-fired unit equal to the gas-fired plants (1,125 MWe). Although this provides less capacity than the existing unit, it ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other methods (see Mixture in Section 7.2.1).

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

Gas-Fired Generation

For purposes of this analysis, WCNOC assumed development of a modern natural gas-fired combined-cycle plant with design characteristics similar to those being developed elsewhere in the midwest, and with a generating capacity similar to WCGS. The Aries Power Plant in Pleasant Hill, Missouri meets these general criteria. Two units with similar equipment to the Aries Power Plant would meet the criteria for replacing WCGS capacity. Therefore, WCNOC used characteristics of this plant and other relevant resources in defining the WCGS gas-fired alternative. WCNOC assumes that the representative plant would be located at the WCGS site, which offers potential advantages of existing infrastructure (e.g., cooling water system, transmission, roads, and technical and administrative support facilities). Table 7-1 presents the basic gas-fired alternative characteristics.

Coal-Fired Generation

NRC has routinely evaluated coal-fired generation alternatives for nuclear plant license renewal. In the GEIS Supplement for McGuire Nuclear Station (NRC 2002b), NRC analyzed 2,400 MWe of coal-fired generation capacity. WCNOC has reviewed the NRC analysis, considers it to be sound, and notes that it analyzed more generating capacity than the 1,125 MWe discussed in this analysis. In defining the WCGS coal-fired alternative, WCNOC has used site- and Kansas-specific input and has applied the NRC analysis, where appropriate.

Table 7-2 presents the basic coal-fired alternative emission control characteristics. WCNOC based its emission control technology and percent control assumptions on alternatives that the U.S. Environmental Protection Agency (EPA) has identified as being available for minimizing emissions (EPA 1998). WCNOC assumes that the representative plant would be located at the WCGS site, which offers potential advantages of existing infrastructure (e.g., cooling water system, transmission, roads, and technical and administrative support facilities). For the purposes of analysis, WCNOC has assumed that coal and lime (calcium oxide) would be delivered to WCGS via an existing rail spur.

7.2.1.2 Construct and Operate New Nuclear Reactor

Since 1997, the NRC has certified four new standard designs for nuclear power plants under 10 CFR 52, Subpart B. These designs are the U.S. Advanced Boiling Water Reactor (10 CFR 52, Appendix A), the System 80+ Design (10 CFR 52, Appendix B), the AP600 Design (10 CFR 52, Appendix C), and the AP1000 Design (71 FR 4464). All of these plants are light-water reactors. NRC evaluated 2,258 MWe of new nuclear generation capacity as an alternative for the McGuire Nuclear Station (NRC 2002b). WCNOC has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed more generating capacity than the 1165 MWe discussed in this analysis. In defining the WCGS new nuclear reactor alternative, WCNOC has used site- and Kansas-specific input and has scaled from the NRC analysis, where appropriate. See Table 8-2 for a detailed description.

7.2.1.3 Purchased Power

WCNOC has evaluated conventional and prospective power supply options that could be reasonably implemented before the existing WCGS license expires. The source of this purchased power is speculative, but may reasonably include new generating facilities developed within the WCGS service territory, elsewhere in Kansas, or in neighboring states. The technologies that would be used to generate this purchased power are similarly speculative. WCNOC assumes that the generating technology used to produce purchased power would be one of those that NRC analyzed in the GEIS. For this reason, WCNOC is adopting by reference the GEIS description of the alternative generating technologies as representative of the purchase power alternative. Of these technologies, facilities fueled by coal and combined-cycle facilities fueled by natural gas are the most cost effective for providing base-load capacity.

WCNOC anticipates that additional transmission infrastructure would be needed in the event that the owners of WCGS purchase power to replace WCGS capacity.

7.2.1.4 Demand Side Management

In the past, the owners of WCGS have offered demand-side management (DSM) programs that either conserve energy or allow the company to reduce customers' load requirements during periods of peak demand. These DSM programs generally fall into three categories:

Conservation Programs

Educational programs that encourage the wise use of energy

Energy Efficiency Programs

Discounted residential rates for homes that meet specific energy efficiency standards

Incentive programs that encourage customers to replace old, inefficient appliances or equipment with new high-efficiency appliances or equipment

Load Management Programs

Standby Generator Program – encourages customers to let electric companies switch loads to the customer's standby generators during periods of peak demand

Interruptible Service Program – encourages customers to allow blocks of their load to be interrupted during periods of peak demand

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

The market conditions which provided initial support for utility-sponsored conservation and load management efforts during the late 1970s and early 1980s can be broadly characterized by:

- increasing long-term marginal prices for capacity and energy production resources;
- forecasts projecting increasing demand for electricity across the nation;

- general agreement that conditions (1) and (2) would continue for the foreseeable future;
- limited competition in the generation of electricity;
- use of average embedded cost as the basis for setting electricity prices within a regulated context.

Changes that have significantly impacted the cost effectiveness of utility-sponsored DSM can be described as follows:

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

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

Other significant changes include:

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

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

7.2.1.5 Other Alternatives

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

Wind

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

Based on American Wind Energy Association (2002) estimates, Kansas has the technical potential (the upper limit of renewable electricity production and capacity that could be brought online, without regard to cost, market acceptability, or market constraints) for roughly 121,900 MWe of installed wind power capacity. The full exploitation of wind energy is constrained by a variety of factors including land availability and land-use patterns, surface topography, infrastructure constraints, environmental constraints, wind turbine capacity factor, wind turbine availability, and grid availability. When these constraints on wind energy development are considered the achievable wind energy potential is expected to fall in the range of 20-40 percent of technical potential estimates or 24,380 - 48,760 MWe. By the end of 2004 a total of 112 MWe of wind energy had been developed in Kansas. Projected new capacity in various stages of review within Kansas includes an additional 2,101 MWe of wind energy (KEC 2004).

Wind farms, the most economical wind option, generally consist of 10-50 turbines in the 1-3 MWe range. Estimates based on existing installations indicate that a utility-scale wind farm would occupy about 50 acres per MWe of installed capacity (McGowan & Connors 2000). Therefore, replacement of WCGS generating capacity with wind power, even assuming ideal wind conditions, would require dedication of about 91 square miles. Based on the amount of land needed to replace WCGS, the wind alternative would require a large green field site, which would result in a large environmental impact. Additionally, wind plants have aesthetic impacts, generate noise, and can harm flying birds and bats.

The scale of this technology is too small to directly replace a power plant of the size of WCGS, capacity factors are low (30 to 40 percent), and the land requirement (91 square miles) is large. Therefore, WCNOC has concluded that wind power is not a reasonable alternative to WCGS license renewal.

Solar

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

The amount of solar radiation that Kansas receives ranges from 3.5 kilowatt hours per square meter per day in the northeast part of the state to nearly 5.0 kilowatt hours per square meter per day in the southwest corner (KEC 2004). Estimates based on existing installations indicate that utility-scale plants would occupy about 7.4 acres per MWe for photovoltaic and 4.9 acres per MWe for solar thermal systems (DOE 2004). Utility-scale solar plants have only been used in regions, such as southern California, that receive high concentrations (5 to 7.2 kilowatt hours per square meter per day) of solar radiation. WCNOC believes that a utility-scale solar plant located in Kansas, which receives 3.5 to 5.0 kilowatt hours of solar radiation per square meter per day, would occupy about 10.62 acres per MWe for photovoltaic and 7.03 acres per MWe for solar thermal systems. Therefore, replacement of WCGS generating capacity with solar power would require dedication of about 12,425 acres (19 square miles) for photovoltaic and 8,225 acres (13 square miles) for solar thermal systems. The existing WCGS site is 9,818 acres, more than half of which is occupied by Coffey County Lake. Neither type of solar electric system would fit at the WCGS site, and both would have large environmental impacts at a green field site.

WCNOC has concluded that due to the high cost limited availability of sufficient incident solar radiation, and amount of land needed (approximately 13 to 19 square miles), solar power is not a reasonable alternative to WCGS license renewal.

Hydropower

According to the U.S. Hydropower Resource Assessment for Kansas (Francfort 1993), there are no sites in Kansas that would be environmentally suitable for a large hydroelectric facility. As the GEIS points out in Section 8.3.4, hydropower's proportion of United States generating capacity is expected to decline because hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and alteration of natural river courses.

The GEIS estimates land use of 1,600 square miles per 1,000 MWe for hydroelectric power. Based on this estimate, replacement of WCGS generating capacity would require flooding approximately 1,872 square miles, resulting in a large impact on land use. Further, operation of a hydroelectric facility would alter aquatic habitats above and below the dam, which would impact existing aquatic communities.

WCNOC has concluded that due to the lack of suitable sites in Kansas for a large hydroelectric facility and the amount of land needed (approximately 1,872 square miles) hydropower is not a reasonable alternative to WCGS license renewal.

Geothermal

As illustrated by Figure 8.4 in the GEIS (NRC 1996a), geothermal plants might be located in the western continental United States, Alaska, and Hawaii, where hydrothermal reservoirs are prevalent. However, because there are no high-temperature geothermal sites in Kansas, WCNOC concludes that geothermal is not a reasonable alternative to WCGS license renewal.

Wood Energy

As discussed in the GEIS (NRC 1996a), the use of wood waste to generate electricity is largely limited to those states with significant wood resources. The pulp, paper, and paperboard industries in states with adequate wood resources generate electric power by consuming wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem. According to the U.S. Department of Energy, Kansas does not have enough wood resources to replace the generating capacity of WCGS (Walsh et al. 2000).

Further, as discussed in Section 8.3.6 of the GEIS (NRC 1996a), construction of a wood-fired plant would have an environmental impact that would be similar to that for a coal-fired plant, although facilities using wood waste for fuel would be built on a smaller scale. Like coal-fired plants, wood-waste plants require large areas for fuel storage, processing, and waste (i.e., ash) disposal. Additionally, operation of wood-fired plants has environmental impacts, including impacts on the aquatic environment and air. Wood has a low heat content that makes it unattractive for base-load applications. It is also difficult to handle and has high transportation costs.

WCNOC has concluded that, due to inadequate resources, the lack of an environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy is not a reasonable alternative to WCGS license renewal.

Municipal Solid Waste

As discussed in Section 8.3.7 of the GEIS (NRC 1996a), the initial capital costs for municipal solid waste plants are greater than for comparable steam turbine technology at wood-waste facilities. This is due to the need for specialized waste separation and handling equipment.

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

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

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

Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol (ethanol is primarily used as a gasoline additive), and gasifying energy crops (including wood waste). As discussed in the GEIS, none of these technologies has progressed to the point of being competitive on a large scale or of being reliable enough to replace a base-load plant such as WCGS.

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

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

Petroleum

Kansas has several petroleum (oil)-fired power plants; and from 1993 to 2002 the percentage share of power produced by oil-fired generating plants has increased from 0.3 percent to about 1.1 percent (EIA 2004b). Kansas is an oil producing state and the increased utilization of oil-fired generation in the state is primarily the result of policies that encourage the use of Kansas' energy resources in electric power production.

However, oil-fired generation represents small portion of the overall generation mix in Kansas and is more expensive than nuclear, gas-, or coal-fired generation. Future increases in petroleum prices are expected to make oil-fired generation increasingly more expensive than gas- or coal-fired generation. Also, construction and operation of an oil-fired plant would have environmental impacts. For example, Section 8.3.11 of the GEIS (NRC 1996a) estimates that construction of a 1,000-MWe oil-fired plant would require about 120 acres. Additionally, operation of oil-fired plants would have environmental impacts (including impacts on the aquatic environment and air) that would be similar to those from a coal-fired plant.

WCNOC has concluded that, due to the high costs and lack of obvious environmental advantage, oil-fired generation is not a reasonable alternative to WCGS license renewal.

Fuel Cells

Fuel cell power plants are in the initial stages of commercialization. While more than 650 large stationary fuel cell systems have been built and operated worldwide, the global stationary fuel cell electricity generating capacity in 2003 was only 125 MWe. In addition, the largest stationary fuel cell power plant is only 11 MWe (Fuel Cell Today 2003). Recent estimates suggest that a company would have to produce about 100 MWe of fuel cell stacks annually to achieve a price of $1,000 to $1,500 per kilowatt (Kenergy 2000). However, the production capability of the largest stationery fuel cell manufacturer is 50 MWe per year (CSFCC 2002). WCNOC thinks that this technology has not matured sufficiently to support production for a facility the size of WCGS. WCNOC has concluded that, due to cost and production limitations, fuel cell technology is not a reasonable alternative to WCGS license renewal.

Delayed Retirement

As the NRC noted in the GEIS (NRC 1996a), extending the lives of existing non-nuclear generating plants beyond the time they were originally scheduled to be retired represents another potential alternative to license renewal. According to the Kansas Energy Council, Kansas is a net importer of electricity and electricity consumption in the state is projected to grow by 2.7 percent through 2009 (KEC 2004). WCNOC is not aware of plans for retiring any of Kansas' electric generating plants and the state expects to need additional capacity in the near future. Nationally, fossil plants slated for retirement tend to be ones that are old enough to have difficulty in meeting today's restrictions on air contaminant emissions. In the face of increasingly stringent restrictions, delaying retirement in order to compensate for a plant the size of WCGS would appear to be unreasonable without major construction to upgrade or replace plant components. WCNOC concludes that the environmental impacts of such a scenario are bounded by its coal- and gas-fired alternatives. For these reasons, the delayed retirement of non-nuclear generating units is not considered a reasonable alternative to WCGS license renewal.

7.2.2 Environmental Impacts of Alternatives

This section evaluates the environmental impacts of alternatives that WCNOC has determined to be reasonable alternatives to WCGS license renewal: gas-fired generation, coal-fired generation, and purchased power.

7.2.2.1 Gas-Fired Generation

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

In the GEIS Supplement for McGuire Nuclear Station (NRC 2002b), NRC evaluated the environmental impacts of constructing and operating five 482 MWe combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal. WCNOC has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed more generating capacity than the 1,125 MWe of net power discussed in this analysis. In defining the WCGS gas-fired alternative, WCNOC has used site- and Kansas-specific input and has scaled from the NRC analysis, where appropriate.

Air Quality

Natural gas is a relatively clean-burning fossil fuel that primarily emits nitrogen oxides (NO_x), a regulated pollutant, during combustion. A natural gas-fired plant would also emit small quantities of sulfur oxides (SO_x), particulate matter, and carbon monoxide, all of which are regulated pollutants. Control technology for gas-fired turbines focuses on NO_x emissions. WCNOC estimates the gas-fired alternative emissions to be as follows:

SO_x = 88 tons per year

NO_x = 282 tons per year

Carbon monoxide = 58 tons per year

Filterable Particulates = 49 tons per year (all particulates are PM_{10})

Table 7-3 shows how WCNOC calculated these emissions.

In 2002, Kansas was ranked 24th nationally in sulfur dioxide (SO_2) emissions (EIA 2004b). Therefore, the electric power plants in 23 states emitted more SO_2 than those located in Kansas. The acid rain requirements of the Clean Air Act Amendments capped the nation's SO_2 emissions from power plants. Each company with fossil-fuel-fired units was allocated SO_2 allowances. To be in compliance with the Act, the companies must hold enough allowances to cover their annual SO_2 emissions. WCNOC would need to obtain SO_2 credits to operate a fossil-fuel-burning plant at the WCGS site.

NO_x effects on ozone levels, SO_2 allowances, and NO_x emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. WCNOC concludes that emissions from the gas-fired alternative at WCGS would noticeably alter local air quality, but would not destabilize regional resources (i.e., air quality). Air quality impacts would therefore be moderate.

Waste Management

The solid waste generated from this type of facility would be minimal. The only noteworthy waste would be from spent selective catalytic reduction (SCR) catalyst used for NO_x control. The SCR process for a 2,400 MWe plant would generate approximately 1,500 cubic feet of spent catalyst per year (NRC 2002b). Based on this estimate, a 1,125 MWe plant would generate approximately 700 cubic feet of spent catalyst per year. WCNOC concludes that gas-fired generation waste management impacts would be small.

Other Impacts

The ability to construct the gas-fired alternative on the existing WCGS site would reduce construction-related impacts. A new gas pipeline would be required for the gas turbine generators in this alternative. To the extent practicable, WCNOC would route the pipeline along existing, previously disturbed, rights-of-way to minimize impacts. Approximately 10 miles of new pipeline construction would be required to connect WCGS to an existing pipeline near the plant. A 16-inch diameter pipeline would necessitate a 50-foot-wide corridor, resulting in the disturbance of as much as 60 acres. WCNOC estimates that 75 acres would be needed for a plant site; this much previously disturbed acreage is available at WCGS, reducing loss of terrestrial habitat. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be noticeable, but small. WCNOC estimates a peak construction workforce of 490 so socioeconomic impacts of construction would be small. However, WCNOC estimates a workforce of 41 for gas operations. The reduction in work force would result in adverse socioeconomic impacts. WCNOC thinks these impacts would be moderate and would be mitigated by the site's proximity to the Topeka and Kansas City metropolitan areas.

Impacts to aquatic resources and water quality would be similar to, but smaller than, the impacts of WCGS, due to the plant's use of the existing cooling water system that withdraws from and discharges to Coffey County Lake, and would be offset by the concurrent shutdown of WCGS. The additional stacks and boilers would increase the visual impact of the existing site. Impacts to cultural resources would be unlikely, due to the previously disturbed nature of the site.

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

7.2.2.2 Coal-Fired Generation

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

The coal-fired alternative that WCNOC has defined in Section 7.2.1.1 would be located at WCGS.

Air Quality

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

SO_x = 1,990 tons per year

NO_x = 1,309 tons per year

Carbon monoxide = 1,309 tons per year

Particulates:

Total suspended particulates = 145 tons per year

PM_{10} (particulates having a diameter of less than 10 microns) = 33 tons per year

Table 7-4 shows how WCNOC calculated these emissions.

The Section 7.2.2.1 discussion of regional air quality is applicable to the coal-fired generation alternative. In addition, NRC noted in the GEIS that adverse human health effects from coal combustion have led to important federal legislation in recent years and that public health risks, such as cancer and emphysema, have been associated with coal combustion. NRC also mentioned global warming and acid rain as potential impacts. WCNOC concludes that federal legislation and large-scale concerns, such as global warming and acid rain, are indications of concerns about destabilizing important attributes of air resources. However, SO_2 emission allowances, low NO_x burners, overfire air, fabric filters or electrostatic precipitators, and scrubbers are regulatorily-imposed mitigation measures. As such, WCNOC concludes that the coal-fired alternative would have moderate impacts on air quality; the impacts would be noticeable and greater than those of the gas-fired alternative, but would not destabilize air quality in the area.

Waste Management

WCNOC concurs with the GEIS assessment that the coal-fired alternative would generate substantial amounts of solid waste. The coal-fired plant would annually consume approximately 5,200,000 tons of coal with an ash content of 5.53 percent (Tables 7-4 and 7-2, respectively). After combustion, 50 percent of this ash, approximately 145,000 tons per year, would be marketed for beneficial reuse. The remaining ash, approximately 145,000 tons per year, would be collected and disposed of onsite. In addition, approximately 109,000 tons of scrubber sludge would be disposed of onsite each year (based on annual lime usage of nearly 36,600 tons). WCNOC estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 114 acres (a square area with sides of approximately 2,224 feet). Table 7-5 shows how WCNOC calculated ash and scrubber waste volumes. While only half this waste volume and acreage would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact.

WCNOC contends that, with proper sitting coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. There would be space within the WCGS property for this disposal. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, WCNOC contends that waste disposal for the coal-fired alternative would have moderate impacts; the impacts of increased waste disposal would be noticeable, but would not destabilize any important resource, and further mitigation would be unwarranted.

Other Impacts

WCNOC estimates that construction of the powerblock and coal storage area would affect approximately 320 acres of land and associated terrestrial habitat. Because most of this construction would be on previously disturbed land, impacts at the WCGS site would be small to moderate but would be somewhat less than the impacts of using a green field site. Upgrades to an existing rail spur would be required for coal and lime deliveries under this alternative. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite. WCNOC estimates a peak construction work force of 750. Socioeconomic impacts from the construction workforce would be minimal, because worker relocation would not be expected, due to the site's proximity to the Kansas City metropolitan area. WCNOC estimates an operational workforce of 92 for the coal-fired alternative. The reduction in workforce would result in adverse socioeconomic impacts. WCNOC contends these impacts would be small, due to WCGS's proximity the Topeka and Kansas City metropolitan areas.

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

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

7.2.2.3 New Nuclear Reactor

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

Air Quality

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

Waste Management

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

Other Impacts

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

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

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

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

7.2.2.4 Purchased Power

As discussed in Section 7.2.1.2, WCNOC assumes that the generating technology used under the purchased power alternative would be one of those that NRC analyzed in the GEIS.

WCNOC is also adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, therefore, environmental impacts would still occur, but they would likely originate from a power plant located elsewhere in Kansas or other states in the Midwest.

7.3 TABLES

Table 7-1. Gas-Fired Alternative.

Characteristic	Basis
Unit size = 562.5 MWe ISO rating net[a]	Manufacturer's standard size gas-fired combined-cycle plant that is < WCGS net capacity - 1,165 MWe
Unit size = 585 MWe ISO rating gross[a]	Calculated based on 4 percent onsite power
Number of units = 2	Assumed
Fuel type = natural gas	Assumed
Fuel heating value = 1,000 Btu/ft^3	2002 value for gas used in Kansas (EIA 2004b)
Fuel SO_x content = 0.0034 lb/MMBtu	EPA 2000, Table 3.1-2a
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_x emissions (EPA 2000)
Fuel NOx content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas fired units with water injection (EPA 2000)
Fuel CO content = 0.00226 lb/MMBtu	Typical for large SCR-controlled gas fired units (EPA 2000)
Fuel PM_{10} content = 0.0019 lb/MMBtu	EPA 2000, Table 3.1-2a
Heat rate = 5,940 Btu/kWh	(Chase and Kehoe 2000)
Capacity factor = 0.85	Assumed based on performance of modern plants

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

Btu = British thermal unit
ft^3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
MM = million
MWe = megawatt
NO_x = nitrogen oxides
PM_{10} = particulates having diameter of 10 microns or less
SCR = selective catalytic reduction
≤ = less than or equal to

Table 7-2. Coal-Fired Alternative.

Characteristic	Basis
Unit size = 562.5 MWe ISO rating net[a]	Calculated to be ≤ WCGS net capacity – 1,165 MWe
Unit size = 596 MWe ISO rating gross[a]	Calculated based on 6 percent onsite power
Number of units = 2	Assumed
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (EPA 1998)
Fuel type = bituminous, pulverized coal	Typical for coal used in Kansas
Fuel heating value = 8,648 Btu/lb	2002 value for coal used in Kansas (EIA 2004b)
Fuel ash content by weight = 5.53 percent[b]	2001 value for coal used in Kansas (EIA 2004c)
Fuel sulfur content by weight = 0.4 percent	2002 value for coal used in Kansas (EIA 2004b)
Uncontrolled NO_x emission = 10 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998)
Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998)
Heat rate = 10,200 Btu/kWh	Typical for coal-fired, single-cycle steam turbines (EIA 2002)
Capacity factor = 0.85	Typical for large coal-fired units
NO_x control = low NO_x burners, overfire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NO_x emissions (EPA 1998)
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions (EPA 1998)
SO_x control = Wet scrubber - lime (95 percent removal efficiency)	Best available for minimizing SO_x emissions (EPA 1998)

a. The difference between “net” and “gross” is electricity consumed onsite.
b. The 2002 average percent ash for coal used in Kansas is not available.

Btu = British thermal unit
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
NSPS = New Source Performance Standard
lb = pound
MWe = megawatt
NO_x = nitrogen oxides
SO_x = oxides of sulfur
≤ = less than or equal to

Table 7-3. Air Emissions from Gas-Fired Alternative.

Parameter	Calculation	Result
Annual gas consumption	$2\ \text{units} \times \frac{585\ \text{MW}}{\text{unit}} \times \frac{5{,}940\ \text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times 0.85 \times \frac{\text{ft}^3}{1{,}000\ \text{Btu}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}}$	51,748,210,800 ft^3 of gas per year
Annual Btu input	$\frac{51{,}748{,}210{,}800\ \text{ft}^3}{\text{yr}} \times \frac{1{,}000\ \text{Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}}$	51,748,211 MMBtu per year
SO_x[a]	$\frac{0.0034\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{51{,}748{,}211\ \text{MMBtu}}{\text{yr}}$	88 tons SO_x per year
NO_x[b]	$\frac{0.0109\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{51{,}748{,}211\ \text{MMBtu}}{\text{yr}}$	282 tons NO_x per year
CO[b]	$\frac{0.00226\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{51{,}748{,}211\ \text{MMBtu}}{\text{yr}}$	58 tons CO per year
TSP[a]	$\frac{0.0019\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{51{,}748{,}211\ \text{MMBtu}}{\text{yr}}$	49 tons TSP per year
PM_{10}[a]	$\frac{49\ \text{tons TSP}}{\text{yr}}$	49 tons PM_{10} per year

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

Table 7-4. Air Emissions from Coal-Fired Alternative.

Parameter	Calculation	Result
Annual coal consumption	$2\text{ unit} \times \frac{596\text{ MW}}{\text{unit}} \times \frac{10{,}200\text{ Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\text{ kW}}{\text{MW}} \times \frac{\text{lb}}{8{,}648\text{ Btu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times 0.85 \times \frac{24\text{ hr}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}}$	5,236,437 tons of coal per year
SO_x[a,c]	$\frac{38 \times 0.4\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{100 - 95}{100} \times \frac{5{,}236{,}437\text{ tons}}{\text{yr}}$	1,990 tons SO_x per year
NO_x[b,c]	$\frac{10\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{100 - 95}{100} \times \frac{5{,}236{,}437\text{ tons}}{\text{yr}}$	1,309 tons NO_x per year
CO[c]	$\frac{0.5\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{5{,}236{,}437\text{ tons}}{\text{yr}}$	1,309 tons CO per year
TSP[d]	$\frac{10 \times 5.53\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{100 - 99.9}{100} \times \frac{5{,}236{,}437\text{ tons}}{\text{yr}}$	145 tons TSP per year
PM_{10}[d]	$\frac{2.3 \times 5.53\text{ lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{100 - 99.9}{100} \times \frac{5{,}236{,}437\text{ tons}}{\text{yr}}$	33 tons PM_{10} per year

a. EPA (1998), Table 1.1-1.
b. EPA (1998), Table 1.1-2.
c. EPA (1998), Table 1.1-3.
d. EPA (1998), Table 1.1-4.
CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_x = oxides of sulfur
TSP = total suspended particulates

Table 7-5. Solid Waste from Coal-Fired Alternative.

Parameter	Calculation	Result
Annual SO_x generated[a]	$\frac{5{,}236{,}437 \text{ tons coal}}{\text{yr}} \times \frac{0.4 \text{ tons S}}{100 \text{ tons coal}} \times \frac{64.1 \text{ tons } SO_2}{32.1 \text{ tons S}}$	41,871 tons of SO_x per year
Annual SO_x removed	$\frac{41{,}871 \text{ tons } SO_x}{\text{yr}} \times \frac{95}{100}$	39,777 tons of SO_x per year
Annual ash generated	$\frac{5{,}236{,}437 \text{ tons coal}}{\text{yr}} \times \frac{5.53 \text{ tons ash}}{100 \text{ ton coal}} \times \frac{99.9}{100}$	289,285 tons of ash per year
Annual lime consumption[b]	$\frac{41{,}871 \text{ tons } SO_2}{\text{yr}} \times \frac{56.1 \text{ tons CaO}}{64.1 \text{ tons } SO_2}$	36,645 tons of CaO per year
Calcium sulfate[c]	$\frac{39{,}777 \text{ tons } SO_2}{\text{yr}} \times \frac{172 \text{ tons } CaSO_4 \bullet 2H_2O}{64.1 \text{ tons } SO_2}$	106,734 tons of $CaSO_4 \bullet 2H_2O$ per year
Annual scrubber waste[d]	$\frac{36{,}645 \text{ tons CaO}}{\text{yr}} \times \frac{100-95}{100} + 106{,}734 \text{ tons } CaSO_4 \bullet 2H_2O$	108,566 tons of scrubber waste per year
Total volume of scrubber waste[e]	$\frac{108{,}566 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{144.8 \text{ lb}}$	59,994,663 ft^3 of scrubber waste
Total volume of ash[f]	$\frac{289{,}285 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	176,662,847 ft^3 of ash
Total volume of solid waste	$59{,}994{,}663 \text{ ft}^3 + 176{,}662{,}847 \text{ ft}^3 \times \frac{100-50}{100}$	148,326,086 ft^3 of solid waste
Waste pile area (acres)	$\frac{148{,}326{,}086 \text{ ft}^3}{30 \text{ ft}} \times \frac{\text{acre}}{43{,}560 \text{ ft}^2}$	114 acres of solid waste
Waste pile area (ft x ft square)	$\sqrt{(148{,}326{,}086 \text{ ft}^3/30 \text{ ft})}$	2,224 feet by feet square of solid waste

Based on annual coal consumption of 5,236,437 tons per year (Table 7-4).

a. Calculations assume 100 percent combustion of coal.
b. Lime consumption is based on total SO_2 generated.
c. Calcium sulfate generation is based on total SO_2 removed.
d. Total scrubber waste includes scrubbing media carryover.
e. Density of $CaSO_4 \bullet 2H_2O$ is 144.8 lb/ft^3.
f. Density of coal bottom ash is 100 lb/ft^3 (FHA 2000).

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

7.4 REFERENCES

AWEA (American Wind Energy Association). 2002. "Inventory of State Incentives For Wind Energy in the U.S. A State By State Survey." September. Available at http://www.awea.org/pubs/inventory.html. Accessed July 19, 2004.

Chase, D. L and Kehoe, P. T. 2000. *GE Combined-Cycle Product Line and Performance*. GER-3574G. GE Power Systems, Schenectady, NY. October.

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

DOE (U.S. Department of Energy). 2004. "PV FAQs - How much land will PV need to supply our electricity?". DOE/GO-102004-1835. Office of Energy Efficiency and Renewable Energy Washington, DC. February. Available at http://www.nrel.gov/ncpv/pdfs/land_faq.pdf. Accessed February 3, 2005.

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

EIA (Energy Information Administration). 2004a. *U.S. Nuclear Plants Wolf Creek*. August. Available at http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/wolfcreek.html. Accessed June 8, 2005.

EIA (Energy Information Administration). 2004b. *State Electricity Profiles 2002*. DOE/EIA-0629(2002). January. Available at http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html. Accessed July 28, 2004.

EIA (Energy Information Administration). 2004c. *Cost and Quality of Fuels for Electric Utility Plants 2001.* DOE/EIA-0191(01). March. Available at http://www.eia.doe.gov/cneaf/electricity/cq/cq_sum.html. Accessed July 28, 2004.

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

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

FEMP (Federal Energy Management Program). 2005. "Restructuring Status of Electric Markets, Kansas." Available at http://www.eere.energy.gov/femp/program/utility/utilityman_elec_ks.cfm. Accessed on May 2, 2005.

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

Francfort, James E. 1993. *U.S. Hydropower Resource Assessment for Kansas.* DOE/ID-10430(KS). Available at http://hydropower.inel.gov/resourceassessment/ ks/. Accessed April 14, 2005.

Fuel Cell Today. 2003. "Fuel Cells Market Survey: Large Stationary Applications." Available at http://www.fuelcelltoday.com. Accessed on September 7, 2004.

KEC (Kansas Energy Council). 2004. "Kansas Energy Report 2005." Available at http://www.kansasenergy.org/KEC/KECpubs.html. Accessed June 10, 2005.

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

McGowan, J. G. and S. Connors. 2000. Windpower: A Turn of the Century Review. *Annual Review of Energy and the Environment*, Volume 25, pages 147-197.

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

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

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

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

NRC (U.S. Nuclear Regulatory Commission). 2002b. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding McGuire Nuclear Station, Units 1 and 2.* NUREG-1437, Supplement 8, Final. Office of Nuclear Reactor Regulation. Washington, DC. December.

Walsh M. E., R. L. Perlack, A. Turhollow, D. de la Torre Ugarte, D. A. Becker, R. L. Graham, S. E. Slinsky, and D. E. Ray. 2000. "Biomass Feedstock Availability in the United States: 1999 State Level Analysis." Oak Ridge National Laboratory. Oak Ridge, TN. April 30, 1999. Updated January, 2000. Available at http://bioenergy.ornl.gov/resourcedata/index.html. Accessed July 28, 2004.

8.0 CHAPTER 8 - COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES

NRC

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

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

8.1 TABLES

Table 8-1. Impacts Comparison Summary.

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

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

Table 8-2. Impacts Comparison Detail.

		No-Action Alternatives			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Alternative Descriptions					
WCGS license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current WCGS license. Adopting by reference, as bounding WCGS decommissioning, GEIS description (NRC 1996, Section 7.1)	New construction at the WCGS site.	New construction at the WCGS site.	New construction at the WCGS site	Would involve construction of new generation capacity in Kansas Adopting by reference GEIS description of alternate technologies (Section 7.2.1.2)
		Use existing rail spur	Construct up to 10 miles of gas pipeline in a 50-foot-wide corridor, disturbing as much as 60 acres. May require upgrades to existing pipelines.	Use existing rail spur for delivery of reactor vessel and other large equipment during construction.	
		Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Construct more than 200 miles of transmission lines
		Two 562.5-MW (net) tangentially-fired, dry bottom unit; capacity factor 0.85	Two 562.5-MW of net power (Combined-cycle turbines to be used); capacity factor 0.85		
		Existing WCGS cooling water intake/ discharge system	Existing WCGS cooling water intake/discharge system	Existing WCGS cooling water intake/ discharge system	

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
		Pulverized bituminous coal, 8,648 Btu/pound; 10,200 Btu/kWh; 5.53% ash; 0.4% sulfur; 10 lb/ton nitrogen oxides; 5,236,437 tons coal/yr	Natural gas, 1,000 Btu/ft^3; 5,940 Btu/kWh; 0.0034 lb sulfur/MMBtu; 0.0109 lb NO_x/MMBtu; 51,748,210,800 ft^3 gas/yr		
		Low NO_x burners, overfire air and selective catalytic reduction (95% NO_x reduction efficiency).	Selective catalytic reduction with steam/water injection		
		Wet scrubber – lime/limestone desulfurization system (95% SO_x removal efficiency); 36,600 tons lime/yr Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency)			
1,100 permanent and 425 long-term contract workers		92 workers (Section 7.2.2.2)	41 workers (Section 7.2.2.1)		

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Land Use Impacts					
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 52, 53)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	MODERATE to LARGE – 320 acres required for the powerblock and associated facilities. (Section 7.2.2.2)	SMALL to MODERATE – 75 acres for facility at WCGS location; 60 acres for pipeline (Section 7.2.2.1). New gas pipeline would be built to connect with existing gas pipeline corridor.	SMALL to MODERATE – 250 acres required for the powerblock and associated facilities. (Section 7.2.2.3)	MODERATE – most transmission facilities could be constructed along existing transmission corridors (Section 7.2.2.4) Adopting by reference GEIS description of land use impacts from alternate technologies (NRC 1996)
Water Quality Impacts					
SMALL – Adopting by reference Category 1 Issue Findings (Attachment A, Table A-1, Issues 3, 5-11 and 32). Two Category 2 groundwater issues not applicable (Section 4.5, Issue 33; and Section 4.7, Issue 35). Under normal conditions WCGS withdrawals do not affect instream flows in the Neosho River. State limits on withdrawals during extreme droughts minimizes potential for related impacts (Section 4.1, Issue 13; Section 4.6, Issue 34) Studies identified no negative impact on groundwater quality as a result of WCGS operations (Section 4.8, Issue 39).	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 89).	SMALL – Construction impacts minimized by use of best management practices. Operational impacts minimized by use of the existing cooling water system that withdraws from and discharges to Coffey County Lake. (Section 7.2.2.2)	SMALL – Reduced cooling water demands, inherent in combined-cycle design (Section 7.2.2.1)	SMALL – Construction impacts minimized by use of best management practices. Operational impacts minimized by use of the existing cooling water system that withdraws from and discharges to Coffey County Lake. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of water quality impacts from alternate technologies (NRC 1996)
Air Quality Impacts					

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 51). Category 2 issue not applicable (Section 4.11, Issue 50).	SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issue 88)	MODERATE – 1,990 tons SO_x/yr 1,309 tons NO_x/yr 1,309 tons CO/yr 145 tons TSP/yr 33 tons PM_{10}/yr (Section 7.2.2.2)	MODERATE – 88 tons SO_x/yr 282 tons NO_x/yr 58 tons CO/yr 49 tons PM_{10}/yr[a] (Section 7.2.2.1)	SMALL – Air emissions would be comparable to those associated with the continued operation of WCGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (NRC 1996)
Ecological Resource Impacts					
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 15-24, 44-48). One Category 2 issue not applicable (Section 4.9, Issue 40). WCGS holds a current NPDES permit, which constitutes compliance with Clear Water Act Section 316(b) (Section 4.2, Issue 25; Section 4.3, Issue 26; Section 4.4, Issue 27)	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table -1, Issue 90)	MODERATE – 57 acres could be required for ash/sludge disposal over 20-year license renewal term. (Section 7.2.2.2)	SMALL to MODERATE – Construction of the pipeline could alter habitat. (Section 7.2.2.1)	SMALL – Impacts would be comparable to those associated with the continued operation of WCGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of ecological resource impacts from alternate technologies (NRC 1996)

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Threatened or Endangered Species Impacts					
SMALL – Two federally-listed threatened or endangered species and one candidate species are known to occur in the vicinity of the WCGS site or along the transmission corridors. A pair of bald eagles has nested at Coffey County Lake since 1994. Peregrine falcons have been observed in the vicinity of Coffey County Lake following the release of five juvenile peregrine falcons in 2004. The Neosho madtom occurs in the Neosho River up- and downstream of its confluence with Wolf Creek. (Section 4.10, Issue 49)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats
Human Health Impacts					
SMALL – Adopting by reference Category 1 issues (Attachment A, Table A-1, Issues 58, 61, 62). Risk due to microbiological organisms minimal. No pathogenic species detected in Coffey County Lake and KDHE consultation did not identify any concerns (Section 4.12, Issue 57) Risk due to transmission-line induced currents minimal due to conformance with consensus code (Section 4.13, Issue 59)	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 86)	MODERATE – Adopting by reference GEIS conclusion that risks such as cancer and emphysema from emissions are likely (NRC 1996)	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (NRC 1996)	SMALL – Impacts would be comparable to those associated with the continued operation of WCGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of human health impacts from alternate technologies (NRC 1996)

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Socioeconomic Impacts					
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 64, 67, 91). Two Category 2 issues are not applicable (Section 4.16, Issue 66 and Section 4.17.1, Issue 68). Existing "surge' capabilities for routine activities, such as outages, minimizes potential for housing impacts. (Section 4.14, Issue 63). Plant property tax payment represents more than 80 percent of Coffey county's total tax revenues. License renewal not expected to influence area land-use pattern, but would continue beneficial impact on county (Section 4.17.2, Issue 69). Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65 and Section 4.18, Issue 70)	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 91)	SMALL – Reduction in permanent work force at WCGS could adversely affect surrounding counties (Section 7.2.2.2).	SMALL to MODERATE – Reduction in permanent work force at WCGS could adversely affect surrounding counties (Section 7.2.2.1)	Construction: MODERATE to LARGE – Peak construction workforce of 2,500 could affect housing and public services in surrounding counties. Operation: SMALL – Impacts would be comparable to those associated with the continued operation of WCGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of socioeconomic impacts from alternate technologies (NRC 1996)
Waste Management Impacts					
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 87)	MODERATE – 144,650 tons of coal ash and 108,570 tons of scrubber sludge would require 57 acres over 20-year license renewal term. Industrial waste generated annually (Section 7.2.2.2, Table 7-5)	SMALL – Almost no waste generation (Section 7.2.2.1)	SMALL – Impacts would be comparable to those associated with the continued operation of WCGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies (NRC 1996)

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Aesthetic Impacts					
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 73, 74)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – The coal-fired power blocks and the exhaust stacks would be visible from a moderate offsite distance (Section 7.2.2.2)	SMALL – Steam turbines and stacks would create visual impacts comparable to those from existing WCGS facilities (Section 7.2.2.1)	SMALL – Impacts would be comparable to those associated with the continued operation of WCGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (NRC 1996)
Cultural Resource Impacts					
SMALL – SHPO consultation minimizes potential for impact (Section 4.19, Issue 71)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.2)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.1)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.3)	SMALL – Adopting by reference GEIS description of cultural resource impacts from alternate technologies (NRC 1996)

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

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

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

8.2 REFERENCES

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

9.0 CHAPTER 9 - STATUS OF COMPLIANCE

9.1 PROPOSED ACTION

NRC

"The environmental report shall list all Federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection…" 10 CFR 51.54(d) as adopted by 10 CFR 51.53(c)(2)

9.1.1 General

Table 9-1 lists environmental authorizations that WCNOC has obtained for current WCGS operations. In this context, WCNOC uses "authorizations" to include any permits, licenses, approvals, or other entitlements. WCNOC expects to continue renewing these authorizations during the current license period. Based on the new and significant information identification process described in Chapter 5, WCNOC is in compliance with applicable environmental standards and requirements.

Table 9-2 lists additional environmental authorizations and consultations that would be conditions precedent to NRC renewal of the WCGS license to operate. As indicated, WCNOC anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.5 discuss some of these items in more detail.

9.1.2 Threatened or Endangered Species

Section 7 of the Endangered Species Act (16 USC 1536) requires federal agencies to ensure that agency action is not likely to jeopardize any species that is listed or proposed for listing as threatened or endangered. Depending on the action involved, the Act requires consultation with the U.S. Fish and Wildlife Service (USFWS) regarding effects on non-marine species, the National Marine Fisheries Service (NMFS) for marine species, or both. USFWS and NMFS have issued joint procedural regulations at 50 CFR 402, Subpart B, that address consultation, and USFWS maintains the joint list of threatened and endangered species at 50 CFR 17.

Although not required by federal law or NRC regulation, WCNOC has chosen to invite comment from federal and state agencies regarding potential effects that WCGS license renewal might have. Appendix C includes copies of WCNOC correspondence with USFWS and the Kansas Department of Wildlife and Parks (KDWP). WCNOC did not consult with NMFS because species under the auspices of NMFS are not found in the vicinity of WCGS.

9.1.3 Coastal Zone Management Program

The federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on applicants for a federal license to conduct an activity that could affect a state's coastal zone. WCGS is located in Coffey County, Kansas, not within a coastal zone. Coastal zone management requirements are not applicable to WCGS license renewal.

9.1.4 Historic Preservation

Section 106 of the National Historic Preservation Act (16 USC 470f) requires federal agencies having the authority to license any undertaking to, prior to issuing the license, take into account the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Council regulations provide for establishing an agreement with any State Historic Preservation Officer (SHPO) to substitute state review for Committee review (35 CFR 800.7). Although not required of an applicant by federal law or NRC regulation, WCNOC has chosen to invite comment by the Kansas SHPO. Appendix D includes a copy of WCNOC correspondence with the SHPO regarding potential effects that WCGS license renewal might have on cultural resources. Based on the WCNOC submittal and other information, the SHPO concurred with WCNOC's conclusion that continued operation of WCGS would have no effect on cultural resources.

9.1.5 Water Quality (401) Certification

Federal Clean Water Act (CWA) Section 401 requires that applicants for a federal license to conduct an activity that might result in a discharge into navigable waters to provide the licensing agency a certification from the state that the discharge will comply with applicable CWA requirements (33 USC 1341). NRC has indicated in its *Generic Environmental Impact Statement for License Renewal* (GEIS) (NRC 1996) that issuance of a National Pollution Discharge Elimination System (NPDES) permit implies certification by the state. WCNOC is applying to NRC for license renewal to continue WCGS operations. Attachment B contains the current WCGS NPDES permit.

Consistent with the GEIS, WCNOC is providing the WCGS NPDES permit as evidence of state water quality (CWA Section 401) certification.

9.2 ALTERNATIVES

NRC

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

The coal, gas, and purchased power alternatives discussed in Chapter 7 probably could be constructed and operated to comply with all applicable environmental quality standards and requirements. WCNOC notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. WCNOC also notes that the U.S. Environmental Protection Agency has new requirements for the design and operation of cooling water intake structures at new and existing facilities (40 CFR 125 Subparts I and J). The requirements could necessitate construction of cooling towers for the coal- and gas-fired alternatives if surface water were used for cooling.

9.3 TABLES

Table 9-1. Environmental Authorizations for Current WCGS Operations.

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to Operate	NPF-42	Issued on 06/04/1985 Expires on 03/11/2025	Operation of Unit 1
U.S. Environmental Protection Agency (EPA); Kansas Department of Health and Environment – Bureau of Water	Clean Water Act (33 USC Section 1251 et seq.); Kansas Statutes Annotated 65-164 and 65-165	Kansas Water Pollution Control Permit	Kansas: I-NE07-PO02 Federal: KS0079057	Issued on 02/01/2005 Expires on 12/31/2008	Contains effluent limits for WCGS discharges to the Neosho River via Wolf Creek via Wolf Creek Cooling Impoundment, Neosho River Basin
Kansas Department of Health and Environment, Bureau of Air and Radiation	K.S.A. 65-3008; K.A.R. 28-19-540	Air Emission Source Class II Operating Permit	0310021	Issued on 09/08/2005 No expiration date	Establishes emissions limits
Kansas Department of Health and Environment	Nuclear Development and Radiation Control Act (L. 1963, Ch. 290); Kansas Annotated Regulations 28-35-133 through 28-35-363	Radioactive Materials License	21-B690-01	Issued on 09/30/2005 Expires on 06/30/2006	Authorizes the transfer, receipt, possession, and use of radioactive material.
U.S. Department of Transportation	79 CFR Part 107, Subpart G; 49 USC 5108	Hazardous materials Certificate of Registration	052703 001 005LN	Issued 05/28/2003 Expires 06/30/2006	
Utah Department of Environmental Quality – Division of Radiation Control	R313-26 of the Utah Radiation Control Rules	Generator Site Access Permit	0309 002 468	Issued on 11/23/2005 Expires on 11/23/2006	Authorizes delivery of radioactive material to a land disposal facility within Utah.

Table 9-1. Environmental Authorizations for Current WCGS Operations. (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Tennessee Department of Environment and Conservation – Division of Radiological Health	Tennessee Code Annotated 68-202-206	License to Ship Radioactive Material	T-KS001-L06	Issued on 11/17/2005 Expires on 12/31/2006	Authorizes shipment of radioactive material to a licensed disposal/ processing facility within the state of Tennessee
South Carolina Department of Health and Environmental Control, Division of Waste Management	Act No. 429 of 1980, South Carolina Radioactive Waste Transportation and Disposal Act	South Carolina Waste Transport Permit	0223-15-06-X	Issued on 11/18/2005 Expires on 12/31/2006	Authorizes transportation of waste into or within the State of South Carolina
Kansas Department of Health and Environment		Aboveground Storage Tank Permits	Facility ID 23762	Issued on 08/01/2005 Expires on 07/31/2006	Authorizes operation of aboveground storage tanks
Kansas Department of Health and Environment		Underground Storage Tank Permits	Facility ID 23762	Issued on 08/01/2005 Expires on 07/31/2006	Authorizes operation of underground storage tanks
Kansas Water Resources Board		Use of state water	76-2	Issued on 01/01/1978 Expires on 12/31/2017	Authorizes withdrawal of water from John Redmond Reservoir

Table 9-2. Environmental Authorizations for WCGS License Renewal.

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License Renewal	Environmental Report submitted in support of license renewal application.
U.S. Fish and Wildlife Service (USFWS)	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with USFWS.
Kansas State Historical Society	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (SHPO).
Kansas Department of Health and Environment, Bureau of Epidemiology and Disease Prevention	10 CFR 51.53(c)(3)(ii)(G); Supplement 1 to Regulatory Guide 4.2 “Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses”	Consultation	Requires the applicant to consult with the state agency as to whether there is a concern about the potential existence and concentration of *Naegleria fowleri* in the receiving waters for plant cooling water discharge.

9.4 REFERENCES

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

ATTACHMENT A - NRC NEPA ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS

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

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

TABLES

Table A-1 WCGS Environmental Report Cross-Reference of License Renewal NEPA Issues.

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
Surface Water Quality, Hydrology, and Use (for all plants)			
1. Impacts of refurbishment on surface water quality	1	NA	Issue applies to an activity, refurbishment, that WCGS has no plans to undertake.
2. Impacts of refurbishment on surface water use	1	NA	Issue applies to an activity, refurbishment, that WCGS has no plans to undertake.
3. Altered current patterns at intake and discharge structures	1	4.0	4.4.2/4-52
4. Altered salinity gradients	1	NA	Issue applies to an activity, discharge to saltwater, that WCGS does not do.
5. Altered thermal stratification of lakes	1	4.0	4.4.2.2.4/4-53
6. Temperature effects on sediment transport capacity	1	4.0	Issue applies to an activity, discharge to a small river, that WCGS does not do.
7. Scouring caused by discharged cooling water	1	4.0	4.4.2.2/4-53
8. Eutrophication	1	4.0	4.4.2.2/4-53
9. Discharge of chlorine or other biocides	1	4.0	4.4.2.2/4-53
10. Discharge of sanitary wastes and minor chemical spills	1	4.0	4.4.2.2/4-53
11. Discharge of other metals in waste water	1	4.0	4.4.2.2/4-53
12. Water use conflicts (plants with once-through cooling systems)	1	NA	Issue applies to a plant feature, once-through cooling, that WCGS does not have.
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	4.1	4.4.2.1/4-52
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	NA	Issue applies to an activity, refurbishment, that WCGS has no plans to undertake.

Table A-1. WCGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
15. Accumulation of contaminants in sediments or biota	1	4.0	4.4.2.2; 4.4.3/4-53; 4-56
16. Entrainment of phytoplankton and zooplankton	1	4.0	4.4.3/4-56
17. Cold shock	1	4.0	4.4.3/4-56
18. Thermal plume barrier to migrating fish	1	4.0	4.4.3/4-56
19. Distribution of aquatic organisms	1	4.0	4.4.3/4-56
20. Premature emergence of aquatic insects	1	4.0	4.4.3/4-56
21. Gas supersaturation (gas bubble disease)	1	4.0	4.4.3/4-56
22. Low dissolved oxygen in the discharge	1	4.0	4.4.3/4-56
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.0	4.4.3/4-56
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4.0	4.4.3/4-56
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)			
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	4.2	4.4.3/4-56
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	4.3	4.4.3/4-56
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	4.4	4.4.3/4-56
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)			
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	NA	Issue applies to a plant feature, cooling towers, that WCGS does not have.
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	NA	Issue applies to a plant feature, cooling towers, that WCGS does not have.
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	NA	Issue applies to a plant feature, cooling towers, that WCGS does not have.

Table A-1. WCGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
Groundwater Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	NA	Issue applies to an activity, refurbishment, that WCGS has no plans to undertake.
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	4.0	4.8.1.1/4-116 and 4.8.2.1/4-119
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	Identified as NA in Section 4.5	Issue applies to an activity, using 100 gpm or more of groundwater, that WCGS does not do.
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	4.6	4.8.1.3/4-117
35. Groundwater use conflicts (Ranney wells)	2	Identified as NA in Section 4.7	Issue applies to a plant feature, Ranney wells, that WCGS does not have.
36. Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney wells, that WCGS does not have.
37. Groundwater quality degradation (saltwater intrusion)	1	NA	Issue applies to a feature, location at an ocean or estuary site, that WCGS does not have.
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Issue applies to a feature, location in a salt march, that WCGS does not have.
39. Groundwater quality degradation (cooling ponds at inland sites)	2	4.8	4.8.3/4-117
Terrestrial Resources			
40. Refurbishment impacts to terrestrial resources	2	Identified as NA in Section 4.9	Issue applies to an activity, refurbishment, that WCGS has no plans to undertake.
41. Cooling tower impacts on crops and ornamental vegetation	1	NA	Issue applies to a feature, mechanical draft cooling towers, that WCGS does not have.
42. Cooling tower impacts on native plants	1	NA	Issue applies to a feature, mechanical draft cooling towers, that WCGS does not have.
43. Bird collisions with cooling towers	1	NA	Issue applies to a feature, natural draft cooling towers, that WCGS does not have.

Table A-1. WCGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
44. Cooling pond impacts on terrestrial resources	1	4.0	4.4.4/4-58
45. Power line right-of-way management (cutting and herbicide application)	1	4.0	4.5.6.1/4-71
46. Bird collisions with power lines	1	4.0	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.0	4.5.6.3/4-77
48. Floodplains and wetlands on power line right-of-way	1	4.0	4.5.7./4-81
Threatened or Endangered Species (for all plants)			
49. Threatened or endangered species	2	4.10	4.1/4-1
Air Quality			
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	Identified as NA in Section 4.11	Issue applies to an activity, refurbishment, that WCGS does not plan to undertake.
51. Air quality effects of transmission lines	1	4.0	4.5.2/4-62
Land Use			
52. Onsite land use	1	4.0	3.2/3-1
53. Power line right-of-way land use impacts	1	4.0	4.5.3/4-62
Human Health			
54. Radiation exposures to the public during refurbishment	1	NA	Issue applies to an activity, refurbishment, that WCGS has no plans to undertake.
55. Occupational radiation exposures during refurbishment	1	NA	Issue applies to an activity, refurbishment, that WCGS has no plans to undertake.
56. Microbiological organisms (occupational health)	1	NA	Issues applies to plant features, cooling towers, that WCGS does not have.
57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	4.12	4.3.6/4-48
58. Noise	1	4.0	4.3.7/4-49
59. Electromagnetic fields, acute effects	2	4.13	4.5.4.1/4-66

Table A-1. WCGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
60. Electromagnetic fields, chronic effects	NA	4.0	4.5.4.2/4-67
61. Radiation exposures to public (license renewal term)	1	4.0	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	1	4.0	4.6.3/4-95
Socioeconomics			
63. Housing impacts	2	4.14	3.7.2/3-10 (refurbishment - not applicable to WCGS) 4.7.1/4-101 (renewable term)
64. Public services: public safety, social services, and tourism and recreation	1	4.0	<u>Refurbishment (not applicable to WCGS)</u> 3.7.4/3-14 (public service) 3.7.4.3/3-18 (safety) 3.7.4.4/3-19 (social) 3.7.4.6/3-20 (tour, rec) <u>Renewal Term</u> 4.7.3/4-104 (public safety) 4.7.3.3/4-106 (safety) 4.7.3.44-107 (social) 4.7.3.6/4-107 (tour, rec)
65. Public services: public utilities	2	4.15	3.7.4.5/3-19 (refurbishment - not applicable to WCGS) 4.7.3.5/4-107 (renewable term)
66. Public services: education (refurbishment)	2	Identified as NA in Section 4.16	Issue applies to an activity, refurbishment, that WCGS does not plan to undertake.
67. Public services: education (license renewal term)	1	4.0	4.7.3.1/4-106
68. Offsite land use (refurbishment)	2	Identified as NA in Section 4.17.1	Issue applies to an activity, refurbishment, that WCGS does not plan to undertake.
69. Offsite land use (license renewal term)	2	4.17.2	4.7.4/4-107
70. Public services: transportation	2	4.18	3.7.4.2/3-17 (refurbishment - not applicable to WCGS) 4.7.3.2/4-106 (renewal term)
71. Historic and archaeological resources	2	4.19	3.7.7/3-23 (refurbishment - not applicable to WCGS) 4.7.7/4-114 (renewal term)

Table A-1. WCGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
72. Aesthetic impacts (refurbishment)	1	NA	Issue applies to an activity, refurbishment, that WCGS has no plans to undertake.
73. Aesthetic impacts (license renewal term)	1	4.0	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	1	4.0	4.5.8/4-83
Postulated Accidents			
75. Design basis accidents	1	4.0	5.3.2/5-11 (design basis) 5.5.1/5-114 (summary)
76. Severe accidents	2	4.20	5.3.3/5-12 (probabilistic analysis) 5.3.3.2/5-19 (air dose) 5.3.3.3/5-49 (water) 5.3.3.4/5-65 (groundwater) 5.3.3.5/5-95 (economic) 5.4/5-106 (mitigation) 5.5.2/5-114 (summary)
Uranium Fuel Cycle and Waste Management			
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4.0	6.2/6-8
78. Offsite radiological impacts (collective effects)	1	4.0	Not in GEIS.
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4.0	Not in GEIS.
80. Nonradiological impacts of the uranium fuel cycle	1	4.0	6.2.2.6/6-20 (land use) 6.2.2.7/6-20 (water use) 6.2.2.8/6-21 (fossil fuel) 6.2.2.9/6-21 (chemical)
81. Low-level waste storage and disposal	1	4.0	6.4.2/6-36 (low-level def) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)
82. Mixed waste storage and disposal	1	4.0	6.4.5/6-63
83. Onsite spent fuel	1	4.0	6.4.6/6-70
84. Nonradiological waste	1	4.0	6.5/6-86
85. Transportation	1	4.0	6.3/6-31, as revised by Addendum 1, August 1999.

Table A-1. WCGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
Decommissioning			
86. Radiation doses (decommissioning)	1	4.0	7.3.1/7-15
87. Waste management (decommissioning)	1	4.0	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88. Air quality (decommissioning)	1	4.0	7.3.3/7-21 (air) 7.4/7-25 (conclusions)
89. Water quality (decommissioning)	1	4.0	7.3.4/7-21 (water) 7.4/7-25 (conclusions)
90. Ecological resources (decommissioning)	1	4.0	7.3.5/7-21 (ecological) 7.4/7-25 (conclusions)
91. Socioeconomic impacts (decommissioning)	1	4.0	7.3.7/7-19 (socioeconomic) 7.4/7-24 (conclusions)
Environmental Justice			
92. Environmental justice	NA	2.6.2	not in GEIS

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

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

NA = not applicable

ATTACHMENT B - NPDES PERMIT

05-00003

K A N S A S

RODERICK L. BREMBY, SECRETARY

KATHLEEN SEBELIUS, GOVERNOR

DEPARTMENT OF HEALTH AND ENVIRONMENT

December 30, 2004

Wolf Creek Nuclear Operating Corporation
P.O. Box 411
Burlington, KS 66839

RE: Kansas Water Pollution Control
Permit No. I-NE07-PO02
Wolf Creek Nuclear

Dear Permittee:

You have fulfilled all the filing requirements for a Kansas Water Pollution Control Permit and Authorization to Discharge under the National Pollutant Discharge Elimination System (NPDES). We are pleased to forward your new permit. While it is permissible to make as many copies as needed for monitoring and reporting purposes, you need to retain the original permit for your files.

We suggest you carefully read the **terms** and conditions of your permit and understand these terms and conditions are enforceable under both State and Federal law.

Please notice the reporting paragraph on page 2 of your permit, where all reports are due by the 28th day of the schedule noted. Please submit reports to the Kansas Department of Health and Environment, Bureau of Water-TSS, 1000 SW Jackson St., Suite 420, Topeka, Kansas 66612-1367.

If you have any questions concerning this permit, contact Ed Dillingham at (785) 296-5513.

Sincerely,

Karl Mueldener, P.E.
Director, Bureau of Water

pc: SE - District Office
OA - Permit File

DIVISION OF ENVIRONMENT
Bureau of Water
CURTIS STATE OFFICE BUILDING, 1000 SW JACKSON ST, STE. 420, TOPEKA. KS 66612-1367
Voice 785-296-5500 Fax 785-296.0086 http:llwww.kdhe.state.ks.us/

Kansas Permit No.: I-NE07-PO02

Federal Permit No.: KS0079057

KANSAS WATER POLLUTION CONTROL PERMIT AND
AUTHORIZATION TO DISCHARGE UNDER
THE NATIONAL POLLUTANT DISCHARGE
ELIMINATION SYSTEM

Pursuant to the Provisions of Kansas Statutes Annotated 65-164 and 65-165, the Federal Water Pollution Control Act as amended, (33 U.S.C. 1251 et seq; the "Act"),

Owner:	Wolf Creek Nuclear Operating Corporation*
Owner's Address:	P.O. Box 411 Burlington, Kansas 66839

* Refer to Supplemental Condition No. 17.

Facility Name:	Wolf Creek Generating Station
Facility Location:	1550 Oxen Lane, NE Burlington, Kansas 66839
Receiving Stream:	Neosho River via Wolf Creek via Wolf Creek Cooling Impoundment, Neosho River Basin

is authorized to discharge from the wastewater treatment facility described herein, in accordance with effluent limitations and monitoring requirements as set forth herein.

This permit shall become effective February 1, 2005, will supersede all previous wastewater permits and/or agreements in effect for the facility described herein between the Kansas Department of Health and Environment and the permittee, and will expire December 31, 2008.

FACILITY DESCRIPTION:

The station consists of a pressurized nuclear reactor steam supply system and an electric turbine-generator. The nuclear steam supply system is comprised of a reactor vessel and four primary coolant loops, each with a reactor coolant pump and steam generator. The net turbine generator output is a nominal 1,175 MWe. Wastewater discharge consists of circulating water, radwaste system, service and essential service water discharge via the essential service water discharge.

Continued on next page

Secretary, Kansas Department of Health and Environment

December 30, 2004
Date

FACILITY DESCRIPTION: Continued

001A SE ¼ Section 6, Township 21S, Range 16E: Two cell domestic waste stabilization pond is discharged on as needed basis into a slough of the Wolf Creek Cooling Impoundment (WCCI); 1.25 mgd.
002 NE ¼ Section 7, Township 21S, Range 16E: storm water run-off through oil water separator into WCCI and outfall 002a constituents; 0.326 mgd.
002A During equipment repair or inspection and/or plant outage, oily waste and other power block sumps; miscellaneous leaks and drain down from various systems routed to the power block sumps and/or storm drains; auxiliary boiler and steam generator draindowns; and groundwater, circulating, service, essential service water reroutes, are rerouted through an oil water separator;
003X NE ¼ Section 7, Township 21S, Range 16E: Circulation water, service water, and discharge from 003a and 003b; oxidation, oil interceptor; 704 mgd.
003A Radioactive wastewater processed through filters, demineralizers, and RO to the secondary liquid waste monitoring tanks A & B and/or to the A & B waste monitoring tank as batch releases to WCCI; continuous steam generator (S/G) blowdown to WCCI; 0.300 mgd.
003B Water treatment plant and wastewater treatment system discharge including: oily waste and other power block sumps; demineralizer regenerate; miscellaneous leaks and draindowns from various system routed to power block sumps; auxiliary boiler and S/G draindowns; groundwater: circulating, service, essential service and (biocide) treated fire protection water reroutes; and pre-sedimentation sludge and neutralized chemical cleaning back washes from RO and electrodeionization (EDI) units; treatment- oil water interceptor, neutralization, settling; 0.195 rngd - intermittent
004A NW ¼ Section 29, Township 21S, Range 16E: Intermittent discharge from the Wolf Creek Cooling Impoundment at the main dam; 2.9 rngd.
005A SE ¼ Section 6, Township 21S, Range 16E: Once a year lime sludge pond discharge of rerouted wastewater from outfall 003b during circulating water system outages, to WCCI; 5.8 mgd.
006A SE ¼ Section 8, Township 21S, Range 16E: Essential service water system discharge to WCCI during routine operations; oxidation; 26.5 mgd.

Eisenhower Learning Center - Three-cell non-ovefflowing domestic wastewater stabilization lagoon.

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

The permittee is authorized to discharge from outfall(s) with serial number(s) as specified in this permit. The effluent limitations shall become effective on the dates specified herein. Such discharges shall be controlled, limited, and monitored by the permittee as specified. There shall be no discharge of floating solids or visible foam in other than trace amounts.

Discharge Monitoring Reports (DMRs) shall be submitted monthly on or before the 28th day of the following month. In the event no discharge occurs, written notification is still required.

002 - Discharae of Oil Water Seperator into Wolf Creek Coolinq Impoundment

The permittee is authorized to discharge from the above named outfall in accordance with the conditions as specified herein:

1 The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units.

A. **EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS** (continued)

2. The discharge shall not cause a violation of Kansas Surface Water Quality Standards, K.A.R. 28-16-28b through 28-16-28e. The permittee shall not discharge the following:

   a. oil or grease in concentrations which cause any visible film or sheen to form upon the surface of the receiving water;

   b. oil or grease which causes a sludge or emulsion to be deposited beneath the surface of the receiving water, upon submerged substrate, or upon adjoining shorelines;

   c. turbidity or color producing substances causing any change in the natural appearance of the stream or water body;

   d. substances in the wastewater which cause objectionable odors in the vicinity of the receiving water;

   e. floating debris, scum, foam, froth, or other floating material in other than trace amounts; or

   f. materials which create deposits of sludge or fine solids causing aesthetic or environmental concerns downstream of the outfall.

The permittee shall, at a minimum, inspect the outfall and receiving stream(s) quarterly to ensure compliance with the above Water Quality Standards. The permittee shall maintain a log documenting the results of any monitoring or inspections performed and shall provide the log to KDHE staff for review upon request.

Any violation of the above general Water Quality Standards shall be reported within 24 hours of discovery, to either the Kansas Department of Health and Environment, Division of Environment at (785) 296-5517 or the appropriate KDHE District Office followed by a letter, within 5 days of discovery, explaining the cause of the water quality violation, the actions taken to correct the violation, and actions taken to prevent recurrence.

Effective Date Outfall Number and Effluent Parameter(s) Units	EFFLUENT LIMITATIONS Final Upon Issuance Daily Average	 Daily Maximum	MONITORING REQUIREMENTS Measurement Frequency	 Sample Type
002A - Oil Water Separator Discharae Over Weir into Culvert (1)				
Flow - mgd		Monitor	daily	Weir
Total Suspended Solids - mg/l	30	100	Weekly	grab
Oil and Grease - mg/l	10	15	Weekly(1)	grab
pH - standard units	Between 6.0 and 9.0		Weekly	grab

(1) Outfall 002A monitoring required only when discharges from power block area are rerouted into the PAB storm drains or into site oil/water separator. Daily monitoring of oil and grease is required when the discharges from power block sumps are rerouted from outfall 003B to this outfall.

A. **EFFLUENT** LIMITATIONS **AND MONITORING REQUIREMENTS** (continued)

Effective Date Outfall Number and Effluent Parameter(s) Units	EFFLUENT LIMITATIONS Final Upon Issuance Daily Average	 Daily Maximum	MONITORING REQUIREMENTS Measurement Freauency	 Sample Type
003X Circulatina Water Svstem Discharae into Wolf Creek Coolina Impoundment [7]				
Flow - MGD		Monitor	Daily	Estimate
Total Residual Oxidant[2] - mg/l		0.2	Daily	grab
Whole Effluent Toxicity	See Supplemental Condition # 1			grab
pH - Standard Units	Between 6.0 and 9.0		Daily	grab
003A Discharae of Radiation Waste and Steam Generator Blowdown into Circulatina Water				
Flow - MGD		Monitor	Weekly	Estimate
Total Suspended Soiids- mg/l	30	100	Monthly	grab
003B Water Treatment Plant and Wastewater Treatment Svstem Discharse into Circulatino Water Svstem Discharqe				
Flow - MGD		Monitor	Weekly	Estimate
Total Suspended Solids- mg/l	30	100	Weekly	grab
Oil and Grease - mg/l	10	15	Weekly	grab
Biochemical Oxygen Demand (5 day) - mg/l		Monitor••)	Monthly	grab
Sulfate - mg/l		Monitor	Monthly	grab
Ammonia as N - mg/l		Monitor [9]	Monthly	grab
Monoethanolamine - mg/l		Monitor	Monthly	grab
pH - Standard Units	Between 6.0 and 9.0		Weekly	grab
004A - Coolinq Impoundment Discharqe to Wolf Creek [4]				
Flow - MGD		Monitor	Weekly[3]	Estimate
Temperature - °F		Monitor	Weekly[3]	grab
Chloride - mg/l		Monitor	Monthly[3]	grab
Nitrate as N - mg/l		Monitor	Monthly[3]	grab
Sulfate - mg/l		Monitor	Monthly[3]	grab
pH - Standard Units	between 6.0 and 9.0		Monthly[3]	grab
Whole Effluent Toxicity	See Supplemental Condition # 2			grab
Metals (Attachment B)		Monitor	Annually[3]	grab

(2) Total Residual Oxidant (TRO) shall also he monitored in the Service Water System (SWS) when the Circulating Water System (CWS) is not in service and SWS is brominated /chlorinated. During this operational mode the sampling location for TRO shall be moved

A. EFFLUENT LIMITATIONS **AND** MONITORING REQUIREMENTS (continued)

upstream of the Radwaste System discharge confluence. TRO monitoring is not required if CWS and SWS are not brominated/chlorinated. Supplemental Condition No. 6 is applicable to the CWS discharge alone and only to the CWS when combined with the SWS. Supplemental Conditions 6(a) does not apply to the SWS discharge regardless of the operating mode of the cooling systems; however, Supplemental Condition 6.b. is still applicable. All requested information is to be reported in the DMRs.

Effective Date / Outfall Number and Effluent Parameter(s) Units	EFFLUENT LIMITATIONS Final Upon Issuance: Daily Average	Daily Maximum	MONITORING REQUIREMENTS: Measurement Frequency	Sample Type
005A - Lime Sludge Pond Discharge to Wolf Creek Cooling Impoundment (5)				
Flow - MGD		Monitor	Weekly	Estimate
Total Suspended Solids- mg/l	30	100	Weekly	grab
Oil and Grease - mg/l	10	15	Weekly	grab
pH - Standard Units	between 6.0 and 9.0		Weekly	grab
006A Service and Essential Service Water System Discharue throuah Essential Service Water Svstem Pipinq into the Ultimate Heat Sink Area of WCCI (6) (7)				
Flow - MGD		Monitor	2/week (3)	Estimate
Total Residual Oxidant - mg/l		1.0	2/week (3)	grab
pH - Standard Units	between 6.0 and 9.0		2/week (3)	grab
001A Two Cell Domestic Wastewater Stabilization Pond Discharge To the Slough (8)				
Flow - MGD		Monitor	weekly (3)	Estimate
Total Suspended Solids- mg/l	80	120	weekly (3)	grab
BOD - mg/l	30	45	weekly (3)	grab
Fecal Coliform - cells/100 ml			weekly (3)	grab
From April 1 to October 31		200		
From November 1 to March 31		2000		
pH - Standard Units	between 6.0 and 9.0		weekly (3)	grab

(3) The first day of each discharge and at the stated frequency thereafter during discharge.

(4) If by September 30 of each year the impoundment has not discharged since January 1 of that year, a sample shall be taken from the impoundment near the dam and analyzed for the indicated parameters. Permittee shall indicate the samples were "dipped" on the monitoring reports.

(5) Discharge of monoethanolarnineinto the lime sludge pond will not be allowed unless prior KDHE approval is received.

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (continued)

(6) The sampling location for 006 shall be at the discharge side of the heat exchanger prior to mixing with ultimate heat sink waters.

(7) Use of any chemical additives including any oxidizing and/or non-oxidizing biocides for Asiatic clam control shall be subject to compliance with the Supplemental Condition No. 6.c and 15.

(8) The two cells of the lagoon system shall be operated in series and the discharge shall be from the final cell only.

(9) After the first full year of sampling, permittee may request KDHE reduce the monitoring frequency or discontinue the requirement for further monitoring of these parameters. To allow for laboratory set up, monitoring for these parameters will not be required until March 1, 2005.

B. STANDARD CONDITIONS

In addition to the specified conditions stated herein, the permittee shall comply with the attached Standard Conditions dated August 1, 1996.

C. SCHEDULE OF COMPLIANCE

None

D. SUPPLEMENTAL CONDITIONS

1. Acute Whole Effluent Toxicity (WET) testing shall be conducted annually on the effluent from outfall 003. The test procedures shall be in accordance with the EPA document, Methods for Measurina the Acute Toxicitv of Effluents and Receivina Waters to Freshwater and Marine Orqanisms, fourth edition as published in August, 1993, (EPA/600/4-90/027F) using test organisms *Pimephales promelas* (fathead minnow) and any of the following daphnid (water flea) species: Daphnia *pulex*, *Daphnia magna*, or *Ceriodaphnia dubia* within a dilution series of 0, 25, 50, 75, 90, and 100% effluent. KDHE reserves the right to increase or decrease testing frequency based upon compliance history and toxicity testing results.

   a. The permittee shall submit to KDHE a copy of the test report within five days of receipt of the information. KDHE reserves the right to require the permittee to take such actions as are reasonable to identify and remedy any identified or predicted toxic conditions in the receiving stream outside of the zone of initial dilution which is caused by the permittee's effluent.

   b. The Permittee shall also test a portion of the same effluent sample used for the WET test for the substances per Attachment B.

      The Permittee shall coordinate sampling for this test with other requirements of this permit and may use the test results to satisfy this and other corresponding testing requirements. The permittee shall use a laboratory approved by KDHE for Whole Effluent Toxicity testing.

D. **SUPPLEMENTAL CONDITIONS** (Continued)

2. Chronic Whole Effluent Toxicity (WET) testing shall be conducted on the effluent from outfall 004 once in calendar year 2005. If by September 30, 2005, the impoundment has not discharged since January 1, 2005, a sample shall be taken from the impoundment near the dam for analysis. Permittee shall indicate the sample was "dipped" on the monitoring reports.

   a. The test procedures shall be in accordance with the EPA document, Short-Term Methods for Estimatinq the Chronic Toxicitv of Effluents and Receivinq Waters to Freshwater Oraanisms, third edition, July 1994, (EPA/600/4-91/002) using test organisms *Pimephales promelas* (fatheadminnow) and *Ceriodaphnia dubia* (water flea) within a dilution series of 0, 25, 50, 75, and 100% effluent. KDHE reserves the right to increase or decrease testing frequency based upon compliance history and toxicity testing results.

   b. The permittee shall submit to KDHE a copy of the test report within five days of receipt of the information. KDHE reserves the right to require the permittee to take such actions as are reasonable to identify and remedy any identified or predicted toxic conditions in the receiving stream outside of the mixing zone which is caused by the permittee's effluent.

   c. Permittee shall coordinate sampling for this test with other monitoring requirements of this permit and may use the test results to satisfy this and other corresponding testing requirements. The permittee shall use a laboratory approved by KDHE for Whole Effluent Toxicity testing.

3. There shall be no discharge of polychlorinated biphenyl compounds.

4. All samples and flow measurements required for permit monitoring shall be taken on the same day except for miscellaneous discharges related to storm water runoff, oil storage area runoff, etc.

5. Miscellaneous discharges related to runoff are regulated by Water Quality Criteria. Runoff contained in the oil storage dike area(s) shall be visually inspected to determine if removal of oil and grease is necessary prior to discharge.

6. Except as provided in the subparagraphs "b" and "c" below:

   a. Total residual oxidant may not be discharged from any single generating unit for more than two hours per day unless the discharger demonstrates to KDHE that discharge for more than two hours is required for macroinvertebrate control. Simultaneous multi-unit oxidation is permitted. Multi-unit oxidation must be designated in the monitoring reports.

   b. A waiver of the total residual oxidant discharge time limit and an increase in the categorical concentration continues for the service water and essential service water systems.

   c. Periodic oxidizing or non-oxidizing biocides treatment for Asiatic clam and Zebra

D. SUPPLEMENTAL CONDITIONS (Continued)

mussel control is permitted as described in the KDHE approved Asiatic clam control program and subsequent updates submitted and approved by KDHE

7. All radioactive components of the discharge are regulated solely by the U.S. Nuclear Regulatory Commission (NRC) under the requirements of the Atomic Energy Act and not by either the Environmental Protection Agency (EPA) under the Clean Water Act or the Kansas Department of Health and Environment under Kansas Water Pollution Control Regulations and Statutes.

8. The permittee shall develop and implement an oxidation schedule indicating the time, dosage and duration of applications for each unit. The records shall be maintained and made available for review upon KDHE or EPA request.

9. This permit shall be modified, or alternatively, revoked and reissued, to comply with any applicable effluent standard or limitation issued or approved under Sections 301 (b)(2), (C), and (D), 304 (b)(2), and 307 (a)(2) of the Clean Water Act, if the effluent standard or limitation so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any effluent limitation in the permit, or

   b. Controls any pollutant not limited in the permit.

   The permit as modified or reissued under this paragraph shall also contain any other requirements of the Act then applicable.

10 In the event the Environmental Protection Agency amends or promulgates the BPT, BAT and/or BCT effluent guideline limitations for a specific Point Source Category or any of the subcategories covering your industry, this permit will be revoked and reissued to incorporate the new limitation(s).

11 There shall be no discharge from the Eisenhower Learning Center waste stabilization lagoon system. Only domestic waste shall be directed to this lagoon system. The following requirements are applicable to all earthen lagoons:

   a. All wastewater lagoons shall maintain a minimum of two feet of freeboard. The permittee shall measure and record weekly the depth of water in each wastewater treatment lagoon from the lowest point of overflow. A written log of all such measurements shall be maintained on site and be made available to KDHE personnel in accordance with Standard Condition No. 12 of this permit.

   b. Permittee shall not change operations so as to introduce into the lagoons chemicals, cleaners, or any hazardous waste, not specifically identified in the permit application or specifically approved by KDHE.

   c. Any solid waste and sludge generated from the lagoon, if disposed of in a landfill shall be in accordance with the requirements of the KDHE, Bureau of Waste Management. Land application of lagoon sludges shall be in accordance with a plan approved by KDHE Bureau of Water.

D. SUPPLEMENTAL CONDITIONS (Continued)

d. All vegetation on the dikes and at the waters edge shall be properly maintained by regular mowing of grass and remaval of cattails and woody vegetation.

e. The permittee shall prepare an alternate plan for emergency disposal of lagoon wastewater which shall be implemented whenever the required freeboard is not maintained.

f. The wastewater treatment plant shall be under the supervision of an operator who has been certified or is in the process of obtaining certification under K.S.A. 65-4501 et seq.

12. Use of earthen lagoons for the handling and treatment of industrial wastes is currently being reevaluated by KDHE. This is an ongoing effort resulting from increased emphasis, at both the state and federal level, in addressing source control as a mechanism for eliminating or minimizing the potential for groundwater contamination. The facility addressed by this permit has yet to be fully evaluated. As such, KDHE may require the installation of additional groundwater monitoring wells or other necessary improvements to the wastewater handling and disposal system. The permittee will be notified and consulted concerning any monitoring well installation requirements or possible lagoon system modifications at a later time. The installation of any monitoring wells or any modifications to the wastewater system requires prior approval by KDHE.

13. A report addressing the disposal of metal cleaning wastes is to be submitted to KDHE for approval at least 10 days or as soon as reasonably practicable before implementing metal chemical cleaning activities. Approval from the Department is required before chemical cleaning waste and wastewater can be disposed. Metal cleaning wastes are defined to be wastes derived from chemical cleaning of any metal process equipment, including boiler fireside cleaning and air preheater cleaning.

14. Changes in Discharges of Pollutant Substances

The permittee shall notify the Department as soon as it knows or has reason to believe:

a. That any activity has occurred or will occur which would result in the discharge on a routine or frequent basis, of any pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

(1) One hundred micrograms per liter (100 μg/l);

(2) Two hundred micrograms per liter (200 μg/l) for acrolein and acrylonitrile; five hundred micrograms per liter (500 μg/l) for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter (1 mg/l) for antimony;

(3) Five (5) times the maximum concentration value reported for that pollutant in the permit application.

D. <u>SUPPLEMENTAL CONDITIONS</u> (Continued)

b. That any activity has occurred or will occur which result in any discharge, on a non-routine or infrequent basis, of a pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

(1) Five hundred micrograms per liter (500 μg/l);

(2) One milligram per liter (1 mg/l) for antimony;

(3) Ten (10) times the maximum concentration value reported for that pollutant in the permit application.

15. Toxic Substances - Water Treatment Additives. If the permittee utilizes or changes water treatment additives:

a. After the mixing zone provided by Kansas Water Quality Standards, the discharge of water treatment additives shall not be harmful to human, animal or plant life uses in the receiving water.

b. The permittee shall keep an ongoing log of the water treatment chemicals used, their potential concentration in the facility discharge, and the associated toxicity data for each chemical. A sample chemical additives evaluation log can be obtained from KDHE.

c. The permittee shall provide KDHE, upon request, toxicity tests and/or a chemical additives evaluation log the permittee uses to determine if the requirements in the paragraphs above are being achieved. In the event the data indicate the requirements in the paragraphs above are not achieved, KDHE reserves the right to amend the facility's NPDES permit to specify additional terms and conditions for toxic substances.

16. Kansas Surface Water Quality Standards will be enforced in Wolf Creek at the point of discharge from the Wolf Creek Cooling Impoundment to Wolf Creek. Discharges to waters of the State shall be guided by the current state surface water quality standards, K A.R. 28-16-28b <u>et seq</u>.

17. Wolf Creek Nuclear Operation Corporation (WCNOC), a Delaware corporation, is the agent for Kansas Gas and Electric Co., Kansas City Power and Light Co. and Kansas Electric Power Cooperative, Inc. The referenced companies shall, in accordance with their Wolf Creek Generating Station Operating Agreement (dated April 15, 1986), be severally liable (in proportion with their ownership shares of the plant) for compliance with the terms and conditions stated in the permit and applicable laws

18. When the flow through Outfall 006 consists solely of service water from the Service Water System diverted to the Essential Service Water System (other than flows recirculated directly from the Wolf Creek Cooling Impoundment), a sample collected from the Service Water System shall be considered representative of Outfall 006 for purposes of monitoring required by this permit.

D. SUPPLEMENTAL CONDITIONS (Continued)

19. Permittee shall maintain and modify the existing stormwater pollution prevention plan as necessary in accordance with **ATTACHMENT A.** A copy of the SWP3 shall be kept on site and be available for **KDHE** or EPA inspection upon request.

20. Discharge of industrial stormwater (as defined in 40 CFR part 122.26 (b)(14)) from the facility, except for stormwater associated with construction activity disturbing 1 acre or more of soil, is authorized under this permit. Such discharges shall be in compliance with the Kansas Surface Water Quality Standards (KAR 28-16-28) and in conformance with the facility stormwater pollution prevention plan developed in accordance with **ATTACHMENT A.**

21. Information required by the 316(b) Phase II regulations, 40 CFR Part 125.95 et sea., shall be submitted to KDHE - Bureau of Water in accordance with the dates indicated in the Phase II regulations.

ATTACHMENT A

STORM WATER POLLUTION PREVENTION PLAN REQUIREMENTS AND GUIDELINES

The Storm water Pollution Prevention plan (SWP2 plan) shall be specific to the industrial activities and site characteristics occurring at the location described in this permit. The permittee shall fully implement the provisions of the SWP2 plan required under this permit as a condition of this permit.

The purpose of the SWP2 plan is to ensure the design, implementation, management, and maintenance of Best Management Practices (BMPs) in order to reduce the amount of pollutants in storm water discharges associated with the industrial activities at the facility. The SWP2 plan shall evaluate BMPs from each of three major classes: managerial/administrative; structural controls and non-structural controls.

The permittee shall evaluate, select, install, utilize, operate and maintain the BMPs in accordance with the concepts and methods described in Environmental Protection Agency (EPA) document number EPA 832-R-92-006, entitled ***Storm water Management for Industrial Activities - Developing Pollution Prevention Plans and Best Management Practices***, published in September. 1992[1]; and the U.S. Environmental Protection Agency's ***Final*** NPDES ***Storm Water Multi-Sector General Permit for Industrial Activities***; Notice dated Sept. 29, 1995, and subsequent modifications.

The SWP2 plan and any amendments shall be prepared by, or under the supervision of, and sealed by a Kansas licensed professional engineer. The SWP2 plan shall be reviewed and re-certified for compliance with accepted engineering standards for storm water pollution prevention at least once every five years. The plan shall contain, at a minimum, the following items:

1. Pollution Prevention Team - Specific individuals shall be identified within the facility organization as members of a Storm water Pollution Prevention Team who are responsible for developing, implementing, maintaining and revising the plan. Each member's responsibilities shall be clearly identified in the plan. The activities and responsibilities of the team shall address all aspects of the facility's storm water pollution prevention plan.

2. Description of potential pollutant sources - pollutant sources which may reasonably be expected to add significant amounts of pollutants to the storm water discharge shall be described. The description shall include, at a minimum:

    a. Site Map - a site map identifying: the outline drainage areas of each storm water outfall; the location of significant materials exposed to precipitation; storage tanks; scrap yards and general refuse areas; fuel storage and distribution areas; vehicle and equipment maintenance and storage areas; loading/unloading areas; waste treatment, storage or disposal areas; short and long term material storage areas (including but not limited to: supplies, construction materials, plant equipment, oils, fuels, used and unused solvents, cleaning materials, paint, water treatment chemicals, fertilizers, and pesticides); landfills; construction sites; stock piles; major spills or leaks; surface water bodies and existing structural control measures to reduce pollutants in storm water runoff (such as bermed areas, grassy swales, etc.).

    b. Inventory of Exposed Materials - a narrative description of significant materials handled, treated, stored, leaked, spilled or disposed of in a manner to allow exposure to storm water within the period starting three years prior to the date of this permit; existing structural and nonstructural control measures to reduce pollutants in storm water runoff; and any treatment the storm water receives. A list of significant spills and leaks of toxic / hazardous materials in exposed areas shall be maintained and kept updated.

    c. Sampling Data - a summary of existing sampling data.

    d. Risk Identification and Summary of Potential Pollutant Sources - A narrative description of the potential pollutant sources and pollutant parameter of concern shall be identified.

---

[1] The EPA Manual entitled ***Storm wafer Management for Industrial Activities - Developing Pollution Prevention Plans and Best Management Practices***, and the ***Final NPDES Storm Water Multi-Sector General Permit for Industrial Activities***; Notice dated Sept. 29, 1995 are available through the EPA Water Resources Center, at (202) 260-7786, e-mail waterpubs@epamad.epa.gov or the National Technical Infomation Services (NTIS). The NTIS publication number is PB92-235969. The NTIS order desk phone number is (800) 553-6847.

3. Measures and Controls - A description of storm water management controls appropriate for the facility which addresses the following minimum components, including a schedule for implementing such controls to the extent practical:

   a. Good housekeeping requiring the maintenance of areas in a clean, orderly manner including handling and storage areas (exposed to precipitation) for raw metals, scrap metals, fines, paints and other process areas.

   b Preventive Maintenance - Including timely inspection and maintenance of storm water management devices, like oil water separators, catch basrns etc.

   c. Spill Prevention and Response Procedures - Appropriate material handling procedure, storage requirements, use of equipment such as diversion valves, and procedures for cleaning up spills should be identified. Availability of the necessary equipment to implement a clean up should be addressed. The following areas should be addressed:

      (1) Metal fabrication and finishing areas - include measures for maintaining clean, dry, orderly conditions and use of dry clean-up techniques;

      (2) Receiving, Unloading and Storage Areas and Raw Material Storage Areas - include measures to prevent spills & leaks; easy access for spill clean-up; quick and correct identification of materials; and train employees on clean-up techniques.

      (3) Storage of Equipment - include procedures for proper clean-up and/or covering of equipment before storing outdoors.

      (4) Storage of Metal Working Fluids - measures to identify proper controls.

      (5) Cleaners and Rinse Water - Include measures to control spills, build-up and disbursement of sand from sand blasting, and use of less toxic cleaners.

      (6) Lubricating Oils and Hydraulic Fluids - include procedures for using detecting and control devices to reduce, prevent, and contain leaks and overflows.

      (7) Chemical Storage Areas - include a program to inspect containers, and identify proper disposal and spill controls to prevent storm water contamination.

   d. Inspections: Identification of qualified facility personnel to inspect at appropriate intervals designated equipment and storage areas for raw metal, finished product, materials and chemicals, recycling, equipment, paint, fueling and maintenance; and loading, unloading, and waste management areas. A set of tracking or follow-up procedures shall be used to ensure that appropriate actions are taken in response to the inspections. Records of inspections shall be maintained on-site for at least three years after the date of the inspection.

   e Employee Training Employee training programs to inform personnel responsible for implementing activities ~~identified in the storm water pollution prevention~~ plan or otherwise responsible for storm water management, at all levels of responsibility, of the components and goals of the stonn water pollution prevention plan The pollution prevention plan shall consider periodic dates for such training, but in all cases training must be held at least annually.

   f. Record keeping and Internal Reporting Procedures: A log to document a description of incidents (such as spills, or other discharges), along with other information which may impact the quality and quantity of storm water discharges needs to be developed and maintained. Reporting procedures, inspections and maintenance activities shall be developed and included in the SWP3 plan.

   g. Non-storm water Discharges -include a certification that the discharge has been tested or evaluated for the presence of dry weather flows. The certification should include all potential significant sources of dry weather flows, all analytical data for quality and quantity of such flows, and signature of the authorized person. The plan shall identify and ensure the implementation of appropriate pollution prevention measure.; for the dry weather flow component(s) of the discharge.

   h Sediment and Erosion Control: Measures to minimize erosion in areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion. At a minimum consider structural, vegetative, and/or stabilization measures to limit erosion. Must include measures to minimize erosion related to the high volume of traffic from heavy equipment for delivery to and from the facility and for equipment operating at the facility on a daily basis such as forklifts, cranes etc.

i. Management of Runoff Describe and consider the appropriateness of traditional storm water management practices (practices other than those which control the generation or source(s) of pollutants) to divert, infiltrate, reuse or otherwise manage storm water runoff in a manner that reduces pollutants in storm water discharges from the site. Include that the measures that the permittee determines to be reasonable and appropriate should be implemented and maintained. The potential of various sources at the facility to contribute pollutants to storm water discharges associated with industrial activity (see Item 3.c) shall be considered when determining reasonable and appropriate measures to implement.

4. Comprehensive Site Compliance Evaluation - Qualified personnel shall conduct site compliance evaluations at least once a year. Such evaluations shall provide for:

a Visual inspection of areas contributing to a storm water discharge associated with industrial activity for evidence of, or the potential for, pollutants entering the drainage system. Evaluation of measures to reduce pollutant loadings to determine whether they are adequate and properly implemented in accordance with the terms of the permit or whether additional control measures are needed. A visual evaluation of equipment needed to implement the plan, such as spill response equipment and containment drums, shall be made to determine it is functioning properly and drums are not corroded.

b. A report summarizing the scope of the evaluation, personnel making the evaluation, the date(s) of the evaluation, major observations relating to the implementation of the storm water pollution prevention plan, and any actions taken shall be made and retained as part of the storm water pollution prevention plan. Where a report docs not identify any incidents of noncompliance, a certification that the facility is in compliance with the storm water pollution prevention plan and this permit needs to be included in the plan.

5 Monitoring and Record Keeping Requirements.

a. Visual Examination of Storm Water Quality: The permittee shall perform and document at least one visual examination of a storm water discharge associated with industrial activity from each identified storm water outfall Visual examination reports shall be maintained in the plan. Each report shall include the date and time, name of the person performing examination, nature of discharge (runoff or snow melt), visual quality of the discharge (i.e., color, odor, clarity, floating solids, suspended solids, foam, oil sheen, and other indicators of storm water pollution) and probable sources of any observed contamination.

b. To ensure the adequacy of the best management practices developed within the SWP2 plan, the permittee needs to periodically monitor[2] the storm water discharges during wet weather events for potential contaminants which may reasonably be expected to be present in the discharge. Record of all storm water monitoring reports, unless otherwise indicated in this permit, shall be kept on file.

6. The plan shall be re-evaluated and modified in a timely manner, but in no case more than 12 weeks after.

a a change in design, construction, operation or maintenance that has a significant effect on the potential for the discharge of pollutants to the waters of the State, or

b. the permittee's inspections (including the regular comprehensive site compliance evaluation required herein) indicate deficiencies in the SWP2 plan or any BMP; or

c. a visual inspection of contributing areas or a visual inspection of the storm water discharges or monitoring of the storm water discharges indicate the plan appears to be ineffective in eliminating or significantly minimizing pollutants from sources identified in the plan.

[2] For sampling methods and procedures please refer to ***NPDES STORM WATER SAMPLING GUIDANCE DOCUMENT, EPA 833-B-92-001*** This document can be obtained by calling (202)564-0746 or the National Technical Information Service (NTIS at (800) 553-0847

ATTACHMENT B

Quantitativelimits for analysis performed for any parameter in conjunction with this permit must be less than or equal to those indicated.

HEAVY METAL DETECTION LIMITS

ANALYTICAL PARAMETER	CAS NUMBER	Quantitative Limit	Units
antimony, total	7440-36-0	10	µg/l
arsenic, total	7440-38-2	10	µg/l
beryllium, total	7440-41-7	5	µg/l
cadmium, total	7440-43-9	3	µg/l
chromium, total	7440-47-3	10	µg/l
copper, total	7440-50-8	10	µg/l
lead, total	7439-92-1	5	µg/l
mercury, total	7439-97-6	0.5	µg/l
nickel, total	7440-02-0	50	µg/l
selenium, total	7782-49-2	5	µg/l
silver, total	7440-22-4	10	µg/l
thallium, total	7440-28-0	10	µg/l
zinc, total	7440-66-6	20	µg/l

OTHERS

Total hardness as $CaCO_3$			mg/l
Ammonia as N		0.2	mg/l
Efftuent Temperature			°F
pH			s.u.

All metals shall be tests and reported as "total recoverable" metals.

STANDARD CONDITIONS FOR
KANSAS WATER POLLUTION CONTROL AND
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM PERMIT

1. Representative Sampling:

A. Samples and measurements taken as required herein shall be representative of the nature and volume of the monitored discharge. All samples shall be taken at the location designated in this permit, and unless specified, at the outfall(s) before the effluent joins or is diluted by any other water or substance.

B Monitoring results shall be recorded and reported on forms acceptable to the Division and postmarkeo no later than the 28th day of the month following the completed reporting period. Signed and certified copies of these, prepared in accordance with KAR 28-16-59 and all other reports required herein, shall be submitted lo

Kansas Department of Health & Environment
Bureau of Water-Technical Services Section
1000 SW Jackson Street, Suite 420
Topeka, KS 66612-1367

Schedule of Compliance: No later than 14 calendar days following each date identified in the "Schedule of Compliance," the permittee shall submit to the above address, either a report of progress or, in the case of specific action being required by identified dates, a written notice of compliance or noncompliance. In the latter case, the notice shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirements, or. if there are no more scheduled requirements, when such noncompliance will be corrected.

3 Definitions:

A The "daily average" discharge means either the total discharge by weight during a calendar month divided by the number of days in the month that the facility was operating or the average concentration for the month. The daily average discharge shall be determined by the summation of all measured daily discharges by weight divided by the number of days during the calendar month when the measurements were made, or by the summation of all concentrations determined during the calendar month divided by the number of samples collected and analyzed.

B. The "daily maximum" discharge means the total discharge by weight or average concentration during a 24 hour period.

C. The "monthly average", other than for fecal coliform bacteria, is the arithmetic mean of the value of effluent samples collected in a period of 30 consecutive days, The monthly average for fecal coliform bacteria is the geometric mean of the value of the effluent samples collected in a period of 30 consecutive days.

D. The "weekly average", other than for fecal coliform bacteria, is the arithmetic mean of the value of effluent samples collected in a period of 7 consecurive days. The weekly average for fecal coliform bacteria is the geometric mean of the value of effluent samples collected in a period of 7 consecutive days.

E. A "grab sample" is an individual sample collected in less than 15 minutes.

F. A "composite sample" is a combination of individual samples in which the volume of each individual sample is proportional to the discharge flow, the sample frequency is proportioned to the flow rate over the sample period, Or the sample frequency is proportional to time.

G. The "act" means the Clean Water Act, 30 USC Section 1251 et seq.

H. The terms "Director", "Division", and "Department" refer to the Director, Division of Environment, Kansas Department of Health and Environment, respectively.

I. "Severe property damage" means substantial physical damage to property, damage 10 the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

J "Bypass" means any diversion of waste streams from any portion of a treatment facility or collection syst

4. Test Procedures: All analysis required by this permit shall conform to the requirements of 33 USC Section 1314(h); and shall be conducted in a laboratory certified by this Department. For each measurement or sample, the permittee shall record the exact place, date, and time of sampling; the date of the analyses, the analytical techniques or methods used, and the individual(s) who performed the sampling and analysis and, the results. If the permittee monitors anv pollutant at the location(s) designated herein more frequently than required by this permit, using approved procedures, the results shall be included in the Discharge Monitoring Report form required in 1.B. above. Such increased frequencies shal~also be indicated.

5. Records Retention: All records and information resulting from the monitoring activities required by this permit, including all records of analyses and calibration and maintenance of instrumentation and recordings from conlinuous monitoring instrumentation, shall be retained for a minimum of 3 years, or longer if requested bv the Division.

6. Change in Discharge: All discharges authorized herein shall be consistent with the terms and conditions of this permit. The discharge of any pollutant not authorized by this permit or of any pollutant identified in this permit more frequently than or at a level in excess of that authorized shall constitute a violation of this permit. Any anticipated facility expansions, productions or flow increases, or process modifications which result in a new, different, or increased discharge of pollutants shall be reported to the Division at least one hundred eighty (180) days before such chan(

7. Noncompliance Notifications: If for any reason, the permittee does not comply with, or will be unable to comply with any daily maximum or weekly average effluent limitations specified in this permit, the permittee shall provide the Department with the following information in writing within five days of becoming aware of such condition:

A. A description of the discharge and cause of noncompliance, and

B. the period of noncompliance including exact dates and times or if not corrected, the anticipated time the noncompliance is expected to continue and steps taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

The above information shall be provided with the submittal of the regular Discharge Monitoring Report form for violations of daily average or monthly average effluent limitations

8. Facilities Operation: The permittee shall at all times maintain in good working order and efficiently and effectively operate all treatment, collection, control systems or facilities, to achieve compliance with the terms of this permit. Such proper operation and maintenance procedures shall also include adequate laboratory controls and appropriate quality assurance procedures. Maintenance of treatment facilities which results in degradation of effluent quality, even though not causing violations of effluent limitations shall be scheduled during noncritical water quality periods and shall be carried out in a manner approved in advance by the Division. The permittee shall take all necessary steps to minimize or Prevent any adverse impact to waters of the State resulting from noncompliance with any effluent limitations specified in this permit, including such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying discharge. When necessary to maintain compliance with the permit conditions, the permittee shall halt or reduce those activities under its control which generate wastewater routed to this facility.

9. Immediate Reporting Required: Any diversion from, or bypass of facilities necessary to maintain compliance with the permit is prohibited, except: where no feasible alternatives to the bypass exist and 1) where necessary to prevent loss of human life, personal injury or severe property damage; or 2) where excessive stormwater inflow or infiltration would damage any facilities necessary to comply with this permit or 3) where the permittee notifies the Director seven days in advance of an anticipated bypass. The Director or Director's designee may approve a bypass, after considering its adverse effects, if any of the three conditions listed above are met. The permittee shall <u>immediately</u> notify the Division by telephone [(913) 296-5517 or the appropriate KDHE District Office] of each bypass and shall confirm the telephone notification with a letter explaining what caused this spill or bypass and what actions have been taken to prevent recurrence. Written notification shall be provided to the Director within five days of the permittee becoming aware of the bypass. The Director or Director's designee may waive the written report on a case-by-case basis.

10. Removed Substances: Solids, sludges, filter backwash, or other pollutants removed in the course of treatment or control of wastewaters shall be disposed of in a manner acceptable to the Division.

11. Power Failures: The permittee shall provide an alternative power source sufficient to operate the wastewater control facilities or otherwise control pollution and all discharges upon the loss of the primary source of power to the wastewater control facilities.

12. Right of Entry: The permittee shall allow authorized representatives of the Division of Environment or the Environmental Protection Agency upon the presentation of credentials, to enter upon the permittee's premises where an effluent source is located, or in which are located any records required by this permit, and at reasonable times, to have access to and copy any records required by this permit, to inspect any monitoring equipment or monitoring method required in this permit. and to sample any influents to, discharges from or materials in the wastewater facilities.

13. Transfer of Ownership: The permittee shall notify the succeeding owner or controlling person of the existence of this permit by certified letter, a copy of which shall be forwarded to the Division. The succeeding owner shall secure a new permit. The permit is not transferable to any person except after notice and approval by the Director. The Director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary.

14. Availability of Records: Except for data determined to be confidential under 33 USC Section 1315, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the offices of the Department. Effluent data shall not **be** considered confidential. Knowingly making any false statement on any such report or tampering with equipment to falsify data may result in the imposition of criminal penalties as provided for in 33 USC Section 1319 and KSA 65-170c.

15. Permit Modifications and Terminations: As provided by KAR 28-16-62, after notice and opportunity for a hearing, this permit may be modified, suspended or revoked or terminated in whole or in part during its term for cause as provided, but not limited to those set forth in KAR 28-16-62 and KAR 28-16-28b through f. The permittee shall furnish to the Director, within a reasonable amount of time, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or to determine compliance with this permit. The permittee shall also furnish upon request, copies of all records required to be kept by this permit.

16. Toxic Pollutants: Notwithstanding paragraph 15 above, if a toxic effluent standard or prohibition (including any schedule of compliance specified at such effluent standards) is established under 33 USC Section 1317(a) for a toxic pollutant which is present in the discharge and such standard or prohibition is more stringent than any limitation for such pollutant in this permit, this permit shall be revised or modified in accordance with the toxic effluent standard or prohibition Notning in this permit relieves the permittee from complying with federal toxic effluent standards as promulgated pursuant to 33 USC Section 1317.

17. Civil and Criminal Liability: Except as authorized in paragraph 9 above, nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance as provided for in KSA 65-170d, KSA 65-167, and 33 USC Section 7319.

18. Oil and Hazardous Substance Liability: Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities or penalties to which the permittee is or may be subject to under 33 USC Section 1321 or KSA 65-164 <u>et seq</u>. The municipal permittee shall promptly notify the Division by telephone upon discovering crude oil or any petroleum derivative in its sewer system or wastewater treatment facilities.

Industrial Users: The municipal permittee shall require any industrial user of the treatment works to comply with 33 USC Section 1317, 1318 and any industrial user of storm sewers to comply with 33 USC Section 1308.

Property Rights: The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights nor any infringements of or violation of federal, state or local laws or regulations.

21. Operator Certification: The permittee shall ensure the wastewater facilities are under the supervision of an operator certified by the Department. If the permittee does not have a certified operator or loses its certified operator, appropriate steps shall be taken to obtain a certified operator as required by KAR 28-16-30 <u>et seq</u>.

22. Severability: The provisions of this permit are severable. If any provision of this permit or any circumstance is held invalid, the application of such provision to other circumstances and the remainder of the permit shall not be affected thereby.

23. Removal from Service: The permittee shall inform the Division at least three months before a pumping station, treatment unit, or any other part of the treatment facility permitted by this permit is to be removed from service and shall make arrangements acceptable to the Division to decommission the facility or part of the facility being removed from service such that the public health and waters of the state are protected.

24. Duty to Reapply: A permit holder wishing to continue any activity regulated by this permit after the expiration date, must apply for a new permit at least 180 days prior to expiration of the permit.

ATTACHMENT C - SPECIAL-STATUS SPECIES CORRESPONDENCE

WOLF CREEK
'NUCLEAR OPERATING CORPORATION

Kevin J. Moles
Manager Regulatory Affairs

September 16, 2005

RA 05-0105

Kansas Department of Wildlife & Parks
Environmental Services
512 SE 25th Ave.
Pratt. KS 67124

Attention: Mr. Jim Hayes, Chief Environmental Services

Subject: Wolf Creek Generating Station, License Renewal:
Request for Information on Threatened or Endangered Species

Dear Mr. Hayes:

Wolf Creek Nuclear Operating Corporation (WCNOC) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Wolf Creek Generating Station (WCGS). The license expires March 11, 2025. The renewal term would be for an additional 20 years beyond the original license expiration date. As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will also request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that we need to address or any information that we should provide to your office to expedite the NRC consultation.

WCGS is a nuclear-powered steam electric generating facility that began commercial operation on September 3, 1985. WCGS is currently owned by Kansas Gas and Electric Company (47 percent), Kansas City Power & Light Company (47 percent), and Kansas Electric Power Cooperative, Inc. (6 percent). WCNOC, the plant operator, is authorized to act as agent for the owners and has exclusive responsibility and control over the operation and maintenance of the facility. The switchyard beyond the first breaker, the 345-kilovolt transmission lines, and one 69-kilovolt transmission line are owned by Westar Energy, a corporation formed by the merger of Kansas Gas and Electric and Kansas Power and Light. Kansas Electric Power Cooperative, Inc. owns one 69-kilovolt line that is connected to the switchyard.

The WCGS facility is located in Coffey County, Kansas, approximately 75 miles southwest of Kansas City, and 3.5 miies east of the Neosho River and the John Redmond Reservoir. The WCGS site encompasses approximately 9,818 acres, of which only 135 or so acres are occupied by generating and support facilities. Coffey County Lake, the station's cooling reservoir, occupies approximately 5,090 acres. Most of the remaining land is made up of

PO Box 411 / Burlington, KS 66839 / Phone (620) 354-8831

Letter RA 05-0105
Page 2 of 2

rangeland, cropland, native prairie, and forested areas. In 2004, approximately 1.422 acres were leased for grazing, 1,272 acres were leased for crop production, and 542 acres were leased for hay production. The attached map shows the WCGS boundaries.

Although there are three transmission lines that connect WCGS to the regional grid, the primary line relevant to license renewal is the WCGS-to-Rose Hill line. This 345-kilovolt line owned by Westar Energy extends from WCGS southwestward for 98 miles in a 150-foot wide corridor to the Rose Hill Substation southeast of Wichita.

A map of the transmission system is attached. In total, the transmission lines of interest are contained in approximately 105 miles of corridor that occupy approximately 1,900 acres. The corridors pass through land that is primarily agricultural and open range. The areas are mostly remote, with low population densities. The lines cross numerous county, state and U.S. highways after leaving the switchyard. Kansas counties crossed by the transmission lines include Coffey (the location of WCGS), Butler, and Greenwood.

WCNOC has no plans to substantially alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No additional land disturbance is anticipated in support of license renewal. As a consequence, we believe that operation of the station, including maintenance of the Rose Hill line, over the license renewal period (an additiona! 20 years) would not adversely affect any threatened or endangered species.

We would appreciate receiving your input in writing by October 31, 2005, detailing any concerns you may have about any listed species or ecologically significant habitats that may occur on the 9.818-acre WCGS site or along the associated Rose Hill transmission corridor. WCNOC will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the WCNOC license renewal application.

Please do not hesitate to call Dan Haines at (620) 364-8831 extension 4672, if you have any questions or require any additional information.

Sincerely,

Kevin J. Moles

Kevin J. Moles

KJM/deh
Attachment

RA 05-0105
Attachment
Page 1 of 3

Attachment

Maps of

WCGS Site Boundary

and

WCGS Transmission Lines

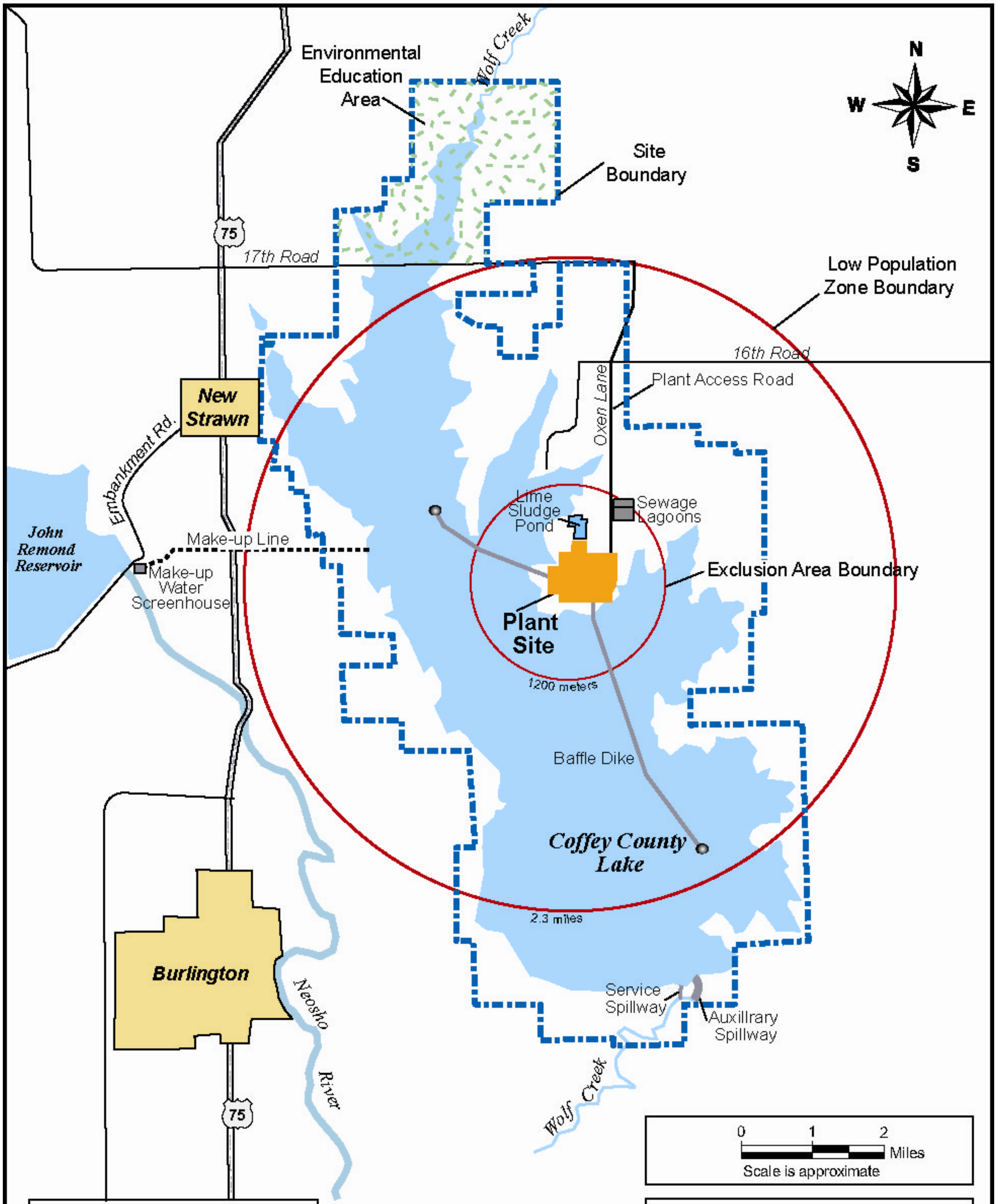
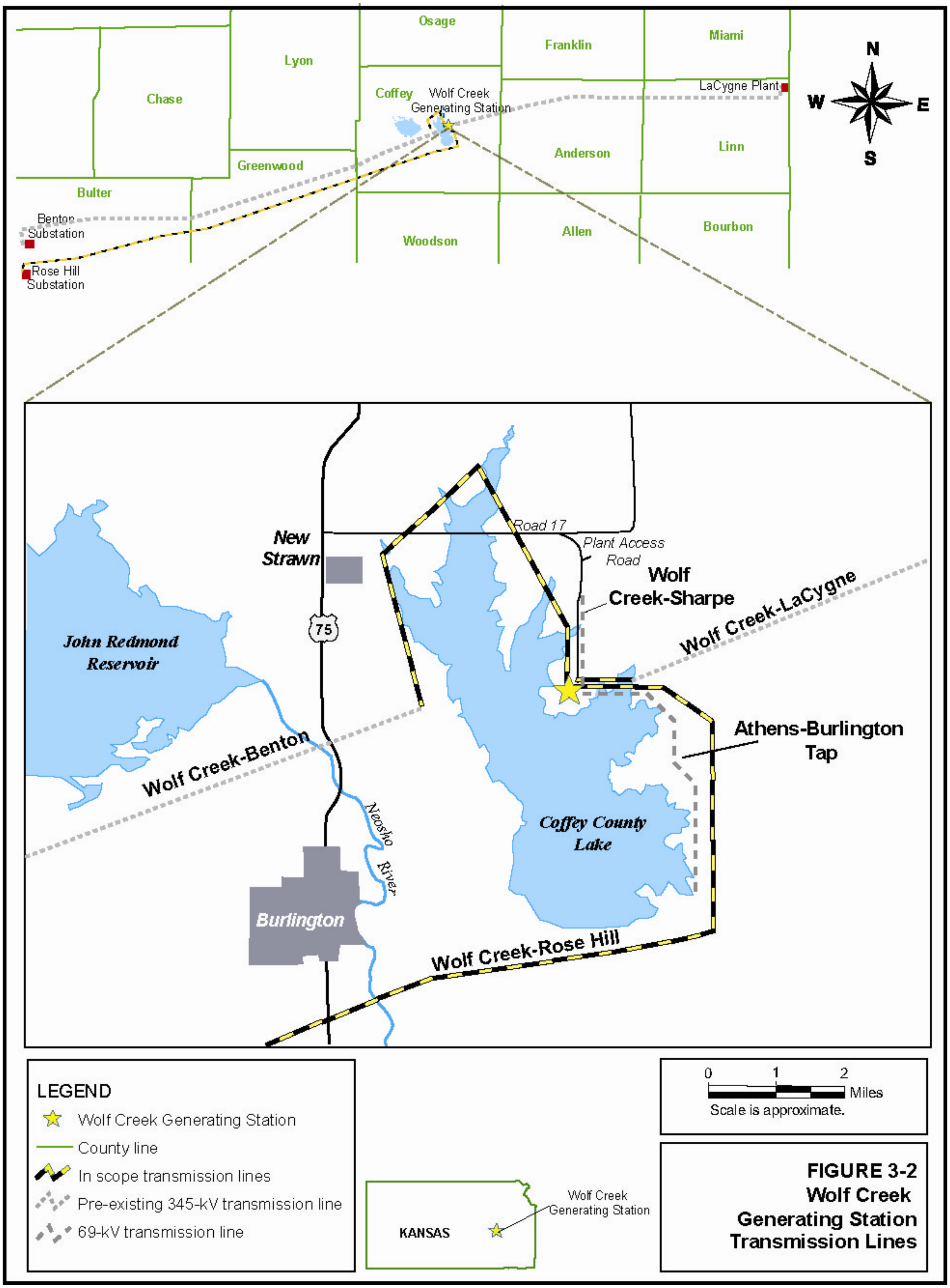


FIGURE 2-3
Wolf Creek Generating Station Site Boundary


Osage
Lyon
Franklin
Miami
Chase
Coffey
Wolf Creek Generating Station
LaCygne Plant
N
W
E
S
Greenwood
Anderson
Linn
Bulter
Benton Substation
Rose Hill Substation
Woodson
Allen
Bourbon
New Strawn
Road 17
Plant Access Road
Wolf Creek-Sharpe
Wolf Creek-LaCygne
75
John Redmond Reservoir
Wolf Creek-Benton
Athens-Burlington Tap
Neosho River
Coffey County Lake
Burlington
Wolf Creek-Rose Hill
LEGEND
Wolf Creek Generating Station
County line
In scope transmission lines
Pre-existing 345-kV transmission line
69-kV transmission line
0
1
2
Miles
Scale is approximate.
KANSAS
Wolf Creek Generating Station
FIGURE 3-2
Wolf Creek Generating Station Transmission Lines

KANSAS

DEPARTMENT OF WILDLIFE 8 PARKS KATHLEEN SEBELIUS, GOVERNOR

November 1, 2005

Kevin J. Moles Ref: D9.0100
Wolf Creek Nuclear Operating Corporation
PO Box 411
Burlington, KS 66839

Dear Mr. Moles:

RE: Application To The U.S. Nuclear Regulatory Commission To Renew The Operating License For The Wolf Creek Generating Station For An Additional 20 Years Beyond The Original License Expiration Date - Coffey County, Kansas.

The referenced project was reviewed for potential impacts on crucial wildlife habitats, current state-listed threatened and endangered species and species in need of conservation, and public recreation areas for which this agency has some administrative authority.

Our review indicates none of the named resources will be impacted. No special mitigation measures are necessary. No Department of Wildlife and Parks permits or special authorizations are needed. Although the state's species listings and the Department's lands obligations periodically change, due to the project's location and design, no future clearances will be required regardless of when the project work starts.

Sincerely,

Jim Hays, Chief
Environmental Services Section

Pratr Operations Office
512 SE 25th Ave., Pratt, KS 67124-8174
Phone 620-672-5911 Fax 620-672-6020 www kdwp state ks us

WOLF CREEK
'NUCLEAR OPERATING CORPORATION

Kevin J. Moles
Manager Regulatory Affairs

September 16, 2005

RA 05-0106

U. S. Fish and Wildlife Service
Kansas Field Office
315 Houston Street, Suite E
Manhattan, KS 66502

Attention: Mr. Mike LeValley, Field Supervisor

Subject: Wolf Creek Generating Station, License Renewal:
Request for Information on Threatened or Endangered Species

Dear Mr. LeValley:

Wolf Creek Nuclear Operating Corporation (WCNOC) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Wolf Creek Generating Station (WCGS), and is requesting your input. The license expires March 11, 2025. The renewal term would be for an additional 20 years beyond the original license expiration date. As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will also request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that we need to address or any information that we should provide to your office to expedite the NRC consultation.

WCGS is a nuclear-powered steam electric generating facility that began commercial operation on September 3, 1985. WCGS is currently owned by Kansas Gas and Electric Company (47 percent), Kansas City Power & Light Company (47 percent), and Kansas Electric Power Cooperative. Inc. (6 percent). WCNOC, the plant operator, is authorized to act as agent for the owners and has exclusive responsibility and control over the operation and maintenance of the facility. The switchyard beyond the first breaker, the 345-kilovolt transmission lines, and one 69-kilovolt transmission line are owned by Westar Energy, a corporation formed by the merger of Kansas Gas and Electric and Kansas Power and Light. Kansas Electric Power Cooperative, Inc. owns one 69-kilovolt line that is connected to the switchyard.

The WCGS facility is located in Coffey County, Kansas, approximately 75 miles southwest of Kansas City, and 3.5 miles east of the Neosho River and the John Redmond Reservoir. The WCGS site encompasses approximately 9,818 acres, of which only 135 or so acres are occupied by generating and support facilities. Coffey County Lake, the station's cooling reservoir, occupies approximately 5,090 acres. Most of the remaining land is made up of rangeland, cropland, native prairie, and forested areas. In 2004, approximately 1,422 acres were leased for grazing, 1,272 acres were leased for crop production, and 542 acres were leased for hay production. The attached map shows the WCGS boundaries.

P.O Box 411 / Burlington, KS 66839 / Phone (620) 364-8831

Letter RA 05-106
Page 2 of 2

Although there are three transmission lines that connect WCGS to the regional grid, the primary line relevant to license renewal is the WCGS-to-Rose Hill line. This 345-kilovolt line owned by Westar Energy extends from WCGS southwestward for 98 miles in a 150-foot wide corridor to the Rose Hill Substation southeast of Wichita.

A map of the transmission system is attached. In total, the transmission lines of interest are contained in approximately 105 miles of corridor that occupy approximately 1,900 acres. The corridors pass through land that is primarily agricultural and open range. The areas are mostly remote, with low population densities. The lines cross numerous county, state and U.S. highways after leaving the switchyard. Kansas counties crossed by the transmission lines include Coffey (the location of WCGS), Butler, and Greenwood.

Based on our direct observations, a preliminary review of WCNOC records, and a review of the U.S. Fish and Wildlife Service web site for federally-listed endangered or threatened species, we believe that the following species could occur in the vicinity of Wolf Creek Generating Station or its associated transmission lines:

- Bald eagles *(Haliaeetus leucocephalus),* federally-listed as threatened, congregate in winter around John Redmond Reservoir and Coffey County Lake. A pair of bald eagles has nested along the northern shore of Coffey County Lake since 1994.
- Meade's milkweed *(Asclepias meadii),* which is federally listed as threatened, has been found within Coffey County
- the Topeka shiner *(Notropis topeka),* federally listed as endangered, is known to occur in small streams in Butler and Greenwood Counties through which the WCGS-to-Rose Hill line passes.
- the Neosho madtom (*Noturus placidus),* federally listed as threatened, has been found in the Neosho River up- and downstream of WCGS
- the Neosho mucket mussel (*Lampsilis rafinesqueana*), a candidate for federal listing, has been recorded in Coffey and Greenwood Counties.

WCNOC is committed to the conservation of significant natural habitats and protected species, and expects that operation of WCGS, including maintenance of the identified transmission lines, through the license renewal period (an additional 20 years) would not adversely affect any listed species. WCNOC has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No additional land disturbance is anticipated in support of license renewal.

Please do not hesitate to call Dan Haines at (620) 364-8831 extension 4672, if you have any questions or require any additional information.

Sincerely,

Kevin J. Moles

Kevin J. Moles

KJM/deh
Attachment

RA 05-0106
Attachment
Page 1 of 3

Attachment

Maps of

WCGS Site Boundary

and

WCGS Transmission Lines

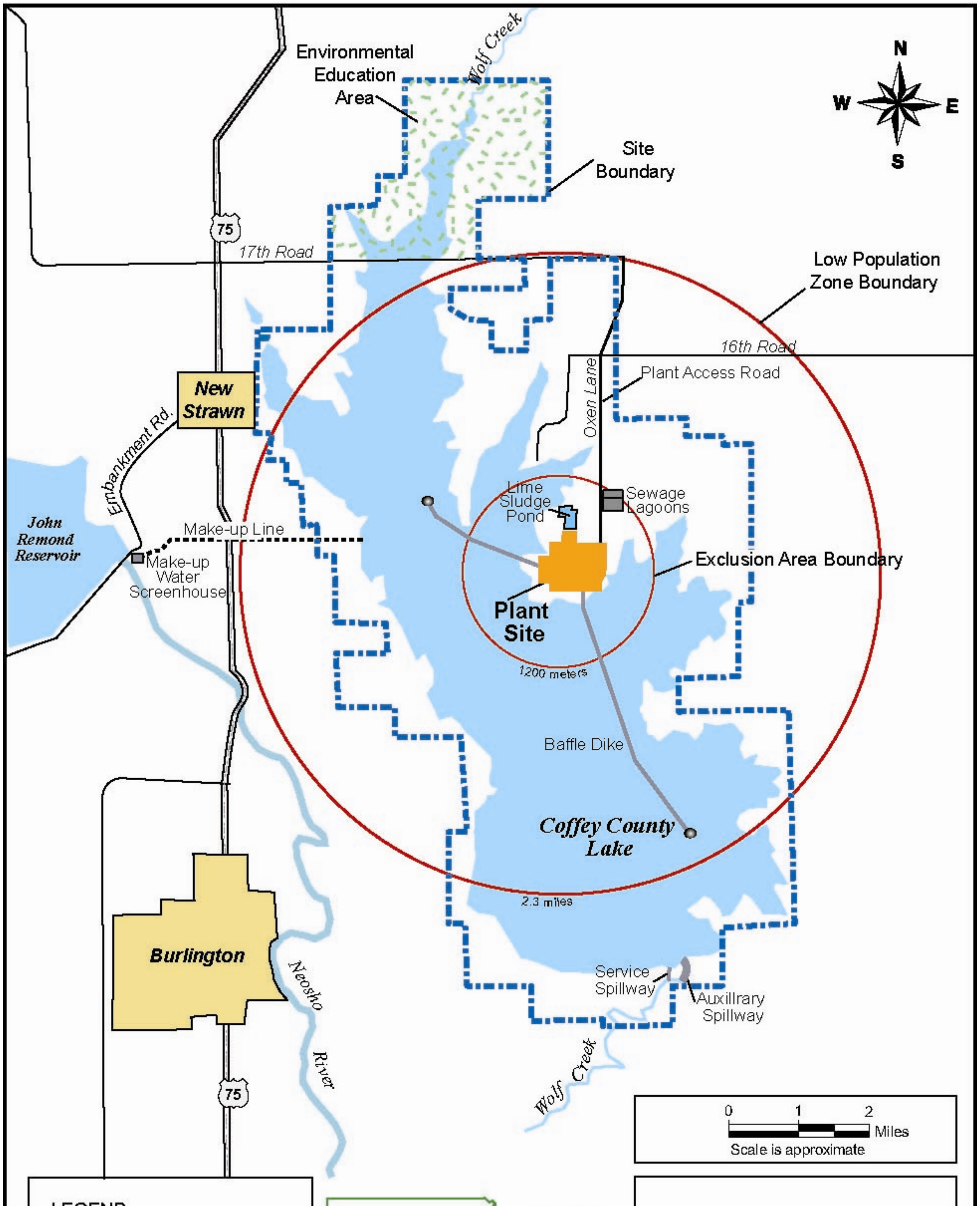


FIGURE 2-3
Site Boundary

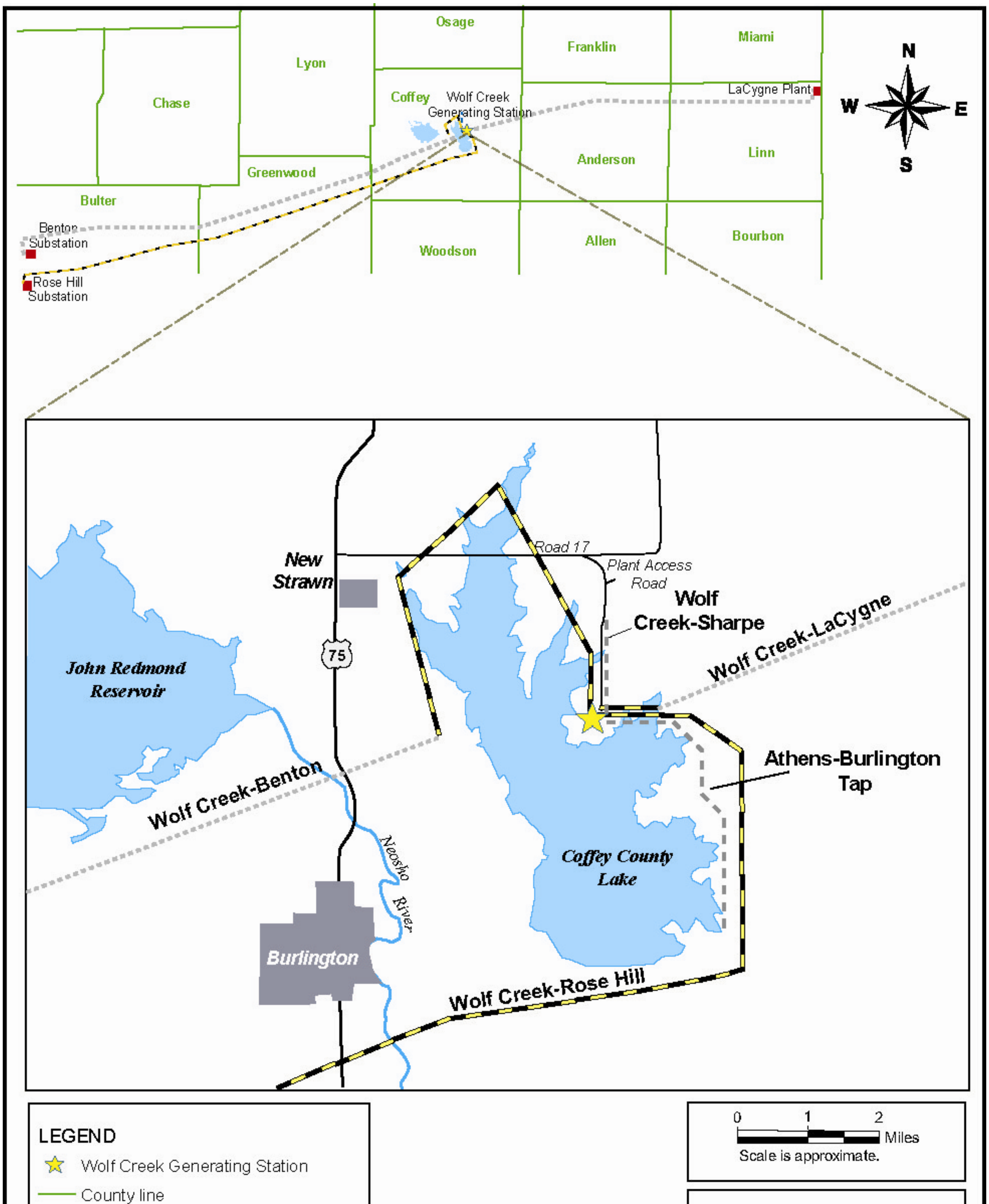


FIGURE 3-2
Transmission Lines

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Kansas Field Office
315 Houston Street, Suite E
Manhattan, Kansas 66502-6172

November 14,2005

Kevin J. Moles
Manager Regulatory Affairs
Wolf Creek Nuclear Generating Station
P.O. Box 411
Burlington, Kansas 66839

RE: WCGS License Renewal

Dear Mr. Moles:

This is in response to your September 16, 2005 letter requesting threatened and endangered species and other resource information relative to your proposal to apply to the U.S. Nuclear Regulatory Commission for a renewal of the operating license for Wolf Creek Nuclear Generating Station in Coffey County, Kansas. The license will expire in March 2025, and the requested renewal would add an additional 20 years to the license. The Generating Station encompasses 9,818 acres, of which only 135 acres are occupied by generating and support facilities. Coffey County Lake, the station's cooling reservoir, occupies another 5,090 acres, and 105 miles of transmission line originate at Wolf Creek. The following information is provided for your consideration.

Your letter accurately described the federally listed threatened and endangered species which may occur in the vicinity of Wolf Creek or its facilities; the bald eagle, Mead's milkweed, Topeka shiner, and Neosho madtom. One candidate species, the Neosho mucket, was also correctly identified as occurring in the Neosho River in the vicinity of the station. The NRC, as the federal licensing agency, must determine whether its action to relicense Wolf Creek's continuing activities may adversely affect any of these species. The potential for impacting these species is briefly discussed in the following.

The bald eagle is known to have nested at Coffey County Lake off and on since 1994, and this species is susceptible to electrocution and mid-air collision with aerial powerlines, poles and transformers. An assessment should be made to ensure all lines conform to guidelines provided in the 1996 Raptor Research Foundation publication, "Suggested Practices for Raptor Protection on Power Lines". This species could also be affected by any chemical or thermal water quality impacts which are detrimental to its fish prey base. The Mead's milkweed is a plant which occurs in unplowed tallgrass prairies. As long as no station activities cause any disruption to this habitat type, there will be no opportunity for adverse effect. The Topeka shiner does not occur in any Coffey County streams, but could be affected by transmission line replacement or construction projects which might involve construction near or over occupied streams in Butler and Greenwood counties. The Neosho madtom and Neosho mucket both occur in the mainstem Neosho River, and could be affected by changes in water quantity and quality, including changes in temperature and in timing, magnitude and duration of flow.

Wildhaber et. al., (2000) found that regulation of Neosho River flows by John Redmond Reservoir had changed short and long-term minimum and maximum flows below the dam and had affected Neosho madtom densities above and below the reservoir. They suggested that changes in reservoir releases could benefit Neosho madtom and other catfishes below the reservoir. Given the need for the project to divert Neosho River flows to augment Coffey County Lake levels, we recommend that your analyses examine Neosho River flows over a range of hydrologic conditions with and without the diversion to ascertain whether the project is adversely or beneficially affecting the Neosho madtom.

If the NRC determines the project may adversely affect any listed species, they should initiate formal consultation with this office pursuant to section 7 of the ESA. If there will be no effect, further consultation is not necessary.

Under the Migratory Bird Treaty Act, construction activities in prairies, wetlands, stream and woodland habitats, and those that occur on bridges (e.g., which may affect swallow nests on bridge girders) that would otherwise result in the taking of migratory birds, eggs, young, and/or active nests should be avoided. Although the provisions of MBTA are applicable year-round, most migratory bird nesting activity in Kansas occurs during the period of April 1 to July 15, although some migratory birds are known to nest outside this period. If the proposed construction project may result in the take of nesting migratory birds, the Service recommends a field survey during the nesting season of the affected habitats and structures to determine the presence of active nests. Our office should be contacted immediately for further guidance if a field survey identifies the existence of one or more active bird nests that cannot be avoided temporally or spatially by the planned construction activities. Adherence to these guidelines will help avoid the take of migratory birds and the possible need for law enforcement action.

Thank you for this opportunity to provide input on your proposal. If you have any additional comments or questions about this project or any of our recommendations, please contact this office again.

Sincerely,

Michael J. LeValley

Michael J. LeValley
Field Supervisor

cc: KDWP, Pratt, KS (Environmental Services)

Wildhaber, M.L., V.M. Tabor, J.E. Whitaker, A.L. Allert, D.M. Mulhern, P.J. Lamberson, and K.L. Powell. 2000. Transactions of the American Fisheries Society. 129:1264-1280.

ATTACHMENT D - CULTURAL RESOURCES CORRESPONDENCE

WOLF CREEK
NUCLEAR OPERATING CORPORATION

Kevin J. Moles
Manager Regulatory **Affairs**

SEP 27 2005

RA 05-0111

Kansas State Historical Society
Cultural Resources Division
6425 SW 6th Avenue
Topeka, KS 66615-1099

Attention: Ms. Jennie Chinn, State Historic Preservation Officer

Reference: Wolf Creek Generating Station, License Renewal

Subject: Request for Information on Historic/Archaeological Resources

Dear Ms. Chinn:

Wolf Creek Nuclear Operating Corporation (WCNOC) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Wolf Creek Generating Station (WCGS). The license expires March 11, 2025. The renewal term would be for an additional 20 years beyond the original license expiration date. As part of the license renewal process, the NRC requires license applicants to "assess whether any historic or archaeological properties will be affected by the proposed project." The NRC will also request an informal consultation with your office at a later date under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470) and the Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that we need to address or any information that we should provide to your office to expedite the NRC consultation.

WCGS is a nuclear-powered steam electric generating facility that began commercial operation on September 3, 1985. WCGS is currently owned by Kansas Gas and Electric Company (47 percent), Kansas City Power & Light Company (47 percent), and Kansas Electric Power Cooperative, Incorporated (6 percent).

The WCGS facility is located in Coffey County, Kansas, approximately 75 miles southwest of Kansas City, and 3.5 miles east of the Neosho River and the John Redmond Reservoir. The WCGS site encompasses approximately 9,818 acres, of which only approximately 135 acres are occupied by generating and support facilities. Coffey County Lake, the station's cooling reservoir, occupies approximately 5,090 acres. Most of the remaining land is made up of rangeland, cropland, native prairie, and forested areas. Attached maps, Figure 2-1 and Figure 2-2, show the location of WCGS in 50- and 6-mile vicinity perspectives. Figure 2-3 and Figure 3-2 show the WCGS boundaries and transmission corridors.

P.O. Box 411 / Burlington, KS 66839 / Phone (620) 364-8831
An Equal Opportunity Employer M/F/HC/VET

RA 05-0111
Page 2 of 2

Although there are three transmission lines that connect WCGS to the regional grid, the primary line relevant to license renewal is the WCGS-to-Rose Hill line. This 345-kilovolt line extends from WCGS southwestward for 98 miles in a 150-foot wide corridor to the Rose Hill Substation southeast of Wichita.

In total, the transmission lines of interest are contained in approximately 105 miles of corridor that occupy approximately 1,900 acres. The corridors pass through land that is primarily agricultural and open range. The areas are mostly remote, with low population densities. The lines cross numerous county, state and U.S. highways after leaving the switchyard. Kansas counties crossed by the transmission lines include Coffey (the location of WCGS), Butler, and Greenwood.

As of 2005. the National Register of Historic Places lists five locations in Coffey County. Of these five locations, two fall within a 6-mile radius of WCGS boundaries: Burlington Carnegie Free Library, 201 N. Third, Burlington and the US Post Office, 107 S. Fourth Street, Burlington. WCNOC does not expect WCGS operations through the license renewal term (an additional 20 years) to adversely affect cultural resources in the area because WCNOC has no plans to substantially alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No additional land disturbance is anticipated in support of license renewal.

We would appreciate receiving your input by October 30, 2005, detailing any concerns you may have about cultural resources on the 9,818-acre WCGS site or along the associated Rose Hill transmission corridor. We would also appreciate a concluding statement that the operation of WCGS over the license renewal term would have no effect on any historical or archeological properties that may occur. WCNOC will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the WCNOC license renewal application.

Please do not hesitate to call Dan Williamson at (620) 364-8831 extension 4609, if you have any questions or require any additional information

Sincerely,

Kevin J. Moles

Kevin J. Moles

KJM/dlw

Attachments (4)

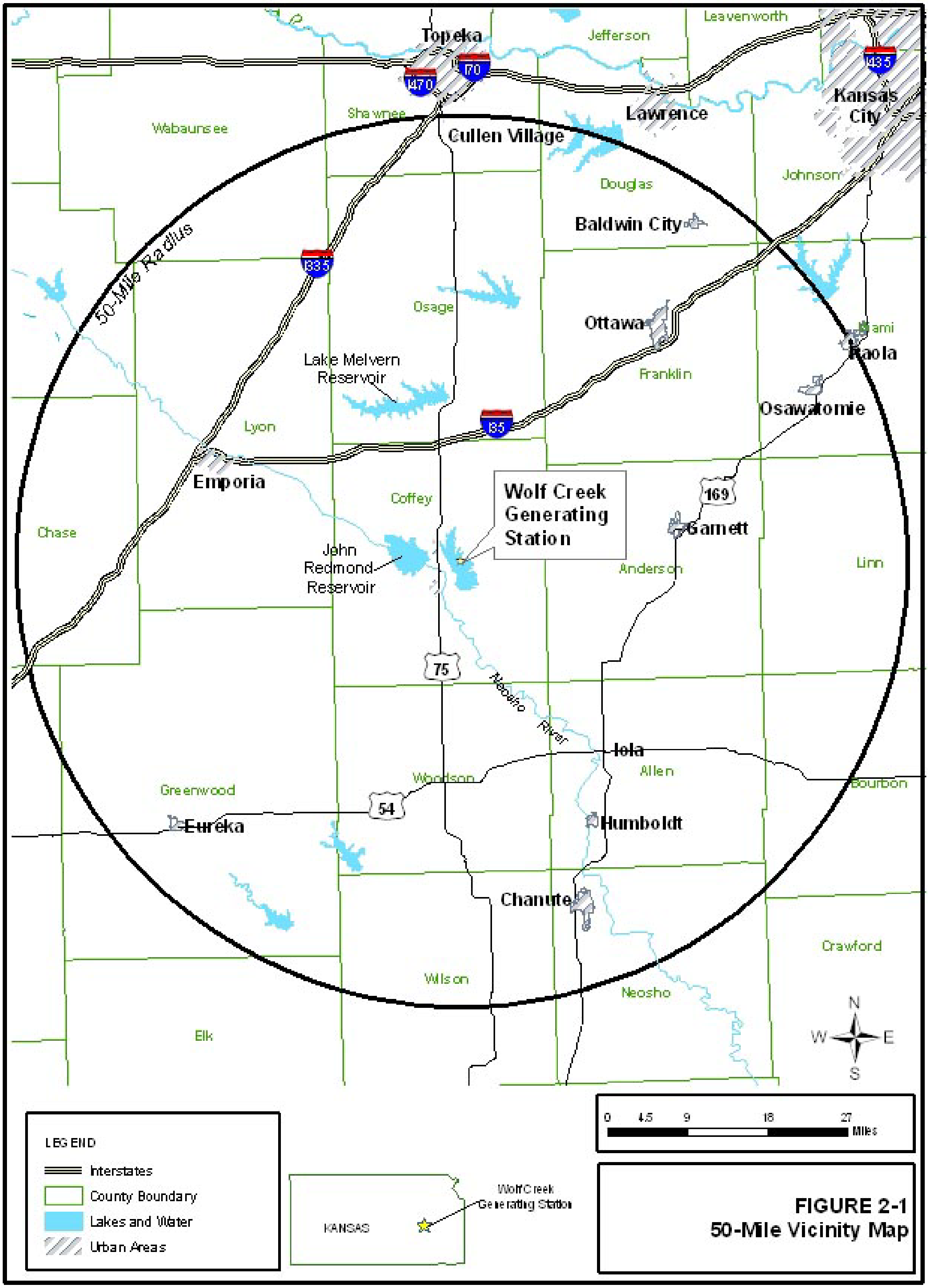
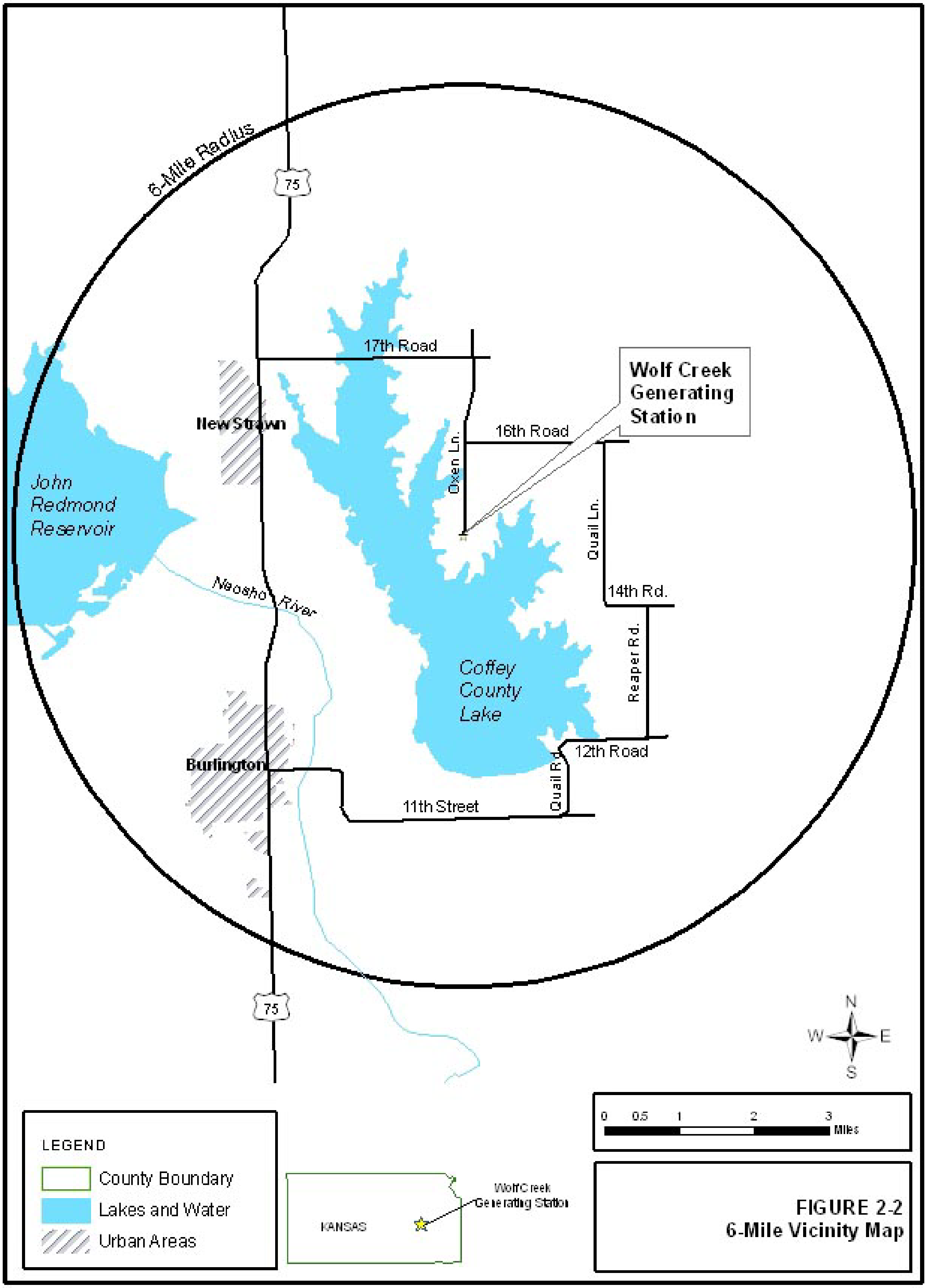


FIGURE 2-1
50-Mile Vicinity Map


6-Mile Radius
75
17th Road
Wolf Creek
Generating
Station
New Strawn
16th Road
Oxen Ln.
John
Redmond
Reservoir
Quail Ln.
14th Rd.
Neosho River
Reaper Rd.
Coffey
County
Lake
12th Road
Burlington
Quail Rd.
11th Street
75
N
W
E
S
0 0.5 1 2 3
Miles
LEGEND
County Boundary
Lakes and Water
Urban Areas
KANSAS
Wolf Creek
Generating Station
FIGURE 2-2
6-Mile Vicinity Map

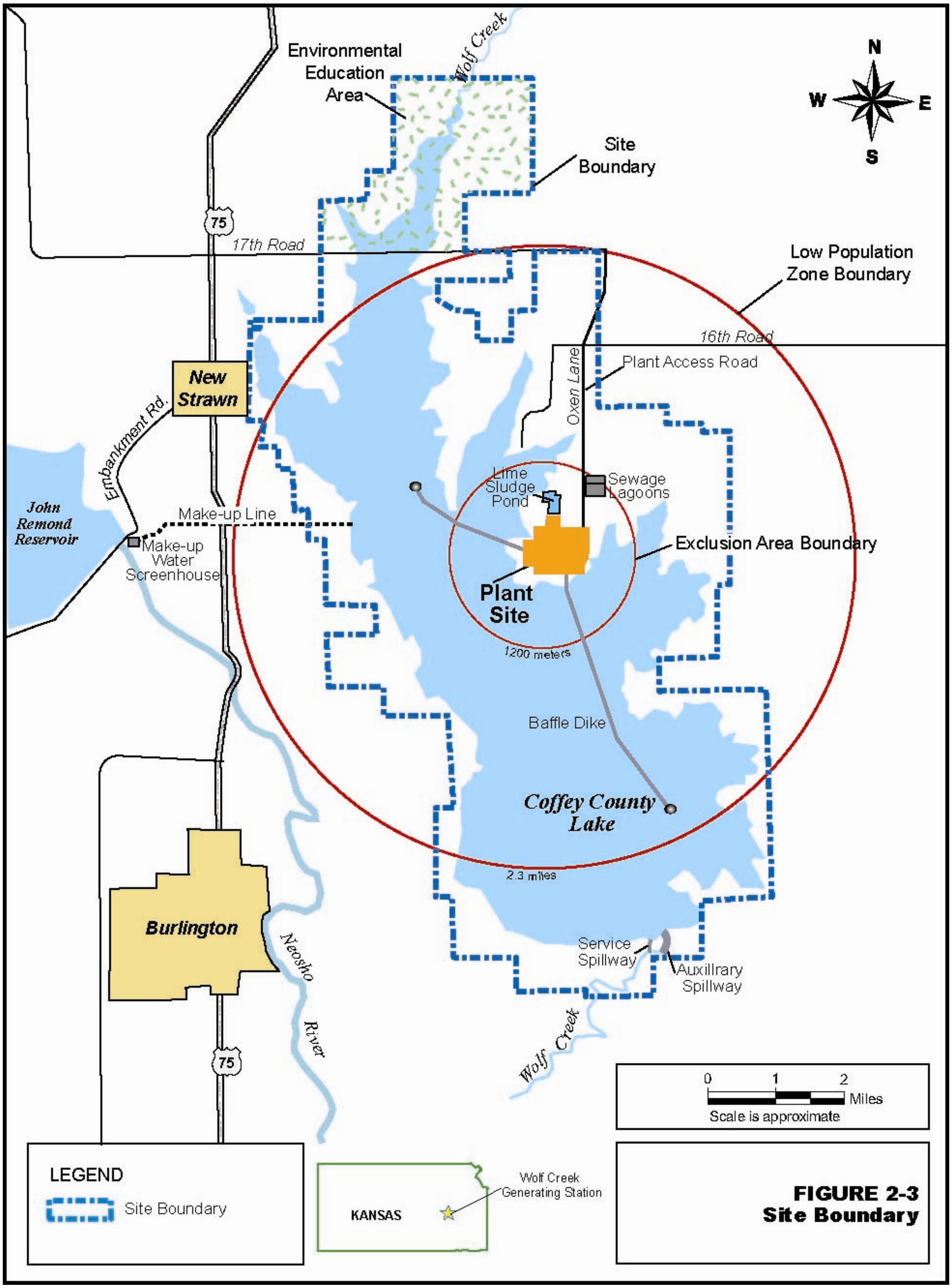


FIGURE 2-3
Site Boundary

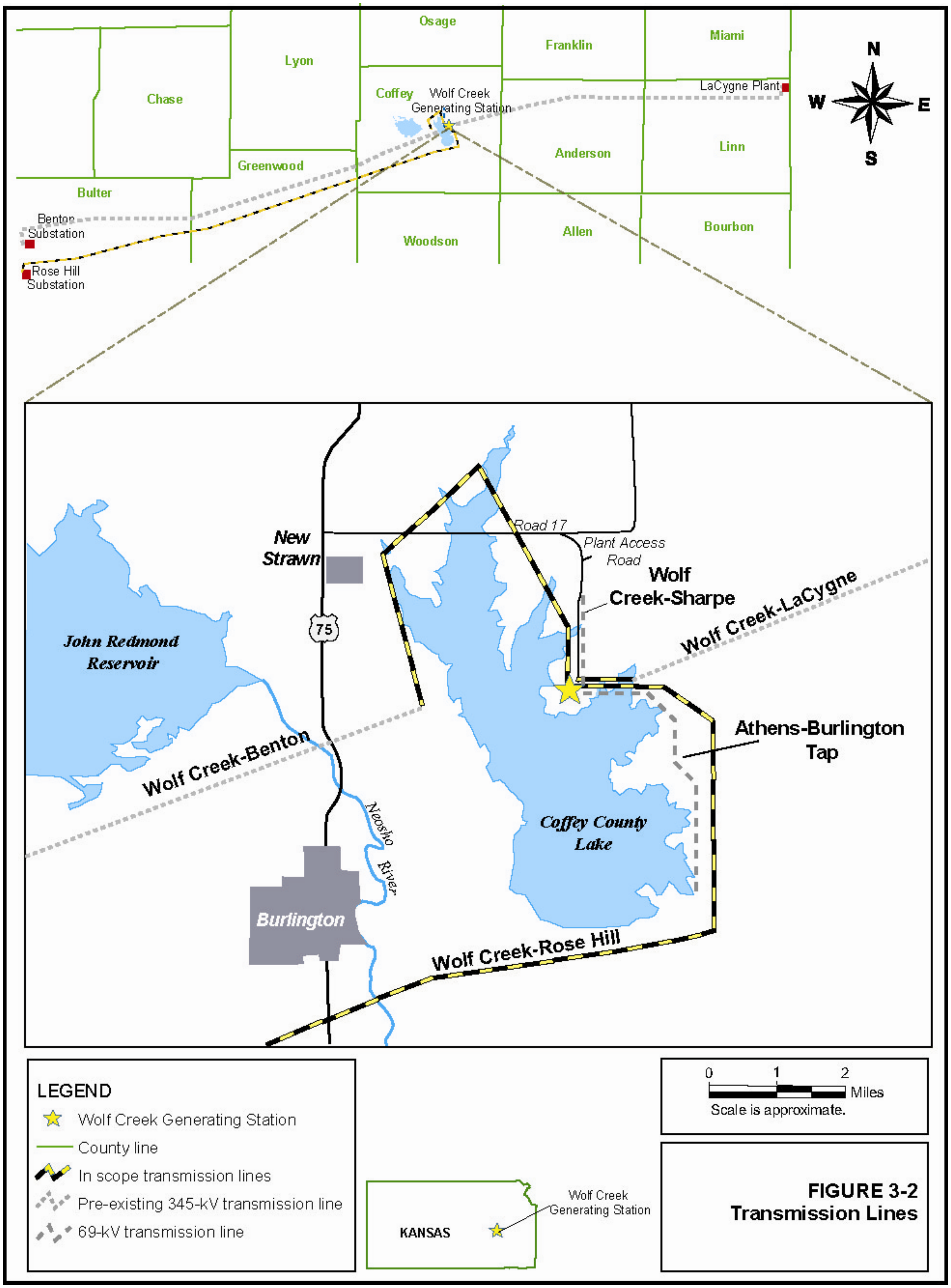


FIGURE 3-2
Transmission Lines

KANSAS

KSR&C No. 05-10-042

Kansas State Historical Society
Jennie Chinn, *Executive Director*

KATHLEEN SEBELIUS, GOVERNOR

05-00550

October 13, 2005

Kevin Moles
Manger, Regulatory Affairs
Wolf Creek Nuclear Operating Corporation
P.O. Box 411
Burlington, Kansas 66839

RE: Wolf Creek Generating Station
License Renewal

Dear Mr. Moles:

In accordance with 36 CFR 800, the Kansas State Historic Preservation Office has reviewed documentation related to renewal of the Wolf Creek Generating Station's operating license. In view of the fact that no substantial alterations to current operations are planned, we conclude that renewal of the station's operating license will have no effect on historic properties as defined in 36 CFR 800. This office has no objection to renewal.

This information is provided at your request to assist you in identifying historic properties, as specified in 36 CFR 800 for Section 106 consultation procedures. If you have questions or need additional information regarding these comments, please contact Tim Weston at 785-272-8681 (ext. 214).

Sincerely,

Jennie Chinn, Executive Director and
State Historic Preservation Officer

Christy Davis
Deputy SHPO

6425 SW Sixth Avenue • Topeka, KS 66615-1099
Phone 785-272-8681 Ext. 205 • Fax 785-272-8682 • Email jchinn@kshs.org • TTY 785-272-8683
www.kshs.org

ATTACHMENT E - MICROBIOLOGICAL ORGANISMS CORRESPONDENCE

WOLF CREEK
'NUCLEAR OPERATING CORPORATION

Kevin J. Moles
Manager Regulatory Affairs

June 3, 2005
RA 05-0064

Bureau of Epidemiology and Disease Prevention
Kansas Department of Health and Environment
1000 SW Jackson, Suite 210
Topeka, KS 66612

Attention: Gail R. Hansen, DVM, MPH, Interim State Epidemiologist

Subject: Wolf Creek Generating Station License Renewal
Request for Information on Thermophilic Microorganisms

Dear Dr. Hansen:

Wolf Creek Nuclear Operating Corporation is currently preparing an application to be sent to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Wolf Creek Generating Station (WCGS). The current operating license expires in 2025. The renewal term would be for an additional 20 years beyond the original license expiration. As shown in Attachment A, WCGS is in Coffey County, Kansas, about 3.5 miles northeast of Burlington.

NRC guidance directs license renewal applicants to consult with the state agency responsible for environmental health to determine if there is a concern about the presence of *Naegleria fowleri* in plant receiving waters. NRC's emphasis is on *Naegleria* because, although humans are generally resistant to infections of Naeglena *fowleri*, once infected, death is generally the end result. Other microorganisms of interest include the enteric pathogens Salmonella, *Shigella*, as well as the Pseudomonas *aeruginosa* bacterium. A less common aquatic microorganism that sometimes occurs in heated waters is Legionella. For your information, an excerpt from the NRC document on the topic of thermophilic organisms is included in Attachment B.

WCGS uses the 5,090-acre Coffey County **Lake** to transfer waste heat from the condensers to the atmosphere. Baffle dikes built in the lake create a longer path between the heated discharge and the cooler intake waters. The baffle dikes create a discharge cove area of approximately 290 acres. During the summer months, water temperatures in the discharge cove, including areas adjacent to the discharge structure, can range from 90°F to 110°F. Water temperature at the intake structure is in the range of 77°F to 81°F. Thermophilic bacteria can exist at temperatures from 77°F to 176°F, but maximum growth occurs from 122°F to **140°F.**

In 1987, WCNOC commissioned a study of *Naegleria fowleri* in the cooling lake. The study did not identify any of the pathogenic species of Naegleria, but did find large populations of the

PO Box 411 / Burlington, KS 66839 / Phone: (620) 364-8831

RA 05-0064
Page 2 of *2*

nonpathogenic species in the discharge cove. No Naegleria were found at the intake structure. It is possible that the nonpathogenic population masked the presence of the pathogenic species. Fishermen are not allowed in the discharge cove as far as the discharge structure and, thus, are not exposed to the warmest water.

WCNOC concludes that the risk from thermophilic organisms to humans using Coffey County Lake is small. This is because (1) although temperatures in the lake can support thermophilic organisms, they are not optimal for propagation of these species, *(2)* fishermen are not allowed in the warmest part of the lake, (3) the 1987 studies did not detect any pathogenic species of Naegleria, **(4)** there have been no incidents of infection reported to WCNOC. WCNOC does not expect conditions in the Coffey County Lake to change appreciably over the license renewal Perm.

We are requesting any information that Kansas Department of Health and Environment may have regarding concerns about thermophilic organisms in Coffey County Lake, including any reported infections that could potentially be attributable to public use of Coffey County Lake. We also seek your concurrence. if appropriate, that there is no significant threat to the public from thermophilic organisms attributable to WCNOC operations.

After your review, we request receiving your input by June 27, 2005. WCNOC will include a copy of this letter and your response in our application for license renewal. Should you have any questions, please contact Robert Hammond at (620) 364-8831, extension 4059.

Sincerely,

Kevin J. Moles

KJM/rlg

Attachment A: Six-mile map of the WCGS vicinity
Attachment B: Section 4.3.6 of the Generic Environmental Impact Statement for License Renewal of Nuclear Plants

RA 05-0064
Attachment A
Page 1 of 2

Attachment A

Six-mile map of the WCGS vicinity

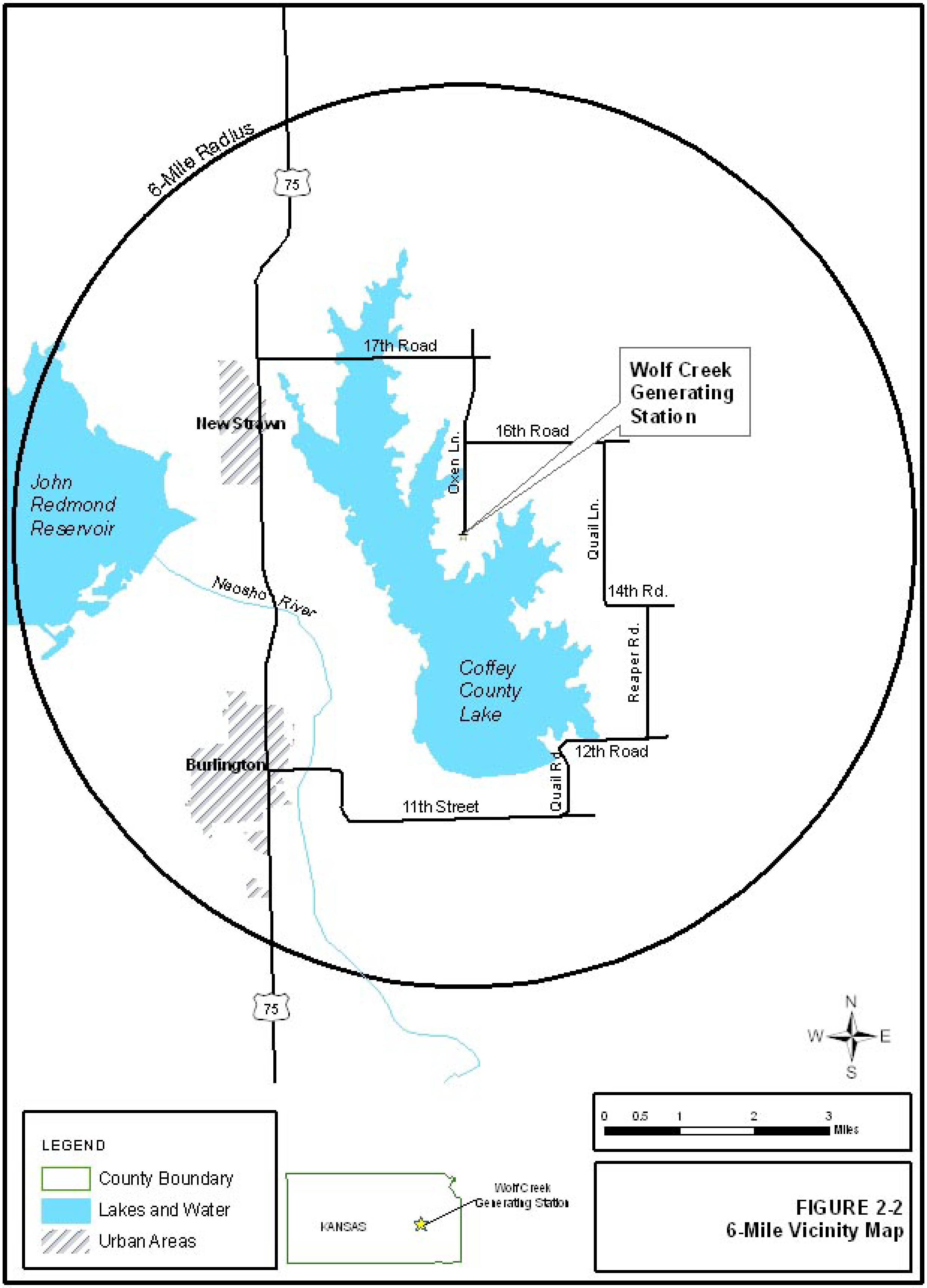


FIGURE 2-2
6-Mile Vicinity Map

Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Nuclear Regulatory Commission Volume 1, Section 4.3.6, "Human health", NUREG 1437, May 1996

cooling towers are large enough to affect local population stability or impair the function of a species within the local ecosystem, consideration of further mitigation is not necessary. Because any contributions of cooling tower collisions to overall bird mortality have already been expressed in species populations, it is not expected that there will be any incremental or cumulative impact on bird populations from cooling tower collision mortality due to relicensing of current nuclear plants. The cumulative effect of bird mortality is further considered with transmission lines in Section 4.5.6.2. Avian mortality resulting from collision with cooling towers is a Category 1 issue.

4.3.6 Human Health

Some microorganisms associated with cooling towers and thermal discharges can have deleterious impacts on human health. Their presence can be enhanced by thermal additions. These microorganisms include the enteric pathogens *Salmonelln* sp. and *Shigella* sp. as well as Pseudomonas *aeruginosa* and the thermophilic fungi (Appendix D). Tests for these pathogens are well established, and factors germane to their presence in aquatic environs are known and in some cases controllable. Other aquatic microorganisms normally present in surface waters have only recently been recognized as pathogenic for humans. Among these are Legionnaires' disease bacteria (*Legionella* sp.) and free-living amoebae of the genera *Naegleria* and *Acanthamoeba,* the causative agents of various, although rare, human infections. Factors affecting the distribution of *Legionella* sp. and pathogenic free-living amoebae are not well understood. Simple, rapid tests for their detection and procedures for their control are not yet available. The impacts of nuclear plant cooling towers and thermal discharges are considered of small significance if they do not enhance the presence of microorganisms that are detrimental to water and public health.

Potential adverse health effects on workers due to enhancement of microorganisms are an issue for steam-electric plants that use cooling towers. Potential adverse health effects on the public from thermally enhanced microorganisms is an issue for the nuclear plants that use cooling ponds, lakes, or canals and that discharge to small rivers. These plants are all combined in the category of small river (average flow less than 2830 m^3/s (100,000 ft^3/s) in Tables 5.18 and 5.19. These issues were evaluated by reviewing what is known about the organisms that are potentially enhanced by operation of the steam-electric plants.

Because of the reported cases of fatal *Naegleria* infections associated with cooling towers, the distribution of these two pathogens in the power plant environs was studied in some detail (Tyndall et al. 1983; see also Appendix D). In response to these various studies (Appendix D), many electric utilities require respiratory protection for workers when cleaning cooling towers and condensers. However, no Occupational Safety and Health Administration (OSHA) or other legal standards for exposure to microorganisms exist at present. Also, for worker protection, one plant with high concentrations of *Naegleria fowleri* in the circulating water successfully controlled the pathogen through chlorination before its yearly downtime operation (Tyndall et al. 1983).

Changes in the microbial population and in the use of bodies of water may occur after the operating license is issued and the application for license renewal is filed. Ancillary factors may also change, including average temperature of water resulting from climatic conditions. Finally, the long-term presence of a power plant may change the natural dynamics of harmful microorganisms within a body of water by raising the level of *N. fowleri,* which are indigenous to the soils. Increased populations of N. *fowleri* may have significant adverse impacts. On entry into the nasal passage of a susceptible individual, *N. fowleri* will penetrate the nasal mucosa. The ensuing infection results in a rapidly fatal form of encephalitis. Fortunately, humans in general are resistant to infection with N. *fowleri.* Hallenbeck and Brenniman (1989) have estimated individual annual risks for primary amebic meningoencephalitis caused by the free living *N. fowleri* to swimmers in fresh water, to be approximately 4×10^{-6}. Heavily used lakes and other fresh bodies of water may merit special attention and possibly routine monitoring for N. *fowleri.*

Thesmophilic organisms may or may not be influenced by the operation of nuclear power plants.:The issue is largely unstudied. However, NRC recognizes a potential health problem stemming from heated effluents. Occupational health questions are currently resolved using proven industrial hygiene principles to minimize worker exposures to these organisms in mists of cooling towers. NRC anticipates that all plants will continue to employ proven industrial hygiene principles so that adverse occupational health effects associated with microorganisms will be of small significance at all sites, and no mitigation measures beyond those implemented during the current term license would be warranted. Aside from continued application of accepted industrial hygiene procedures, no additional mitigation measures are expected to be warranted as a result of license renewal. This is a Category 1 issue.

Public health questions require additional consideration for the 25 plants using cooling ponds, lakes, canals, or small rivers (all under the small river category in Tables 5.18 and 5.19) because the operation of these plants may significantly enhance the presence of thermophilic organisms. The data for these sites are not now at hand and it is impossible to predict the level of thermophilic organism enhancement at any given site with current knowledge. Thus the impacts are not known and are site-specific. Therefore, the magnitude of the potential public health impacts associated with thermal enhancement of N. *fowleri* cannot be determined generically. This is a Category *2* issue.

4.3.7 Noise Impacts

When noise levels are below the levels that result in hearing loss, impacts have been judged primarily in terms of adverse public reactions to the noise. Generally, power plant sites do not result in off-site levels more than 10 dB(A) above background. However, some sites have calculated impacts to critical receptors at this level and above. Noise level increases larger than 10 dB(a) would be expected to lead to interference with outdoor speech communication, particularly in rural areas or low-population areas where the day-night background noise level is in the range of 45–55 dB(A). Generally, surveys around major sources of noise such as large highways and airports have Found that, when the day-night level increases beyond 60 to *65* dB(A) (FICN 1992), noise complaints increase significantly. Noise

05-00353

RODERICK L. BREMBY, SECRETARY

K A N S A S

DEPARTMENT OF HEALTH AND ENVIRONMENT

KATHLEEN SEBELIUS, GOVERN

June 22,2005

Kevin J. Moles
Manager Regulatory Affairs
Wolf Creek Nuclear Operating Corporation
P.O. Box 411
Burlington, KS 66839

Dear Mr. Moles:

The Kansas Department of Health and Environment, Bureau of Epidemiology and Disease Prevention (KDHE/BEDP) is responsible for collecting statewide information on infectious diseases. Besides the reportable diseases and conditions (list enclosed), all unusual diseases and all outbreaks of disease are to be reported for further investigation. There have not been any reports of illness from thermophilic pathogens associated with the Coffey County Lake or with recreation in the area.

It would be unlikely that fish caught and properly prepared would be a source of illness from a thermophilic pathogen described. Since swimming in Coffey Lake are not allowed, I do not believe that there is a likely threat from pathogens to the public's use of the lake. If you have any questions, please feel free to contact me at (785) 296-1127.

Sincerely,

Gail R. Hansen, DVM, MPH
State epidemiologist
KDHE

DIVISION OF HEALTH
Bureau of Epidemiology and Disease Prevention
Epidemiologic Services Section
CURTIS STATE OFFICE BUILDING, 1000 SW JACKSON ST., STE. 210, TOPEKA, KS 66612-1274
Voice 785-296-1127 Fax 785-291-3775 http:llwww.kdhe.state.ks.us
Disease Reporting & Public Health Emergencies:
Toll Free Phone 1-877-427-7317 Toll Free FAX 1-877-427-7318

2004 **REPORTABLE DISEASES IN KANSAS** for health care providers, hospitals, and laboratories
(K.S.A. 65-118, 65-128, 65-6001 through 65-6007, **K.A.R. 28-1-2, 28-1-4,** and 28-1-18)

☎ *Bold* --Telephone report within four hours of *suspect* or *confirmed* cases to KDHE toll free at 1-877-427-7317.
① Isolates must be sent to: Division of Health and Environmental Laboratories
Forbes Field, Building #740, Topeka, KS 66620-0001
Phone: (785) 296-1636

8 DISEASES REQUIRING SPECIAL ATTENTION ☎

Anthrax ☎
Botulism ☎
Cholera ☎
Measles (rubeola) 8
Meningitis, bacterial ☎
Meningococcemia ①☎
Mumps ☎
Pertussis (whooping cough) ☎
Plague ☎
Poliomyelitis ☎
Q Fever ☎
Rabies, human and animal ☎
Rubella, including congenital rubella syndrome ☎
Severe Acute Respiratory Syndrome (SARS) ①☎
Smallpox ☎
Tuberculosis, active disease ① ☎
Viral hemorrhagic fever ☎
Escherichia coli O157:H7
(and other enterohemorrhagic, enteropathogenic and enteroinvasive E. ***coli)*** ①
Salmonellosis, including typhoid fever ①
Shigellosis ①
Streptococcal invasive disease, Group *A* from ***Streptococcus*** or ***Streptococcus pneumoniae*** ①

Acquired Immune Deficiency Syndrome (AIDS)
Amebiasis
Anthrax ☎
Botulism ☎
Brucellosis
Campylobacter infections
Chancroid
***Chlamydia** trachomatis* genital infection
Cholera ☎
Cryptosporidiosis
Cyclospora infection
Diphtheria
Ehrlichiosis
Encephalitis, infectious (includes West Nile virus)
Escherichia coli *O157:H7*
(and other enterohemorrhagic, enteropathogenic and enteroinvasive *E. coli)* ①
Giardiasis
Gonorrhea
Haemophilus influenza, invasive disease
Hantavirus Pulmonary Syndrome
Hemolytic uremic syndrome, postdiarrheal
Hepatitis, viral (acute and chronic)
Hepatitis B during pregnancy
Human Immunodeficiency Virus (HIV) (includes Viral Load Tests)
Legionellosis
Leprosy (Hansen disease)
Listeriosis
Lyme disease
Malaria
Measles (rubcola) ☎
Meningitis, arboviral (includes West Nile virus)
Meningitis, bacterial ☎
Meningococcemia ①☎
Mumps ☎
Pertussis (whooping cough) ☎
Plague ☎
Poliomyelitis ☎
Psittacosis
Q Fever ☎
Rabies, human and animal ☎
Rocky Mountain Spotted Fever
Rubella, including congenital rubella syndrome ☎
Salmonellosis, including typhoid fever ①
Severe Acute Respiratory Syndrome (SARS) ①☎
Shigellosis ①
Smallpox ☎
Streptococcal invasive disease, Group A from
Streptococcus or ***Streptococcus pneumoniae*** ①
Syphilis, including congenital syphilis
Tetanus
Toxic shock syndrome. streptococcal and staphylococcal
Trichinosis
Tuberculosis, nctive disease ①☎
Tuberculosis, latent infection
Tularemia
Varicella (chickenpox)
Viral ***hemorrhagic fever*** ☎
Yellow fever

In addition, laboratories **must** report:
- Viral load results of reportable diseases
- ALL blood lead levels, as of 1212002 (KCLPPP/ABLES)
- CD4+ T-lymphocyte count < 500/ µl or CD4+ T-lymphocytes <29% of total lymphocytes

Outbreaks, unusual occurrence of any disease, exotic or newly recognized diseases, and suspect acts of terrorism should be reported within 4 hours by telephone to the Epidemiology **Hotline:** 1-877-427-7317

Mail or fax reports to your local health department **or** to:
Bureau of Epidemiology & Disease Prevention - Disease Surveillance, 1000 SW Jackson, Suite 210 Topeka, KS 66612-1274
Fax: 1-877-427-7318 (toll free)

ATTACHMENT F - SEVERE ACCIDENT MITIGATION ALTERNATIVES ANALYSIS

TABLE OF CONTENTS

Section Page

List of Tables

Acronyms Used in Attachment F

ABWR	advanced boiling water reactor
AFW	auxiliary feedwater
ATW	anticipated transient without
ATWS	anticipated transient without scram
BE	basic events
BWR	boiling water reactor
CCF	common cause failure
CCDP	conditional core damage probability
CCP	centrifugal charging pump
CCW	component cooling water
CDF	core damage frequency
CIF	containment isolation failure
CLI	cold leg injection
CR	control room
CRD	control rod drive
CS	containment spray
CST	condensate storage tank
DG	diesel generator
ECCS	emergency core cooling system
EDG	emergency diesel generator
EPRI	electric power research institute
EPZ	emergency planning zone
ESF	engineered safety feature
F&O	fact and observation
FLB	feedwater line break
FP	fire protection
FPS	fire protection system
HEP	human error probability
HCLPF	high confidence of low probability of failure
HPCI	high pressure coolant injection
HPI	high pressure injection
HPSI	high pressure safety injection
HI	human interaction
HRA	human reliability analysis
HVAC	heating ventilation and air-conditioning system
INEEL	Idaho National Engineering and Environmental Laboratory
IE	initiating event
IPE	individual plant examination
IPEEE	individual plant examination – external events
ISL	interfacing systems LOCA
ISLOCA	interfacing system LOCA
LCF	late containment failure
LERF	large early release frequency

Acronyms Used in Attachment F

LOCA	Loss-of-coolant accident
LOOP	loss of off-site power
LPSI	low pressure safety injection
MAAP	modular accident analysis program
MACCS2	melcor accident consequences code system, version 2
MACR	maximum averted cost-risk
MCC	motor control center
MCR	main control room
MET	meteorological
MFW	main feedwater
MMACR	modified maximum averted cost-risk
MOV	Motor operated valve
MSIV	main steam isolation valve
NCF	no containment failure
NCP	Normal charging pump
NPSH	net positive suction head
NRC	U.S. nuclear regulatory commission
OECR	off-site economic cost risk
OPA	operator action
OSP	off-site power
PDP	positive displacement charging pump
PMP	probable maximum precipitation
PRA	probabilistic risk analysis
PSA	probabilistic safety assessment
PORV	pressure operated relief valve
PWR	pressurized water reactor
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RDR	real discount rate
RHR	residual heat removal
RHRSW	residual heat removal service water
RPV	reactor pressure vessel
RRW	risk reduction worth
RWST	refueling water storage tank
SAMA	severe accident mitigation alternative
SBO	station blackout
SGTR	steam generator tube rupture
SI	safety injection
SMA	seismic margins analysis
SNUPPS	standardized nuclear unit power plant system
SRP	standard review plan
SRV	safety relief valve
SSC	structures, systems, and components
SSE	safe shutdown equipment

Acronyms Used in Attachment F

SW	service water
SWS	service water system
TD	turbine driven
WCGS	Wolf Creek Generating Station
WCNOC	Wolf Creek Nuclear Operating Corporation
WOG	Westinghouse owners group

Attachment F
Severe Accident Mitigation Alternatives

The severe accident mitigation alternatives (SAMA) analysis discussed in Section 4.20 of the Environmental Report is presented below.

F.1 METHODOLOGY

The methodology selected for this analysis is based on the NEI SAMA Analysis Guidance Document (NEI 2005) and involves identifying SAMA candidates that have the highest potential for reducing plant risk and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. The metrics chosen to represent plant risk include the core damage frequency (CDF), the dose-risk, and the off-site economic cost-risk. These values provide a measure of both the likelihood and consequences of a core damage event. The SAMA process consists of the following steps:

- Wolf Creek Generating Station (WCGS) Probabilistic Safety Assessment (PSA) Model – Use the WCGS Internal Events PSA model as the basis for the analysis (Section F.2). Incorporate external events contributions as described in Section F.5.1.8.

- Level 3 PSA Analysis – Use WCGS Level 1 and 2 Internal Events PSA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 PSA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section F.3).

- Baseline Risk Monetization – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of the unmitigated WCGS severe accident risk. This becomes the maximum averted cost-risk (MACR) that is possible (Section F.4).

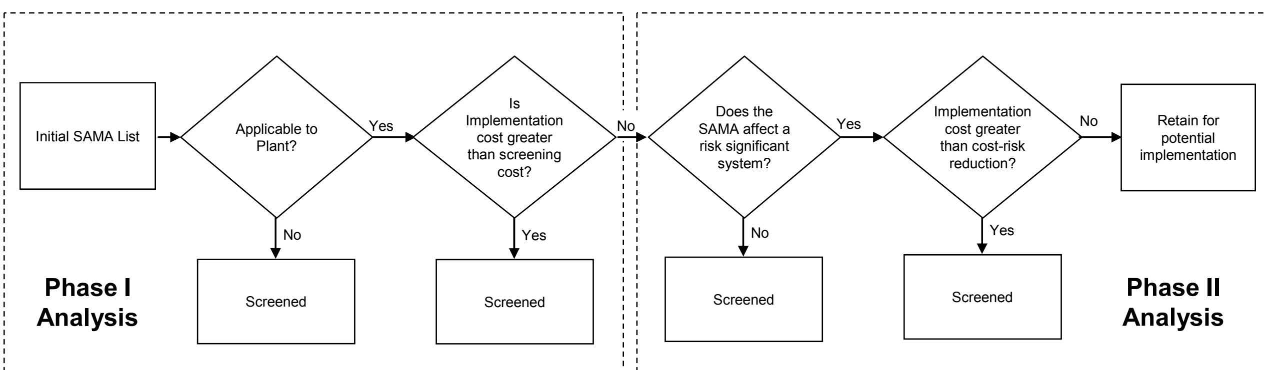
- Phase I SAMA Analysis – Identify potential SAMA candidates based on the WCGS PSA, Individual Plant Examination – External Events (IPEEE), and documentation from the industry and NRC. Screen out Phase I SAMA candidates that are not applicable to the WCGS design or are of low benefit in pressurized water reactors (PWRs) such as WCGS, candidates that have already been implemented at WCGS or whose benefits have been achieved at WCGS using other means, and candidates whose estimated cost exceeds the possible MACR (Section F.5).

- Phase II SAMA Analysis – Calculate the risk reduction attributable to each remaining SAMA candidate and compare to a more detailed cost analysis to identify the net cost-benefit. PSA insights are also used to screen SAMA candidates in this phase (Section F.6).

- Uncertainty Analysis – Evaluate how changes in the SAMA analysis assumptions might affect the cost-benefit evaluation (Section F.7).

- Conclusions – Summarize results and identify conclusions (Section F.8).

The steps outlined above are described in more detail in the subsections of this attachment. The graphic below summarizes the high-level steps of the SAMA process.



F.2 WCGS PSA MODEL

The Level 1 Internal Events PSA Model used for the SAMA analysis was the most recent internal events risk model, 2002 PSA Update, that contains modeling of all plant changes implemented up to 12/31/2002, uses failure and unavailability data to the same date, and resolves nearly all industry peer review comments on the 1998 revision of the model. Due to ongoing projects that influenced the official issuance of the 2002 PSA Update, the model itself was not finalized until March of 2006. Due to resource limitations, the internal flooding evaluation was not included in the most recent PSA model update. The internal flooding evaluation was requantified in 1996 with one area flooding event added; but for the most part reflects plant configuration and data as utilized for the original PSA model developed for the Individual Plant Examination (IPE) (1992 submittal). Section 5.1.7 discusses how Internal Flooding is addressed in the SAMA analysis.

The original Wolf Creek Generating Station (WCGS) Probabilistic Risk Assessment (PRA) model was generated in order to satisfy the requirements of NRC Generic Letter 88-20 for performance of an Individual Plant Examination (IPE). The IPE Summary Report (WCNOC 1992) reflects the general content and results of the original WCGS PRA.

The PRA was also generated to provide a risk based tool for evaluation of plant design and procedural changes and for guidance in addressing the severe accident management issue in the future. In this regard, the PRA was developed with the intent that it be updated and revised periodically to reflect plant design and/or procedure changes, or to incorporate changes resulting from resolution of comments or questions regarding model construction and/or modeling assumptions, or advances in analysis techniques and software.

F.2.1 PRA MODEL UPDATE HISTORY

In mid-1994, initial quantification began for the Fire Risk Analysis portion of the Individual Plant Examination for External Events (IPEEE). Quantification for the Fire Risk Analysis involved determination of a Conditional Core Damage Probability (CCDP) value for a large number of plant areas, with failure of the modeled equipment in those areas due to a postulated fire. Re-quantification to determine CCDP values was progressing at a very slow pace with the PRA software used for the IPE PRA model.

This was deemed unacceptable due to the large number of scenarios to be considered and the time required for performance of each quantification.

Therefore, the decision was made to convert the WCGS PRA model to a PRA computer software package which could support calculation of CCDP values for a large number of scenarios by quantification of the appropriate event tree(s) in a rapid manner. Conversion of the WCGS PRA model to the NUPRA code (NUS Corporation) began in late November, 1994. Conversion of the WCGS PRA model was not a "one for one" process. NUS Corporation (now Scientech) PRA personnel performed a review of the original WCGS PRA model as a part of the technology transfer process of converting to the NUPRA code. A number of changes to the WCGS model were implemented at the time of model conversion in response to recommendations by NUS personnel. For the most part, these changes were recommended, or required, to accommodate differences between the Westinghouse and NUPRA software packages. Some changes were also made to allow for utilization of desirable features in the NUPRA code, which were not available with the Westinghouse software.

As a result of questions in the NRC Request for Additional Information (RAI) regarding the IPE Submittal, two major model changes were made. First, the Common Cause Failure events were revised to utilize generic common cause factor values. Second, the Human Reliability Analysis (HRA) values were revised to address a number of RAI comments specific to the HRA performed for the original WCGS PRA. The core damage frequency resulting from incorporation of these changes into the model was 6.19E-05/year. These changes are presented and described in letters ET 96-0034 and ET 96-0068 sent from Richard A. Muench to the NRC (WCNOC 1996a, WCNOC 1996b).

A final review of the new HRA values resulted in a revision to several of the HRA events. In addition, the final HRA resolved a number of instances where dependencies between HRA actions were not explicitly accounted for in the PRA model. These HRA action dependencies were described in letter ET 96-0034. It was estimated in this letter that an explicit modeling of these HRA action dependencies would result in a CDF increase of approximately 4 percent over the 6.19E-05/year value. With the final HRA values and the inclusion of explicit HRA action dependencies, the resultant CDF value was 6.31E-05/year.

Additionally, with development of the Safety Monitor configuration risk determination tool, a number of changes were made to the fault tree models to accommodate the Safety Monitor format and purpose. Changes made include replacement of all initiating event (IE) house events with the initiating event basic event itself, setting all test and maintenance type events to a value of zero, and addition of a number of configuration house events to reflect the more common or potentially more risk significant configurations for a number of systems. These changes were described and discussed in the Safety Monitor evaluation (WCNOC 1997).

The WCGS PRA model was subsequently updated using an end of 1998 design and procedure change freeze date. Changes associated with the 1998 update included update of plant specific component failure and unavailability values, update of plant specific and generic initiating event frequency values, update of Human Interaction (HI) failure rates, incorporation of applicable plant design changes [i.e., replacement of the positive displacement charging pump (PDP) with a normal charging pump (NCP)], and fault tree modeling of a number of low safety significance systems previously represented in the model as a single basic event. Quantification of the 1998 PRA model resulted in a CDF value of 5.479E-05/year. The 1998 PRA model did not include an update to the internal flooding risk evaluation, nor does the CDF value indicated include any contribution from internal flooding.

Changes associated with the 2002 update included update of plant specific component failure and unavailability values, update of plant specific and generic initiating event frequency values, update of HI failure rates, utilization of the WOG 2000 Reactor Coolant Pump (RCP) Seal Leakage model, incorporation of applicable plant design changes [i.e., automatic opening of component cooling water (CCW) isolation valves to the residual heat removal (RHR) heat exchangers on switchover to ECCS recirculation mode], and incorporation of resolution to a number of Facts & Observations (F&Os) from the WOG Peer Review of the WCGS PRA model.

F.2.2 PSA MODEL UPDATE MILESTONES

Key milestones and results for the development of the WCGS PSA model are as follows:

Date	Milestone
Sept. 1992	Final comparison to the Callaway Plant PSA model under Standardized Nuclear Unit Power Plant System (SNUPPs) IPE
Sept. 1992	Original PSA (4.2E-05 CDF/rx yr) submitted in response to NRC Generic Letter 88-20 requirement to perform an IPE
Early 1995	Conversion from Westinghouse PSA Software to Scientech (NUS) PSA Software
June 1995	Individual Plant Examination of External Events (IPEEE) submitted to the NRC
July 1996	Response to NRC RAI on IPE resulted in July 1996 Quantification (6.3E-05 CDF/rx yr)
Nov. 1996	IPE Safety Evaluation Report (SER) received from the NRC
Dec. 1997	Implementation of the Safety Monitor™ at WCGS included development of a large early release frequency (LERF) top logic model
Feb. 1998	Self-Assessment to identify PSA weaknesses and guide update priorities
March 1998	Fire Risk Evaluation Re-Analysis (5.92E-06 CDF/rx yr)
July 1998	Comprehensive PSA Model - 98 Update (5.48E-05 CDF/rx yr)
Dec. 1999	Limited scope Shutdown modes PSA model developed as part of the Safety Monitor™ risk evaluation tool
Feb. 2000	IPEEE SER received from the NRC
Aug. 2000	WOG Peer Review of 1998 PSA Model
Nov. 2001	WOG Peer Review Final Report issued on WCGS PSA Model
Oct. 2003	Modified 1998 Model for Risk-Informed Tech. Spec. change – Additional AC Power Source
March 2006	Comprehensive PSA Model - 2002 Update (2.985E-05 CDF/rx yr)
June 2006	Safety Monitor™ LERF 2002 Update (2.54E-06 LERF/rx yr) (This work is included in the 2002 PSA Update model, but the project signoff occurred after the model freeze date.)
Late 2006	Incorporation of Sharpe Station (a nearby off-site AC power source) (not included in the baseline SAMA model)

F.2.3 1998 WCGS PSA MODEL UPDATE DETAILS

The 1998 model update was a comprehensive update and included significant changes and additions.

Notable Initiating Event Frequencies

Initiating Event / Frequency	IPE	1998 Update
Transient With Main Feedwater (MFW)	4.30	1.17
Transient Without MFW	0.19	0.17
Loss of Offsite Power	5.10E-02	2.84E-02
Steam Generator Tube Rupture (SGTR)	1.10E-02	5.90E-03

(Changes based on Industry and WCGS plant-specific experience)

F.2.3.1 COMPUTED INITIATING EVENT FREQUENCIES

Imported during final Quantification Process as Fault Tree Solution (cutset file)

- Loss of Component Cooling Water
- Loss of All Service Water
- Loss of 125 VDC Busses: NK01 and NK04

Allows impact of Component(s) Out-of-Service to be reflected in both the:

- Initiating Event Frequency
- Event Mitigation Probability

Event Tree Changes

- Event Trees changed to more readily accept Initiating Event cutset files and Train level system recovery values:
- Loss of Component Cooling Water
- Loss of All Service Water

- Loss of RCP Seal Cooling
- Interfacing Systems LOCA (ISLOCA) re-evaluation using NUREG/CR-5928 and NUREG/CR-5744
- Anticipated transient without scram (ATWS) Event Tree revised to reflect WCAP-11992 ATWS evaluation structure

F.2.3.2 REACTOR PROTECTION FAULT TREES

Added:

- Logic for failure of automatic actuation of Auxiliary Feedwater Pumps on Steam Generator Level
- Reactor trip failure due to mechanical control rod binding

Electrical Power System Fault Trees

- New Non-Safety AC and DC Power Fault Trees
- Consolidates failure logic located in several higher level system fault trees
- Swing Battery Chargers included in Loss of 125 VDC Bus Initiating Event fault trees
- Improved Dependency/Logic Loop break modeling

F.2.3.3 ESSENTIAL SERVICE WATER / NORMAL SERVICE WATER SYSTEM FAULT TREES

Added:

- ESW/SW System failure caused by Frazil icing conditions/warming line failures
- ESW T&M Unavailability event when Service Water back-up is not feasible (e.g., ESW drained)

F.2.3.4 AFW AND CCW SYSTEM FAULT TREES

Auxiliary Feedwater System

- Added undetected internal valve failure for condensate storage tank (CST) AFW pumps suction header manual isolation valve APV0015

Component Cooling Water System

- Added T&M Unavailability event for entire CCW Train OOS (previously T&M events modeled at CCW pump level only)

F.2.3.5 EMERGENCY CORE COOLING/ RCP SEAL COOLING SYSTEM FAULT TREES

- Replaced PDP With NCP
- Changed valves BGHV8357A/B to MOVs
- Added undetected internal valve failure for refueling water storage tank (RWST) ECCS pumps suction header manual isolation valve BNV0011
- Revise Accumulator Fault Tree in accordance with WCAP-15049 (Increased CT from 1 hr to 24 hrs)
- Added Common Cause failure event for CCPs & safety injection (SI) Pumps due to gas entrainment/binding

F.2.3.6 NEW FAULT TREES

Previously modeled as a single system level failure event (black box)

- Circulating Water System
- Condenser Vacuum System
- Fire Protection System (FPS)

- Closed Cooling Water System

F.2.3.7 DATA ANALYSIS CHANGES

- Several generic data values
- Plant specific data updated through 1994
- Major active risk significant component groups
- Incorporated Maintenance Rule component failure history subsequent to 1994
- Parameter data file developed for rapid update of event values in basic event data (BED) file and fault trees
- Incorporation of new NRC Common Cause factors as appropriate
- Generic common cause failure (CCF) retained when NRC CCF database applicability entries were sparse

F.2.3.8 SAFETY MONITORTM TIE-IN

Top logic fault tree developed to import model into the Safety Monitor. Top logic fault tree translates the Event Tree core damage sequences into a fault tree logic structure.

F.2.4 2002 WCGS PSA MODEL UPDATE DETAILS

The 2002 model update was a comprehensive update and included significant changes and additions. Discussion of the LERF update used for the SAMA reviews is also listed here. High level summary results are shown in Table F.2.3, Core Damage Frequency By Initiating Event, and Table F.2.4, Core Damage Frequency By Event Tree Sequence (> 91% Total CDF).

Notable Initiating Event Frequency Changes

Initiating Event	2002 Update	1998 Update
Large LOCA	2.78E-08	5.00E-04

Initiating Event	2002 Update	1998 Update
Medium LOCA	1.44E-07	1.00E-03
* Loss of All Service Water	8.61E-08	7.20E-05
* Loss of Vital DC Bus NK01	1.23E-07	9.30E-03
* Loss of Vital DC Bus NK04	1.51E-07	9.30E-03
Very Small LOCA	1.25E-06	1.30E-02
* Loss of Component Cooling Water	2.14E-04	2.50E-05

* Results from quantification of the associated Initiating Event Fault Tree Model. Initiating Event Frequency is input into the quantification process as a cutset file, not as a scalar value.

F.2.4.1 AUXILIARY FEEDWATER SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update, addition of configuration events for Motor Driven Auxiliary FeedWater (MDAFW) pumps cross-tie line, elimination of logic for using ruptured steam generator for plant cooldown following a SGTR, add failure of AFW pump suction header low pressure transmitters, removed pre-initiator HRA events for AFW pump discharge valves, and added pre-initiator HRA event for failure to remove steam dump valve isolation.

F.2.4.2 CIRCULATING WATER SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update; addition of common cause events for CW pump “failure to run”, addition of events for failure of CW pump discharge motor operated valves and change warming line isolation valve from a motor operated valve to a manually operated valve.

F.2.4.3 CLOSED COOLING WATER SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update; replacement of the INIT-LSP and XXNB-LOOPOWER-SA events with associated logic transferred from the RPSCCW fault tree; combining pump and heat exchanger failure events under a single gate representing failure of the associated train; and use of a single operator action (using a screening value) representing alignment of a standby train following failure of the operating train instead of two operator actions – one for failure to align the standby train pump and a second for failure to align the standby train heat exchanger.

F.2.4.4 COMPONENT COOLING WATER SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update, and modified global common cause CCW pump start and run failure logic.

F.2.4.5 CONDENSER AIR REMOVAL SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update; addition of common cause events for CV and Seal Water pumps “failure to run” and “failure to start” for the standby pumps, addition of events for failure of CV and Seal Water pumps circuit breakers, and addition of external transfer from the Service Water System as a support system for seal water heat exchanger cooling.

F.2.4.6 CONTAINMENT SAFEGUARDS SYSTEMS NOTEBOOK

Primary changes include: data and common cause factors update, removal of the hydrogen mixing fans from the containment cooling fault tree, and addition of a Containment Cooling fault tree model (CCSSWA) representing failure of an ESW warming line heat source.

F.2.4.7 ELECTRICAL POWER SYSTEMS NOTEBOOK

Primary changes include: data and common cause factors update; addition of configuration events for EDG in standby or operating, addition of configuration events for outside air temperature < 79F when EDG room forced ventilation not required, EDG mission times adjusted for SBO and non-SBO events, and addition of spare battery chargers along with configuration events for spare battery charger alignments.

F.2.4.8 EMERGENCY CORE COOLING SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update, deletion of RWST Refill fault tree, added plugging/internals failure for ECCS angle throttle valves, added justification for not including switchover to hot leg recirculation in the LPR fault tree, added recirculation diversion flow path via EJHV8816A/B for Large LOCA, added recirculation diversion flow paths back to the RWST from the ECCS pumps suction lines, and added system dependency matrices.

F.2.4.9 ESSENTIAL SERVICE WATER SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update, and removal of “failure to close on demand” failure modes for EFHV0037/0038.

F.2.4.10 FIRE PROTECTION SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update; addition of battery failure events for the diesel driven fire pump along with Assumption 8 regarding mission time determination; correction of check valve flow diversion logic; and the addition of Assumption 9 regarding “fail safe” operation of diesel fire pump controller.

F.2.4.11 INSTRUMENT AIR SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update; correction of logic under gate GIA-192; add assumption 10 concerning representation of central chilled water system failure by a single failure event and add wording to Assumption 7 regarding inclusion of start failure events for a running compressor.

F.2.4.12 PSA MAIN FEEDWATER / CONDENSATE SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update; and addition of INIT-FLB inside containment under GMFW120 and outside containment under GMFW122.

F.2.4.13 MISCELLANEOUS SYSTEMS NOTEBOOK - PRIMARILY PRESSURIZER PRESSURE RELIEF AND MAIN STEAM/FEEDWATER

Other fault trees not directly associated with a specific system or function are also described and presented in this calculation. Primary changes include: data and common cause factors update, added flag event to indicate that initiation of feed portion of feed and bleed function will result in automatic ESW start, added feedwater isolation failures to faulted steam generator for an INIT-FLB, deleted common cause failure of nitrogen backup tanks, added pre-initiator events for failure to remove steam dump valve isolation, and added events and disallowed event combinations associated with incorporation of the WOG 2000 RCP Seal Leakage modeling.

F.2.4.14 REACTOR COOLANT PUMP SEAL COOLING NOTEBOOK

Primary changes include: data and common cause factors update, removed a loss of CCW as resulting in a loss of RCP seal cooling, removed NCP room cooling dependency, removed alignment options for CCPs to normal charging/seal injection – only PBG05B is modeled for normal seal injection, modification and update of offsite AC power, loss of component cooling water and loss of service water recovery/non-recovery events and values, and addition of support system dependency matrix.

F.2.4.15 REACTOR PROTECTION SYSTEM NOTEBOOK

Primary changes include: data and common cause factors update; added pressurizer pressure bistable miscalibration pre-initiator event to SIA & SIB fault trees, added feedwater line break (FLB) as an event that results in an SI Signal (GRAF580), added steam generator level bistable miscalibration pre-initiator event to RPSAFW fault tree, expanded loss of offsite power event logic in RPSCCW fault tree (GRCW170, GRCW360), added relay K743A/B (FWIS) failure logic to RPSMSI (GRMS512, GRMS612) and added relay K644A/B failure logic to RPSSPRAY (GRSP512, GRSP612).

F.2.4.16 DATA ANALYSIS NOTEBOOK

Plant specific data (component failure rates and system/train unavailability) was updated based on plant experience as documented in the Maintenance Rule database. Common cause Factors were updated based on WCAP-15167. The parameter file (WCPRA.PRM) was expanded in scope and updated to allow rapid updating of the Basic Event Data file (WCPRA.BED) and performance of parametric uncertainty estimations.

F.2.4.17 EVENT TREE ANALYSIS NOTEBOOK

For each internal initiating event category (except ISLOCA), the accident sequences that may stem from the initiating event are modeled in terms of an event tree. The event trees are constructed in terms of front line safety systems and operator actions that either respond to the initiating events, or mitigate failures of other front line systems. The event tree models are constructed to lead to core damage end states. The success criteria for front line systems and operator actions identified in the event trees are also provided in this notebook.

Major changes to event trees for the 2002 PRA model update include: modeling the FLB event as a separate event tree from the Steamline Break (SLB) event. Incorporating the WOG 2000 RCP Seal Leakage Model in the Loss of RCP Seal Cooling type event trees – Station Blackout (SBO), Loss of CCW, Loss of All Service Water (SWS) and Loss of RCP Seal Cooling (RCI).

F.2.4.18 HRA DEPENDENCY ANALYSIS

The objective of this evaluation is to evaluate any dependency between two or more operator actions that may exist in a given cutset. Dependency can be low, medium, high or complete. If a dependency exists between Operator Actions (OPAs), an adjustment must be made to the failure probability value to account for that dependency.

Dependencies between different OPAs are important to consider where such OPAs occur in the same cutset or accident sequence. If dependencies are not considered, the cutset probabilities, and hence the top event probability, can be significantly underestimated. Dependencies may be identified and examined during the initial review of event tree sequences, during operator interviews, and during review of cutsets with multiple operator actions.

F.2.4.19 HUMAN RELIABILITY ANALYSIS-POST INITIATORS

This evaluation provides documentation of the Human Reliability Analysis (HRA)/Update which was performed as a part of the 2002 update of the WCGS PSA model. Revisions of applicable procedures since the time of the previous HRA were reviewed and values were adjusted if necessary. Several new HI events were added and some deleted based on revised Event Tree and Fault Tree modeling. Description of the HRA methodology used is documented in WCGS Human Reliability Analysis Guideline, dated April 30, 2004, Rev.0. WCGS has decided to use the Cause-Based Decision Tree Method (CBDTM) and the Technique for Human Error Rate Prediction (THERP) methods for HRA analysis.

F.2.4.20 INITIATING EVENT NOTEBOOK

The initiating event frequency values being applied in the WCGS PSA 2002 model were reviewed and updated as appropriate.

F.2.4.21 INTERFACING SYSTEMS LOCA ANALYSIS

This ISLOCA Analysis uses the guidance and methodology provided in NUREG/CR-5744, NUREG/CR-5928 and NSAC-154. Primary changes include: data and common cause factors update; removed isolation failure events from HPSI-CLI, HPSI-HLI, LPSI-CLI, RHR-ISL and TBCC-ISL; removed individual check valve rupture events from HPSI-CLI, HPSI-HLI, LPSI-CLI and LPSI-HLI; and revised TBCC failure frequency based on 10 sections instead of 1 section.

F.2.4.22 MODEL QUANTIFICATION NOTEBOOK

The quantification results are tabulated by initiating event and event tree. Top core damage cutsets are provided on an overall and core damage sequences are presented on a per initiating event basis. Uncertainty is considered by a parametric evaluation and by performance of a number of sensitivity quantifications. A mapping of event tree transfer sequences is provided. The core damage top logic model is updated and presented. Update of the Internal Flooding Risk Evaluation was not performed for the 2002 PRA model update.

F.2.4.23 LERF TOP LOGIC DEVELOPMENT

The LERF top logic model allows the Safety Monitor to calculate a point estimate of LERF given various plant configurations. The Level I event tree core damage sequences are reviewed to determine which end states were considered to be in the LERF category. Those core damage sequences that directly translated into a LERF were identified (i.e., ISLOCA and some SGTR). For other core damage sequences, containment safeguards failures necessary to precipitate a LERF category sequence were identified. A LERF top logic model was developed for these sequences. Changes in the Level 1 event trees required a thorough reexamination of the LERF top locic. This ensured that the proper sequences were selected and assigned to the appropriate category. Examination of the LERF top logic model solution reveals the first four cutsets as contributing a total of 1.536E-6/year, utilizing a LERF cutoff of 1E-10/year.

F.2.5 WCGS PSA QUALITY

F.2.5.1 IPE CROSS COMPARISON - 1992

In September 1992, Wolf Creek completed its participation in a cross-comparison review of its PRA model with its sister plant. The SNUPPS IPE Subcommittee performed the work. The charter called for “a comparison and reconciliation of final results of the two studies.” The result noted “good agreement for two independent studies of two very similar plants.” Different vendor support, computer codes, and IPE philosophies carried out each plant’s study. While the reviews lacked the review checklists of today, the comparison nonetheless was a detailed assessment of the overall quality in assessing severe accident vulnerability.

F.2.5.2 PSA SELF ASSESSMENT - EARLY 1998

A Self Assessment in early 1998 was used to help guide the completion of the 1998 PSA model update priorities. A Westinghouse Engineer, another PWR PSA Engineer and in-house reviewers performed the reviews.

F.2.5.3 INDUSTRY PEER REVIEW - AUGUST 2000

The WCGS 1998 PSA Model was used for the Westinghouse Owner's Group (WOG) Peer Review in August 2000. The Final report was issued in November 2001. The General Summary reads in part, "All of the technical elements were graded as sufficient to support applications involving risk ranking (e.g., high/low risk determination). The WCGS PSA thus provides an appropriate and sufficiently robust tool to support such activities as initial Maintenance Rule implementation, supported as necessary by deterministic insights and plant expert panel input."

Table F.2.1 contains the grades of the individual PRA Elements recorded by the Peer Review Team. Table F.2.2 discusses the status/resolution of each of the Category A and B F&Os.

The Peer Review Report also credits items of strength in the Wolf Creek PSA.

Some PRA Strengths:

- Experienced PRA personnel who know the model and its history. The Wolf Creek PRA group retains several utility engineers who worked on the original IPE and the subsequent updates, and who are intimately familiar with the details of most of the PRA models. Having this in-house knowledge can compensate for some of the observations regarding need for additional documentation, at least while the group composition is stable. The PRA engineers were able to provide most of the details regarding the current and historical bases for the PRA in response to reviewer questions during the review.

- Special initiating event frequency calculations:
  The fault tree logic for quantification of the initiating event frequencies for special initiating events has been incorporated into the master PRA fault tree. This simplifies the process but more importantly allows a more accurate indication of structures, systems, and components (SSC) importance for those SSCs that affect both the initiating event frequency and system transient response.

- Good accident sequence development:
  Accident progression and top event description discussions are provided for each event tree developed. Critical safety functions are addressed for each event tree, as are critical timing issues.

- Success criteria documentation and traceability:
  The documentation of success criteria in Appendix A of the Event Tree Analysis Notebook provides a clear summary of the rationale and bases for the success criteria for each event tree top event / fault tree system. It includes a table summarizing this information and citing references to the underlying analyses, briefly stating how the information has been interpreted and applied.

- System notebooks:
  The system notebooks/fault tree calcs provide significant discussion of assumptions made in the development of the fault trees, including thorough justification for omission of components from the trees. This level of detail exceeds that typically found in other PRAs.

- PRA Innovations:
  The WCGS PSA incorporates fault tree logic for special initiating event frequencies in a manner that allows direct estimation of basic event importance including the contribution of the basic event associated with the special initiator frequency. This is not currently a widely-implemented technique among PRAs with which the reviewers are familiar.

F.2.5.3 2003 ELECTRICAL MODEL CHANGE FOR SHARPE STATION USAGE - INFORMAL PEER REVIEW

The Sharpe Station PRA model was not subjected to a formal outside peer review. However, a meeting was held with another utility's PRA personnel preparing a similar change request of a similar design plant. The meeting purpose was to resolve apparent result differences through discussion of assumptions and modeling. The level of knowledge in this utility's PRA group, relative to Sharpe Station configuration and operation, was limited to that included in the completion time extension evaluation provided to them. No comments relative to the structure of the Sharpe Station PRA model were provided. Critical discussions during the meeting served the same function as would occur during a more formal Peer Review.

F.2.6 TRUNCATION AND CONVERGENCE

The 2002 PSA Update Core Damage Frequency results are based on quantification of the WCGS PRA internal events accident sequences using a truncation value of 1.0E-10. This truncation value is greater than five orders of magnitude less than the annual core damage frequency value of 2.985E-05/year.

In order to demonstrate convergence of the WCGS PRA model results towards an approximate core damage frequency value, the accident sequences were quantified using a batch input file with various quantification truncation values. The core damage frequency results based on accident sequence quantification at various truncation values are provided below:

Truncation Value	Core Damage Frequency (No. of Cutsets)
1.0E-09	2.779E-05 (1,803)
1.0E-10	2.985E-05 (8,718)
1.0E-11	3.042E-05 (27,394)
2.0E-12	3.051E-05 (34,042)

While all internal events accident sequences will properly solve using a truncation value of 1.0E-12, combining (concatenating) all of the accident sequence solution files into a single core damage cutset equation file with a truncation value of 1.0E-12 exceeds the code concatenation limit of 60,000 cutsets. Therefore, a truncation limit of 2.0E-12 was applied for concatenation of core damage cutsets.

The core damage frequency value appears to be converging towards a value somewhat greater than 3.05E-05/yr, but less than 3.1E-05/yr. Performance of accident sequence quantification using a truncation value of 1.0E-10 is capturing approximately 97.7 percent of the core damage frequency value that would be realized from quantification using a truncation value of 2.0E-12. It is considered that accident sequence quantification using a truncation value of 1.0E-10 is capturing a significant majority of the core damage results. The minor increase in core damage frequency realized from quantification using a truncation value less than 1.0E-10 does not justify the associated significant increase in time required for model quantification.

F.2.7 PSA MODEL MAINTENANCE

The WCGS PSA is based on a detailed model of the plant that was developed from the WCGS IPE. Improvements to the WCGS PSA model are an ongoing process. Updates to the PSA model are scheduled on a periodic basis by the PSA group. Planned updates include an information-gathering phase that is intended to capture plant changes that had not been previously identified by the PSA team.

The WCNOC engineering design process contains procedural screening questions to identify changes with potential impact to the PSA model. Example changes with identified impacts include changing an air-operated valve to a motor-operated valve and change-out of a reciprocating charging pump to a centrifugal pump with less cooling dependencies. With a mature plant and revised PSA model, plant changes that impact the model in a negative manner are becoming quite infrequent. Validation of operator action times for Safety Analysis purposes are used by the PSA group to confirm modeling of the human reliability analysis terms. PSA group judgment of SSC performance issues identified under the Maintenance Rule has altered the failure probabilities of an SSC until its performance was returned (or confirmed) to a satisfactory level.

F.2.8 SAMA QUANTIFICATION STRATEGY

In order to calculate the averted cost-risk for each SAMA, the WCGS Level 1 and 2 PRA is required to provide a CDF and release category frequencies for input into the Level 3 model. The CDF was calculated using the process provided in the WCGS Quantification Notebook and no changes were necessary to support the SAMA analysis. However, in order to obtain the Level 2 results that were determined to be required to characterize public risk, it was necessary to modify the quantification process. Given that the current WCGS Level 2 analysis is only a LERF model, it does not explicitly provide any information on non-LERF scenarios. Based on information in the WCGS IPE, most non-LERF accidents pose little risk to the public compared to the LERF cases; however, a process was developed to approximate the contributions from late containment failures (LCF) and leakage/no containment failure (NCF) scenarios to address the non-LERF cases for WCGS.

Table 4.3.3 of the WSGS IPE (WCNOC 1992) includes information that can be used to estimate the frequency of a given release category based on the Level 1 IPE results. Conditional probabilities are provided that can be multiplied by the CDF to obtain the frequency of any release category. While these conditional release category frequencies are based on the IPE model, it has been assumed that the conditional probabilities can be used to obtain the release category frequencies for the current PRA model. These conditional probabilities are provided below. Note that the leakage/NCF category is the sum of the “S” and “A” release categories:

Conditional Probabilities for the Non-LERF Release Categories

RELEASE CATEGORY	DEFINITION	P(RC|CD)
S	No containment failure (leakage only, successful maintenance of containment integrity; containment not bypassed; isolation successful)	0.593
A	No containment failure within mission time	0.345
	Total	0.938
K	Late containment failure - <0.1% volatiles released	3.78E-02

In summary, the release category frequency for leakage/NCF and LCF are:

- Leakage/NCF = CDF * 0.938
- LCF = CDF * 3.78E-02

While the contribution of the Non-LERF evolutions has been addressed for completeness, the LERF sequences are the important contributors to public risk for WCGS. As discussed in WCGS calculation PSA-05-0025 (WCNOC 2005), the Wolf Creek definition of LERF is:

- An unscrubbed containment bypass pathway occurring with core damage, or
- An unscrubbed containment failure pathway of sufficient size to release the contents of the containment (i.e., one volume change) within one hour, which occurs before or within four hours of vessel breach.

The WCGS LERF model quantifies four distinct LERF contributor types that are used in the SAMA analysis to characterize radionuclide releases:

- Interfacing Systems Loss of Coolant Accidents (ISLOCAs)
- Steam Generator Tube Ruptures (SGTRs)
- Containment Isolation Failure (CIFs)
- Early Containment Failures (ECFs)

The frequency for each of these contributors is obtained by quantifying the fault tree gate corresponding to the contributor in the LERF model. The following table summarizes the baseline Level 2 results for WCGS:

Baseline Release Category Frequencies

Release Category	**CIF**	**SGTR**	**ISLOCA**	**ECF**	**LCF(K)**	**Leakage/ NCF**	**Total**
Frequency (/yr)$_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**

The source terms for these release categories are based on the WCGS IPE and are described in Section F.3.3.

F.3 LEVEL 3 PSA ANALYSIS

WCNOC used the MACCS2 computer code (CHAN 1997) to determine two types of consequences of severe accidents: human health in terms of dose and economic in terms of cost. For human health impacts, WCNOC calculated collective dose to the 50-mile population. Economic costs include the costs associated with short-term relocation of people, decontamination of property and equipment, interdiction of food supplies, land, and equipment use, and condemnation of property.

The MACCS2 code was specifically developed for NRC to evaluate severe accidents at nuclear power plants. It primarily addresses the air pathway, but it does calculate dose from runoff and deposition on surface water. The exposure pathways modeled include external exposure to the passing plume, external exposure to material deposited on the ground and skin, inhalation of material in the passing plume and resuspended from the ground after deposition, and ingestion of contaminated food and surface water.

The input parameters given with the MACCS2 "Sample Problem A" formed the basis for the present analysis. These generic values were supplemented with parameters specific to WCGS and the surrounding area. Site-specific data included population, economic, and agricultural parameters as well as radionuclide release and meteorological (MET) data. The modeled behavior of the population during a release was based on plant and site-specific set points (i.e., declaration of a General Emergency) and the emergency planning zone evacuation times. These data were used to simulate the probability distribution of impact risks (exposure and economic) to the surrounding population (within 50 miles from the representative accident sequences at WCGS).

F.3.1 POPULATION

The resident population within a 50-mile radius of WCGS was estimated based on the most recent United States Census Bureau decennial census data as provided by the program SECPOP2000 (NRC 2003). The population distribution was estimated in 10 concentric bands at 0 to 1 mile, 1 to 2 miles, 2 to 3 miles, 3 to 4 miles, 4 to 5 miles, 5 to

10 miles, 10 to 20 miles, 20 to 30 miles, 30 to 40 miles, and 40 to 50 miles from WCGS and 16 directional sectors, each direction consisting of 22.5 degrees. The transient population was then combined with the resident population.

Once the 2000 population was determined for each of the 160 sectors, projections were made for the year 2040. Growth rates were calculated for each county based on 1990 and 2000 census populations (USCB 1990, USCB 2000). If a negative growth rate was calculated (i.e., the 2000 county population was less than the 1990 population), a growth rate of zero (multiplier of 1) was used. Once county growth rates were determined, ArcView 3.1 was used to determine the percentage of each sector occupied by a particular county. ArcView 3.1 is geographic information system (GIS) software developed by Environmental Research Systems Institute (ESRI). The sectors were divided into fractions by county, and projections for each fraction were calculated based on the county growth rate. The population projections for the year 2040 were then totaled by sector, and rounded to the nearest whole number to obtain the final result. The sector population projections by emergency planning zone sector are depicted in Table F.3-1.

F.3.2 ECONOMY AND AGRICULTURE

WCNOC used SEPOP2000 to determine the spatial distribution of certain economic data in the same manner as the population. In addition, generic economic data that is applied to the region as a whole was revised from the MACCS2 sample problem input when better information was available. Several parameters were escalated from 1986 to 2005 by the ratio of the consumer price index of 1.75 derived from www.bls.gov/cpi/home/htm. These revised parameters include value of farm and non-farm wealth and fraction of farm wealth from improvements (e.g., buildings, equipment). The average value per hectare of farm land and buildings within 50 miles and the average value per hectare of nonfarm land and buildings within 50 miles were calculated with a spreadsheet using county data from the U.S. Department of Agriculture and the Bureau of Economic Analysis. A geographical information system analysis assisted in determining the weighted contribution of each county in the 50-mile radius.

F.3.3 RADIONUCLIDE RELEASE

The core inventory used for the analysis was derived from the plant's safety analysis, based on Westinghouse Letter SAP-99-145 (WEST 1999). The release data (Table F.3-2) were for six release classes, which were determined by Modular Accident Analysis Program (MAAP) runs. A ground-level release was assumed. Sensitivity studies showed that the ground-level release was slightly conservative compared to an elevated release through the plant vent. Accordingly, buoyant plume rise was not considered.

F.3.4 EVACUATION

Scram for each sequence was taken as time zero relative to the core containment response times. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. General Emergency declarations ranged from 3 hours for the containment leakage sequence to 19.5 hours for the late containment failure sequence.

The MACCS2 Users Guide input parameters of 95 percent of the population within 10 miles of the plant (Emergency Planning Zone) evacuating and 5 percent not evacuating were employed. These values have been used in similar license renewal SAMA analyses and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the emergency planning zone.

Evacuation speed of 1.6 meters per second was selected based on data in the Wolf Creek procedure AP 06-002, "Radiological Emergency Response Plan (RERP)." Adverse weather conditions were assumed. A 30 minutes delay after alarm was assumed before start of evacuation. The speed 1.6 meters per second was conservatively selected as lower than any speed calculated from the data in AP 06-002. Two zones, Coffey County Lake and John Redmond Reservoir, had longer evacuation times, but the numbers of people were small and the selected value for evacuation speed was less than that calculated for these zones. As noted in AP 06-002, the evacuation times are considered to be conservative for the reasons provided there.

F.3.5 METEOROLOGY

Data from the WCGS meteorological monitoring program were used to build the meteorological data file. The input file contains hourly data for an entire year for direction, speed, stability class, and precipitation. Data were available for 2000 to 2004, but each year had some fraction of bad data as follows:

- 2000 – 5.0%
- 2001 – 1.0%
- 2002 – 6.0%
- 2003 – 10%
- 2004 – 6.0%

The year 2001 was initially chosen for use, given its high percentage of good data. A sensitivity case was run with MACCS2 comparing 2001 data with 2004 data with 2001 being slightly more conservative. Therefore, 2001 meteorological data was confirmed as the choice for use in the analysis.

Missing data were filled in by simple interpolation for short spans. In just a few cases, longer spans of missing data (on the order of a day or two) were borrowed from 2004 data. Mixing heights were taken from *Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution throughout the Contiguous United States* (HOLZ 1972).

Some of the precipitation data in all the meteorological files was suspect (e.g., data or hourly variations outside of the expected range). It was checked against daily data for the John Redmond Reservoir just three miles from WCGS (http://www.swt-wc.usace.army.mil/JOHNcharts.html). In the few cases where there were large differences in which the WCGS data were suspect, Redmond data were used to adjust the WCGS data.

F.3.6 MACCS2 RESULTS

The resulting annual risks from the seven WCGS release sequences are provided in Table F.3-3. The largest risks are from sequences ISLOCA and Early Containment Failure. These sequences are not marked by high frequencies but by higher dose and economic cost. These two sequences contribute over 94 percent of the exposure risk and over 96 percent of the economic risk from WCGS.

F.4 BASELINE RISK MONETIZATION

This section explains how WCNOC calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). WCNOC also used this analysis to establish the maximum benefit that could be achieved if all risk for reactor operation were eliminated.

F.4.1 OFF-SITE EXPOSURE COST

The baseline annual off-site exposure risk was converted to dollars using NRC's conversion factor of $2,000 per person-rem, and discounted to present value using NRC standard formula (NRC 1997a):

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

Where:

W_{pha}	=	monetary value of public health risk after discounting
C	=	$[1-\exp(-rt_f)]/r$
t_f	=	years remaining until end of facility life = 20 years
r	=	real discount rate (RDR) (as fraction) = 0.03 per year
Z_{pha}	=	monetary value of public health (accident) risk per year before discounting ($ per year)

The Level 3 analysis showed an annual off-site population dose risk of about 2.86 person-rem. The calculated value for C using 20 years and a 3 percent discount rate is approximately 15.04. Therefore, calculating the discounted monetary equivalent of accident dose-risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (15.04). The calculated off-site exposure cost is estimated to be $86,027.

F.4.2 OFF-SITE ECONOMIC COST RISK

The Level 3 analysis showed an annual off-site economic risk of $1,974. Calculated values for off-site economic costs caused by severe accidents must be discounted to present value as well. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $29,688.

F.4.3 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using NRC methodology that involves separately evaluating immediate and long-term doses (NRC 1997a).

For immediate dose, NRC recommends using the following equation:

Equation 1:

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

Where:

W_{IO}	=	monetary value of accident risk avoided due to immediate doses, after discounting
R	=	monetary equivalent of unit dose ($2,000 per person-rem)
F	=	accident frequency (2.98E-05 events per year)
D_{IO}	=	immediate occupational dose [3,300 person-rem per accident (NRC estimate)]
$_S$	=	subscript denoting status quo (current conditions)
$_A$	=	subscript denoting after implementation of proposed action
r	=	RDR (0.03 per year)
t_f	=	years remaining until end of facility life (20 years).

Assuming F_A is zero, the best estimate of the immediate dose cost is:

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

$$= 2{,}000 * 2.98\text{E-}05 * 3{,}300 * \{[1 - \exp(-0.03 * 20)]/0.03\}$$

$$= \$2{,}958$$

For long-term dose, NRC recommends using the following equation:

Equation 2:

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

Where:

W_{LTO} = monetary value of accident risk avoided long-term doses, after discounting, $

D_{LTO} = long-term dose [20,000 person-rem per accident (NRC estimate)]

m = years over which long-term doses accrue (as long as 10 years)

Using values defined for immediate dose and assuming F_A is zero, the best estimate of the long-term dose is:

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

$$= 2{,}000 * 2.98E\text{-}05 * 20{,}000 * \{ [1 - \exp(-0.03*20)]/0.03\} \{[1 - \exp(-0.03*10)]/0.03*10\}$$

$$= \$15{,}488$$

The total occupational exposure is then calculated by combining Equations 1 and 2 above. The total accident related on-site (occupational) exposure risk (W_O) is:

$$W_O = W_{IO} + W_{LTO} = (\$2{,}958 + \$15{,}488) = \$18{,}446$$

F.4.4 ON-SITE CLEANUP AND DECONTAMINATION COST

The total undiscounted cost of a single event in constant year dollars (C_{CD}) that NRC provides for cleanup and decontamination is $1.5 billion (NRC 1997). The net present value of a single event is calculated as follows. NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$PV_{CD} = [C_{CD}/mr][1-\exp(-rm)]$$

Where:

PV_{CD} = net present value of a single event

C_{CD} = total undiscounted cost for a single accident in constant dollar years

r = RDR (0.03)

m = years required to return site to a pre-accident state

The resulting net present value of a single event is \$1.3E+09. The NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$U_{CD} = [PV_{CD}/r][1-\exp(-rt_f)]$$

Where:

PV_{CD} = net present value of a single event (\$1.3E+09)

r = RDR (0.03)

t_f = 20 years (license renewal period)

The resulting net present value of cleanup integrated over the license renewal term, \$1.95E+10, must be multiplied by the total CDF (2.98E-05) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is \$580,801.

F.4.5 REPLACEMENT POWER COST

Long-term replacement power costs were determined following NRC methodology in NUREG/BR-0184 (NRC 1997a). The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

$$PV_{RP} = [\$1.2\times10^8/r] * [1 - \exp(-rt_f)]^2$$

Where:

PV_{RP} = net present value of replacement power for a single event, (\$)

r = RDR (0.03)

t_f = 20 years (license renewal period)

To attain a summation of the single-event costs over the entire license renewal period, the following equation is used:

$$U_{RP} = [PV_{RP} / r] * [1 - \exp(-rt_f)]^2$$

Where:

U_{RP} = net present value of replacement power over life of facility ($-year)

After applying a correction factor to account for WCGS size relative to the generic reactor described in NUREG/BR-0184 (i.e., 1165 megawatt electric/910 megawatt electric) the replacement power costs are determined to be 7.07E+09 ($-year). Multiplying this value by the CDF (2.98E-05) results in a replacement power cost of $210,800.

F.4.6 TOTAL COST RISK

The sum of the baseline costs is as follows:

Off-site exposure cost	=	$86,027
Off-site economic cost	=	$29,688
On-site exposure cost	=	$18,446
On-site cleanup cost	=	$580,801
Replacement Power cost	=	$210,800
Total cost	=	$925,762

The total cost risk represents the maximum averted cost risk if all risk were eliminated. The MACR based on on-line internal events contributions, which is rounded to next highest thousand ($926,000) for SAMA calculations.

As described in Section F.5.1.8, the internal events MACR is doubled to account for external events contributions. The resulting modified MACR (MMACR) is $1,852,000 and was used in the Phase I screening process.

F.5 PHASE I SAMA ANALYSIS

The Phase I SAMA analysis, as discussed in Section F.1, includes the development of the initial SAMA list and a coarse screening process. This screening process eliminated those candidates that are not applicable to the plant's design or are too expensive to be cost beneficial even if the risk of on-line operations were completely eliminated. The following subsections provide additional details of the Phase I process.

F.5.1 SAMA IDENTIFICATION

The initial list of SAMA candidates for WCGS was developed from a combination of resources including:

- WCGS PSA results
- Industry Phase II SAMAs
- WCGS IPE (WCNOC 1992)
- WCGS IPEEE (WCNOC 1995)
- WCGS Fire Risk Evaluation Re-Analysis (WCNOC 1998A)

These resources are judged to provide a list of potential plant changes that are most likely to reduce risk in a cost-effective manner for WCGS.

In addition to the "Industry Phase II SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the WCGS plant specific SAMA list. While the industry SAMA review cited above was used to identify SAMAs that might have been overlooked in the development of the WCGS SAMA list due to PSA modeling issues, a generic SAMA list was used as an idea source to identify the types of changes that could be used to address the areas of concern identified through the WCGS importance list review. For example, if long term DC power availability was determined to be an important issue for WCGS, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address Wolf Creek's needs. If an appropriate SAMA was found to exist, it would be used in the WCGS list to address the DC power issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of several industry SAMA analyses and has been provided in Addendum 1 for reference purposes.

F.5.1.1 LEVEL 1 WCGS IMPORTANCE LIST REVIEW

The WCGS PSA was used to generate a list of events sorted according to their risk reduction worth (RRW) values. The top events in this list are those events that would provide the greatest reduction in the WCGS CDF if the failure probability were set to zero. The events were reviewed down to the 1.02 level, which corresponds to about a 2.0 percent change in the CDF given 100 percent reliability of the event. If the dose-risk and off-site economic cost-risk were also assumed to be reduced by a factor of 1.02, the corresponding averted cost-risk would be approximately $18,200. Applying a factor of 2 to estimate the potential impact of external events (refer to Section F.5.1.8), the result is about $36,400. This is less that what is considered to be the lower end of implementation costs for potential plant changes, especially given that this estimate is based on complete reliability of the proposed change. The lower end of the cost of implementation for a SAMA is based on the cost of a procedural change, which has been estimated to be about $50,000. (CPL 2004) No further review of the importance listing was performed below the 1.02 level. Table F.5-1 documents the disposition of each event in the Level 1 WCGS RRW list with RRW values of 1.02 or greater.

F.5.1.2 LEVEL 2 WCGS IMPORTANCE LIST REVIEW

A similar review was performed on the importance listings from the Level 2 results. In this case, a composite file based on the top 93 percent of all dose-risk was used to identify potential SAMAs. The composite file was composed of the results from the ISLOCA and Early Containment Failure release categories. This method was chosen to prevent high frequency-low consequence events from dominating the importance listing.

The Level 2 RRW values were reviewed down to the 1.02 level. As described for the Level 1 RRW list, events below the 1.02 threshold value are estimated to yield an averted cost-risk less than $36,400 and are not considered to be likely candidates for identifying cost effective SAMAs. As such, the events with RRW values below 1.02 were not reviewed. Table F.5-2 documents the disposition of each event in the Level 2 WCGS RRW list with RRW values greater than 1.02.

F.5.1.3 INDUSTRY SAMA ANALYSIS REVIEW

The SAMA identification process for WCGS is primarily based on the PSA importance listings, the IPE, and the IPEEE. In addition to these plant-specific sources, selected industry SAMA submittals were reviewed to identify any Phase II SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the WCGS SAMA list if they were considered to be potentially cost beneficial for WCGS.

While many of these SAMAs are ultimately shown not to be cost beneficial, some are close contenders and a small number have been estimated to be cost beneficial at other plants. Use of the WCGS importance ranking should identify the types of changes that would most likely be cost beneficial for WCGS, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for WCGS due to PSA modeling differences or SAMAs that represent alternate methods of addressing risk. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the WCGS SAMA identification process.

Phase II SAMAs from the following U.S. nuclear power sites have been reviewed:

- Turkey Point (FPL 2000)
- H.B. Robinson (CPL 2002)
- Point Beach (NMC 2004)
- V.C. Summer (SCE&GC 2002)

- Peach Bottom (Exelon 2001)
- Quad Cities (Exelon 2003b)

Four PWR and two boiling water reactor (BWR) sites were chosen from available documentation to serve as the Phase II SAMA sources. Few of the Phase II SAMAs from these sources were included in the initial WCGS SAMA list. Many of the industry Phase II SAMAs were already represented by other SAMAs in the WCGS list, were known not to impact important plant systems, or were judged not to have the potential to be close contenders for WCGS. These SAMAs were not considered further. The following provides a summary of some of the issues considered during the review of the industry SAMAs.

F.5.1.3.1 Turkey Point

Turkey Point used a generic SAMA list as its starting point and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. Some of the SAMAs included in the Phase 2 list were, however, related to important issues at Wolf Creek. One SAMA provided a potentially cost beneficial means of preventing seal LOCAs:

- Turkey Point SAMA 12 – This SAMA suggests using the hydrostatic test pump as an alternate means of providing seal injection. While seal LOCAs are important for Wolf Creek, they are driven by SBO scenarios. Given that WCGS would not greatly benefit from the installation of an AC powered seal injection pump, it was not considered for the WCGS SAMA list. In addition, the WCGS list includes a SAMA to install a dedicated generator for the NCP for SBO seal injection, which does address SBO seal LOCAs.

F.5.1.3.2 H.B. Robinson

While a generic SAMA list similar to the one used for Turkey Point was used in the H.B. Robinson SAMA submittal, a SAMA was passed to the Phase 2 list related to ISLOCA, which is an important issue for WCGS. Phase 2 SAMA 3 suggested an increased testing frequency for valves in ISLOCA pathways. This SAMA is not included in the WCGS SAMA list because the Maintenance Rule is considered to address maintenance issues for all valves in ISLOCA pathways. In addition, it is recognized that increased testing does not necessarily correspond to a reduced ISLOCA frequency. In some cases, increased testing results in an increased ISLOCA frequency due to maintenance errors.

F.5.1.3.3 Point Beach

As with Turkey Point, this analysis relied on a generic SAMA list and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. The SAMAs identified in the Point Beach submittal as potentially cost effective appeared to be procedural updates to include checkoff provisions within the procedures. Some HRA methodologies credit placekeeping aids in procedures as a means of reducing the potential to skip a step in the cognitive portion of the HEP. While inclusion of such provisions is reflected quantitatively in the PRA, it would be difficult to justify changes to a large number of procedures based on a detail in a specific HRA methodology. This type of SAMA was not included in the WCGS SAMA list.

F.5.1.3.4 V.C. Summer

V.C. Summer's Phase 2 SAMA list is based on an industry SAMA list similar to those used by Turkey Point, Point Beach, and H.B. Robinson. However, it included a change related to ISLOCAs not included in the other Phase 2 SAMA lists. The SAMA suggested that the plant ensure all ISLOCA releases are scrubbed. This is an unconventional approach that was considered for inclusion on the WCGS SAMA list. Review of the WCGS ISLOCA analysis revealed that this SAMA would not be a likely cost-beneficial candidate due to the fact that the rooms in which the highest ISLOCA contributors occur are open areas that could not be flooded without damaging other safety equipment. In addition, these ISLOCA events are explicitly treated in the WCGS SAMA list by another proposed change that is considered to be a more appropriate alternative for WCGS. As a result, the V.C. Summer ISLOCA SAMA has not been included on the WCGS SAMA list.

F.5.1.3.5 Peach Bottom

The Peach Bottom Phase 2 SAMA list, while based on an industry SAMA list similar to those for the PWRs examined as part of this task, included some additional plant changes that could be applicable to WCGS.

- Phase 2 SAMA number 1 suggests improving procedural guidance for use of cross-tied CCW pumps. The WCGS CCW system does not include an existing CCW cross-tie. The scope of this SAMA for WCGS requires the installation of piping and valves that could be used to cross-tie the CCW loops. This has been added to the WCGS SAMA list (SAMA 16).

- Phase 2 SAMA number 30 suggests installation of hardware to allow for the cross-tie of DC divisions. While isolation of the divisions is desirable in most conditions to preclude common failures, there are conditions in which the ability to provide power from one division to another would be helpful. This SAMA has been included in the WCGS SAMA list (SAMA 17).

F.5.1.3.6 Quad Cities

Of the Phase 2 SAMAs considered for Quad Cities, only a limited number were found to be potentially applicable to WCGS. One such SAMA was Phase 2 SAMA 5, which suggests installing an alternate cooling system for the EDGs. The importance listings for WCGS did not identify EDG cooling as an issue that could yield cost beneficial SAMAs; however, as emergency AC power availability is an important issue for WCGS in general, it was considered worth investigating. A review of the WCGS configuration shows that EDG cooling is provided by ESW. This means that if the cooling is lost to the EDGs, multiple other systems required for accident mitigation are also unavailable and any alternate cooling alignments that only impact the EDGs will have a limited impact. The scope of the SAMA would have to be changed from its original low cost vision to a large scale change that would involve multiple systems. Based on these considerations, this SAMA is not considered to be a potentially cost beneficial change for WCGS and it has not been included on the SAMA list.

F.5.1.3.7 Industry SAMA identification Summary

The important issues for WCGS are considered to be addressed by the SAMAs developed through the PRA importance list review. Further, the plant changes suggested as part of that review were developed to meet the specific needs of the plant such that those SAMAs are more likely to provide effective means of risk reduction than SAMAs taken from other sites. However, a review of the SAMA analysis submittals from six other sites resulted in the identification of several plant changes which address important safety functions. As the approaches taken to reduce risk by these SAMAs are credible alternatives to those based on the importance list review, they were included for consideration:

- SAMA 16: Proceduralize the use of the inter-division CCW loop cross-tie. (Peach Bottom)
- SAMA 17: Install hardware to allow cross-ties between DC battery buses and proceduralize their use. (Peach Bottom)

F.5.1.4 WCGS IPE

The WCGS IPE generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPE process are implemented and closed out; however, there are some items that are not completed within the industry due to high projected costs or other criteria. Because the criteria for implementation of a SAMA may be different than what was used in the post-IPE decision-making process, these recommended improvements are re-examined in this analysis.

While the IPE concluded that there were no vulnerabilities at WCGS, six potential plant improvements were identified and considered for implementation at the plant. The following table summarizes the status of these plant improvements.

Improvement Considered	Review Completed	WCGS Status	Included On WCGS SAMA List?
1. RCP Seal O-rings: Replace the existing O-rings with high temperature qualified O-rings.	3/31/93	Implemented	No, already implemented.
2. Positive Displacement Charging Pump Replacement: Replace the PDP with a centrifugal style charging pump. Suggested enhancements include a self cooling pump and a backup AC power supply.	3/31/93	Implemented (no backup AC supply included)	Yes. A backup AC supply for the NCP is included on the SAMA list.
3. Switch for restoring Main Feedwater: Restoring MFW after a plant trip when AFW has failed requires the use of jumpers to bypass the feedwater isolation signal. To reduce the complexity and manipulation time for the action, a switch could be installed that could be used for isolation bypass.	3/31/93	Not implemented	No. The risk reduction worth for the relevant operator action (OPA-MFW) is only 1.001, which is below the review cutoff for SAMA.
4. Equipment Dependency for Room Cooling: Several pumps and the EDGs depend on room cooling for success. Proceduralizing actions to perform alternate cooling methods could reduce the impact of this dependency.	12/31/93	Not implemented	Yes. A SAMA is included for providing alternate room cooling to the EDGs. Room cooling for other equipment is below the risk reduction worth review cutoff for SAMA.
5. Procedures for Loss of CCW & SW: Development of procedures for loss of CCW and SW would improve operator response.	Post IPE	Implemented	No, already implemented.
6. Internal Flooding	12/31/93	Not implemented	No. Bounding estimates for internal flooding SAMAs show that none would be cost beneficial.

Given that numbers 2 and 4 were not completed, they have been addressed in the WCGS SAMA list.

F.5.1.5 WCGS IPEEE AND FIRE RE-ANALYSIS

Similar to the IPE, there may be a number of proposed plant changes that were previously rejected based on non-SAMA criteria that should be re-examined. In addition, there may be issues that are in the process of being resolved, which could be important to the disposition of some SAMAs. The IPEEE and the Fire Re-Analysis were used to identify these items.

The following table summarizes the status of the potential plant enhancements resulting from the IPEEE/Fire Re-Analysis processes and their treatment in the SAMA analysis:

Potential Plant Enhancement	Status of Implementation	Disposition
Correct various housekeeping issues related to seismic interaction.	Implemented	No further review required
Install bolts on a transformer to secure it to the inside of its inverter.	Implemented	No further review required
Remove and/or secure support steel and fire protection materials located in close proximity to electrical cabinets and MCCs.	Implemented	No further review required
Rotate victualic coupling on drain line so that adequate clearance exists between it and the nearby MCC.	Implemented	No further review required
Tighten bolts and add missing shim plates to chiller/AC units	Implemented	No further review required
Increase the seismic ruggedness of the four battery racks and eight electrical cabinets that could not be screened to a 0.3g pga HCLPF (0.20g pga assigned)	Not Implemented	No further review required. Reduced scope plants require a HCLPF value of only 0.20g pga for screening.

An effort was also made to use the IPEEE and the Fire Re-Analysis to develop new SAMAs based on a review of the original results. However, the WCGS IPEEE was not maintained as a “living” analysis. This limits the capability of the models that make up the IPEEE as they do not include the latest PSA practices nor do they necessarily represent the current plant configuration or operating characteristics. The fact that the models are not currently in a quantifiable state presents further difficulty because the results are limited to what has been retained from the original analysis. These factors limit the qualitative insights and quantitative estimates that can be made with regard to external events contributors. In addition, it was necessary to review the changes to the site and surrounding area that were implemented after the completion of the IPEEE and Fire Re-analysis to determine if the changes could impact the conclusions of those analyses. The only change considered to have the potential to impact the IPEEE was the construction of a diesel generating station used to provide "peaking" power (Sharpe Station). The potential hazards posed by Sharpe Station were assessed (WCNOC 2002) and it was concluded that they posed no threat to plant operations.

On a larger scale, given that the industry has generally not pursued external events modeling at a level consistent with internal events models, the technology for external events analysis is not as robust or refined. The result is that the CDF values yielded by the internal and external events models are not necessarily comparable. External events models are considered to be useful tools for identifying important accident sequences and mitigative equipment, but the quantitative results should not be directly combined with those from the internal events models. In this analysis, external events contributions are estimated for the reasons described above.

F.5.1.6 USE OF EXTERNAL EVENTS IN THE WCGS SAMA ANALYSIS

The IPEEE and Fire Re-Analysis were used in the WCGS SAMA analysis primarily to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences. The types of events considered in the WCGS external events analysis included:

- Internal Fires (Section F.5.1.6.1)
- Seismic Events (Section F.5.1.6.2)
- High Wind Events (Section F.5.1.6.3)
- External Flooding and Probable Maximum Precipitation (Section F.5.1.6.4)
- Transportation and Nearby Facility Accidents (Section F.5.1.6.5)

Some initiating event types that have been identified as potential candidates for inclusion in external events analyses by the industry were not explicitly evaluated based on inapplicability to the plant, low frequency of occurrence, or because the events or consequences of the events are already addressed by the PRA. The following are examples of these types of events:

- Severe temperature transients (extreme heat, extreme cold)
- Severe storm (ice, hail, snow, dust, and sand storms)
- Lightning
- External Fires
- Extraterrestrial Activity (meteor strikes, satellite falls)
- Volcanic activity
- Earth movement (avalanche, landslide)

The type of information available for the initiators evaluated by WCGS varied due to the manner in which they were addressed in the IPEEE. For instance, the fire analysis used an approach that combined the deterministic evaluation techniques from the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology with classical PRA techniques. The WCGS seismic analysis was performed using the EPRI Seismic Margins Assessment methodology (NP-6041-SL) as a “reduced scope” analysis. Due to limitations of the Fire and Seismic modeling processes, however, the results of these kinds of analyses are not necessarily compatible with those of the internal events analysis. As a result, each of the external event contributors must be considered in a manner suiting the type of analysis performed. A summary of the review process used to identify SAMAs is provided for each of the external event types listed above followed by a description of the method used to quantitatively incorporate external events contributions into the SAMA analysis.

F.5.1.6.1 Internal Fires

As discussed above, the techniques used to model external events vary according to the type of initiator being analyzed. The WCGS Fire Model shares many of the same characteristics as the internal events model, but limitations on the state of technology produce results that are more conservative than the internal events model. The following summarizes the fire PRA topics where quantification of the CDF may introduce different levels of modeling uncertainty than the internal events PRA.

In general, fire PRAs are useful tools to identify design or procedural items that could be clear areas of focus for improving the safety of the plant. Fire PRAs use a structure and quantification technique similar to that used in the internal events PRA. Since less attention historically has been paid to fire PRAs, conservative modeling is common in a number of areas of the fire analysis to provide a “bounding” methodology for fires. This concept is contrary to the base internal events PRA, which has had more analytical development and is judged to be closer to a realistic assessment (i.e., best estimate) of the plant. There are a number of fire PRA topics involving technical inputs, data, and modeling that prevent the effective comparison of the CDF between the internal events PRA and the fire PRA. These areas are identified as follows:

PSA Topic	Comment
Initiating Events:	The frequency of fires and their severity are generally conservatively overestimated. A revised NRC fire events database indicates the trend toward lower frequency and less severe fires. This trend reflects the improved housekeeping, reduction in transient fire hazards, and other improved fire protection (FP) steps at plants.
System Response:	FP measures such as sprinklers, CO_2, and fire brigades may be given minimal (conservative) credit in their ability to limit the spread of a fire.
Sequences:	Sequences may subsume a number of fire scenarios to reduce the analytic burden. The subsuming of initiators and sequences is done to envelope those sequences included. This results in additional conservatism.
Fire Modeling:	Fire damage and fire spread are conservatively characterized. Fire modeling presents bounding approaches regarding the immediate effects of a fire (e.g., all cables in a tray are always failed for a cable tray fire) and fire propagation.
HRA:	There is little industry experience with crew actions under conditions of the types of fires modeled in fire PRAs. This has led to conservative characterization of crew actions in fire PRAs. Because the CDF is strongly correlated with crew actions, this conservatism has a profound effect on the calculated fire PRA results.

PSA Topic	Comment
Level of Detail:	The fire PRAs may have reduced level of detail in the mitigation of the initiating event and consequential system damage.
Quality of Model:	The peer review process for fire PRAs is not as developed as internal events PRAs. For example, no industry standard, such as NEI 00-02, exists for the structured peer review of a fire PRA. This may lead to less assurance of the realism of the model.

The results of the WCGS Fire IPEEE accident sequence quantification were derived from a methodology that includes a number of conservative assumptions. Examples include:

1. To save money and analysis time, conservative fire modeling was performed to initially screen rooms and scenarios. This resulted in a conservative assignment of safe shutdown equipment (SSE) damage. In many cases, all SSE in a given fire area was assumed damaged given propagation of the fire into the overhead cables. A more detailed analysis would have shown a smaller degree of SSE damage and resulted in a lower CDF. However, with 66 detailed scenarios, detailed fire modeling would have been cost prohibitive. Additionally, the generic cabinet fire COMPBRN runs were performed assuming non-IEEE-383 cables in the cabinets. This resulted in higher than expected damage areas due to the much higher cabinet heat release rate.

2. Manual suppression was not credited for any fire. There are three reasons for this analysis assumption. First, credit for manual suppression would have required detailed fire modeling including timing of detection. This was not performed. Second, most un-screened rooms contained Halon protection which was credited for protection of SSE cables not directly above a fire. Finally, the results were dominated by a fire originating within a cabinet or switchgear, and manual suppression could not be credited in protecting the cabinet itself.

3. Thermo-lag fire barrier wrap was not credited in the analysis. This resulted in a few areas, such as A-6, that did not initially screen (Phase II,

Step 2), but only un-screened Fire Areas A-8, A-16 and A-18 contained Thermo-lag. Not crediting Thermo-lag wrap did not affect the final results for these areas.

4. Electrical cabinet fires, including MCC and switchgear fires, were assumed to result in failure of the entire cabinet. For example, switchgear NB01 and NB02, which each feed an entire train of SSE, are assumed to fail the entire switchgear for all cubical fires. This includes fires in pump supply cubicles, as well as the feeder breakers for load centers NG01, NG02, NG03 and NG04. NB02 has 15 cubicles, including 1 feeder cubical, 1 DG feed, 1 crosstie cubical, and 12 other cubicles. The cubicles for NG02 and NG04 have a CCDP of 1.75E-03 and 3.84E-05 respectively as compared to a switchgear CCDP of 3.33E-03. This data shows that for the MCC feeder cubicles, we may be as much as a factor of 3 to 8 high for these cubicles. If we assume a CCDP of 1.8E-3 for 14 cubicles, a 0.1 probability of failing the entire bus with each cubical fire (a fire may result in a short of the bus), and 3.33E-03 for the feeder cubical, the average CCDP would be 2.2E-03. This average CCDP is a factor of 1.5 lower than the calculated CCDP of 3.3E-03. The factor would be slightly higher if the actual CCDPs are used. Thus this assumption results in approximately a factor of 2 conservatism for switchgear fires.

In addition to modeling limitations, the fire PRA may be subject to more modeling uncertainty than the internal events PRA evaluations. While the fire PRA is generally self-consistent within its calculational framework, the fire PRA does not compare well with internal events PRAs because of the number of conservative assumptions that have been included in the fire PRA process. Therefore, the use of the fire PRA results as a reflection of CDF may be inappropriate. Any use of fire PRA results and insights should consider areas where the “state of the art” in fire PRAs is less evolved than other PRA topics.

While the ability to directly compare the results of the internal events and fire models is limited, information is available that may be used to identify the most important contributors for WCGS. The Fire Re-Analysis document provides some information related to equipment failures by Fire Area and Fire Scenario. This information has been summarized in the table below for selected scenarios from the five largest contributing Fire Areas.

Fire Area	Fire Scenario	CDF	Major Equipment Failed
A-18	NG01B	9.91E-8	Motor Driven AFW Train A, Turbine Driven AFW Train, Potential Stuck Open PORV, Loss of CCW cooling to RCP TBCCs, Train A of Charging Safety Injection, RHR Train A Recirculation
	RJ159A-D	4.14E-7	Same as NG01B
A-21	EGK10	1.23E-7	Motor Driven AFW Train B, Main Feedwater Recovery, RCP Seal Injection, Train B of Component Cooling Water, RHR Train B Recirculation, Train B of Charging Safety Injection, Train B of Class 1E A/C Unit, Emergency Diesel Generator (EDG) NE02
	NG04C	1.97E-7	Same as EGK10
A-22	NG03C	8.76E-7	Motor Driven AFW Train A, Turbine Driven AFW Train, Main Feedwater Recovery, Loss of CCW Cooling to RCP TBCCs, Train A of Component Cooling Water, RHR Train A Recirculation
C-9	All	1.76E-6	Train A of ESF Functions, Motor Driven AFW Train A, Emergency Diesel Generator NE01, Train A Charging Safety Injection, Train A Safety Injection, Train A RHR
C-10	All	1.52E-6	Train B of ESF Functions, Motor Driven AFW Train B, Turbine Driven AFW Train, Emergency Diesel Generator NE02, Train B Charging Safety Injection, Train B Safety Injection, Train B RHR

Considering that the total WCGS fire risk was only estimated to be 5.92E-6/yr, the table above demonstrates that the risk is distributed evenly among the contributing Fire Areas. In addition, while fires in each of these areas results in the loss of a wide range of equipment, it is typically limited to a single division. As a result, redundant equipment is often available to mitigate the fire events. Further discussion is provided for each of the fire areas below.

Fire Area A-18

Any of the failures identified alone in this scenario are not significant failures for WCGS. Even when all the failures occur together as part of the fire scenario, the plant is capable of mitigating the accident:

- Train B of AFW is potentially available,
- Train B of Charging SI is potentially available,
- Train B of RHR is potentially available,
- Seal injection is potentially available,
- A stuck open PORV can be mitigated with the remaining systems.

While SAMAs could be suggested to address each of the degraded safety systems impacted by a fire in this area, a change to address fire propagation is more likely to be cost effective. In this area, a fire in cabinets RJ-159A-D are the largest contributors based on the assumed damage to cables that run over the cabinets. A potential means of reducing the impact of a fire in these cabinets is to install fire barriers around the sensitive cables that run over the fire source or to reroute the cables (SAMA 15).

Fire Area A-21

Any of the failures identified alone in this scenario are not significant failures for WCGS. Even when all the failures occur together as part of the fire scenario, the plant is capable of mitigating the accident:

- The turbine driven AFW pump and the train A motor driven AFW pump are potentially available for steam generator makeup,
- Train A of CCW is potentially available, which can provide thermal barrier cooling,
- Train A of RHR recirculation is potentially available,

- Train A of Charging SI is potentially available,

- The B Class 1E AC system is potentially available.

For this fire area, one of the concerns is the limited seal cooling capability given that seal injection is disabled in conjunction with train A of CCW. In the event that the remaining CCW train fails, SAMA 1 could provide an alternate means of seal cooling.

The unavailability of EDG NE01 could be an issue for this fire area; however, offsite power is not lost as a result of the fire event and would likely be available.

Failure of RHR train A would eliminate all low pressure ECCS, but with two trains of AFW and several high pressure makeup sources available to the primary coolant loop, cooldown is still possible and this is not considered to be a major issue for this fire area.

While SAMAs could be suggested to address each of the degraded safety systems impacted by a fire in this area, a change to address fire propagation is more likely to be cost effective. In this area, a fire in MCC NG04C is the largest contributor based on the assumed damage to cables that run over the MCC. A potential means of reducing the impact of a fire in this equipment is to install fire barriers around the sensitive cables that run over the fire source or to reroute the cables (SAMA 15).

Fire Area A-22

The impact of a fire in this area is similar to one in fire area A-18. An additional concern, however, is the unavailability of CCW train A, which only leaves train B of charging SI available for seal injection. SAMA 1 is a potential means of addressing degraded seal cooling issues that would result from a fire in this area. However, it was noted that the main source of risk for this fire area results from damage to the cables that run above MCC NG03C. A potential means of reducing the impact of a fire in this MCC is to install fire barriers around the sensitive cables that run over the fire source or to reroute the cable (SAMA 15).

Fire Area C-9

A fire in this area fails a large portion of the A train safety systems. Due to the wide range of failures resulting from such a fire, multiple SAMAs would be required to address the failed safety functions of an unsuppressed fire. As a result, cost effective changes are more likely to be found in methods directed at preventing the fire or damage from the fire.

A major consideration when considering the results of fires in area C-9 is that limited credit is taken for the existing Halon system and no credit is taken for manual suppression. If means were available to realistically characterize the impact of the existing fire suppression capabilities, the CDF contribution from this are would likely be much less.

However, it was noted that the fire with the largest contribution to this area's CDF is from a 480V load center (NG03) that has sensitive cables located directly above the load center such that they are likely to be damaged if a fire occurs in the load center. A potential means of reducing the impact of a fire in this load center is to install fire barriers around the sensitive cables that run over the fire source or to reroute the cable (SAMA 15).

Fire Area C-10

This fire area is similar to fire area C-9. While the largest contributor for this area is a fire in cabinet GS01B, the same types of changes are suggested (SAMA 15).

Fire SAMA Identification Summary

Based on the review of the WCGS fire area results, the fire areas with the largest CDF contributions impact multiple systems such that several SAMAs would be required to address all of the fire related equipment failures. However, in the fire areas with the largest contributions to CDF, safety equipment damage is the result of damage to cables running over equipment fires. In each case, the change that has been suggested to reduce plant risk is to either re-route the cable or place protective barriers around the cables (SAMA 15).

A consideration related to the identification of this SAMA is that the results may be biased based on the limited credit taken for automatic and manual fire suppression. As a result, the true benefit of any changes to protect cables may be skewed.

F.5.1.6.2 Seismic Events

The EPRI seismic margins methodology (EPRI 1991) is used to identify the minimal set of equipment required to safely shut the reactor down and to determine if that equipment is capable of surviving the Review Level Earthquake (RLE). Equipment that is not capable of withstanding the RLE is identified and required to be addressed. While methods exist for using this information to develop a seismically induced core damage frequency, this was not performed as part of the WCGS IPEEE. It should also be noted that even in a seismic analysis developed to yield a CDF, the pedigree of information is not equivalent to what is used in the internal events models. Given that there is a limited amount of seismic response information available for nuclear power plants, analysis techniques developed to model the plant response often compensate by ingraining a conservative bias in their methodologies to prevent overestimating the capabilities of the plants. While seismic risk evaluations are helpful in the identification of potential plant weaknesses, the methodologies have not evolved to a point where the results can be directly compared with the internal events models.

As indicated above, the seismic margins analysis (SMA) results are useful in the identification of potential plant weaknesses, but the foundations of the SMA should be acknowledged when considering the results. For example, the WCGS IPEEE identifies multiple examples of the conservative biases that are present in the plant's SMA:

1. The design basis ground spectra were based on a conservative envelope of several natural earthquakes that occurred on soil and rock sites. In addition, the vertical direction of response is equal to the horizontal direction rather than two thirds of the horizontal direction.

2. A synthetic earthquake acceleration time history was derived for use as an input to generate floor response spectra. A response spectrum of the synthetic time history envelopes the original design basis ground response spectrum with a significant margin that varies in magnitude along the frequency range.

3. Seismic design of Category I structures was performed by using linear elastic techniques. However, experience tells us that past near failures involve some degree of yielding, which results in nonlinear inelastic energy absorption. The original seismic design documents did not account for these inelastic energy absorption mechanisms and consequently substantial factors of safety were built in at various design states.

4. For seismic equipment qualification by testing, the test response spectra usually envelop the required response spectra over the frequency range of interest with a reserve margin.

5. For dynamic qualification of similar pieces of equipment, dynamic demand was usually calculated by conservatively enveloping demand at different floor locations. This usually results in unrealistic dynamic demand with more than one peak and broad frequency content.

With these limitations in mind, the WCGS IPEEE seismic results and history were reviewed in order to determine if there were any unresolved issues that could impact WCGS risk. The types of issues that were of interest included:

Unfinished plant enhancements that were determined to be required to ensure the equipment on the Safe Shutdown List would be capable of withstanding the RLE. Additional plant enhancements that were identified as means of reducing seismic risk but were not implemented at the plant.

An effort was also made to use the results of the equipment and structural screening documentation to determine if any outlier issues that were screened in the IPEEE could impact seismic risk at WCGS. The following subsections summarize this review.

F.5.1.6.2.1 Unfinished Plant Enhancements

All seismic plant enhancements that were suggested for implementation have been completed at Wolf Creek. These were minor items addressed using the plant's work request program.

F.5.1.6.2.2 Additional Plant Enhancements

The equipment analysis identified few items that could not be assigned high confidence of low probability of failure (HCLPF) capacities of at least 0.30g pga. The exceptions to this were as follows:

- Battery Racks: The battery racks for NK011, NK012, NK013, and NK014 were found to have been constructed with spaces between the side rails and the batteries greater than the specified maximum. Without comprehensive testing to determine how the additional space in the racks would impact the equipment's seismic response, it was not possible to assign the racks a HCLPF value greater than 0.20g pga. The conclusion of the IPEEE was that further testing or modifications to the battery racks would not be cost effective and no changes were made to the battery racks. Given that a HCLPF value of 0.20g pga is all that is required to screen equipment for a reduced scope plant such as WCGS, no further action was required. However, subsequent efforts by the plant resulted in the modification of the battery racks to meet the 0.30g pga HCLPF requirement.

- ESFAS Cabinets: Eight ESFAS/LSELS cabinets 90"H x 24"W x 30"D are located adjacent to each other with no gaps. Only cabinets SA036E, SA036C, and SA036D are connected. The connection between the assemblies is via bushings for cable entries. Cabinets SA036A, SA036B, NF039A, NF039B and NF039C did not appear to be bolted together. While some coupling existed between the cabinets, the fastenings did not meet the requirements for the cabinets to be assigned HCLPF values of 0.30g pga or greater and a value of 0.20g pga was assigned. Given that a HCLPF value of 0.20g pga is all that is required to screen equipment for a reduced scope plant such as WCGS, no further action was required.

Seismic Summary

Based on the review of the WCGS seismic analysis, no seismic specific SAMAs have been included on the WCGS SAMA list.

F.5.1.6.3 High Wind Events

For the High Winds analysis, WCGS employed a progressive screening approach in the IPEEE to assess the potential plant vulnerabilities. This approach included the following steps:

1. Data contemporary to the analysis was collected and reviewed in order to characterize the hazard for the site. The hazard characterization was then compared to the WCGS design basis as documented in the Updated Safety Analysis Report (USAR) (WCNOC 2006a) and the related design basis documents;

2. The changes that had been made to the plant since the issuance of the operating license were reviewed to determine if any significant modifications had been made that would impact plant response to the relevant initiators;

3. Based on the updated characterization of the external events hazards and the assessment of the plant changes made after issuance of the operating license, the WCGS design was reviewed to determine if it conformed to the requirements of the Standard Review Plan (SRP) (NRC 1987).

If the requirements of the SRP were determined to be met, no further investigation of High Winds events were considered to be required. Further provisions to perform a risk based analysis of the high winds hazard were included in the External Events assessment methodology; however, this was not required for Wolf Creek.

No substantive climatological changes or event were identified that would require revision to the plant design basis. As a result, the high wind hazard for the plant at the time of the IPEEE was considered to be unchanged from that considered for issuance of the operating license and no plant changes were identified that would impact plant response to a high winds event.

All of the equipment in the plant required for safe shutdown was determined to be contained within Category I buildings. As these buildings were designed to withstand high winds events equivalent to those documented in the SRP, no vulnerabilities were identified for Wolf Creek. In addition, the IPEEE plant walkdowns did not reveal potential vulnerabilities not considered in the original design basis.

For the SAMA analysis, these results were considered to be an acceptable basis for precluding the inclusion of plant changes related to High Winds on the WCGS SAMA list.

F.5.1.6.4 External Flooding and Probable Maximum Precipitation

The External Flooding and Probable Maximum Precipitation event analysis followed the same methodology described for the High Winds analysis described in section F.5.1.6.3.

Based on a revised National Weather Service methodology for estimating local rainfall, the Probable Maximum Precipitation (PMP) estimate for WCGS changed from what was used for the original assessment for operating license issuance. Generic Letter 89-22 required nuclear licenses to assess the effects of the new estimates on their plants. The evaluation performed for WCGS demonstrated that the revised PMP estimates would not result in on-site flood levels or roof ponding that would adversely affect the safe operation of the plant.

With respect to plant changes, the revisions of the plant “S” drawing were reviewed to determine if any changes would impact how the plant would respond to an external flooding event. In addition, all of the plant modification packages that were linked to plant drawing revisions were evaluated. While some changes were performed in areas with the potential to impact external flooding, they were determined to have either no impact of the external flooding analysis, or their impact on the external flooding hazard for safety related facilities was found to be acceptable.

Given that WCGS was designed to conform with the requirements of the SRP (NRC 1987) and the requirements contained within Regulatory Guides 1.59 (NRC 1977) and 1.102 (NRC 1976), the plant was found to meet the criteria required by the SRP for flood events. A plant walkdown was performed as part of the IPEEE to identify any issues that deviated from plant design. The walkdown did not reveal any vulnerabilities associated with external flooding that were not included in the external flooding hazards analysis.

For the SAMA analysis, these results were considered to be an acceptable basis for precluding the inclusion of plant changes related to External Flooding on the WCGS SAMA list.

F.5.1.6.5 Transportation and Nearby Facility Accidents

Transportation and nearby facility accidents were included in the WCGS IPEEE to account for human errors or equipment failures that may occur in events not directly related to the power generation process at the plant. The types of hazards identified for analysis included:

- Transportation accidents
    - Aircraft Activity
    - Roads/Highways
    - Railroad
    - Pipelines
    - Aviation
- Nearby Industrial Facilities
- Nearby Military Facilities

- Hazardous Material Releases from Onsite Storage
- Other Onsite Hazards

As was the case with the high winds and external flooding analyses, the progressive screening approach was used to evaluate the threats from these events.

At the time the IPEEE was performed, available information related to military, commercial, and general aviation traffic was used to estimate the frequency of a release of radionuclides caused by aircraft impact. Given the information and conditions present at the time of the analysis, the frequency was determined to be less than 5.5E-08 per year and further analysis was not considered warranted.

It is recognized that the types of credible threats to nuclear facilities by aircraft have changed since the time the IPEEE was published. While this is true, efforts are underway within the industry to address this issue in conjunction with other forms of sabotage. Based on the fact that this topic is currently being analyzed in another forum and due to the complexity of the issue, aircraft impact events are considered to be out of the scope of the SAMA analysis.

The remaining Transportation and Nearby Facility related events were evaluated at the time WCGS was licensed. The results of the original evaluation are documented in the USAR Sections 2.2 and 3.5. (WCNOC 2006a) As part of the development of the WCGS IPEEE, these hazards were reviewed to determine if there had been any substantive changes which may have increased the plant vulnerability to the hazard. This included a review of both the nature of the traffic and facilities near the plant and changes to the plant itself. The review of these issues focused on identifying any changes that could result in a new or increased threat of the following:

- Explosions
- Release of Flammable Vapor Clouds
- Release of Toxic Chemicals

- Fires that Could Threaten Plant Operation
- Collisions with Intake Structures
- Liquid Spills

It was determined that none of the plant changes made since issuance of the operating license had the potential to introduce conditions that would pose a threat to the safe operation of the plant.

The plant/site area walkdown that was performed as part of the IPEEE confirmed that the information used in the external events analysis was representative of the actual conditions and that the plant conformed to the SRP (NRC 1987) design criteria.

For the SAMA analysis, these results were considered to be an acceptable basis for precluding the inclusion of plant changes related to Transportation and Nearby Facility accidents on the WCGS SAMA list.

F.5.1.7 INTERNAL FLOODING

Like the external events analyses, the WCGS internal flooding model has not been maintained as part of the living PRA. As a result, the flood related SAMA identification and quantification efforts have been performed separately from those performed using the internal events analysis.

In order to determine if any flood scenarios could yield potentially cost beneficial SAMAs, a screening was performed by quantifying the cost-risk associated with the largest flood scenario (FL3) and comparing it with the minimum expected SAMA implementation cost ($50,000). If the cost-risk corresponding to FL3 is less than the minimum expected SAMA implementation cost, then no cost effective SAMAs are expected to be found. If the FL3 cost-risk is greater than the minimum expected SAMA implementation cost, then further investigation to identify potential SAMAs for reducing flood risk would be required. This process is considered to be adequate to determine if any internal flooding SAMA could be potentially cost beneficial SAMAs given that the changes developed for any specific flood scenario would not likely reduce the risk of the other flood scenarios without a proportional cost expenditure. The exception would be a flood safe system that could provide an alternate safe shutdown path for any of the internal flooding scenarios. In this case, a single cost of implementation would impact all flood scenarios. This possibility is also analyzed.

F.5.1.7.1 Flood Scenario Examination

Based on the latest available internal flooding analysis (WCNOC 1996c), the flooding scenario with the largest CDF is Scenario 3 (FL3), with a CDF of 1.37E-06/yr. For the purposes of this analysis, it is assumed that the internal flooding CDF is directly comparable to the current internal events CDF. It is also assumed that the distribution of the flooding CDF among the Level 2 release categories is the same as the non-ISLOCA/SGTR initiators. Using these assumptions and the methodology in Section F.4, a cost-risk can be calculated that corresponds to the elimination of all on-line FL3 risk.

In order to calculate the release category frequencies related to FL3 risk, the baseline distribution of the CDF among the non-ISLOCA/SGTR release categories was first calculated. This was done by dividing each non-ISLOCA/SGTR release category frequency by the total frequency of the CIF, ECF, LCF, and Leakage/NCF release categories:

Distribution of Non-ISLOCA/SGTR Events Among Release Categories

Release Category	CDF Contribution	Fraction of Non-ISLOCA/SGTR Total
CIF	3.42E-08	1.16E-03
ECF	4.48E-07	1.51E-02
LCF	1.13E-06	3.82E-02
Leakage/NCF	2.80E-5	9.45E-01
Total	2.96E-5	1.0

Given an FL3 CDF of 1.37E-06/yr, the corresponding release category frequencies can then be calculated. For a given release category, the release category frequency would be:

$$RC\ Freq_{FL3} = CDF_{FL3} * \text{Non-ISLOCA/SGTR Fraction}$$

Where:

- RC $Freq_{FL3}$ = The individual release category frequency based on FL3 risk,
- CDF_{FL3} = The CDF associated with FL3,
- Non-ISLOCA/SGTR Fraction = The fraction of the CDF distributed to a given release category when SGTR and ISLOCA initiators are excluded from consideration.

Once the release categories are calculated, the dose-risk and OECR can then be calculated as they are directly proportional to frequency. The following table summarizes these results:

FL3 Level 2 and 3 Results Summary

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.40E-08	2.54E-07	1.93E-06	4.48E-07	1.13E-06	2.80E-05	**3.18E-05**
Frequency (/yr)$_{FL3}$	1.59E-09	0.0	0.0	2.07E-08	5.23E-08	1.29E-06	**1.37E-06**
Dose-Risk$_{BASE}$	0.01	0.06	2.57	0.14	0.04	0.09	**2.91**
Dose-Risk$_{FL3}$	0.00	0.00	0.00	0.01	0.00	0.00	**0.01**
OECR$_{BASE}$	$17	$110	$1,668	$239	$2	$0	**$2,036**
OECR$_{FL3}$	$1	$0	$0	$11	$0	$0	**$12**

This information is then used to calculate an associated “total cost-risk” using the methodology provided in F.4. The results of this calculation are provided in the following table.

FL3 Total Cost-Risk

Off-site exposure cost	=	$301
Off-site economic cost	=	$180
On-site exposure cost	=	$848
On-site cleanup cost	=	$26,701
Replacement Power cost	=	$9,691

Total cost	=	$37,721

Given that cost-risk associated with FL3 is only $37,721 and that the minimum cost of a plant change is expected to be $50,000, even if a change were devised to eliminate all on-line FL3 risk, the change would not be cost beneficial (the cost of implementation is greater than the benefit of realizing the change). Based on this assessment, no further investigation into flood specific scenarios to identify SAMAs is considered to be required.

F.5.1.7.2 Total Flood Risk Examination

While it has been determined that no flood scenario specific changes would be cost-effective for WCGS, there is a potential that a flood safe system that would provide a safe shutdown path for any flood scenario could be cost effective. The same process used to examine the individual flood scenarios is used to estimate the total cost risk for all floods.

The latest available internal flooding analysis (WCNOC 1996c) indicates that the total internal flooding CDF is 2.53E-06/yr. The Level 2 release category frequencies and the corresponding dose-risk and OECR are calculated in the same way as for FL3. The following table summarizes these results:

Total Internal Flooding Level 2 and 3 Results Summary

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.40E-08	2.54E-07	1.93E-06	4.48E-07	1.13E-06	2.80E-05	**3.18E-05**
Frequency (/yr)$_{Flood}$	2.93E-09	0.00E+00	0.00E+00	3.82E-08	9.66E-08	2.39E-06	**2.53E-06**
Dose-Risk$_{BASE}$	0.01	0.06	2.57	0.14	0.04	0.09	**2.91**
Dose-Risk$_{Flood}$	0.00	0.00	0.00	0.01	0.00	0.01	**0.02**
OECR$_{BASE}$	$17	$110	$1,668	$239	$2	$0	**$2,036**
OECR$_{Flood}$	$1	$0	$0	$20	$0	$0	**$21**

This information is then used to calculate an associated "total cost-risk" using the methodology provided in F.4. The results of this calculation are provided in the following table.

Total Internal Flooding Cost-Risk

Off-site exposure cost	=	$602
Off-site economic cost	=	$316
On-site exposure cost	=	$1,566
On-site cleanup cost	=	$49,310
Replacement Power cost	=	$17,897
Total cost	=	$69,691

While the total internal flooding cost-risk of about $70,000 exceeds the minimum expected cost of implementation for a SAMA ($50,000), the cost of implementation for any flood safe system would greatly exceed the minimum SAMA implementation cost. For example, addition of a passive injection system in the design phase of a reactor was estimated to cost over $1.7 million (GE 1994). This change would not even provide a protected means of providing containment heat removal, which would be required for a flood-safe shutdown path at WCGS. Based on the total cost-risk associated with all internal flooding events and the high costs associated with installing systems that could mitigate all flood scenarios or combinations of scenarios, no further investigation of internal flooding based SAMAs is considered to be warranted.

F.5.1.8 QUANTITATIVE STRATEGY FOR EXTERNAL EVENTS

The quantitative methods available to evaluate external events risk at WCGS are limited, as discussed above. In order to account for the external events contributions in the SAMA analysis, a multi-staged process has been implemented to provide gross estimates of the averted cost-risk based on external events accidents. Internal flooding is also addressed here as the internal flooding model has not been maintained with the internal events model.

The first part of this process is used in the Phase I analysis and is based on the assumption that the risk posed by external and internal events is approximately equal. For WCGS, the external events analysis, which has been identified as a conservative analysis, yielded a CDF of only 5.92E-06/yr for the quantified event types (Fire). While no CDF was quantified for the seismic, high wind, flood, and transportation and nearby facility event types, fire risk is typically the largest of these contributors. If it is assumed that the risk for each of the non-quantified contributors is comparable to fire risk (5.0E-06/yr), the total external events risk could be estimated as the sum of these contributors. The latest internal flooding contribution was estimated to be 2.53E-06/yr and is also included here:

Event Type	CDF
Fire	5.92E-06
Seismic	5.00E-06
High Wind	5.00E-06
External Flood	5.00E-06
Transportation and Nearby Facility Accidents	5.00E-06
Internal Flooding	2.53E-06
Total	2.84E-05

As this is comparable to the internal events CDF of 2.98E-05 per year, the assumption that the external events contributions are equal to the internal events contributions is not considered to be unreasonable.

Given that the risk is assumed to be equal, the MACR calculated for the internal events model has been doubled to account for external events contributions. This total is referred to as the modified MACR (MMACR). The MMACR is used in the Phase I screening process to represent the maximum achievable benefit if all risk related to on-line power operations was eliminated. Therefore, those SAMAs with costs of implementation that are greater than the MMACR were eliminated from further review.

The second stage of this strategy is to also apply the doubling factor to the Phase II analysis. Any averted cost-risk calculated for a SAMA was multiplied by two to account for the corresponding reduction in external events risk.

The final stage of the process is used for SAMAs that were identified based on IPEEE insights. For these cases, IPEEE insights and the Internal Events PSA are used, as appropriate, to develop an averted cost-risk for the SAMA that accounts for the external and internal events risk reductions. For instance, the IPEEE typically provides information that can be used to estimate bounding changes in risk that would be realized if the SAMAs were implemented. These risk changes are used to approximate averted cost-risks based on external events contributions. Then, if it can be determined that the SAMA would impact the internal events model, the PSA is used to quantify the averted cost-risk based on its internal events contributions. The cost-risks from the external and internal events results are then added to yield the total for the SAMA. In some cases, the SAMAs do not impact the internal events models and the calculations do not require the use of the PSA model.

F.5.2 PHASE I SCREENING

The initial list of SAMA candidates is presented in Table F.5-3. The process used to develop the initial list is described in Section F.5.1.

The purpose of the Phase 1 analysis is to use high-level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. The following screening criteria were used:

Applicability to the Plant: If a proposed SAMA does not apply to the WCGS design, it is not retained.
Implementation Cost Greater than Screening Cost: If the estimated cost of implementation is greater than the modified Maximum Averted Cost-Risk, the SAMA cannot be cost beneficial and is screened from further analysis.

Table F.5-3 provides a description of how each SAMA was dispositioned in Phase 1. Those SAMAs that required a more detailed cost-benefit analysis are evaluated in Section F.6.

F.6 PHASE II SAMA ANALYSIS

Not all of the Phase 2 SAMA candidates require detailed analysis. The Phase 2 process allows for the screening of SAMAs known to be related to non-risk significant systems or to components/functions with low importance rankings. Due to the nature of the PSA based process used to develop the SSES SAMA list, there are limited avenues for SAMAs of this type to be included in the list. However, potential pathways do exist:

- Inclusion of unresolved proposed plant changes from previous WCGS risk analyses,
- Inclusion of SAMAs based on the results of conservative modeling methods.

While no calculations are required for eliminating a SAMA that is linked to a non-risk significant system or components, some quantitative efforts are usually required to screen SAMAs that were developed to address risk contributors based on conservative modeling techniques. These cases are identified in Table F.5-4 and discussed in detail in the SAMA specific subsections of F.6.

For the SAMAs requiring detailed analysis, a more detailed conceptual design was prepared along with a more detailed estimated cost. This information was then used to evaluate the effect of the candidates' changes upon the plant safety model.

The final cost-risk based screening method is defined by the following equation:

Net Value = (baseline cost-risk of site operation (MMACR) – cost-risk of site operation with SAMA implemented) – cost of implementation

If the net value of the SAMA is negative, the cost of implementation is larger than the benefit associated with the SAMA and the SAMA is not considered beneficial. The baseline cost-risk of plant operation was derived using the methodology presented in Section F.4. The cost-risk of plant operation with the SAMA implemented is determined in the same manner with the exception that the revised PSA results reflect implementation of the SAMA.

The implementation costs used in the Phase 2 analysis include both WCGS specific estimates developed by plant personnel and estimates taken from other SAMA submittals for those SAMAs that were determined to be highly similar. It should be noted that the WCGS specific implementation costs do not include contingency costs for unforeseen difficulties or any replacement power costs that may be incurred due to consequential shutdown time.

Sections F.6.1 – F.6.13 describe the detailed cost-benefit analysis that was used for each of the remaining candidates.

F.6.1 SAMA NUMBER 1: PERMANENT, DEDICATED GENERATOR FOR THE NCP WITH LOCAL OPERATION OF TD AFW AFTER 125V DC DEPLETION

This SAMA addresses the largest WCGS SBO risk contributors, which are seal LOCAs that develop due to loss of seal cooling in those scenarios. The installation of a permanent EDG dedicated to providing power to the NCPs is a means of reducing the probability that seal injection will be unavailable in those scenarios. In order to limit the size of potential seal LOCAs, a requirement of this SAMA is that it must provide the capability to rapidly align the dedicated EDG to the NCPs so that seal cooling can be restored within 13 minutes of the initial seal cooling loss. Based on the power requirements of the NCP, the dedicated EDG should be at least 500kW in size. While the dedicated EDG provides a means of supporting seal injection and primary side makeup, it is also necessary for the operators to implement existing plant procedures to operate the TD AFW pump without 125V DC power for success.

In order to represent this SAMA, the Level 1 model was modified by adjusting the probabilities of the sequences determined to be impacted by the proposed changes. SBO sequences SBOS02 through SBOS32 would all be impacted by this SAMA and were considered to result in a safe endstate given successful operation of the dedicated NCP EDG and local operation of the TD AFW pump. For the purposes of this analysis, the total failure probability of the operator errors and hardware was assumed to be 1.0E-1. Lower values for this estimate are not suggested given the short time available to start and align the NCP EDG, the unavailability of RWST, CST, and steam generator level instrumentation, and the high stress factor that would be present in the SBO scenario.

The total CDF frequency of SBO sequences SBOS02 through SBOS32 is 1.61E-06. Multiplying this total by the SAMA failure probability of 1.0E-01 results in a frequency of 1.61E-06, which represents a reduction of 1.45E-05 (1.61E-05 – 1.61E-06 = 1.45E-05).

For the Level 2 model, the proposed SAMA will provide negligible or no risk reduction to the ISLOCA and SGTR release categories. Therefore, the release category frequencies for these contributors are assumed to remain unchanged. The ECF and CIF release category frequencies are determined based on the remaining CDF cutsets and Level 2 containment safeguards systems failures (containment coolers, containment sprays, containment isolation). Since the proposed NCP/DG change will provide negligible additional benefit for the containment safeguards systems, an upper bound estimate of the impact of this SAMA on the ECF and CIF frequencies may be obtained by reducing their baseline frequencies by the percentage reduction realized for CDF. The LCF and NCF release category frequencies are estimated using the conditional probabilities determined in the IPE, as described in Section F.2.8.

The cost of implementation for providing a dedicated diesel generator (DG) for the advanced boiling water reactor (ABWR) Feedwater or Condensate pumps was estimated to be $1.2 million in 1994 (GE 1994). The capacity of the generator required for the ABWR application likely exceeds that required for the WCGS NCP, which is only about 500kW. As a result, the ABWR cost has been reduced by 33 percent and not inflated to 2006 dollars to estimate a cost of implementation for this SAMA ($800,000).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.98E-05	2.86	$1,974
SAMA Results	1.53E-05	2.73	$1,849
Percent Change	48.6	4.6	6.3

A further breakdown of this information is provided below according to release category.

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency (/yr)$_{SAMA}$	1.66E-09	1.65E-07	1.92E-06	2.18E-07	5.78E-07	1.44E-05	**1.72E-05**
Dose-Risk$_{BASE}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
Dose-Risk$_{SAMA}$	0.04	2.55	0.07	0.02	0.05	**2.73**	0.04
OECR$_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
OECR$_{SAMA}$	$1	$72	$1,659	$116	$1	$0	**$1,849**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 1 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,052,118	$799,882	$800,000	-$118

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.6.2 SAMA NUMBER 2: MODIFY THE CONTROLS AND OPERATING PROCEDURES FOR SHARPE STATION TO ALLOW FOR RAPID RESPONSE

An off-site diesel generating plant (Sharpe Station) has an agreement with Wolf Creek to provide power to the site in the event that Wolf Creek experiences a Station Blackout. While the ten 2MW diesel generators have the capacity to power the emergency loads, the time to align power to WCGS is long and is not expected to be complete before 4 hours after the onset of degraded AC conditions. Providing the WCGS control room

(CR) with the ability to start and align these generators to the WCGS emergency buses through the switchyard is a means of restoring power to WCGS in non-weather related loss of offsite power (LOOP) events.

Currently, the Sharpe Station is only given full credit during a 7-day, time-of-year-specific, pre-planned maintenance interval. Local operator action is needed to black-start Sharpe Station. Hardware modifications at Sharpe Station and in the Wolf Creek Control Room (as a minimum) would be needed to allow remote, black-start by the WC Control Room. Additional local Wolf Creek switchyard settings of transformers/breakers are necessary to align Sharpe Station power to the Wolf Creek Class IE electrical bus. The equipment related to these switchyard actions may also have to be modified to allow remote operation to maximize the benefit of the SAMA.

In order to represent this SAMA, the SBO flag event was modified in the Sharpe Station sensitivity module from a value of 1.0 to the top event probability of 0.294 that Sharpe fails to deliver power to the WCGS switchyard. The top event probability accounts for weather related issues that fail the lines between Sharpe Station and WCGS, Sharpe Station hardware failures, WCGS switchyard component failures, and other non-recoverable failures such as XNB01 transformer failures or failures of both ESW trains.

The cost of this enhancement has been estimated to be $400,000k (WCNOC 2006b).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.98E-05	2.86	$1,974
SAMA Results	1.80E-05	2.71	$1,802
Percent Change	39.6	5.2	8.7

A further breakdown of this information is provided below according to release category.

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency (/yr)$_{SAMA}$	1.00E-09	1.65E-07	1.92E-06	1.32E-07	6.80E-07	1.69E-05	**1.98E-05**
Dose-Risk$_{BASE}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
Dose-Risk$_{SAMA}$	0.00	0.04	2.55	0.04	0.03	0.05	**2.71**
OECR$_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
OECR$_{SAMA}$	$0	$72	$1,659	$70	$1	$0	**$1,802**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 2 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,196,288	$655,712	$400,000	$255,712

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

F.6.3 SAMA NUMBER 3: AC CROSS-TIE CAPABILITY

Failure of an EDG combined with the failure of safety equipment in the opposite electrical division results in the unavailability of equipment that could be used if power were aligned to it. WCGS currently has no emergency procedures to provide power between the class 1E 4kV buses. Developing a 4kV AC cross-tie capability is considered to be a viable means of reducing the risk of LOOP events for WCGS. Providing the ability to perform the cross-tie in a time frame consistent with supporting mitigating efforts in a loss of injection case would maximize the benefit of this SAMA.

The intent of this SAMA is to provide WCGS with cross-tie capability through procedure changes and minimal hardware modifications. The proposed changes include providing a mechanism to easily bypass the emergency 4kV AC feeder breaker interlocks such that new procedures would allow the operators to cross-tie buses in non-maintenance conditions.

F.6.3.1 LEVEL 1 MODELING

In order to represent this SAMA, the cutsets were reviewed to identify contributions that would benefit from the implementation of this SAMA. Once the cutsets were identified, their frequencies were modified to mimic the availability of the cross-tie.

It was determined that cross-tie of the buses should only be necessary if there is a loss of AC power to one bus, but an AC power source is available to the opposite bus. Power can be lost to an ESF bus from the offsite power source by either failure of the ESF transformer associated with the bus, or by a total loss of offsite power condition. A review of those core damage cutsets that include failure of an ESF transformer indicates that the contribution from failure of these transformers has a small impact on the overall CDF (four cutsets in the low E-10 range). Accordingly, no appreciable benefit would be gained by considering cross-tie capability for these cutsets.

For cutsets where offsite power is lost, the power supply to the ESF buses is from the associated EDG. However, there would be no benefit to having cross-tie capability for any cutsets where there is a loss of offsite power along with failure of both EDGs, or failure of both trains of Essential Service Water.

An estimate of the benefit of an AC bus cross-tie was obtained by first generating a fault tree model reflecting loss of offsite power conditions along with the major component failure combinations that would fail both EDGs or both ESW trains. This fault tree was quantified and the resultant cutsets were removed from the total internal events core damage cutset equation file. The resulting file included those core damage cutsets where consideration of an AC bus cross-tie might reasonably provide some benefit.

The total internal events core damage frequency is 2.98E-05. Removal of loss of offsite power cutsets where both EDGs or both ESW trains fail results in a core damage cutset file with value of 2.06E-05.

It was assumed that an AC bus cross-tie would have a failure probability on the order of 5.0E-02. This factor was applied, using the WinNUPRA sensitivity module, to all remaining cutsets which included failure of an EDG.

Applying a factor of 0.05 for all EDG related failure events for cutsets in the file where failures of both EDGs and ESW divisions were removed resulted in a final core damage cutset file with value of 1.53E-05.

The benefit due to addition of an AC bus cross-tie would therefore be approximately 5.30E-06 (2.06E-05 – 1.53E-05). Applying this same CDF reduction to the total internal events cutset file would result in a CDF value of 2.45E-05 (2.98E-05 – 5.30E-06).

E.6.3.2 LEVEL 2 MODELING

In order to quantify the impact of this SAMA on the Level 2 results, a cutset review/manipulation process was used for each release category.

The proposed SAMA will provide minimal or no benefit for the ISLOCA containment bypass sequences. Therefore, the ISLOCA release category frequency is assumed to remain unchanged.

For the SGTR, CIF, and ECF release categories, the fault tree reflecting a loss of offsite power condition with failure of both EDGs or both ESW trains was quantified and the resultant cutsets were removed as non-recoverable using the AC bus cross-tie.

- CIF: Removal of the dual division EDG and ESW failures resulted in removal of all of the cutsets in the CIF release category. Therefore, CIF release category frequency remained unchanged.

- SGTR: Application of a reduction factor of 0.05 for all cutsets containing an EDG failure results in a revised frequency of 1.56E-07 (no dual division EDG/ESW failures existed in the original cutsets).

- ECF: Removal of the cutsets with dual division EDG/ESW failures resulted in a frequency of 1.06E-07. Application of a cross-tie failure probability of 0.05 for the remaining cutsets yielded a frequency of 1.86E-08. The reduction in the ECF frequency is 8.74E-08 (1.06E-07 – 1.86E-08). The final frequency for this release category is 3.61E-07 (4.48E-07 – 8.74E-08).

The LCF and NCF release category frequencies are estimated using the conditional probabilities determined in the IPE, as described in Section F.2.8.

Susquehanna Steam Electric Station (SSES), a dual unit site, estimated an implementation cost of $656,000 to develop emergency 4kV cross-tie procedures and to install interlock bypass capability to reduce the difficulty and manipulation time of the task (PPL 2006). In this case, the hardware for the cross-tie existed and implementation required only smaller hardware changes. This implementation cost is considered to be a reasonable estimate for the cost of the changes that would be required for WCGS when adjusted to account for single unit implementation. The single unit cost of implementation is estimated by dividing the $656,000 cost by 2, which yields $328,000.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.98E-05	2.86	$1,974
SAMA Results	2.45E-05	2.80	$1,924
Percent Change	17.8	2.1	2.5

A further breakdown of this information is provided below according to release category.

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency (/yr)$_{SAMA}$	3.42E-09	1.56E-07	1.92E-06	3.61E-07	9.26E-07	2.30E-05	**2.63E-05**
Dose-Risk$_{BASE}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
Dose-Risk$_{SAMA}$	0.00	0.03	2.55	0.11	0.04	0.07	**2.80**

$OECR_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
$OECR_{SAMA}$	$2	$68	$1,659	$193	$2	$0	**$1,924**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 3 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,558,748	$293,252	$328,000	-$34,748

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.6.4 SAMA NUMBER 4: ISLOCA ISOLATION

The current Wolf Creek PRA model does not credit actions to isolate the modeled ISLOCAs as it has not been confirmed that the relevant isolation valves can fully close with RCS pressure against them. The plant engineering staff estimates that while some valve movement would be possible, the valves would only reach a partially closed position before exceeding the torque limit of the valve operator. Based on this assessment, it is assumed that it is not possible to isolate these types of ISLOCAs and that core damage would eventually occur in these accidents. This is considered conservative and bounding since partial motor operated valve (MOV) closure would likely significantly reduce the break flow allowing additional time for possible local, manual isolation of the break. In addition, there may be other in-series manual valves that could be locally closed to isolate the reduced break flow. Ensuring that procedures direct this isolation in all ISLOCA events is a potential means of addressing some of the ISLOCA scenarios (those where access is possible). Alternatively, the valves in the most important ISLOCA paths could be replaced with a type that can close against RCS pressure.

In order to simulate implementation of changes that would allow ISLOCA isolation, modifications were made to the PRA model to include isolation credit for the largest

ISLOCA contributors. Specifically, the Low Pressure Safety Injection (LPSI) Cold Leg Injection (CLI) line ISLOCA scenarios were addressed as they account for 94 percent of the ISLOCA risk (given no isolation credit). While some risk reduction may be possible through procedure and hardware changes for the remaining ISLOCA scenarios, they are small contributors and are not included in the cost benefit calculations performed for this SAMA.

Two quantifications have been performed to address the different approaches that are proposed by this SAMA for reducing ISLOCA risk:

- Case 1, Replace Valves: Estimate the benefit of installing new valves that are capable of isolating against RCS pressure,

- Case 2, Proceduralize Local Actions: Estimate the benefit of including guidance to direct equipment operators to perform local isolations of any valves that fail to close remotely.

F.6.4.1 CASE 1 – REPLACE VALVES

WCGS ISLOCA risk is driven by two LPSI CLI scenarios:

- RHR CLI Scenario #1: Failure to isolate LPSI breaks between 8730A/8730B and EJHV8809A/8809B

- RHR CLI Scenario #2: Failure to isolate LPSI breaks between the RHR Suction piping and 8730A/8730B

Both of these scenarios could be mitigated if the RHR EJHV8809A and EJHV8809B valves were replaced with models that were capable of closing against full RCS pressure. However, even after valve replacement, there is still a possibility that isolation of the break would fail. These failure probabilities were previously developed as part of the WCGS PRA ISLOCA analysis (WCNOC 1998b) and can be used here to estimate the effectiveness of the SAMA changes. The isolation failure probabilities include the following contributors:

1. The operator fails to attempt isolation in time to mitigate the event, or
2. The isolation valve (EJHV8809A/B) fails to close, or
3. The LPSI CLI ISLOCA occurs in the room where the isolation valve is located, and spray from the break is assumed to render the isolation valve non-functional (and prevent local manual action to close the valve).

Given that item 3 from above depends on the ISLOCA path being analyzed, each ISLOCA scenario requires a unique isolation failure probability to account for the effects of the initiating event. The following table summarizes the failure probabilities for the two LPSI CLI scenarios based on the PRA ISLOCA Analysis:

LPSI CLI ISLOCA Isolation Failure Probability Summary

Description of Break Type	Human Error Contribution	Isolation MOV Inoperable due to IE	Random Isolation Valve Faults	Total for Break Type
RHR CLI Scenario #1: Failure to isolate LPSI breaks between 8730A/8730B and EJHV8809A/8809B	0.147	0.033	0.003	0.183
RHR CLI Scenario #2: Failure to isolate LPSI breaks between the RHR Suction piping and 8730A/8730B	0.147	0.038	0.003	0.188

The revised CDF resulting from the implementation of this SAMA can be estimated by multiplying the current CDF for each ISLOCA scenario by the corresponding isolation failure probability:

Revised Scenario CDF = Scenario CDF * Isolation Failure Probability

This approach assumes that a successful isolation directly corresponds to a safe endstate. While this overestimates the benefit of a successful isolation, it is considered to be an acceptable method for this analysis. The results for the two LPSI CLI scenarios are:

LPSI CLI Scenario #1: 1.54E-06 * 0.183 = 2.82E-07

LPSI CLI Scenario #2: 2.83E-07 * 0.188 = 5.32E-08

Total Revised CDF = 2.82E-07 + 5.32E-08 = 3.35E-07

The CDF reduction is the difference between the initial ISLOCA CDF of 1.82E-06 and the revised CDF of 3.35E-07 (1.48E-06). Given that these scenarios map directly to the ISLOCA release category frequency, the CDF reduction is also ISLOCA release category frequency reduction.

F.6.4.2 CASE 2 – ENHANCE PROCEDURES

The impact of revising the procedure to direct local isolation of the EJHV8809A and EJHV8809B valves can be estimated in a manner similar to what was performed for Case 1. The primary difference is that the isolation failure probability must consider the fact that operator action to remotely isolate the break has successfully been initiated, but the isolation valve motors were not capable of completing the isolation. The following formula can be used to determine the isolation failure probabilities for this case:

Fail to Iso = (Successful Remote Iso * Local Iso Failure) + IE Prevents Local Iso

The PRA ISLOCA analysis provides the values for two of these variables:

- Successful Remote Iso: Successful remote isolation is taken to be the complement of the remote isolation failure probability provided in the original analysis. Successful Remote Iso = 1 – Remote Isolation Failure (1 – 0.147 = 0.853).

- IE Prevents Local Iso: This contribution was described as the probability that the break caused failure of the valve actuators AND prevented local action. While the valve actuators are ultimately assumed to fail in all scenarios, this probability still represents the probability that the effects of the initiating event prevent local action.

The probability that the operators fail to perform a local isolation of a break is estimated by multiplying the remote isolation failure probability by a factor of 3 to account for stress and environmental challenges. The result is a failure probability of 0.441. The following table summarizes the probabilities that are used for each of the two scenarios:

Description of Break Type	Remote Isolation Successfully Initiated	Local Isolation Fails	Isolation MOV Inoperable due to IE	Total for Break Type
RHR CLI Scenario #1: Failure to isolate LPSI breaks between 8730A/8730B and EJHV8809A/8809B	0.853	0.441	0.033	0.409
RHR CLI Scenario #2: Failure to isolate LPSI breaks between the RHR Suction piping and 8730A/8730B	0.853	0.441	0.038	0.414

The revised CDF resulting from the implementation of this SAMA can be estimated by multiplying the current CDF for each ISLOCA scenario by the corresponding isolation failure probability:

Revised Scenario CDF = Scenario CDF * Isolation Failure Probability

This approach assumes that a successful isolation directly corresponds to a safe endstate. While this overestimates the benefit of a successful isolation, it is considered to be an acceptable method for this analysis. The results for the two LPSI CLI scenarios are:

LPSI CLI Scenario #1: 1.54E-06 * 0.409 = 6.30E-07

LPSI CLI Scenario #2: 2.83E-07 * 0.414 = 1.17E-07

Total Revised CDF = 6.30E-07 + 1.17E-07 = 7.47E-07

The CDF reduction is the difference between the initial ISLOCA CDF of 1.82E-06 and the revised CDF of 7.47E-07 (1.07E-06). Given that these scenarios map directly to the ISLOCA release category frequency, the CDF reduction is also ISLOCA release category frequency reduction.

F.6.4.3 COST OF IMPLEMENTATION

The cost of implementation for each of the two cases is developed separately:

- Case 1 - Replacing the isolation valves included in the dominant ISLOCA scenarios (two RHR valves) may cost several hundred thousand dollars each. Assuming a total of $500,000 is required to replace both valves and that $100,000 is required for initial engineering analysis, a total of $600,000 would be required for valve replacement.

- Case 2 – Procedure changes have been estimated to cost as little as $50,000 (CPL 2004). This estimate is used to represent the cost of adding guidance to the emergency procedure to perform local isolation of the EJHV8809A and EJHV8809B valves in the event that they cannot be closed.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following tables.

Case 1

	CDF (/yr)	**Dose-Risk**	**OECR**
Base Results	2.98E-05	2.86	$1,974
SAMA Results	2.82E-05	0.90	$695
Percent Change	5.4	68.5	64.8

Case 2

	CDF (/yr)	**Dose-Risk**	**OECR**
Base Results	2.98E-05	2.86	$1,974
SAMA Results	2.87E-05	1.44	$1,049
Percent Change	3.7	49.6	46.8

A further breakdown of this information is provided below according to release category.

Case 1

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency (/yr)$_{SAMA}$	3.42E-09	1.65E-07	4.40E-07	4.48E-07	1.13E-06	2.80E-05	**3.02E-05**
Dose-Risk$_{BASE}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
Dose-Risk$_{SAMA}$	0.00	0.04	0.59	0.14	0.04	0.09	**0.90**
OECR$_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
OECR$_{SAMA}$	$2	$72	$380	$239	$2	$0	**$695**

Case 2

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency (/yr)$_{SAMA}$	3.42E-09	1.65E-07	8.50E-07	4.48E-07	1.13E-06	2.80E-05	**3.06E-05**
Dose-Risk$_{BASE}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
Dose-Risk$_{SAMA}$	0.00	0.04	1.13	0.14	0.04	0.09	**1.44**
OECR$_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
OECR$_{SAMA}$	$2	$72	$734	$239	$2	$0	**$1,049**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table for the two different cases that were analyzed.

SAMA Number 4 Net Value (Case 1)

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,608,632	$243,386	$600,000	-$356,614

SAMA Number 4 Net Value (Case 2)

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,678,950	$173,050	$50,000	$123,050

Case 1 - Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

Case 2 - Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

F.6.5 SAMA NUMBER 5: OPEN DOORS FOR ALTERNATE DG ROOM COOLING

Diesel Generator Heating, Ventilating, Air Conditioning (DGHVAC) system is assumed to be required to provide cooling to the EDG rooms during the summer months when elevated outside temperatures reduce the passive heat transfer from the EDG rooms to the environment. This assumption is based on WCGS calculation AN-02-010 (WCNOC 2003), which determined the outside air temperature at which the EDG room temperature would exceed the allowable temperature of 119 degrees Fahrenheit without the operation of the heating ventilation and air-conditioning system (HVAC) supply fan. The results of this evaluation indicated that the maximum temperature increase of the EDG during operation is 40 degrees Fahrenheit. Therefore, the conclusion is made that the 119-degree temperature would not be exceeded if the outside air temperature remained below 79 degrees. However, when the outside temperature is above 79°F, it was determined that the EDG rooms would exceed the temperature operability limit within the EDG mission time. Basic event OTH-OAT-OVER-78F represents the probability that the outside temperature could exceed 79 degrees for any given 24 hour period. For those cases, the EDG Room doors could be opened to provide outside air exchange cooling to the EDG rooms to prevent EDG failure. Procedures could be modified to direct this action when high EDG room temperatures are identified.

While AN-02-010 (WCNOC 2003) does show that DGHVAC is required when the outside air temperature is over 79°F, the conservative assumptions used in that calculation have a measurable impact on WCGS risk.

A very important conservatism is contained in the basis of evaluation AN-02-010 itself. According to discussions with the verifier of the calculation, conservative assumptions were imposed within the evaluation such that the results from a similar "best estimate" evaluation would provide significantly different results that would, in turn, cause the 79°F value to increase. Perhaps the most significant of such assumptions is the extrapolation of building heat load test data beyond the testing period to predict the ultimate heat load of the room. This value was predicted to be 2.0 times the heat load at the end of the testing (220 minutes). According to the calculation verifier, this is extremely conservative since the test data curve was already beginning to level off at the end of the testing period.

Another significant conservatism can be realized in the use of data from AN-02-010. Currently, this evaluation considers all occurrences where the temperature reached or exceeded 79°F. This is significant because AN-02-010 also evaluates the time duration before the room temperature reaches the predefined TRM value of 119°F without the operation of the HVAC supply fan. For this timing estimate, it was assumed the outside air temperature and the EDG room temperature were initially equal at 90°F. As a result, the calculation implicitly did not consider:

- The conditions where the outside temperature might be between 79°F and 90°F,
- The fact that the initial EDG Room temperature would be less than 90°F even if outside temperatures are over 90°F when DGHVAC is initially lost.

The results of this evaluation, using self-imposed conservatisms previously mentioned, indicate that the room would reach 119 degrees in 410 minutes after loss of DGHVAC. A more realistic treatment of these parameters would increase the estimated outside temperature at which the EDGs could operate without DGHVAC; however, no modifications were made to the AN-02-010 calculation for this analysis.

In order to estimate the impact of implementing this SAMA, the probability of basic event OTH-OAT-OVER-78F was reduced from 2.0E-01 to 2.0E-02 to simulate the inclusion of an HEP with a failure probability of 1.0E-01 for opening the EDG room doors for alternate cooling. This was done for both the Level 1 and Level 2 models.

This SAMA can be implemented through a procedure change, which has been estimated to cost about $50,000 (CPL 2004).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.98E-05	2.86	$1,974
SAMA Results	2.88E-05	2.86	$1,967
Percent Change	3.4	0.0	0.4

A further breakdown of this information is provided below according to release category.

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency $(/yr)_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency $(/yr)_{SAMA}$	3.42E-09	1.65E-07	1.92E-06	4.34E-07	1.09E-06	2.70E-05	**3.06E-05**
Dose-Risk_{BASE}	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
Dose-Risk_{SAMA}	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
$OECR_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
$OECR_{SAMA}$	$2	$72	$1,659	$232	$2	$0	**$1,967**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 5 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,797,424	$54,576	$50,000	$4,576

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

F.6.6 SAMA NUMBER 6: MANUAL RECIRCULATION WITH RWST LEVEL INSTRUMENTATION FAILURE

The review of the Level 1 WCGS importance list identified that common cause failure of 2 of 4 RWST level instrumentation channels (CABN--RWSTLLO-SA) is an important contributor to the WCGS CDF. This is primarily due to the assumption that this failure event results in the failure of recirculation initiation by both automatic and manual means. Review of the RWST level instrumentation design indicates that this assumption is overly conservative and that the importance of this failure is artificially inflated as a result of the assumption.

While failure of 2 of 4 RWST level instrumentation channels will both prevent the RHR suction path from automatically realigning to the sump on low RWST level and fail the annunciator associated with low RWST level, the remaining instrumentation channels will provide the operators with a means of monitoring RWST level. In addition, there are other forms of information that the operators could use to diagnose the need to swap to recirculation mode. These include containment sump level indicators and knowledge of the duration of the injection phase. If credit is taken for these other information sources to aid in the diagnosis of the need to manually initiate recirculation mode, the importance of the 2 of 4 RWST level instrument channel failure event would be reduced below the RRW review threshold of 1.02 and no SAMAs would be required to address this issue. As the Level 2 importance of CABN--RWSTLLO-SA is already below the RRW review threshold of 1.02, the Level 2 results do not need to be re-examined.

In order to more realistically represent the current WCGS capabilities, the failure probability of CABN--RWSTLLO-SA was changed from 4.40E-04 to 4.40E-05 to simulate an HEP of 0.1 for initiating recirculation mode given failure of the relevant RWST level instrumentation. Use of the revised value for CABN--RWSTLLO-SA yields an RRW of only 1.005 for the event, which is well below the RRW review threshold of 1.02. No SAMAs are suggested to address RWST level instrumentation failure.

F.6.7 SAMA NUMBER 7: MANUAL RECIRCULATION WITH AUTO INITIATION FAILURE

Failure to auto swap to recirculation mode can be caused by failure of the logic components responsible for governing the swap, by power failure to the logic, or other hardware failures. For the majority of these cases, a cue would be available to alert the operators of the need to swap to recirculation mode; however, no credit is currently taken for manual swap to recirculation mode after auto initiation failure due to modeling complexities. As a result, the importances of auto swap failures are artificially inflated.

If reasonable credit is taken for the operators to manually align recirculation mode, it can be shown that the importance of the critical event causing automatic swap failure is reduced below the RRW review threshold of 1.02 and no SAMAs would be required to improve recirculation initiation capabilities. The primary event of concern for this case was identified during the importance list review to be the common cause failure of the Channel I and IV LOCA Sequencer (basic event ID ESNFLOCASEQ12SF1).

In order to more realistically represent the current WCGS capabilities, the failure probability of ESNFLOCASEQ12SF1 was changed from 8.64E-05 to 8.64E-06 to simulate an HEP of 0.1 for initiating recirculation mode given failure of the automated logic. Use of the revised value for ESNFLOCASEQ12SF1 yields an RRW of only 1.003 for the event, which is well below the RRW review threshold of 1.02. No SAMAs are suggested to address automatic recirculation initiation failures.

F.6.8 SAMA NUMBER 8: HIGH VOLUME MAKEUP TO THE RWST

For SGTR, ISLOCA, and LOCA scenarios where the RWST could be depleted, providing a means of refilling the RWST with a high flow system would reduce the risk of core damage given recirculation failure. A hard piped connection to the FPS is a possible means of providing this capability. While an RWST makeup system exists at WCGS, the capacity is not large enough to mitigate the high flows required to mitigate many LOCA events.

While this modification does not provide a means of placing the plant in a stable endstate due to the open path through containment and/or lack of a closed containment heat removal method, it will provide the operators with a means of indefinitely delaying core damage while actions are taken to isolate the steam generator(s), ISLOCA path, or repair the recirculation failures.

The importance list review identified the RWST refill SAMA based on the cutsets including common cause failure of the RHR pumps to start (MPEJ-01AB-12-BS1), which results in core damage when they are required for recirculation mode in a LOCA. While this event impacts sequences other than RWST depletion, it has been used to estimate the impact of implementing this SAMA since it is the main contributor to RWST depletion sequences and because the most important contribution the event MPEJ-01AB-12-BS1 makes to any sequence is to RWST depletion. A review of the Level 1 cutsets demonstrated that the top RWST depletion cutset for Small LOCA was greater than the next highest contributor by a factor of 50. As the results for each failure mode will be similar to the top cutset, the quantification for this SAMA was simplified by addressing only the RWST depletion cases for the corresponding Small LOCA sequence (SLOS03). The failure probability of MPEJ-01AB-12-BS1 was reduced from 2.68E-04 to 2.68E-06 and SLOS03 was requantified to determine the CDF reduction related to this SAMA. This change simulates a 1.0E-02 failure probability to provide makeup from the Fire water system and it is assumed to account for any hardware and human errors.

The Level 2 LERF cutsets were reviewed to determine if any RWST depletion cutsets were included in the results. As expected, none were found and the release category frequencies for ISLOCA, SGTR, ECF, and CIF were unchanged. The LCF and NCF release category frequencies are estimated using the conditional probabilities determined in the IPE, as described in Section F.2.8.

Calvert Cliffs estimated a cost of $565,000 to provide a connection between the Fire Protection system and the RHR system's heat exchangers. As with the modification investigated by Calvert Cliffs, this SAMA also involves changes to provide an additional flow path from Fire Protection to another system. This estimate is considered to be a reasonable estimate for the type of change proposed for this SAMA.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.98E-05	2.86	$1,974
SAMA Results	2.90E-05	2.86	$1,974
Percent Change	2.7	0.0	0.0

A further breakdown of this information is provided below according to release category.

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency $(/yr)_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency $(/yr)_{SAMA}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.10E-06	2.72E-05	**3.08E-05**
Dose-$Risk_{BASE}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
Dose-$Risk_{SAMA}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
$OECR_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
$OECR_{SAMA}$	$2	$72	$1,659	$239	$2	$0	**$1,974**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 8 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,808,508	$43,492	$565,000	-$521,508

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.6.9 SAMA NUMBER 13: ALTERNATE FUEL OIL TANK WITH GRAVITY FEED CAPABILITY

EDG failures related to unavailability of the fuel oil transfer pumps or the flowpath are currently considered to be unrecoverable in the PRA model. The installation of a large volume tank at an elevation greater than the EDG fuel oil day tanks would allow for emergency refill of the day tanks in the event of fuel oil transfer pump failure. The gravity fill design is considered to be desirable because it extends the time that refill can be performed to beyond the time that the EDGs can operate on the day tank volume.

Installation of a portable fuel oil pump was considered as a potential means to address fuel oil transfer failures; however, plant personnel have indicated that gaining access to the fuel oil tanks at WCGS requires a crane and about 10 hours of work. This implies that the time required to align the portable fuel oil transfer pumps is longer than the time available to prevent core damage and that it is not a feasible mitigation method. Changes to make the tanks more accessible are believed to be comparable to installing an additional fuel oil transfer pump when critical path outage time is considered. For WCGS, installation of the additional fuel oil tank is believed to be the most effective change to address fuel oil transfer issues.

In order to represent this SAMA, the largest contributing fuel oil transfer failure events were combined with a reserve tank alignment failure probability of 1.0E-02 (estimate) in the Level 1 and LERF model results:

- Cutsets including MPEJ--PEJ01A-GPS and MPEJ--PEJ01B-GPS,
- Cutsets including MPJE-01AB-12-GS1.

The LCF and NCF release category frequencies are estimated using the conditional probabilities determined in the IPE, as described in Section F.2.8.

While there are other events included in the cutsets related to fuel oil transfer, such as valve and pump run failures, their contributions are orders of magnitude smaller than the events identified above, do not impact the results in a meaningful way, and are not included in the quantification.

The cost of implementation for this SAMA was estimated to be $150,000 (WCNOC 2006d).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.98E-05	2.86	$1,974
SAMA Results	2.78E-05	2.83	$1,953
Percent Change	6.7	1.0	1.1

A further breakdown of this information is provided below according to release category.

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency (/yr)$_{SAMA}$	3.42E-09	1.50E-07	1.92E-06	4.22E-07	1.05E-06	2.61E-05	**2.96E-05**
Dose-Risk$_{BASE}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
Dose-Risk$_{SAMA}$	0.00	0.03	2.55	0.13	0.04	0.08	**2.83**
OECR$_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
OECR$_{SAMA}$	$2	$65	$1,659	$225	$2	$0	**$1,953**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 13 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,740,832	$111,168	$150,000	-$38,832

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.6.10 SAMA NUMBER 14: PERMANENT, DEDICATED GENERATOR FOR THE NCP, ONE MOTOR DRIVEN AFW PUMP, AND A BATTERY CHARGER

This is SAMA is similar to the change proposed in Section F.6.1, but it also addresses the scenarios in which the TD AFW pump is unavailable. This scope increase requires a larger dedicated generator to carry the additional load of a single motor driven AFW pump and one division of DC power for pump and valve control. An additional benefit of powering a DC division is that SG level instrumentation would be available to allow for indefinite operation of the AFW pump. Fire Protection is not suggested as an alternate source of SG makeup given that it is a low pressure system and would not be available early in an accident.

The impact of this SAMA on CDF has been estimated by multiplying the frequency of all SBO sequences by 5E-02 to represent the failure probability to align the dedicated generator to the required loads. The total CDF of the SBO sequences for WCGS is 1.68E-05, which is reduced to 8.40E-07 by this SAMA (1.68E-05 * 5E-02 = 8.40E-07). The reduction in CDF is the difference between the baseline SBO CDF and the revised SBO CDF: 1.68E-05 – 8.40E-07 = 1.60E-5. This corresponds to a total revised CDF of 1.38E-05 (2.98E-05 – 1.60E-5 = 1.38E-05).

The Level 2 changes were estimated based on the Level 1 CDF reduction. As no SBO sequences are included in the SGTR and ISLOCA results, the frequencies for those release categories remained unchanged. The ECF and CIF release category frequencies are determined based on the CDF cutsets and Level 2 containment safeguards systems failures (containment coolers, containment sprays, containment isolation). Since the proposed changes will provide negligible additional benefit for the containment safeguards systems, an upper bound estimate of the impact of this SAMA on the ECF and CIF frequencies may be obtained by reducing their baseline frequencies by the percentage reduction realized for CDF. The LCF and NCF release category frequencies are estimated using the conditional probabilities determined in the IPE, as described in Section F.2.8.

The cost of implementation for providing a dedicated diesel generator for the ABWR Feedwater or Condensate pumps was estimated to be $1.2 million in 1994 (GE 1994). The capacity of the generator required for the ABWR application is likely comparable to the capacity required for the WCGS NCP, AFW pump, and battery charger; therefore, the same cost of implementation is used for this SAMA ($1.2 million in 1994 dollars).

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.98E-05	2.86	$1,974
SAMA Results	1.38E-05	2.72	$1,845
Percent Change	53.7	4.9	6.5

A further breakdown of this information is provided below according to release category.

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency (/yr)$_{SAMA}$	1.60E-09	1.65E-07	1.92E-06	2.09E-07	5.22E-07	1.29E-05	**1.58E-05**
Dose-Risk$_{BASE}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
Dose-Risk$_{SAMA}$	0.00	0.04	2.55	0.07	0.02	0.04	**2.72**
OECR$_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
OECR$_{SAMA}$	$1	$72	$1,659	$112	$1	$0	**$1,845**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 14 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$969,848	$882,152	$1,200,000	-$317,848

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.6.11 SAMA NUMBER 15: INSTALL FIRE BARRIERS AROUND CABLES OR REROUTE THE CABLES AWAY FROM FIRE SOURCES

The overall fire CDF at WCGS is low compared with the internal events CDF even with its conservative modeling characteristics. However, three of the fire areas account for 70 percent of the fire CDF and these area have been investigated to determine if there are potentially cost beneficial changes that could be made to reduce the WCGS fire risk.

The WCGS Fire Re-Analysis (WCNOC 1998A) indicates that the major fire contributors include the following areas:

- A-22 (North Control Room Air Conditioning and Filtration Unit (Train A) Room): 8.76E-07 (14.8 percent)
- C-9 (Train A ESF Switchgear Room): 1.76E-06 (29.7 percent)
- C-10 (Train B ESF Switchgear Room): 1.52E-06 (25.7 percent)

For each of these fire areas, there is a similar situation that exacerbates the consequences of cabinet fires in the area. SSE cables in each of these fire areas are routed over other cabinets in the area such that a fire in any one of the cabinets has the potential to damage an entire train of SSE. Even if the importance of the equipment within any given cabinet is low, the consequences of a fire may be severe depending on whether the fire suppression system works or if it can even be credited based on the location of the overhead cables. For those cables that are located directly over a cabinet such that they are in the flames of a cabinet fire, the Halon system is not credited.

Potential SAMAs could include:

- Case 1: Rerouting the SSE cables so that they do not pass over other cabinets or,
- Case 2: Providing fire barriers capable of preventing fire propagation and damage to the overhead cables.

Both of these changes are assumed to be capable of preventing propagation of the initial cabinet fire, which the Fire Analysis defines as the spread of a cabinet fire into the overhead cables. Based on review of the switchgear room configurations, it has been determined that crediting fire barriers may be difficult to justify and that the cost of providing barriers that will effectively prevent propagation to the cables or even delay cable damage long enough for the Halon system to extinguish the fire would be high. Both mitigating strategies have been examined in this evaluation.

The impact of these types of changes has been estimated using available information from the fire model and engineering judgment. No model quantification was performed for this evaluation.

It is assumed that if the portion of the WCGS CDF and release consequences related to fire areas A-22, C-9, and C-10 can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the overall modified MACR attributable to external events,
- Determine the component of the external events cost-risk attributable to fire events,
- Determine the component of the fire based cost-risk attributable to fire areas A-22, C-9, and C-10,
- Calculate the percent reduction in fire area CDF that would occur for each of the fire areas if the SAMA is implemented and reduce the cost-risk for the fire area by the same percent. The reduction in cost-risk is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the WCGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the modified MACR is $926,000, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that no CDF was developed for the other external events contributors. The seismic evaluation was a margins analysis and the other events were precluded from detailed review using screening processes. For the purposes of this calculation, it is assumed that the fire events comprise 85 percent of the external events risk. This corresponds to a cost-risk of $787,100.

The cost-risk associated with each fire area can then be determined based on their relative contributions to the total fire CDF:

Fire Area	Percent of Fire Risk	Corresponding Cost-Risk
A-22	14.8	$116,491
C-9	29.7	$233,769
C-10	25.7	$202,285

The risk reduction possible for each of these areas is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. Neither change (barriers or cable rerouting) is considered to be capable of preventing damage to the equipment in the cabinet where the fire starts; however, both changes are assumed to prevent damage to overhead cables. The averted cost-risk for these changes, therefore, is based on the difference between the CDF when propagation is considered and the CDF when propagation is eliminated.

The quantification of the benefit of this SAMA was performed using information from the fire event trees. The CDF corresponding to the “no propagation” case was estimated by multiplying the ignition frequency for each fire scenario by the conditional core damage probability corresponding to the loss of all equipment contained within the cabinet where the fire started. This was performed for all of the fire scenarios included in fire areas A-22, C-9, and C-10 as summarized in the following table:

Calculation of “No Propagation” Fire Area CDF

Fire Area	Ignition Source	IE Frequency	CCDP	CDF (no propagation)
A-22	MCC NG03C	2.55E-04	3.06E-04	7.80E-08
			Total =	7.80E-08
C-9	MCC NG01A	2.00E-04	3.87E-04	7.74E-08
	PN09	7.90E-05	1.26E-05	9.95E-10
	GS01A	1.28E-04	1.26E-06	1.61E-10
	RP-139	1.28E-04	8.50E-05	1.09E-08
	NB01	1.28E-04	1.83E-03	2.34E-07
	NG01 and XNG01	2.00E-04	3.51E-04	7.02E-08
	NG03	2.00E-04	4.57E-06	9.14E-10
			Total =	3.95E-07
C-10	NG04	1.68E-04	4.20E-05	7.06E-09
	NG02	1.68E-04	1.35E-03	2.27E-07
	NB02	9.58E-05	1.77E-03	1.70E-07
	MCC NG02A	1.68E-04	1.37E-03	2.30E-07
	RP-140	9.58E-05	5.68E-05	5.44E-09
	GS01B	9.58E-05	1.26E-06	1.21E-10
	PN10	7.90E-05	1.26E-06	9.95E-11
	SB148A/B	1.92E-04	1.26E-06	2.42E-10
	RP-334	9.58E-05	5.77E-06	5.53E-10
	RP-335	9.58E-05	8.78E-06	8.41E-10
	RP-147A/B	1.92E-04	8.67E-06	1.66E-09
			Total =	6.43E-07

The “no propagation” cost-risk for each fire area is determined by multiplying the baseline fire area cost-risk by the ratio of the “no propagation” fire area frequency to the baseline fire area frequency:

Calculation of “No Propagation” Fire Area Cost-Risk

Fire Area	Baseline Fire Area CDF	"No Propagation" Fire Area CDF	Ratio of "No Propagation" CDF to Baseline CDF	Baseline Fire Area Cost-Risk	"No Propagation" Fire Area Cost-Risk
A-22	8.76E-07	7.80E-08	8.91E-02	$116,491	$10,376

C-9	1.76E-06	3.95E-07	2.24E-01	$233,769	$52,437
C-10	1.52E-06	6.43E-07	4.23E-01	$202,285	$85,511
			Total =	$552,544	$148,325

The difference between the baseline fire area cost-risk and the "no propagation" fire area cost-risk is the averted cost-risk for this SAMA: $552,544 - $148,325 = $404,219.

It should be noted that the averted cost-risk calculated here is impacted by the baseline assessment of the probability that an electrical fire in a sealed cabinet will propagate. The WCGS Fire Re-Analysis developed the sealed cabinet propagation probabilities based on industry fire events and an assumption that half of the cabinet fires that were extinguished by unknown means would not be extinguished. The Fire Re-Analysis document indicates that the data is highly uncertain, but conservative and that the propagation probabilities should be reviewed when used. No changes have been made to the baseline propagation probabilities for use in the SAMA analysis, but if the probabilities were modified to reflect "more realistic" propagation probabilities, the baseline risk calculated for Fire Areas A-22, C-9, and C-10 would be reduced.

The cost of implementation for each of the SAMA strategies is estimated below:

- Case 1: Rerouting the cables in Fire Areas A-22, C-9, and C-10 includes changing the positions of all cable trays such that no cable tray passes over any electrical cabinet. The changes will require re-routing the cables originating in the local cabinets as well as any cables originating in other rooms. The effort will likely require engineering analysis, new cable trays, new cables, and potentially critical path outage time to complete the changes. The cost of this change has been estimated to be $3,250,000 million (WCNOC 2006c).

- Case 2: If the existing cable routing is maintained, fireproof barriers could be constructed around all of the overhead cable trays to prevent cabinet fires from propagating to those cables or damaging them in the initial fire. The cost of this change has been estimated to be $1,000,000 (WCNOC 2006c).

Results

The results of the fire area analysis and the implementation cost estimates are used as input to the cost-benefit calculation. The results of this calculation are provided in the following table for the two different SAMA strategies.

SAMA Number 15 Net Value (Case 1)

Averted Cost-Risk	Cost of Implementation	Net Value
$404,219	$3,250,000 (estimate for demonstration only)	-$2,845,781

SAMA Number 15 Net Value (Case 2)

Averted Cost-Risk	Cost of Implementation	Net Value
$404,219	$1,000,000 (estimate for demonstration only)	-$595,781

Case 1: Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

Case 2: Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.6.12 SAMA NUMBER 16: INTER-TRAIN CCW CROSS-TIE FOR EMERGENCY OPERATION

A cross-tie between the CCW loops could increase the availability of CCW flow to cooling loads. Certain failure combinations that disable CCW could be eliminated if the use of a cross-tie valve was available to provide flow to required loads. For example, if the "A" loop CCW heat exchanger is out of service and the "B" loop of CCW has failed, the "A" loop of CCW could be used to cool the "B" loop CCW heat exchanger pending isolation of unused loads. For WCGS, cross-tie lines do not exist and new crosstie lines with isolation valves would have to be installed 1) between the pump suction lines, and 2) between the pump discharge lines upstream of the heat exchangers.

In order to evaluate the Level 1 impact of a cross-tie between the A and B-train of CCW on plant risk, it was necessary to do an individual cutset inspection, which is described below.

The WCGS CDF cutset file was filtered to contain only cutsets that contain one or more basic events (BEs) with the CCW system designator. This filtering was performed by visual inspection and resulted in 556 cutsets. The percentage of the total CDF contributed by these cutsets is 2.30%.

The basic event database file was then examined and filtered for all basic events that contained an “EG” system designator. This filtering resulted in 143 BEs. These BEs were reviewed to determine which ones would not see risk benefit from a cross-tie between the A and B-train of the CCW system. Four BEs were identified:

1. CVEG37126-1-4AC6 (global failure of check valves 3, 7, 12, and 16)

2. MPEG-1AD-1-4-CR6 (common cause all 4 CCW pumps fail to run)

3. MPEG-1AD-1-4-CS6 (common cause all 4 CCW pumps fail to start)

4. MVEG-1012-12-HO1 (common cause failure of EGHV0101 / 0102 – RHR)

Removal of all cutsets containing the above four BEs resulted in reducing the total number of CCW system cutsets to 480. The percentage of the total CDF contributed by these remaining cutsets is 1.58%.

These remaining 480 cutsets were further examined to identify the cutsets comprised of more than one “EG” BE. These combinations of “EG” failures were evaluated in context with the entire cutset to determine if the existence of a cross-train line would stem the progression to core damage. The most prominent combinations included a loss of offsite power initiator with complete failure of one train (both pumps, both check valves, combination, or heat exchanger failure) coupled with a failure of the opposite train's EDG (i.e., no power to opposite train's pumps). When these cutsets are removed from the applicable cutsets, the total number of cutsets is reduced to 431 with a contribution to total CDF of 1.5%.

The remaining 431 cutsets are event sequences that would realize risk benefit from a cross-tie between the two trains of CCW. To determine the approximate reduction to the remaining 1.5% of CDF (4.47E-07), these cutsets values need only to be multiplied by the probability of failure of the cross-tie line to work. This failure probability would be a combination of equipment and operator failures.

If a value of 0.1 is assumed as the probability of the operator to diagnose and realign the CCW system to take advantage of a cross-tie, the CDF is reduced by 4.02E-07 (4.47E07 – (4.47E-07 * 0.1) = 4.02E-07). The overall CDF is, therefore, reduced from 2.98E-05 to 2.94E-05, or a 1.3% reduction. The low CDF impact is indicative of cooling trains with two pumps per train and other generally passive components. It should also be noted that this estimate does not account for any increases in risk that could result from cross-tie induced failures (e.g. bypass events).

The impact on the Level 2 results was performed in a similar manner, but because CCW failures are small contributors to the SGTR, ISLCOA, CIF, and ECF release categories, all cutsets with “EG” events in them were set to 0.0 for simplicity. The LCF and NCF release category frequencies are estimated using the conditional probabilities determined in the IPE, as described in Section F.2.8.

Calvert Cliffs estimated a cost of $565,000 (BGE 1998) to provide a connection between the FPS and the RHR system's heat exchangers. As with the modification investigated by Calvert Cliffs, this SAMA also involves changes to a cooling water system primarily involving the addition of piping and valves. The cost of implementation developed for Calvert Cliffs is considered to be a reasonable estimate for the type of change proposed for this SAMA.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.98E-05	2.86	$1,974
SAMA Results	2.94E-05	2.85	$1,964
Percent Change	1.3	0.4	0.5

A further breakdown of this information is provided below according to release category.

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.40E-08	2.54E-07	1.93E-06	4.48E-07	1.13E-06	2.80E-05	**3.18E-05**
Frequency (/yr)$_{SAMA}$	3.42E-09	1.64E-07	1.91E-06	4.48E-07	1.11E-06	2.76E-05	**3.12E-05**
Dose-Risk$_{BASE}$	0.01	0.06	2.57	0.14	0.04	0.09	**2.91**
Dose-Risk$_{SAMA}$	0.00	0.04	2.54	0.14	0.04	0.09	**2.85**
OECR$_{BASE}$	$17	$110	$1,668	$239	$2	$0	**$2,036**
OECR$_{SAMA}$	$2	$71	$1,650	$239	$2	$0	**$1,964**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 16 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,829,352	$22,648	$565,000	-$542,352

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.6.13 SAMA NUMBER 17: DC CROSS-TIE

Failure of power to a battery charger or loss of a battery with the failure of safety equipment in the opposite division results in the unavailability of equipment that could be used if power were aligned to it. WCGS already has a swing charger in each division that can supply both 125V DC buses within a given division using:

- A Class 1E 480V AC supply from the corresponding division, or
- A non-class 1E 480V AC power supply.

This design does provide some benefit, especially for maintenance issues; however, the non-safety power supplies would not be available when offsite power has been lost. While the Class 1E supply would be available in a LOOP, its failure impacts both the normal and swing charger. As a result, installation of a cross-tie between 125V DC divisions would provide a means of reducing LOOP and SBO risk.

WCGS also has a maintenance cross-tie line between the 125V DC buses in a single division, but the capacity is only 100 amps and it is not credited in the current model. Some credit could be taken for this cross-tie, but the line capacity limits its flexibility and the largest contributors to long term loss of DC power are EDG failures, so the alternate train's battery would also not be available for the critical cases.

In order to estimate the Level 1 and Level 2 benefit of installing the cross-tie line, the DC batteries were selected as surrogate components to evaluate the proposed change. Thirteen different basic events involving battery failure are present in the WCGS results. The basic events include single battery, double common cause, and triple common cause failures. Manipulation of these events is considered to address the contributors for which the cross-tie would be most beneficial: SBO events in which one or more batteries fail with otherwise operable equipment within the division. The battery failure basic events were reduced in value by a factor of 1.0E-02 in the results files in order to address the failure probability of aligning the cross-tie when it is required (assumed to account for hardware and operator failures). The LCF and NCF release category frequencies are estimated using the conditional probabilities determined in the IPE, as described in Section F.2.8.

The cost of installing a DC cross-tie at Peach Bottom was estimated to be about $250,000 given that only minor changes would have been required (Exelon, 2001). For WCGS, the changes required to install DC cross-tie capability are more complex and considered to be comparable to the $1.1 million change that was estimated for Brunswick (CPL 2004). As Brunswick is a dual unit plant and the implementation cost is presented on a site basis, the cost must be adjusted for WCGS. The single unit cost is estimate by dividing the Brunswick cost by two, yielding $550,000.

Results

Implementation of this SAMA yields a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.98E-05	2.86	$1,974
SAMA Results	2.86E-05	2.86	$1,971
Percent Change	4.0	0.0	0.2

A further breakdown of this information is provided below according to release category.

Release Category	CIF	SGTR	ISLOCA	ECF	LCF(K)	Leakage/ NCF	Total
Frequency (/yr)$_{BASE}$	3.42E-09	1.65E-07	1.92E-06	4.48E-07	1.13E-06	2.80E-05	**3.16E-05**
Frequency (/yr)$_{SAMA}$	3.42E-09	1.65E-07	1.92E-06	4.42E-07	1.08E-06	2.68E-05	**3.04E-05**
Dose-Risk$_{BASE}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**

Dose-Risk$_{SAMA}$	0.00	0.04	2.55	0.14	0.04	0.09	**2.86**
OECR$_{BASE}$	$2	$72	$1,659	$239	$2	$0	**$1,974**
OECR$_{SAMA}$	$2	$72	$1,659	$236	$2	$0	**$1,971**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table.

SAMA Number 17 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,852,000	$1,786,672	$65,328	$550,000	-$484,672

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.7 UNCERTAINTY ANALYSIS

Sensitivity cases were run for the following conditions to assess their impact on the overall SAMA evaluation:

- Use a real discount rate of 7 percent, instead of the 3 percent value used in the base case analysis.
- Use the 95th percentile PRA results in place of the mean PRA results.
- Use alternate MACCS2 input variables for selected cases.

F.7.1 REAL DISCOUNT RATE

A sensitivity study has been performed in order to identify how the conclusions of the SAMA analysis might change based on the value assigned to the real discount rate (RDR). The original RDR of 3 percent, which could be viewed as conservative, has been changed to 7 percent and the modified maximum averted cost-risk was re-calculated using the methodology outlined in Section F.4. The Phase 1 screening against the MMACR was re-examined using the revised MMACR to identify any SAMA candidates that could be screened from further analysis based on the premise that their costs of implementation exceeded all possible benefit. In addition, the Phase 2 analysis was re-performed using the 7 percent RDR.

Implementation of the 7 percent RDR reduced the MMACR by 19.9 percent compared with the case where a 3 percent RDR was used. This corresponds to a decrease in the MMACR from $1,852,000 to $1,484,000. The Phase 1 SAMA list was reviewed to determine if such a decrease in the MMACR would impact the disposition of any SAMAs. It was determined that no additional SAMAs could have been screened in the Phase 1 if an RDR of 7 percent were used in place of the 3 percent value.

The Phase 2 SAMAs are dispositioned based on PRA insights or detailed analysis. All of the PRA insights used to screen the SAMAs are still applicable given the use of the 7 percent real discount rate as the change only strengthens the factors used to screen them. The SAMA candidates screened based on these insights are considered to be addressed and are not investigated further.

The remaining Phase 2 SAMAs were dispositioned based on the results of a SAMA specific cost-benefit analysis. This step has been re-performed using the 7 percent real discount rate to calculate the net values for the SAMAs.

As shown below, the determination of cost effectiveness changed for one Phase 2 SAMA when the 7 percent RDR was used in lieu of 3 percent. However, the margin by which SAMA 5 becomes "not cost beneficial" is small and it does not mean that this SAMA would be screened from consideration if a 7 percent real discount rate were applied in the SAMA analysis as other factors influence the decision making process, such as the 95th percentile sensitivity analysis.

Phase 2 Results Summary for 7 Percent RDR Sensitivity

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (7 percent RDR)	Net Value (7 percent RDR)	Averted Cost- Risk (3 percent RDR)	Net Value (3 percent RDR)	Change in Cost Effective-ness?
1	$800,000	$648,966	-$151,034	$799,882	-$118	No
2	$400,000	$531,540	$131,540	$655,712	$255,712	No
3	$328,000	$237,840	-$90,160	$299,252	-$34,748	No
4 (case 1)	$600,000	$182,610	-$417,390	$243,368	-$356,632	No
4 (case 2)	$50,000	$129,648	$79,648	$173,050	$123,050	No
5	$50,000	$44,334	-$5,666	$54,576	$4,576	Yes
8	$565,000	$35,346	-$529,654	$43,492	-$521,508	No
13	$150,000	$90,114	-$59,886	$111,168	-$38,832	No
14	$1,200,000	$715,760	-$484,240	$882,152	-$317,848	No
15 (case 1)	$3,250,000	$323,899	-$2,926,101	$404,219	-$2,845,781	No
15 (case 2)	$1,000,000	$323,899	-$676,101	$404,219	-$595,781	No
16	$565,000	$18,318	-$546,682	$22,648	-$542,352	No
17	$550,000	$53,086	-$496,914	$65,328	-$484,672	No

F.7.2 95TH PERCENTILE PSA RESULTS

The results of the SAMA analysis can be impacted by implementing conservative values from the PRA's uncertainty distribution. If the best estimate failure probability values were consistently lower than the "actual" failure probabilities, the PRA model would underestimate plant risk and yield lower than “actual” averted cost-risk values for potential SAMAs. Re-assessing the cost benefit calculations using the high end of the failure probability distributions is a means of identifying the impact of having consistently underestimated failure probabilities for plant equipment and operator actions included in the PRA model. This sensitivity uses the 95th percentile results to examine the impact of uncertainty in the PRA model.

For WCGS, the WinNUPRA software code was used to perform the Level 1 internal events model uncertainty analysis. The results of the calculation are provided below:

PARAMETER	VALUE
Mean	2.99E-05
5 percent	1.65E-05
50 percent	2.52E-05
95 percent	5.70E-05
Standard Deviation	1.97E-05

The PRA uncertainty calculation identifies the 95th percentile CDF as 5.70E-05 per year. This is a factor of 1.9 greater than the CDF point estimate produced by the WCGS PRA.

F.7.2.1 PHASE I IMPACT

For Phase I screening, use of the 95th percentile PRA results will increase the MMACR and may prevent the screening of some of the higher cost modifications. However, the impact on the overall SAMA results due to the retention of the higher cost SAMAs for Phase II analysis is typically small. This is due to the fact that the benefit gleaned from the implementation of those SAMAs must be extremely large in order to be cost beneficial.

The impact of uncertainty in the PRA results on the Phase I SAMA analysis has been examined. The MMACR is the primary Phase I criteria affected by PRA uncertainty. Thus, this portion of this sensitivity is focused on recalculating the MMACR using the 95th percentile PRA results and re-performing the Phase I screening process.

As discussed above, the 95th PRA results are approximately a factor of 1.9 greater than point estimate CDF. The uncertainty analyses that are available for the Level 1 models are not available for Level 2 and 3 PRA models. In order to simulate the use of the 95th percentile results for the Level 2 and 3 models, the same scaling factor calculated for the Level 1 results was assumed to apply to the Level 2 and 3 models. Because the MMACR calculations scale linearly with the CDF, dose-risk, and offsite economic cost-risk, the 95th percentile MMACR can be calculated by multiplying the base case MMACR by 1.9. This results in a 95th percentile MMACR of $3,518,800.

The initial SAMA list has been re-examined using the revised MMACR to identify SAMAs that would be retained for the Phase 2 analysis. Those SAMAs that were previously screened due to costs of implementation that exceeded $1.85 million are now retained if the costs of implementation are less than $3.52 million. Of the SAMAs screened in the Phase 1 analysis, only SAMA 12 (installation of primary side SG isolation valves) would be retained based on the use of the 95th percentile MMACR.

The CDF based RRW for the SGTR initiating event, which is the initiating event relevant to SAMA 12, is only 1.03. In addition, SGTR sequences account for less than 4 percent of the dose-risk and offsite economic cost-risk for WCGS. Even if this SAMA was 100 percent effective in mitigating SGTR events, the averted cost-risk would be less than 4 percent of the total 95th percentile MMACR. Given that the cost of implementation for SAMA 12 is over 76 percent of the 95th percentile MMACR, this SAMA would not be cost beneficial and is screened from further analysis.

F.7.2.2 PHASE II IMPACT

As mentioned above, the 95th percentile PRA results are not available for the Level 2 and 3 models. In order to estimate the impact of using the 95th percentile PRA results in the Phase 2 SAMA analysis, the same process used to calculate the revised MMACR was applied to each of the Phase 2 SAMAs (the averted cost-risk for each SAMA was increased by a factor of 1.9 over the base case).

The following table provides a summary of the impact of using the 95th percentile PSA results in the detailed cost-benefit calculations that have been performed.

Results Summary for the 95th Percentile PSA Results

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
1	$800,000	$799,882	-$118	$1,519,776	$719,776	Yes
2	$400,000	$655,712	$255,712	$1,245,853	$845,853	No
3	$328,000	$299,252	-$34,748	$557,179	$229,179	Yes
4 (case 1)	$600,000	$243,368	-$356,632	$462,399	-$137,601	No
4 (case 2)	$50,000	$173,050	$123,050	$328,795	$278,795	No
5	$50,000	$54,576	$4,576	$103,694	$53,694	No
8	$565,000	$43,492	-$521,508	$82,635	-$482,365	No
13	$150,000	$111,168	-$38,832	$211,219	$61,219	Yes
14	$1,200,000	$882,152	-$317,848	$1,676,089	$476,089	Yes
15 (case 1)	$3,250,000	$404,219	-$2,845,781	$768,017	-$2,481,983	No
15 (case 2)	$1,000,000	$404,219	-$595,781	$768,017	-$231,983	No
16	$565,000	$22,648	-$542,352	$43,031	-$521,969	No
17	$550,000	$65,328	-$484,672	$124,123	-$425,877	No

Of the SAMAs classified as “not cost beneficial” in the baseline Phase 2 analysis, four SAMAs (1, 3, 13, and 14) were found to be cost beneficial when the 95th percentile PRA results were applied. The use of the 95th percentile PRA results is not considered to provide the most realistic assessment of the cost effectiveness of a SAMA; however, these four additional SAMAs could be considered for implementation to address the uncertainties inherent in the SAMA analysis.

Given the similarities between SAMAs 1 and 14, implementation of either one of these SAMAs would make implementation of the other of the two SAMAs not cost beneficial as the relevant risk factors would be addressed. For WCGS, SAMA 14 would likely be the more effective SAMA because it provides power to the DC buses so that steam generator level indication and valve/motor control power would be available for AFW operation. SAMA 1 requires local operation of the TD AFW pump, which would be a less reliable option.

Just as SAMAs 1 and 14 address the same types of risks, SAMA 3 addresses these same factors at a different level. AC cross-tie ability could prevent the conditions that would require the use of either SAMA 1 or 14 by powering equipment required to maintain primary makeup and primary/secondary side heat removal. Implementation of SAMAs 1 or 14 would reduce plant risk such that the AC cross-tie would no longer be cost effective, but from an operations standpoint, it would be preferable to maintain front-line systems rather than rely on non-safety generators. However, the drawback is that the AC cross-tie solution does not address SBO conditions, which is quantitatively a larger concern for WCGS.

Finally, SAMA 13 also provides a means of addressing SBO cases, but only the subset of SBOs caused by fuel oil transfer problems. Implementation of other SAMAs addressing SBO risk will result in a reduction in the averted cost-risk associated with SAMA 13, but this low cost enhancement should still be considered for implementation at WCGS.

F.7.3 MACCS2 INPUT VARIATIONS

The MACC2 model was developed using the best information available for the WCGS site; however, reasonable changes to modeling assumptions can lead to variations in the Level 3 results. In order to determine how certain assumptions could impact the SAMA results, a sensitivity analysis was performed on a group of parameters that has previously been shown to impact the Level 3 results. These parameters include:

- Meteorological data
- Population estimates
- Evacuation effectiveness
- Radionuclide release height

The risk metrics produced by MACCS2 that are evaluated in the sensitivity analyses are the 50 mile population dose and the 50 mile offsite economic cost. The subsections below discuss the changes in these results for each of the sensitivity cases identified above. The final subsection, F.7.3.7, correlates the worst case changes identified in the sensitivity runs to a change in the site's averted cost-risk and discusses the implications of the sensitivity analysis on the SAMA analysis. The following table summarizes the results of the WCGS MACCS2 outputs for the sensitivity cases analyzed:

Case	Description	Pop. Dose Risk Δ Base (%)	Cost Risk Δ Base (%)
Base Case	Base Case (Year 2001 MET data)	--	--
MET2004	Use of Year 2004 MET data in place of 2001 data	+0.01 (+0.3%)	-$166 (-8.4%)
1.3POP	Year 2045 population values increased uniformly by a factor of 1.3 over base case.	+0.41 (+14.3%)	+$580 (+29.4%)
50EVAC	Evacuation speed decreased by 50%	+0.01 (+0.3%)	$0 (0%)
HEIGHT	Release height set to top of reactor building	-0.49 (-17.1%)	+$65 (+3.3%)

F.7.3.1 Meteorological Sensitivity

In addition to the base case meteorological data (year 2001), data was also available for the year 2004. Analysis of this alternate data set yielded a 0.3 percent higher population dose-risk and an offsite economic cost-risk that was lower than the 2001 data by 8.4 percent. These are relatively small perturbations.

As no particular criteria have been defined by the industry related to determining which meteorological data set should be used as a base case for a site, the year 2001 data was conservatively chosen for WCGS given that it yielded the largest results.

F.7.3.2 Population Sensitivity

The population sensitivity case demonstrates a significant dependence on population estimates. This was expected given that the population dose and offsite economic costs are primarily driven by the regional population.

In this sensitivity, the baseline 2045 population was uniformly increased by 30 percent in all sectors of the 50-mile radius. This change increased the estimated population dose-risk by 14.3 percent and the offsite economic cost by over 29 percent. The percent increase in dose-risk is low compared with the percent increase in the total population given that the highest population areas are located outside of the projected release plume.

The population changes were not assumed to impact the percentage of the total population that is evacuated, which is 95 percent, as described in Section F.3.4.

F.7.3.3 Evacuation sensitivity

The evacuation sensitivity case demonstrates minor population dose-risk impacts associated with evacuation assumptions due to the relatively low population impacted by evacuation effects. While evacuation assumptions can impact the population dose-risk estimates, they do not impact MACCS2 offsite economic cost-risk estimates because MACCS2 calculated cost-risks are based on land contamination levels which remain unaffected by evacuation assumptions and the number of people evacuating.

For WCGS, evacuation assumptions have a relatively minor impact on dose-risk. A 50 percent decrease in the evacuation speed increased the dose-risk by only 0.3 percent.

Changes in the evacuation speed were not assumed to impact the percentage of the total population that is evacuated, which is 95 percent, as described in Section F.3.4.

F.7.3.4 Radioactive release sensitivity

This sensitivity case quantifies the impact of the assumptions related to the height of the release. This sensitivity assumes that the release occurs from the top of the plant stack rather than at ground level. The higher release height shows a decrease in dose-risk of 17.1 percent and an increase in OECR of about 3 percent.

F.7.3.5 Impact on SAMA Analysis

Several different Level 3 input parameters have been examined as part of the SSES MACCS2 sensitivity analysis. The primary reason for performing these sensitivity runs was to identify any reasonable changes that could be made to the Level 3 input parameters that would impact the conclusions of the SAMA analysis. While the table in Section F.7.3 summarizes the changes to the dose-risk and OECR estimates for each sensitivity case, it was necessary to determine if any of these changes would result in the retention of the SAMAs that were screened using the baseline results.

Of all the MACCS2 sensitivity cases, the largest increase in both dose-risk and OECR was shown in case 1.3POP (14.3 and 29.4, respectively). The WCGS MMACR was recalculated using these results to determine the impact of using the worst case for each parameter simultaneously. The resulting MMACR was $1,894,060, which is less than $3,518,800 calculated in Section F.7.2 for the 95th percentile PRA results. The 95th percentile PRA results sensitivity is considered to bound this case and no SAMAs would be retained based on this sensitivity that were not already identified in Section F.7.2.

F.8 CONCLUSIONS

The benefits of revising the operational strategies in place at WCGS and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. Use of the PSA in conjunction with cost-benefit analysis methodologies has, however, provided an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on offsite dose and economic impacts. The results of this study indicate that of the identified potential improvements that can be made at WCGS, several are cost beneficial based on the methodology applied in this analysis and warrant further review for potential implementation.

The baseline Phase II analysis indicates that the following SAMAs have positive net values:

- SAMA 2: Modify the Controls and Operating Procedures for Sharpe Station to Allow for Rapid Response
- SAMA 4 (case 2): Update emergency procedures to direct local, manual closure of the RHR EJHV8809A and EJHV8809B valves if they fail to close remotely.
- SAMA 5: Enhance procedures to direct operators to open EDG Room doors for alternate room cooling.

SAMA 2 provides an effective means of enhancing AC capabilities at WCGS. Addition of the capability to control Sharpe Station and provide power to the emergency buses in time to prevent RCP seal damage addresses one of the largest risk contributors for WCGS. The logistics of authorizing changes to a plant partially owned by other utilities is a drawback to this SAMA, but if obtaining such authorization does not require resources far beyond what has been estimated for the cost of implementation, then this SAMA should be considered for implementation.

SAMA 4 appears to be a cost effective means of improving plant response in the highest frequency ISLOCA scenarios. Given that WCGS operators are trained to perform valve closures when remote operation fails in other cases, it is reasonable to believe that the same action would be taken for the RHR EJHV8809A and EJHV8809B valves in an ISLOCA if the technical support center were involved in directing recovery action. However, in time limited scenarios, having clear procedural guidance that explicitly directs this action could result in more timely and reliable response. It is recommended that this SAMA be considered for implementation at WCGS.

SAMA 5 is only marginally cost-beneficial even though the importance of the DGHVAC system is likely overestimated based on the conservative nature of the analysis used to define room cooling requirements (AN-02-010) in the PRA. While the use of a more realistic room heatup calculation would likely yield a negative net value for this SAMA, the proposed procedure change provides a low cost strategy for addressing the loss of a critical system in an accident scenario. It is recommended that this SAMA be considered for implementation at WCGS.

The 95th percentile PRA results show that the following additional SAMAs are cost beneficial:

- SAMA 1: Permanent, Dedicated Generator for the NCP with Local Operation of TD AFW After 125V Battery Depletion
- SAMA 3: AC Cross-tie Capability
- SAMA 13: Alternate Fuel Oil Tank with Gravity Feed Capability
- SAMA 14: Permanent, Dedicated Generator for the NCP, one Motor Driven AFW Pump, and a Battery Charger

These SAMAs could all be considered to be cost beneficial alone, but given the similarities between SAMAs 1, 3, and 14, implementation of any one of them would make implementation of the remaining SAMAs not cost beneficial as the relevant risk factors would be addressed. For WCGS, SAMA 14 would likely be the most effective SAMA based on the following factors:

- SAMA 14 provides power to the DC buses so that steam generator level indication and valve/motor control power would be available for AFW operation. SAMA 1 requires local operation of the TD AFW pump, which would be a less reliable option.

- SAMA 3 does not address SBO conditions, which are important WCGS contributors.

SAMA 13 is a practical, relatively low cost enhancement that addresses a small, but real subset of SBO scenarios. While this change would not likely be cost effective after implementation of SAMAs 1 or 14, it should still be investigated as it increases the capability of the plant and could also provide benefit under non-accident conditions.

In summary, SAMAs 4 (case 2), 5, and 13 have the potential to measurably impact plant risk for a relatively small cost and should be considered for implementation at WCGS. For the higher cost changes, SAMAs 1, 2, 3, and 14 all address LOOP/SBO conditions (excluding SBO for SAMA 3) and could be considered cost beneficial alone, but SAMA 2 appears to be the most effective SAMA as the cost of implementation is relatively low and it addresses SBO scenarios.

While these results are believed to accurately reflect potential areas for improvement at the plant, WCNOC notes that this analysis should not necessarily be considered a formal disposition of these proposed changes as other engineering reviews are necessary to determine ultimate implementation. WCNOC will implement or continue to consider the 7 SAMAs (1, 2, 3, 4 (case 2), 5, 13, and 14) identified in the analysis through the appropriate WCGS design process.

F.9 TABLES

TABLE F.2.1
WOG PEER PRA SUMMARY REPORT

OVERALL ASSESSMENT	
PRA ELEMENT	GRADE BASED ON SUB-ELEMENTS
Initiating Events	3 (C)
Accident Sequence Evaluation	3
Thermal Hydraulic Analysis	3 (C)
System Analysis	3
Data Analysis	3 (C)
Human Reliability Analysis	3 (C)
Dependencies	3
Structural Response	3
Quantification	3 (C)
Containment Performance	3 (C)
Maintenance & Update	3 (C)

Overall Assessment: The WCGS PSA can be effectively used to support risk significance evaluations with deterministic input, subject to addressing the recommendations for improvement included in the element summaries and F&O sheets, or suitable alternatives, as appropriate for specific applications.

Areas Requiring Enhancement: The recommendations for improvement noted in Section 4 of the peer review report should be addressed. These include issues regarding several technical elements, as described in more detail in the “A” and “B” significance level F&O sheets listed in Table F.2.2 WOG Peer F&O Review Status.

TABLE F.2.2
WOG PEER F&O REVIEW STATUS

Level	Item	Observation	Status
A	DA-2	No unique time frame in plant data collection used in developing plant specific data.	A standard time frame for the 2002 PRA update was 1997through the end of year 2002. While it may be desirable to have the same time frame for all components, it is not always practical or reasonable. When the standard timeframe is not used, justification is provided. PRA notebookPSA-05-0020, 'Data Analysis' describes the scope and time frame considered for the collection of plant specific data in the 2002 PRA model update. This issue is closed with approval of the 2002 PRA model update.
A	QU-2	Several logic discrepancies with application of loss of service water recovery factor. Recoveries appear to be applied globally in the fault tree without consideration of the specific failure scenario.	All discrepancies noted in the observation for the loss of service water event quantification have been corrected in the 2002 PRA model update. This issue is closed with approval of the 2002 PRA model update.
B	AS-1	AFW success criteria for SGTR allow indefinite heat removal with the ruptured SG if feed water to 1 of 3intact SGs fails (model lacks sufficient logic steps).	The logic for using a ruptured steam generator for plant cooldown following a SGTR was eliminated. Only the three intact SG's are now modeled for heat removal following a SGTR. This issue is closed with approval of the 2002 PRA model update.
B	AS-6	The sequence transfer process does not appear adequate to ensure that all transfer sequences are transferred to the assigned tree. There is generic indication of possible omission of sequence transfers.	For the 2002 PRA update a transfer sequence tracking table was added to ensure all transfer sequences were properly transferred. This issue is closed with approval of the 2002 PRA model update.
B	DA-1	Insufficient data development guidance available.	The F&O does not state the process used was inappropriate or inadequate. This is considered a "documentation issue" and does not affect PRA modeling or results.
B	DA-3	The start failures for all motor-driven pumps are taken as a group. This could cause MD pumps to have an artificially narrow distribution and result in optimistic failure rates.	In the 1998 model, the pumps were treated as a group for' failure to start'. In the 2002 PRA update, the failure rate data for major safety related motor driven pumps were calculated for each individual system. This issue is closed with approval of the 2002 PRA model update.

TABLE F.2.2
WOG PEER F&O REVIEW STATUS

Level	Item	Observation	Status
B	DA-6	There is no discussion of the process used to identify components selected for common cause treatment. Suggested using an approach based on Idaho National Engineering and Environmental Laboratory (INEEL) CCF database instead ofNSAG-004.	The 2002 PRA update considered WCAP-15167 andNUREG\CR-4550 when establishing CCFs. WCAP-15167includes CC multiple greek letter (MGL) factor tables from NUREG/CR-5497that are based on the INEEL database. Only the discussion of the CCF treatment process has not yet been addressed. This is considered a "documentation issue" and does not affect PRA modeling or results.
B	HR-1	There is little guidance for handling operator actions for recovery other than the HEP calculation. Indication of inconsistencies in event/fault trees and at least one inappropriate use of operator action for recovery	Dependencies between cutsets containing multiple operator action (OPA) basic events were identified. This issue is closed with approval of the 2002 PRA model update. The lack of guidance outside the HEP calculation is considered a documentation issue and does not affect the PRA modeling or results.
B	HR-3	Apparent cognitive errors related to unrealized dependencies.	Dependencies between cutsets containing multiple operator action (OPA) basic events were identified. The change in dependencies was factored back into the final core damage quantification. This issue is closed with approval of the 2002 PRA model update.
B	IE-3	PSA notebook AN-98-044, 'Initiating Event Notebook' Attachment B uses Bayesian update based on gamma distribution. This Bayesian updating method is not recommended for updating event frequency with a mean probability greater than 0.05.	For the 2002 PRA model update the R-DAT Plus Reliability Data Collection and Analysis Tool (Version1.5.2) was used for all Bayesian updates that were performed. The R-DAT tool contains many Bayesian update options, allowing the most appropriate method to be selected for each situation. This issue is closed with approval of the 2002 PRA model update.
B	IE-4	Insufficient documentation provided for screening out 4 reactor trips from the transient initiating event frequencies and significant decrease in transients with power conversion frequency.	The 2002 PRA model update includes all trips between1988 and the end of 2002. No trips were excluded from the transient initiating event frequency. This issue is closed with approval of the 2002 PRA model update.
B	IE-8	Quantification process for determining loss of CCW and loss of SWS IE frequency does not correctly account for common cause failures.	The CCW and SWS initiating event frequency fault trees were revised to account for the common cause contribution in the 2002 PRA model update. This issue is closed with approval of the 2002 PRA model update.

TABLE F.2.2
WOG PEER F&O REVIEW STATUS

Level	Item	Observation	Status
B	IE-9	Lack of documentation discussing use of NUREG/CR-4550 LOCA frequencies vs. the more recentNUREG/CR-5750 LOCA frequencies in Initiating Event Notebook.	The primary reference for non-transient, non-loss of offsite power initiating event frequency values is NUREG/CR-5750. The NRC is currently reviewing the LOCA frequency values in NUREG/CR-5750 and has provided interim LOCA frequency values in, “Technical Work to Support Possible Rulemaking For a Risk-Informed Alternative to 10CFR50.46/GDC 35”. The 2002 PRA model update utilizes, where appropriate, the interim LOCA frequency values. This issue is closed with approval of the 2002 PRA model update.
B	L2-1	IPE Level 2 Class G is omitted from the LERF model without sufficient documentation.	A more detailed analysis of containment performance would have partitioned Bin 14 (Release Category G) sequences and avoided any double counting. Table 4.3-4of the IPE Submittal listed the containment release mode and contribution to source term. It is easily seen that ISL dominates the contribution to release source term. A reduction of the Containment Isolation Failure mode would have increased the Normal Leakage and the ISL release modes. Treatment of containment isolation in the WCGS IPE was simple and conservative (Sequences greater than 1.0E-06 were also treated as containment isolation failures - double counting). Resolution of the F&Os focused on Level 1 items that cascaded throughout the quantification. This Level 2 F&O needs further analytical work to completely address the identified concern.
B	L2-2	The conditional probability of LERF (CLERP) for a very small LOCA appears disproportionately high when compared with other initiators. The reason for this is not obvious.	This is considered to be a documentation issue and does not have significant impact on PRA modeling results. Resolution of the F&Os focused on Level 1 items that cascaded throughout the quantification. This Level 2 F&O needs further analytical work to completely address the identified concern.
B	MU-2	PSA model update guidance lacks sufficient detail regarding activities to be included as part of an update.	The F&O does not indicate that the update process is inadequate or incomplete. Higher tier issues from the Peer Review, in part, guided the 2002 PSA Model Update. Changes in a guidance document would not have altered the strategy for model improvements. This is considered a “documentation issue” and does not affect PRA modeling or results.
B	MU-3	PSA model update guidance lacks emphasis that determining updating urgency should consider impact on risk-informed applications as well as on the base PSA.	This is considered a “documentation issue” and does not affect PRA modeling or results. General guidance and direction is currently in the PSA Desktop instruction.

TABLE F.2.2
WOG PEER F&O REVIEW STATUS

Level	Item	Observation	Status
B	QU-3	Quantification process incorporates incorrect usage of the code (XCOM specifically) potentially resulting in sequences with negative frequency values.	The software code used for quantification of the 2002 PRA model update includes a feature that automatically changes negative values for XCOM events to zero. No negative XCOM events appear in the 2002 basic event data file. This issue is closed with approval of the 2002 PRA model update.
B	QU-4	Equations duplicate the same name potentially resulting in quantification using the wrong equation.	In the 2002 PRA model update, the names of the event tree and associated quantification files were changed to remove the duplication. Reference PSA Change Notification 2005-006. This issue is closed with approval of the 2002 PRA model update.
B	QU-6	Recommend review of top ranking events ensuring data values used are reasonable and reflect current operating conditions of the plant.	Data for major risk significant components and core damage sequences and dominant cutsets were reviewed during the model documentation review process for the2002 model update. This issue is closed with approval of the 2002 PRA model update.
B	QU-7	Lack of documentation of a results convergence analysis on the truncation limit used in the quantification.	Convergence of the core damage results is demonstrated by quantification in the 2002 PRA update. This issue is closed with approval of the 2002 PRA model update.
B	QU-8	Limited documentation in the area of uncertainty and sensitivity analyses.	The 2002 PRA model update includes several sensitivity quantification runs performed for uncertainty considerations including: parametric uncertainty, uncertainty in various data values and uncertainty in success criteria. This issue is closed with approval of the 2002 PRA model update.
B	QU-9	Internal flooding scenarios have not been included in PRA updates.	Regulatory Guide 1.200 indicates that Internal Flooding is required for a full scope PRA. While WCNOC does not have internal flooding as part of its PRA model, the intent is to develop the model and include it in the future.
B	SY-8	Lacking evaluation for equipment credited in model that would not be expected to perform in an anticipated degraded environment following core damage.	Very little non-safety related equipment is credited in the WCNOC PRA. Non-safety related equipment is generally not in a harsh environment for the events where it is credited. For events that result in a known harsh environment in an area, non-safety related equipment in that area is not credited (e.g., a steam line break in the turbine building). This is primarily a documentation improvement issue that has negligible impact on results.
B	TH-1	Misuse of MAAP 3.0B code results and reliance on non-plant specific results.	Quantifications using different, more conservative, success criteria indicated an insignificant increase to CDF. The impact to the WCGS PSA model has been bounded. New modeling work is underway to improve plant specific thermal hydraulic analyses for TH-7.

TABLE F.2.2
WOG PEER F&O REVIEW STATUS

Level	Item	Observation	Status
B	TH-6	Event Tree Analysis Notebook lacks definition of core damage and the definition provided by other sources is, at best, subjective and may be overly conservative in one sense and not bounding in another.	From the Peer Review Report, "It is important to use a clearly-stated definition of core damage that is not overly optimistic. However, a review of the Level 1 MAAP analysis calc indicates that the 30-minute criterion was not likely a factor in determining success or failure in many (if any) of the analyses performed for the IPE." An improvement in definitions is an area that will augment the changes underway for future specific thermal hydraulic analyses.
B	TH-7	Inconsistencies and conservatism in success criteria definitions due to lack of development guidance and old bases.	The documentation issues have no affect on the PRA modeling or results. Westinghouse developed the Wolf Creek success criteria and fault trees. Westinghouse demonstrated the applicability to the Wolf Creek Generating Station. While WCNOC recognizes and acknowledges that the success criteria documentation and development guidance can be improved, the success criteria are reasonable and adequate at this time. New modeling work is underway to improve plant specific thermal hydraulic analyses for TH-7.

TABLE F.2.3
CORE DAMAGE FREQUENCY BY INITIATING EVENT

Initiating Event	Initiating Event Frequency (/yr)	Core Damage Frequency (/yr)	Percent Contribution
Loss of Offsite Power	2.880E-02	1.710E-05	57.286%
Small LOCA	3.000E-03	6.960E-06	23.317%
Interfacing Systems LOCA		1.927E-06	6.456%
Very Small LOCA	6.200E-03	1.250E-06	4.188%
Steam Generator Tube Rupture	3.670E-03	8.737E-07	2.927%
Transients With Power Conversion Systems Available	1.050E+00	3.875E-07	1.298%
Reactor Vessel Failure	3.000E-07	3.000E-07	1.005%
Steamline Break	1.130E-02	2.449E-07	0.820%
Transients Without Power Conversion Systems Available	1.150E-01	1.775E-07	0.595%
Loss of Vital DC Bus NK04	2.635E-03	1.506E-07	0.505%
Medium LOCA	6.100E-05	1.442E-07	0.483%
Loss of Vital DC Bus NK01	2.635E-03	1.228E-07	0.411%
Loss of All Service Water	6.858E-06	8.611E-08	0.288%
Loss of Component Cooling Water	2.144E-04	5.795E-08	0.194%
Feedwater Line Break	3.170E-03	3.312E-08	0.111%
Large LOCA	7.200E-06	2.780E-08	0.093%
		2.985E-05/year	

TABLE F.2.4
CORE DAMAGE FREQUENCY BY EVENT TREE SEQUENCE (> 91% TOTAL CDF)

Number	Sequence Identifier	Sequence Frequency (/yr)	Percent Contribution	Sequence Description
1	SBOS04	1.085E-05	36.35%	Station Blackout Event Occurs; Auxiliary Feedwater Supply function is successful; RCS Cooldown and Depressurization is successful; 21 gpm per pump RCP Seal Leakage exists; Offsite AC Power not recovered within 11 hours.
2	SLOS03	5.813E-06	19.47%	Small LOCA Initiating Event Occurs; High Pressure Safety Injection (HPSI) is successful; Auxiliary Feedwater Supply function is successful; RCS Cooldown and Depressurization per EMG ES-11 fails; High Pressure Recirculation function fails.
3	SBOS12	3.582E-06	12.00%	Station Blackout Event Occurs; Auxiliary Feedwater Supply function is successful; RCS Cooldown and Depressurization is successful; 182 gpm per pump RCP Seal Leakage exists; Offsite AC Power not recovered within 4 hours.
4	ISL	1.927E-06	6.46%	Interfacing Systems LOCA Initiating Event Occurs (ISL Notebook provides description and presentation of the individual ISL scenarios).
5	VLOS07	1.249E-06	4.18%	Very Small LOCA Initiating Event Occurs; High Pressure Safety Injection function fails; Auxiliary Feedwater Supply function is successful; RCS Cooldown and Depressurization function is successful; Low Pressure Safety Injection function fails.
6	SLOS13	1.134E-06	3.80%	Small LOCA Initiating Event occurs; High Pressure Safety Injection function fails; Auxiliary Feedwater Supply function is successful; RCS Cooldown and Depressurization function is successful; Low Pressure Safety Injection function fails.
7	SBOS02	7.739E-07	2.59%	Station Blackout Event Occurs; Auxiliary Feedwater supply function is successful; RCS Cooldown and Depressurization is successful; 21 gpm per pump RCP Seal Leakage exists; Offsite AC power recovered within 11 hours; RCS Inventory Restoration function is successful; High Pressure Recirculation function fails.
8	SBOS03	7.518E-07	2.52%	Station Blackout Event Occurs; Auxiliary Feedwater Supply function is successful; RCS Cooldown and Depressurization successful; 21 gpm per pump RCP Seal Leakage exists; Offsite AC power recovered within 11 hours; RCS Inventory Restoration function fails.

TABLE F.2.4
CORE DAMAGE FREQUENCY BY EVENT TREE SEQUENCE (> 91% TOTAL CDF)

Number	Sequence Identifier	Sequence Frequency (/yr)	Percent Contribution	Sequence Description
9	SGRS03	6.201E-07	2.08%	Steam Generator Tube Rupture Initiating Event Occurs; Auxiliary Feedwater Supply function is successful; High Pressure Safety Injection function is successful; Isolation of Ruptured Steam Generator is successful; RCS and Steam Generator Pressure Stabilization before overfill fails; Steam Generator relief valves successfully reclose; RCS and Steam Generator pressure stabilization after overfill fails.
10	SBOS37	5.743E-07	1.92%	Station Blackout Event Occurs; Auxiliary Feedwater supply function fails; Offsite AC power is not recovered within 1 hour.

TABLE F.3-1
WCGS POPULATION PROJECTION FOR 2040

Radius (miles)	Direction	2040 Projected Population	Radius (miles)	Direction	2040 Projected Population
1	N	0	3	NW	4
1	NNE	0	3	NNW	0
1	NE	0	4	N	2
1	ENE	0	4	NNE	0
1	E	0	4	NE	19
1	ESE	0	4	ENE	12
1	SE	0	4	E	4
1	SSE	0	4	ESE	0
1	S	0	4	SE	2
1	SSW	0	4	SSE	16
1	SW	0	4	S	0
1	WSW	0	4	SSW	10
1	W	0	4	SW	1167
1	WNW	0	4	WSW	20
1	NW	0	4	W	2
1	NNW	0	4	WNW	485
2	N	0	4	NW	30
2	NNE	0	4	NNW	2
2	NE	6	5	N	5
2	ENE	0	5	NNE	12
2	E	0	5	NE	10
2	ESE	5	5	ENE	2
2	SE	1	5	E	11
2	SSE	0	5	ESE	9
2	S	0	5	SE	10
2	SSW	0	5	SSE	7
2	SW	14	5	S	27
2	WSW	5	5	SSW	2
2	W	0	5	SW	2192
2	WNW	0	5	WSW	27

TABLE F.3-1
WCGS POPULATION PROJECTION FOR 2040

Radius (miles)	Direction	2040 Projected Population	Radius (miles)	Direction	2040 Projected Population
2	NW	2	5	W	0
2	NNW	0	5	WNW	55
3	N	4	5	NW	1
3	NNE	6	5	NNW	1
3	NE	4	10	N	82
3	ENE	11	10	NNE	97
3	E	5	10	NE	88
3	ESE	41	10	ENE	62
3	SE	5	10	E	59
3	SSE	0	10	ESE	61
3	S	0	10	SE	114
3	SSW	14	10	SSE	113
3	SW	16	10	S	35
3	WSW	0	10	SSW	122
3	W	42	10	SW	301
3	WNW	46	10	WSW	127
10	W	21	40	W	210
10	WNW	166	40	WNW	12751
10	NW	104	10	WNW	166
10	NNW	98	40	NW	1317
20	N	1109	40	NNW	2708
20	NNE	1426	50	N	13979
20	NE	393	50	NNE	8166
20	ENE	399	50	NE	17308
20	E	532	50	ENE	25897
20	ESE	370	50	E	4302
20	SE	209	50	ESE	1260
20	SSE	1035	50	SE	1842
20	S	155	50	SSE	10551
20	SSW	139	50	S	4217
20	SW	678	50	SSW	1074

TABLE F.3-1
WCGS POPULATION PROJECTION FOR 2040

Radius (miles)	Direction	2040 Projected Population	Radius (miles)	Direction	2040 Projected Population
20	WSW	215	50	SW	3822
20	W	317	50	WSW	173
20	WNW	1156	50	W	1251
20	NW	1728	50	WNW	1280
20	NNW	282	50	NW	406
30	N	3320	50	NNW	2502
30	NNE	3880			
30	NE	3481			
30	ENE	1753			
30	E	4966			
30	ESE	1100			
30	SE	8282			
30	SSE	789			
30	S	2037			
30	SSW	207			
30	SW	210			
30	WSW	1233			
30	W	1449			
30	WNW	22670			
30	NW	937			
30	NNW	5119			
40	N	6540			
40	NNE	3515			
40	NE	23102			
40	ENE	4115			
40	E	1783			
40	ESE	1365			
40	SE	2065			
40	SSE	4223			
40	S	838			
40	SSW	866			

TABLE F.3-1
WCGS POPULATION PROJECTION FOR 2040

Radius (miles)	Direction	2040 Projected Population	Radius (miles)	Direction	2040 Projected Population
40	SW	669			
40	WSW	107			

TABLE F.3-2
WOLF CREEK RELEASE DATA

	Release Category					
	Leakage/NCF	**LCF(K)**	**SGTR**	**ISLOCA**	**CIF**	**ECF**
Time after Scram when Gen Emergency is declared	3.0 hr	19.5 hr	4.5 hr	4.0 hr	2.9 hr	13.3 hr
Fission Product Group:						
1) Noble						
Total Release[1] **Fraction** at "End"	1.10E-03	3.30E-01	6.70E-01	9.80E-01	9.45E-01	9.50E-01
Start of Release (hr)	3 hr	42 hr	5.5 hr	4.0 hr	3.0 hr	16 hr
End of Release (hr)	48 hr	48 hr	5.5 hr	4.0 hr	48 hr	48 hr
Total Release **Fraction** at "End"						
Start of Release (hr)						
End of Release (hr)						
2) CsI						
Total Release **Fraction** at "End"	2.20E-05	3.80E-05	5.80E-02	8.60E-01	6.92E-02	8.80E-02
Start of Release (hr)	3 hr	20 hr	5.5 hr	4.0 hr	3.0 hr	16 hr
End of Release (hr)	8 hr	42 hr	5.5 hr	4.0 hr	48 hr	40 hr
Total Release **Fraction** at "End"		7.40E-04				
Start of Release (hr)		42 hr				
End of Release (hr)		48 hr				
3) TeO2						
Total Release **Fraction** at "End"	3.30E-07	0.00E+00	0.00E+00	1.90E-05	1.10E-03	0.00E+00
Start of Release (hr)	6 hr			6.4 hr	8 hr	
End of Release (hr)	8 hr			8.5 hr	10 hr	
Total Release **Fraction** at "End"						
Start of Release (hr)						
End of Release (hr)						
4) SrO						
Total Release **Fraction** at "End"	4.50E-07	7.10E-08	2.70E-04	3.80E-03	1.20E-03	9.40E-04
Start of Release (hr)	3 hr	20 hr	5.5 hr	4.1 hr	8 hr	16 hr
End of Release (hr)	8 hr	42 hr	5.5 hr	8.0 hr	10 hr	20 hr
Total Release **Fraction** at "End"		8.00E-07				
Start of Release (hr)		42 hr				
End of Release (hr)		48 hr				
5) MoO2						
Total Release **Fraction** at "End"	2.40E-06	3.00E-06	1.60E-02	8.80E-02	4.30E-04	1.50E-02
Start of Release (hr)	3 hr	20 hr	5.5 hr	4.5 hr	2.9 hr	16 hr
End of Release (hr)	8 hr	42 hr	5.5 hr	4.5 hr	9 hr	20 hr
Total Release **Fraction** at "End"		3.40E-05				
Start of Release (hr)		42 hr				
End of Release (hr)		48 hr				
6) CsOH						
Total Release **Fraction** at "End"	2.10E-05	3.20E-05	5.50E-02	8.80E-01	6.00E-02	5.10E-02
Start of Release (hr)	3 hr	20 hr	5.5 hr	4.0 hr	3 hr	16 hr
End of Release (hr)	8 hr	42 hr	5.5 hr	4.0 hr	48 hr	48 hr
Total Release **Fraction** at "End"		6.90E-04				
Start of Release (hr)		42 hr				
End of Release (hr)		48 hr				

TABLE F.3-2
WOLF CREEK RELEASE DATA

	Release Category					
	Leakage/NCF	LCF(K)	SGTR	ISLOCA	CIF	ECF
7) BaO						
Total Release **Fraction** at "End"	8.90E-07	9.40E-07	3.60E-03	2.50E-02	7.20E-04	8.90E-03
Start of Release (hr)	3 hr	20 hr	5.5 hr	4.5 hr	3 hr	16 hr
End of Release (hr)	8 hr	42 hr	5.5 hr	4.5 hr	10 hr	20 hr
Total Release **Fraction** at "End"		1.10E-05				
Start of Release (hr)		42 hr				
End of Release (hr)		48 hr				
8) La2O3						
Total Release **Fraction** at "End"	6.40E-08	5.00E-09	1.80E-05	3.00E-04	1.90E-04	1.20E-04
Start of Release (hr)	3 hr	20 hr	5.5 hr	4.5 hr	3 hr	16 hr
End of Release (hr)	8 hr	42 hr	5.5 hr	8.0 hr	10 hr	20 hr
Total Release **Fraction** at "End"		5.80E-08				
Start of Release (hr)		42 hr				
End of Release (hr)		48 hr				
9) CeO2						
Total Release **Fraction** at "End"	7.70E-07	3.10E-08	9.10E-05	2.50E-03	2.10E-03	4.70E-03
Start of Release (hr)	3 hr	20 hr	5.5 hr	4.5 hr	8 hr	16 hr
End of Release (hr)	8 hr	42 hr	5.5 hr	8.0 hr	10 hr	20 hr
Total Release **Fraction** at "End"		3.70E-07				
Start of Release (hr)		42 hr				
End of Release (hr)		48 hr				
10) Sb						
Total Release **Fraction** at "End"	1.90E-05	2.80E-05	8.40E-02	3.50E-01	4.70E-02	1.20E-01
Start of Release (hr)	3 hr	20 hr	5.5 hr	4.5 hr	3 hr	16 hr
End of Release (hr)	8 hr	42 hr	5.5 hr	4.5 hr	10 hr	25 hr
Total Release **Fraction** at "End"		4.70E-04				
Start of Release (hr)		42 hr				
End of Release (hr)		48 hr				
11) Te2						
Total Release **Fraction** at "End"	2.60E-05	0.00E+00	0.00E+00	3.30E-02	6.50E-02	2.20E-02
Start of Release (hr)	4 hr			6 hr	8 hr	47 hr
End of Release (hr)	8 hr			6 hr	10 hr	48 hr
Total Release **Fraction** at "End"						
Start of Release (hr)						
End of Release (hr)						
12) UO2						
Total Release **Fraction** at "End"	2.50E-09	0.00E+00	0.00E+00	7.80E-06	6.80E-06	1.70E-07
Start of Release (hr)	4 hr			6 hr	8 hr	47 hr
End of Release (hr)	8 hr			8 hr	10 hr	48 hr
Total Release **Fraction** at "End"						
Start of Release (hr)						
End of Release (hr)						

TABLE F.3-3
RESULTS OF WCGS LEVEL 3 PSA ANALYSIS

	Leakage/NCF	LCF(K)	SGTR	ISLOCA	CIF	ECF	Total
Frequency	2.80E-05	1.13E-06	1.65E-07	1.92E-06	3.42E-09	4.48E-07	3.16E-05
Conditional Dose within 50 miles	0.09	0.04	0.04	2.55	0.00	0.14	2.86
Conditional Cost within 50 miles	0	2	72	1659	2	239	1,974

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
FG-FLAG	1.00E+00	9.138	GENERIC FLAG EVENT FOR CUTSET EDITING REPLACEMENT FILE	This flag does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
INIT-LSP	2.88E-02	2.342	LOSS OF OFFSITE POWER INITIATING EVENT FREQUENCY	The importance of the LOOP event provides limited information about plant risk given that the LOOP category is broad and includes several different contributors. These contributors are represented by other events in this importance list that better define specific failures that can be investigated to identify means of reducing plant risk. No credible means of reducing the WCGS grid-centered LOOP frequency have been identified. Implementation of the Maintenance Rule with risk informed maintenance planning is considered to address on-line risk management and equipment reliability issues such that no measurable improvement in the plant centered LOOP frequency is likely available based on enhancing maintenance practices. It may be possible to improve switchyard work planning and/or practices, but a reliable means of quantifying the impact of these types of changes is not available. No SAMAs suggested.
SBO	1.00E+00	2.28	FLAG FOR LOSS OF OFFSITE POWER WITH SBO	The general importance of an SBO suggests that plant risk could be reduced by providing the reactor with a means of operating for an indefinite period of time without AC or DC power. For Wolf Creek, the most immediate problem is the ability to provide RCP seal cooling in an SBO. This would be followed by the need to maintain inventory in the Primary Coolant system (PCS) and provide secondary side cooling. Installation a dedicated diesel generator that could rapidly be aligned to the NCP in conjunction with the ability to operate the turbine driven AFW pump without DC power would allow for long term operation in an SBO (SAMA 1). The existing procedures for operating the turbine driven AFW pump without DC power are not currently credited in the WCGS PRA model. Changes to allow rapid alignment of Sharpe Station would also reduce the risk of SBO scenarios (SAMA 2).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
21--GPM-RCP-LEAK	7.90E-01	1.742	PROBABILITY OF 21 GPM PER RCP SEAL LEAKAGE	The largest contributors to seal LOCAs for Wolf Creek are sequences where an SBO leads to a loss of seal cooling. A dedicated diesel generator that could be rapidly aligned to the NCP from the main control room (MCR) would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2).
11HR-FAILS	1.19E-01	1.571	OFFSITE AC POWER NOT RECOVERED WITHIN 11 HOURS	The importance of this event is predominantly tied to the event "21--GPM-RCP-LEAK", which is addressed above.
INIT-SLO	3.00E-03	1.304	SMALL LOCA INITIATING EVENT FREQUENCY	The largest contributors for Small LOCA are random failures that disable injection after the initiating event. No credit is currently taken for the existing NCP to mitigate small LOCAs; however, as the performance of the pump is comparable to the CCPs that are currently credited to mitigate SLOCAs, the NCP could be credited for this task. Providing a dedicated diesel to power the NCP would improve the ability of the pump to respond to LOCA scenarios in which non-safety bus PB03 is unavailable (SAMA 1).
DGNE-----NE01-PR	5.16E-02	1.218	DIESEL GENERATOR NE01 FAILS TO RUN	A large portion of this event's importance is linked to the SBO induced seal LOCA. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2). Some reduction in risk could be possible by providing the ability to perform a 4kV AC emergency bus cross-tie (SAMA 3).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
DGNE-----NE02-PR	5.16E-02	1.203	DIESEL GENERATOR NE02 FAILS TO RUN	A large portion of this event's importance is linked to the SBO induced seal LOCA. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2). Some reduction in risk could be possible by providing the ability to perform a 4kV AC emergency bus cross-tie (SAMA 3).
EDGA---11HRMT	4.58E-01	1.153	11 HOUR MISSION TIME FOR EDG A	A mission time of 24 hours for the EDGs is applied for all events except SBO. The EDG mission time for SBO event tree core damage sequences are either 1, 4, 9, 10 or 11 hours depending on the time of offsite AC power recovery considered for each sequence. The EDG mission time is established during the post-processing portion (rule based recovery) of sequence quantification. Flag events representing a 24-hour EDG mission time are logically ANDed with EDG run failure type events in the ACNB01 and ACNB02 fault trees [FG-EDGA---24HRMT, FG-EDGB---24HRMT, FG-DGS-CCR24HRMT (common cause fail to run events for both EDGs)]. During the rule based recovery portion of sequence quantification, the flag events are replaced with the following basic events that provide a reduction factor to the EDG run failure type events in accordance with the mission time for the associated core damage sequence. This event is tied to 21--GPM-RCP-LEAK, which is addressed above.
182-GPM-RCP-LEAK	1.98E-01	1.152	PROBABILITY OF 182 GPM PER RCP SEAL LEAKAGE	The largest contributors to seal LOCAs for Wolf Creek are sequences where an SBO leads to a loss of seal cooling. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
EDGB---11HRMT	4.58E-01	1.145	11 HOUR MISSION TIME FOR EDG B	A mission time of 24 hours for the EDGs is applied for all events except SBO. The EDG mission time for SBO event tree core damage sequences are either 1, 4, 9, 10 or 11 hours depending on the time of offsite AC power recovery considered for each sequence. The EDG mission time is established during the post-processing portion (rule based recovery) of sequence quantification. Flag events representing a 24-hour EDG mission time are logically ANDed with EDG run failure type events in the ACNB01 and ACNB02 fault trees [FG-EDGA---24HRMT, FG-EDGB---24HRMT, FG-DGS-CCR24HRMT (common cause fail to run events for both EDGs)]. During the rule based recovery portion of sequence quantification, the flag events are replaced with the following basic events that provide a reduction factor to the EDG run failure type events in accordance with the mission time for the associated core damage sequence. This event is tied to 21--GPM-RCP-LEAK, which is addressed above.
4HR-FAILS	2.86E-01	1.136	OFFSITE AC POWER NOT RECOVERED WITHIN 4 HOURS	This event represents the probability that AC power has not been recovered by 4 hours. It is used in conjunction with the 182 gpm RCP seal LOCA scenario, which is addressed above for event 182-GPM-RCP-LEAK.
DGNE-NE0102---RA	1.18E-03	1.076	COMMON CAUSE DG NE01 AND NE02 FTR	The importance of this event is predominantly tied to SBO scenarios in which seal LOCAs ensue, which are addressed in the events for the individual diesel running failures above (DGNE-----NE01-PR and DGNE-----NE02-PR). EDG CCF also contributes to other scenarios, including SBO with small size LOCAs. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2). Some reduction in risk could be possible by providing the ability to perform a 4kV AC emergency bus cross-tie (SAMA 3).
EDGS-CCR11HRMT	4.58E-01	1.058	11 HOUR MISSION TIME EDGS COMMON CAUSE FTR	This event is used in the same way as event EDGB---11HRMT and is linked to the 21 gpm RCP seal LOCA scenario, which is addressed above for event 21--GPM-RCP-LEAK.

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
PP-RCS-CV8730-RP	1.80E-01	1.054	RHR PIPING ON RCS SIDE OF CV8730A/B FAILS	No credit is taken for isolation of the break using the MOVs that would typically be available, as it has not been confirmed that the isolation valves can close against RCS pressure. It may be possible to show that the current valve type can close or that it can be closed with additional local action. If not, new isolation valves would be required to ensure isolation is possible. This SAMA is included on the lists as SAMA 4, ISLOCA Isolation.
INIT-ISL-LPSI-CL	5.19E-01	1.054	LPSI COLD LEG INJECTION ISLOCA FREQUENCY	The importance of this event is tied directly to PP-RCS-CV8730-RP, which is addressed above.
OTH-OAT-OVER-78F	2.00E-01	1.05	FRACTION OF YEAR WITH OUTSIDE AIR TEMP OVER 78 F	Open the EDG room door for alternate cooling (SAMA 5).
CABN--RWSTLLO-SA	4.40E-04	1.05	FAILURE OF RWST LEVEL LO 2/4 INSTRUMENTATION	This event is associated with ECCS auto suction swap to the sump from the RWST for re-circulation mode. For mode 1, the model does not credit manual backup of the automatic function as the same RWST low-low 1 level signal responsible for auto suction swap initiation would cue the operator that manual action is required. While this is true, other factors would alert the operator to the need to initiate recirculation mode, including sump level indication, low suction pressure trip, and an awareness of the time spent in injection mode. Even if limited credit for manual action were included, the importance of the low level sensor failure event would be reduced below the review threshold for SAMA. For documentation purposes, this is tracked as SAMA 6, Manual Recirculation with RWST Level Instrumentation Failure.
DGNE-----NE01-TM	7.77E-03	1.049	TRAIN A OF EDG IN T&M	This term reflects the need to perform elective or emergent work on the affected SSC. The importance of this event is primarily associated with SBO induced seal LOCA events. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2). Some reduction in risk could be possible by providing the ability to perform a 4kV AC emergency bus cross-tie (SAMA 3).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
INIT-VLO	6.20E-03	1.044	VERY SMALL LOCA INITIATING EVENT FREQUENCY	The top cutsets including INIT-VLO involve failures of the auto-initiation logic for the injection systems. These failures include logic hardware failures and failures of the power supplies to the logic components. Manual action to initiate injection is not currently credited due to modeling issues. If credit were taken for the manual action, the importance of this initiating event would be reduced below the review threshold for SAMA. For documentation purposes, this is tracked as SAMA 7, Manual Recirculation with Auto Initiation Failure.
11HR-SUCCESSFUL	8.81E-01	1.04	OFFSITE AC POWER RECOVERED WITHIN 11 HOURS	This term is located on the success path of the event tree. The counterpart basic event is addressed by the 'fail to recover' term discussed above. After recovery of offsite power in an SBO induced seal LOCA scenario, it is necessary to provide primary system makeup to mitigate the seal LOCA. The top contributors linked to this event include initiation logic failures, manual injection initiation failure, and injection system management failures. Credit for the existing NCP capabilities would reduce the risk highlighted by this event, which is addressed by SAMA 1.
XXEF-ESWB-ALL-TM	3.47E-03	1.039	ESW B UNAVAILABLE FOR MAINTENANCE (SW XTIE UNAVAIL)	This term reflects the need to perform elective or emergent work on the affected SSC. It is linked to SBO induced seal LOCAs through the unavailability of ESW B causing an SBO in conjunction with an "A" emergency power failure. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2).
DGNE-----NE02-TM	5.80E-03	1.036	DG NE02 UNAVAILABLE DUE TO TEST OR MAINTENANCE	This term reflects the need to perform elective or emergent work on the affected SSC. The importance of the event is primarily associated with SBO induced seal LOCA events. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2). Some reduction in risk could be possible by providing the ability to perform a 4kV AC emergency bus cross-tie (SAMA 3).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
INIT-SGR	3.67E-03	1.03	STEAM GENERATOR TUBE RUPTURE INIT FREQUENCY	The importance of this general initiating event category suggests that mitigating enhancements could address a variety of aspects related to SGTR accidents: improved detection and isolation capabilities, enhancing makeup capabilities to the reactor pressure vessel (RPV), providing makeup to the RWST, greater primary side depressurization reliability, or means of reducing the initiating event frequency. Examples of such enhancements for WC might include: - additional instrumentation in the SG to measure radioactivity (SAMA 9), - additional high pressure injection (HPI) capability (SAMA 1), - install isolation valves on the primary side of the SGs, (SAMA 12) - make-up to the RWST (SAMA 8) - additional SGTR training (SAMA 10), - SG tube inspection/replacement (SAMA 11)
ESNFLOCAS EQ12SF1	8.64E-05	1.03	CHANNEL I AND IV LOCA SEQUENCER FAIL COMMON CAUSE	This issue is related to the failure to generate an SI signal. These failures include logic hardware failures and failures of the power supplies to the logic components. Manual action to initiate injection is not currently credited due to modeling issues. If credit were taken for the manual action, the importance of this event would be reduced below the review threshold for SAMA. For documentation purposes, this is tracked as SAMA 7, Manual Recirculation with Auto Initiation Failure.
XXNB-LOCALOOP-SA	2.00E-02	1.03	LOSS OF OFFSITE POW ER SUPPLY IN 24 HOU RS AFTER A LOCA	LOOP following occurrence of a non-LOOP initiating event is included in the WCGS PRA model (basic event XXNB-LOOPOWER-SA). This basic event directly fails the offsite AC power supply to the main safety related (NB01, NB02) and non-safety related (PA02, PA02) AC buses. This event, combined with the Transient initiators (INIT-TRA, INIT-TRO) is included in the LOOP initiating event frequency. A value of 2.0E-03 is assigned to the XXNB-LOOPOWER-SA event. Loss of offsite power following a LOCA initiator is included in the model as basic event XXNB-LOCALOOP-SA. A value of 2.0E-02 is assigned to event XXNB-LOCALOOP-SA. Plant response following a INIT-VLO initiating event is considered more like a transient type response than a LOCA type response. Accordingly, loss of offsite power following an INIT-VLO event is represented using the XXNB-LOOPOWER-SA basic event. SAMA 1 provides a means of alternate HPI given failure of the existing AC sources and is considered to address the major contributors associated with LOCA-LOOP events. SAMA 2 would also improve AC recovery response.

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
MPEJ-01AB-12-BS1	2.68E-04	1.03	COMMON CAUSE FAIL TO START RHR PUMPS PEJ01A&B	The largest contributors including this event are related to the inability to provide makeup to the reactor vessel after depletion of the RWST in small LOCA/leak cases. SAMA 8 addresses these cases.
XXEF-----ESWA-TM	4.28E-03	1.027	TRAIN A OF ESSENTIAL SERVICE WATER IN TST & MANT	This term reflects the need to perform elective or emergent work on the affected SSC. The importance of the event is tied to its effect of failing the "A" EDG in SBO sequences that lead to seal LOCAs. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2).
MPJE--PJE01A-GPS	3.00E-03	1.026	FUEL OIL TRANSFER PUMP PJE01A FAILS TO START	The importance of this event is tied to its effect of failing the "A" EDG in SBO sequences that lead to seal LOCAs. SAMA 1 addresses these cases. However, a more cost effective enhancement for this type of failure may be to provide an alternate, large volume fuel oil tank that could be used to refill the EDG day tanks by gravity feed (SAMA 13).
XXEF-----ESWB-TM	4.08E-03	1.026	TRAIN B OF ESSENTIAL SERVICE WATER IN TST & MANT	This term reflects the need to perform elective or emergent work on the affected SSC. The importance of the event is tied to its effect of failing the "B" EDG in SBO sequences that lead to seal LOCAs. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
DGNE-----NE01-PS	2.87E-03	1.025	DIESEL GENERATOR NE01 FAILS TO START	A large portion of this event's importance is linked to the SBO induced seal LOCAs. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2). Some reduction in risk could be possible by providing the ability to perform a 4kV AC emergency bus cross-tie (SAMA 3).
MPJE--PJE01B-GPS	3.00E-03	1.025	FUEL OIL TRANSFER PUMP PJE01B FAILS TO START	The importance of this event is tied to its effect of failing the "B" EDG in SBO sequences that lead to seal LOCAs. SAMA 1 addresses these cases. However, a more cost effective enhancement for this type of failure may be to provide an alternate, large volume fuel oil tank that could be used to refill the EDG day tanks by gravity feed (SAMA 13).
DGNE-----NE02-PS	2.87E-03	1.024	DIESEL GENERATOR NE02 FAILS TO START	A large portion of this event's importance is linked to the SBO induced seal LOCAs. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1). Rapid alignment of Sharpe Station could help mitigate seal LOCA scenarios (SAMA 2). Some reduction in risk could be possible by providing the ability to perform a 4kV AC emergency bus cross-tie (SAMA 3).
SSV-SUCCESS	5.00E-01	1.021	MAIN STEAM SAFETY VALVES RECLOSE AFTER OVERFILL	This event is associated with sequences in which the operators fail to control SG pressure and level before SG overfills. Isolation valves on the primary loop side of the SGs are a means of terminating a SGTR accident (SAMA 12). Additional SGTR training is a theoretical means of reducing the probability of overfill (SAMA 10).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1HR-FAILS	5.00E-01	1.021	FAILURE TO RESTORE AC POWER WITHIN 1 HOUR	This failure is primarily associated with SBO sequences in which AFW fails early. SBO with AFW failure is important to address; however, even if the AFW failure alone were mitigated, a seal LOCA would likely ensue. The mitigation of these cases requires a means of providing seal cooling and SG makeup without AC support. A potential solution is to expand SAMA 1 by installing additional power connections to one of the motor driven AFW pumps and a battery charger to provide DC support (SAMA 14).
NR-CCWA	1.00E+00	1.02	CCWA NOT RECOVERED GIVEN A RECOVERY HAS OCCURRED	This event is primarily associated with seal LOCA scenarios due to the loss of CCW. A dedicated diesel generator that could be rapidly aligned to the NCP from the MCR would provide a means of limiting the size of seal LOCAs after a loss of cooling and provide a means of primary system makeup in an SBO. After 125V DC battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling (SAMA 1).
EDGA---04HRMT	1.67E-01	1.02	4 HOUR MISSION TIME FOR EDG A	A mission time of 24 hours for the EDGs is applied for all events except SBO. The EDG mission time for SBO event tree core damage sequences are either 1, 4, 9, 10 or 11 hours depending on the time of offsite AC power recovery considered for each sequence. The EDG mission time is established during the post processing portion (rule based recovery) of sequence quantification. Flag events representing a 24 hour EDG mission time are logically ANDed with EDG run failure type events in the ACNB01 and ACNB02 fault trees [FG-EDGA---24HRMT, FG-EDGB---24HRMT, FG-DGS-CCR24HRMT (common cause fail to run events for both EDGs)]. During the rule based recovery portion of sequence quantification, the flag events are replaced with the following basic events that provide a reduction factor to the EDG run failure type events in accordance with the mission time for the associated core damage sequence. This event is tied to 182-GPM-RCP-LEAK, which is addressed above.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
LERF	1.00E+00	999999	DUMMY EVENT FOR LARGE EARLY RELEASE CUTSETS	This flag does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
PP-RCS-CV8730-RP	1.80E-01	2.831	RHR PIPING ON RCS SIDE OF CV8730A/B FAILS	Addressed in the Level 1 importance list.
INIT-ISL-LPSI-CL	5.19E-01	2.829	LPSI COLD LEG INJECTION ISLOCA FREQUENCY	The importance of this event is tied directly to PP-RCS-CV8730-RP, which is addressed in the Level 1 importance list.
CV-LPSICD-12-RP1	4.11E-06	1.237	DOUBLE CCF OF CVS EP8818D & BB8948D (VAR-NUREG/CR-5744)	The importance of this event is tied directly to PP-RCS-CV8730-RP, which is addressed in the Level 1 importance list.
CV-LPSICB-12-RP1	4.11E-06	1.237	DOUBLE CCF OF CVS EP8818B & BB8948B (VAR-NUREG/CR-5744)	The importance of this event is tied directly to PP-RCS-CV8730-RP, which is addressed in the Level 1 importance list.
CV-LPSICA-12-RP1	4.11E-06	1.237	DOUBLE CCF OF CVS EP8818A & BB8948A (VAR-NUREG/CR-5744)	The importance of this event is tied directly to PP-RCS-CV8730-RP, which is addressed in the Level 1 importance list.
CV-LPSICC-12-RP1	4.11E-06	1.237	DOUBLE CCF OF CVS EP8818C & BB8948C (VAR-NUREG/CR-5744)	The importance of this event is tied directly to PP-RCS-CV8730-RP, which is addressed in the Level 1 importance list.
XXNB-LOCALOOP-SA	2.00E-02	1.232	LOSS OF OFFSITE POW ER SUPPLY IN 24 HOU RS AFTER A LOCA	Addressed in the Level 1 importance list.
INIT-SLO	3.00E-03	1.232	SMALL LOCA INITIATING EVENT FREQUENCY	Addressed in the Level 1 importance list.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
FG-FLAG	1.00E+00	1.232	GENERIC FLAG EVENT FOR CUTSET EDITING REPLACEMENT FILE	This flag does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
PP--RHR-SUCT--RP	7.90E-01	1.155	RHR HX OR PIPING ON SUCTION SIDE OF 8730 FAILS	No credit is taken for isolation of the break using the MOVs that would typically be available, as it has not been confirmed that the isolation valves can close against RCS pressure. It may be possible to show that the current valve type can close or that it can be closed with additional local action. If not, new isolation valves would be required to ensure isolation is possible. This SAMA is included on the lists as SAMA 4, ISLOCA Isolation.
INIT-ISL-EJ-CLI	5.19E-01	1.135	EXPOSURE CALC FOR LPSI/HPSI CLI (ISL NTBK, 4.3.2)	This event is directly related to PP--RHR-SUCT--RP, which is addressed above.
DGNE-----NE01-PR	5.16E-02	1.119	DIESEL GENERATOR NE01 FAILS TO RUN	Addressed in the Level 1 importance list.
DGNE-----NE02-PR	5.16E-02	1.116	DIESEL GENERATOR NE02 FAILS TO RUN	Addressed in the Level 1 importance list.
CVEJ---8730A-FTC	2.10E-02	1.063	CV EJ8730A FAILS TO CLOSE (SEE ISL N OTEBOOK,TABLE C-1)	This event is directly related to PP--RHR-SUCT--RP, which is addressed above.
CVEJ---8730B-FTC	2.10E-02	1.063	CV EJ8730B FAILS TO CLOSE (SEE ISL N OTEBOOK,TABLE C-1)	This event is directly related to PP--RHR-SUCT--RP, which is addressed above.
DGNE-NE0102---RA	1.18E-03	1.031	COMMON CAUSE DG NE01 AND NE02 FTR	Addressed in the Level 1 importance list.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
PP--HPSI--CLI-RP	1.60E-01	1.025	PROBABILITY OF HPSI SUCTION PIPING RUPTURING	No credit is taken for isolation of the break using the MOVs that would typically be available as it has not been confirmed that the isolation valves can close against RCS pressure. It may be possible to show that the current valve type can close or that it can be closed with additional local action. If not, new isolation valves would be required to ensure isolation is possible. This SAMA is included on the lists as SAMA 4, ISLOCA Isolation.
INIT-ISL-HPSI-CL	5.19E-01	1.025	INITIATING EVENT MARKER FOR HPSI CL INJ ISLOCA	This event is directly related to PP--HPSI--CLI-RP, which is addressed above.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
1	Permanent, Dedicated Generator for the NCP with Local Operation of TD AFW After 125V Battery Depletion	This SAMA provides a means of limiting the size of a seal LOCA and providing primary side makeup through the installation of a diesel generator that can be rapidly aligned to the NCP from the MCR. Long term secondary side cooling can be provided through the operation of the turbine driven AFW pump using existing WCGS procedures. This arrangement would make it possible to provide adequate core cooling in extended SBO evolutions.	WCGS Level 1 Importance List	The cost of implementation for providing a dedicated diesel generator for the ABWR Feedwater or Condensate pumps was estimated to be $1.2 million in 1994 (GE 1994). The capacity of the generator required for the ABWR application likely exceeds that required for the WCGS NCP, which is only about 500kW. As a result, the ABWR cost has been reduced by 33 percent and not inflated to 2006 dollars to estimate a cost of implementation for this SAMA ($800,000).	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
2	Modify the Controls and Operating Procedures for Sharpe Station to Allow for Rapid Response	An off-site diesel generating plant (Sharpe Station) has an agreement with Wolf Creek to provide power to the site in the event that Wolf Creek experiences a Station Blackout. While the ten 2MW diesel generators have the capacity to power the emergency loads, the time to align power to WCGS is long and is not expected to be complete before 4 hours after the onset of degraded AC conditions. Providing the WCGS control room with the ability to start and align these generators to the WCGS emergency buses through the switchyard would be a means of restoring power to WCGS in non-weather related LOOP events.	WCGS Level 1 Importance List	The cost of this enhancement has been estimated to be $400,000k (WCNOC 2006b).	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
3	AC Cross-tie Capability	Providing the ability to perform a timely 4kV AC cross-tie under emergency conditions would allow operators more flexibility to operate required equipment to protect the core.	WCGS Level 1 Importance List	SSES, a dual unit site, estimated an implementation cost of $656,000 to develop emergency 4kV cross-tie procedures and to install interlock bypass capability to reduce the difficulty and manipulation time of the task (PPL 2006). In this case, the hardware for the cross-tie existed and implementation required only smaller hardware changes. This implementation cost is considered to be a reasonable estimate for the cost of the changes that would be required for WCGS when adjusted to account for single unit implementation. The single unit cost of implementation is estimated by dividing the $656,000 cost by 2, which yields $328,000.	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
4	ISLOCA Isolation	The current Wolf Creek PSA model does not credit operator actions to isolate ISLOCAs using available MOVs as it has not been confirmed that those valves can isolate with RCS pressure against them. The plant engineering staff estimates that the motors could move the valves to a partially closed position before exceeding the torque limit of the valve operator. From that point, it would be possible to complete the valve closure locally assuming that the valves are accessible. Ensuring that procedures direct this isolation in ISLOCA events is a potential means of addressing some of the ISLOCA scenarios (those where access is possible). Alternatively, the valves could be replaced with a type that can close against RCS pressure.	WCGS Level 1 Importance List	Two implementation strategies have been identified for this SAMA. Case 1: Replacing the EJHV8809A and EJHV8809B with models that can close against RCS pressure would eliminate most of the ISLOCA risk, but the cost may be as high as several hundred thousand dollars each. Assuming a total of $500,000 for both valves and $100,000 for the initial valve analysis results in a total of $600,000 for the cost of implementation. Case 2: Enhancing the existing emergency procedures to direct local isolation of the EJHV8809A and EJHV8809B valves and updating training materials is an alternate solution that would cost much less than valve replacement. This option is estimated to require at least $50,000 based on industry estimates for procedure change costs (CPL 2004).	As both the procedure change and hardware replacement strategies are less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
5	Open Doors for Alternate DG Room Cooling	For cases when DGHVAC fails and inside air temperatures are high, the EDG Room doors could be opened to provide outside air exchange cooling to the EDG rooms.	WCGS Level 1 Importance List	The cost of implementation for this SAMA has been estimated to be $50,000 (CPL 2004).	This SAMA has been retained for Phase 2 analysis to demonstrate that no EDG HVAC procedure changes would be cost beneficial.
6	Manual Recirculation with RWST Level Instrumentation Failure	This SAMA is specifically related to the failure of auto swap to recirculation mode due to the RWST level instrumentation. Because this instrumentation is responsible for both the auto swap signal and the annunciator that would alert the operator that recirculation mode is required, the main cue that would instigate operator action is not available. While other means of identifying the need for manual swap are available, the PSA model currently assumes that manual alignment of recirculation always fails in these scenarios because the low RWST level signal has failed. If reasonable credit is taken for the operators to use other means to diagnose the need to align recirculation mode, the importance of the level instrumentation failure is greatly reduced.	WCGS Level 1 Importance List	N/A - PSA analysis will be used to demonstrate that the current model conservatively assigns a high importance to the RWST level instrumentation and that no plant changes are required.	This SAMA has been retained for Phase 2 analysis to demonstrate that no changes to the RWST level instrumentation design would be cost beneficial.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
7	Manual Recirculation with Auto Initiation Failure	Failure to auto swap to recirculation mode can be caused by failure of the logic components responsible for governing the swap, by power failure to the logic, or other hardware failures. For the majority of these cases, a cue would be available to alert the operators of the need to swap to recirculation mode; however, no credit is currently taken for manual swap to recirculation mode after auto initiation failure due to modeling complexities. If reasonable credit is taken for the operators to align recirculation mode, the importance of the scenarios including automatic swap failure is greatly reduced.	WCGS Level 1 Importance List	N/A - PSA analysis will be used to demonstrate that the current model conservatively assigns a high importance to the scenarios including auto swap to recirculation failures and that no plant changes are required.	This SAMA has been retained for Phase 2 analysis to demonstrate that no changes to the auto recirculation hardware would be cost beneficial.
8	High Volume Makeup to the RWST	For SGTR, ISLOCA, and LOCA scenarios where the RWST will be depleted and HPI fails or the sump will be unavailable for recirculation mode, the addition of water to the RWST will allow for continued core cooling. A hard piped connection to the FPS is a possible means of providing this capability.	WCGS Level 1 Importance List	Calvert Cliffs estimated a cost of $565,000 to provide a connection between the FPS and the CCW system. As with the modification investigated by Calvert Cliffs, this SAMA also involves changes to provide an additional flow path from Fire Protection to another system. This estimate is considered to be a reasonable estimate for the type of change proposed for this SAMA.	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
9	Additional Instrumentation in the SG to Measure Radioactivity	Early detection of a SGTR may increase the probability of successful isolation and mitigation.	WCGS Level 1 Importance List	WCGS has multiple radiation instruments that are used in the diagnosis of SGTR events, including sensors that are specific to each loop. The HEP associated with the diagnosis of an SGTR event would not be impacted in any measurable way by the addition of more instrumentation.	No measurable benefit achievable. Not retained for Phase 2 analysis.
10	Additional Training on SGTR Accidents	Enhanced training on detection and mitigation of SGTR scenarios may improve operator response.	WCGS Level 1 Importance List	The WCGS operators are currently trained on SGTR scenarios in both classroom and simulator exercises. The instruction program is continually reviewed and improved, as required. While it may be possible to further improve the SGTR training program, the results of such changes would be difficult to measure using current HRA methods.	No measurable benefit achievable. Not retained for Phase 2 analysis.
11	SG Tube Inspection, Replacement	Improved maintenance on the SG tubes may reduce the frequency of tube ruptures.	WCGS Level 1 Importance List	The cost of implementation for this SAMA has been estimated to be greater than $100 million (BGE 1998).	As the cost of implementation is greater than the MMACR, this SAMA has not been retained for Phase 2 analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
12	Install SG Isolation Valves on the Primary Loop Side	Installation of primary side isolation valves provides an additional means of isolating and controlling an SGTR event. These valves would also eliminate the need for local action to complete a steam generator isolation after a tube rupture has occurred.	WCGS Level 1 Importance List	Calvert Cliffs estimated a cost of $2.7 million to replace the plant's primary loop PORVs with larger versions of the valves. As with the modification investigated by Calvert Cliffs, this SAMA also involves changes to primary loop valves; however, 4 valves are required for the WCGS application and control equipment/logic would have to be added to complete the SAMA. As a result, $2.7 million is considered to be a low end estimate for the cost of implementation for this SAMA.	As the cost of implementation is greater than the MMACR, this SAMA has not been retained for Phase 2 analysis.
13	Alternate Fuel Oil Tank with Gravity Feed Capability	EDG failures related to failure of the fuel oil transfer pumps are currently considered to be unrecoverable in the PSA model. The installation of a large volume tank at an elevation greater than the EDG fuel oil day tanks would allow for emergency refill of the day tanks in the event of fuel oil transfer pump failure.	WCGS Level 1 Importance List	The cost of this enhancement has been estimated to be $150,000 (WCNOC 2006d).	Retained for Phase 2 analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
14	Permanent, Dedicated Generator for the NCP, one Motor Driven AFW Pump, and a Battery Charger	This is similar to SAMA 1, but addresses the additional scenarios in which the TD AFW pump is unavailable. Increasing the capacity of the diesel generator would be required to carry the additional load of the AFW pump and a battery charger for long term SBO success. Fire Protection is not suggested as an alternate source of SG makeup given that it is a low pressure system and would not be available early in an accident.	WCGS Level 1 Importance List	The cost of implementation for providing a dedicated diesel generator for the ABWR Feedwater or Condensate pumps was estimated to be $1.2 million in 1994 (GE 1994). The capacity of the generator required for the ABWR application is likely comparable to the capacity required for the WCGS NCP, AFW pump, and battery charger; therefore, the same cost of implementation is used for this SAMA ($1.2 million).	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase 2 analysis.
15	Install Fire Barriers Around Cables or Reroute the Cables Away from Fire Sources	Equipment fires have the potential to damage safety systems that are not directly related to the original equipment fires. If cables required for safety system operation are located above ignition sources or equipment to which fires may propagate, all associated safety systems depending on those cables may fail. Protecting the overhead cables or rerouting them away from equipment could reduce the consequences of fires in these areas.	WCGS Fire Results	Case 1, Reroute cables: The cost of this enhancement has been estimated to be $3.25 million (WCNOC 2006c). Case 2, Protect Cables: The cost of this enhancement has been estimated to be $1 million (WCNOC 2006c).	Retained for Phase 2 analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
16	Inter-Train CCW Cross-tie for Emergency Operation	A cross-tie between the CCW loops could increase the availability of CCW flow to cooling loads. Certain failure combinations that disable CCW could be eliminated if the use of a cross-tie valve was available to provide flow to required loads. For example, if the "A" loop CCW heat exchanger is out of service and the "B" loop of CCW has failed, the "A" loop of CCW could be used to cool the "B" loop CCW heat exchanger pending isolation of unused loads. For WCGS, an entire crosstie line with isolation valves would have to be installed, as there is no existing crosstie.	Industry SAMA List Review (Peach Bottom)	Calvert Cliffs estimated a cost of $565,000 (BGE 1998) to provide a connection between the FPS and the RHR system's heat exchangers. As with the modification investigated by Calvert Cliffs, this SAMA also involves changes to a cooling water system primarily involving the addition of piping and valves. The cost of implementation developed for Calvert Cliffs is considered to be a reasonable estimate for the type of change proposed for this SAMA.	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase 1 Disposition
17	Install DC Cross-tie Capability	This SAMA would improve DC capability/flexibility in accident conditions.	Industry SAMA List Review (Peach Bottom)	The cost of installing a DC cross-tie at Peach Bottom was estimated to be about $250,000 given that only minor changes would have been required (Exelon, 2001). For WCGS, the changes required to install DC cross-tie capability are more complex and considered to be comparable to the $1.1 million change that was estimated for Brunswick (CPL 2004). As Brunswick is a dual unit plant and the implementation cost is presented on a site basis, the cost must be adjusted for WCGS. The single unit cost is estimate by dividing the Brunswick cost by two, yielding $550,000.	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase 2 analysis.

TABLE F.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION	Cost Effective (Baseline Results)?
1	Permanent, Dedicated Generator for the NCP with Local Operation of TD AFW After 125V Battery Depletion	This SAMA provides a means of limiting the size of a seal LOCA and providing primary side makeup through the installation of a diesel generator that can be rapidly aligned to the NCP from the MCR. Long term secondary side cooling can be provided through the operation of the turbine driven AFW pump using existing WCGS procedures. This arrangement would make it possible to provide adequate core cooling in extended SBO evolutions.	WCGS Level 1 Importance List	The averted cost-risk associated with this SAMA is $799,882. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
2	Modify the Controls and Operating Procedures for Sharpe Station to Allow for Rapid Response	An off-site diesel generating plant (Sharpe Station) has an agreement with Wolf Creek to provide power to the site in the event that Wolf Creek experiences a Station Blackout. While the ten 2MW diesel generators have the capacity to power the emergency loads, the time to align power to WCGS is long and is not expected to be complete before 4 hours after the onset of degraded AC conditions. Providing the WCGS control room with the ability to start and align these generators to the WCGS emergency buses through the switchyard would be a means of restoring power to WCGS in non-weather related LOOP events.	WCGS Level 1 Importance List	The averted cost-risk associated with this SAMA is $655,712. As this is greater than the estimated cost of implementation, the SAMA is cost beneficial.	Yes

TABLE F.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION	Cost Effective (Baseline Results)?
3	AC Cross-tie Capability	Providing the ability to perform a timely 4kV AC crosstie under emergency conditions would allow operators more flexibility to operate required equipment to protect the core.	WCGS Level 1 Importance List	The averted cost-risk associated with this SAMA is $293,252. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
4	ISLOCA Isolation	The current Wolf Creek PSA model does not credit operator actions to isolate ISLOCAs using available MOVs as it has not been confirmed that those valves can isolate with RCS pressure against them. The plant engineering staff estimates that the motors could move the valves to a partially closed position before exceeding the torque limit of the valve operator. From that point, it would be possible to complete the valve closure locally assuming that the valves are accessible. Ensuring that procedures direct this isolation in ISLOCA events is a potential means of addressing some of the ISLOCA scenarios (those where access is possible). Alternatively, the valves could be replaced with a type that can close against RCS pressure.	WCGS Level 1 Importance List	Case 1: The averted cost-risk associated with this SAMA is $243,368. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial. Case 2: The averted cost-risk associated with this SAMA is $173,050. As this is larger than the estimated cost of implementation, this SAMA is cost-beneficial.	Case 1: No Case 2: Yes
5	Open Doors for Alternate DG Room Cooling	For cases when DGHVAC fails and inside air temperatures are high, the EDG Room doors could be opened to provide outside air exchange cooling to the EDG rooms.	WCGS Level 1 Importance List	The averted cost-risk associated with this SAMA is $54,576. As this is larger than the estimated cost of implementation, this SAMA is cost-beneficial.	Yes

TABLE F.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION	Cost Effective (Baseline Results)?
6	Manual Recirculation with RWST Level Instrumentation Failure	This SAMA is specifically related to the failure of auto swap to recirculation mode due to the RWST level instrumentation. Because this instrumentation is responsible for both the auto swap signal and the annunciator that would alert the operator that recirculation mode is required, the main cue that would instigate operator action is not available. While other means of identifying the need for manual swap are available, the PSA model currently assumes that manual alignment of recirculation always fails in these scenarios because the low RWST level signal has failed. If reasonable credit is taken for the operators to use other means to diagnose the need to align recirculation mode, the importance of the level instrumentation failure is greatly reduced.	WCGS Level 1 Importance List	After applying appropriate credit for manual recirculation initiation given failure of 2/4 RWST level instrument channels, the RRW 2/4 RWST level instrument channel event was reduced below the 1.02 SAMA review threshold. This SAMA would not be cost beneficial and was not considered for further review.	Not Applicable.

TABLE F.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION	Cost Effective (Baseline Results)?
7	Manual Recirculation with Auto Initiation Failure	Failure to auto swap to recirculation mode can be caused by failure of the logic components responsible for governing the swap, by power failure to the logic, or other hardware failures. For the majority of these cases, a cue would be available to alert the operators of the need to swap to recirculation mode; however, no credit is currently taken for manual swap to recirculation mode after auto initiation failure due to modeling complexities. If reasonable credit is taken for the operators to align recirculation mode, the importance of the scenarios including automatic swap failure is greatly reduced.	WCGS Level 1 Importance List	After applying appropriate credit for manual recirculation initiation given failure of auto initiation logic failures, the RRW of the dominant auto initiation logic event was reduced below the 1.02 SAMA review threshold. This SAMA would not be cost beneficial and was not considered for further review.	Not Applicable.
8	High Volume Makeup to the RWST	For SGTR, ISLOCA, and LOCA scenarios where the RWST will be depleted and HPI fails or the sump will be unavailable for recirculation mode, the addition of water to the RWST will allow for continued core cooling. A hard piped connection to the FPS is a possible means of providing this capability.	WCGS Level 1 Importance List	The averted cost-risk associated with this SAMA is $43,492. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No

TABLE F.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION	Cost Effective (Baseline Results)?
13	Alternate Fuel Oil Tank with Gravity Feed Capability	EDG failures related to failure of the fuel oil transfer pumps are currently considered to be unrecoverable in the PSA model. The installation of a large volume tank at an elevation greater than the EDG fuel oil day tanks would allow for emergency refill of the day tanks in the event of fuel oil transfer pump failure.	WCGS Level 1 Importance List	The averted cost-risk associated with this SAMA is $111,168. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
14	Permanent, Dedicated Generator for the NCP, one Motor Driven AFW Pump, and a Battery Charger	This is similar to SAMA 1, but addresses the additional scenarios in which the TD AFW pump is unavailable. Increasing the capacity of the diesel generator would be required to carry the additional load of the AFW pump and a battery charger for long term SBO success. Fire Protection is not suggested as an alternate source of SG makeup given that it is a low-pressure system and would not be available early in an accident.	WCGS Level 1 Importance List	The averted cost-risk associated with this SAMA is $882,152. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
15	Install Fire Barriers Around Cables or Reroute the Cables Away from Fire Sources	Equipment fires have the potential to damage safety systems that are not directly related to the original equipment fires. If cables required for safety system operation are located above ignition sources or equipment to which fires may propagate, all associated safety systems depending on those cables may fail. Protecting the overhead cables or rerouting them away from equipment could reduce the consequences of fires in these areas.	WCGS Fire Results	Case 1: The averted cost-risk associated with this SAMA is $404,219. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial. Case 2: The averted cost-risk associated with this SAMA is $404,219. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	Case 1: No Case 2: No

TABLE F.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION	Cost Effective (Baseline Results)?
16	Inter-Train CCW Cross-tie for Emergency Operation	A cross-tie between the CCW loops could increase the availability of CCW flow to cooling loads. Certain failure combinations that disable CCW could be eliminated if the use of a cross-tie valve was available to provide flow to required loads. For example, if the "A" loop CCW heat exchanger is out of service and the "B" loop of CCW has failed, the "A" loop of CCW could be used to cool the "B" loop CCW heat exchanger pending isolation of unused loads. For WCGS, an entire crosstie line with isolation valves would have to be installed, as there is no existing crosstie.	Industry SAMA List Review (Peach Bottom)	The averted cost-risk associated with this SAMA is $22,648. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
17	Install DC Cross-tie Capability	This SAMA would improve DC capability/flexibility in accident conditions.	Industry SAMA List Review (Peach Bottom)	The averted cost-risk associated with this SAMA is $65,328. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No

F.10 REFERENCES

BGE 1998 BGE (Baltimore Gas and Electric). 1998. *Calvert Cliffs Application for License Renewal*, Attachment 2 of Appendix F - Severe Accident Mitigation Alternatives Analysis. April.

CHAN 1997 Chanin, David I. and Mary L. Young 1997. Code Manual for MACCS2: Volume 1, User's Guide, SAND97-0594, Sandia National Laboratories, Albuquerque, New Mexico. March.

CPL 2002 CPL (Carolina Power and Light). 2002. *Applicant's Environmental Report; Operating License Renewal Stage; H. B. Robinson Steam Electric Plant Unit No. 2*. Appendix F Severe Accident Mitigation Alternatives, Letter, J. W. Moyer (CP&L) to U.S. Nuclear Regulatory Commission. "Application for Renewal of Operating License." June 14. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/robinson.html.

CPL 2004 CPL (Carolina Power and Light). 2004. *Applicant's Environmental Report; Operating License Renewal Stage; Brunswick Steam Electric Plant*. Appendix F Severe Accident Mitigation Alternatives. October. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/brunswick.html.

EPA 1972 EPA (U.S. Environmental Protection Agency). 1972. *Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States*. AP-101. Holzworth. George. C. January.

Exelon 2001 — EXELON (Exelon Corporation). 2001. *Peach Bottom Application for License Renewal*, PBAPS (Peach Bottom Atomic Power Station). Appendix E - Environmental Report and Appendix G - Severe Accident Mitigation Alternatives.

Exelon 2003a — EXELON (Exelon Corporation). 2003a. *Applicant's Environmental Report; Operating License Renewal Stage; Dresden Nuclear Power Station Units 2 and 3*. Section 4.20 Severe Accident Mitigation Alternatives (SAMA) and Appendix F SAMA Analysis, Letter, Benjamin, Exelon, to U. S. Nuclear Regulatory Commission. Application for Renewed Operating Licenses. January 3. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/dresden-quad.html.

Exelon 2003b — EXELON (Exelon Corporation). 2003b. *Applicant's Environmental Report; Operating License Renewal Stage; Quad Cities Nuclear Power Station Units 1 and 2*. Section 4.20 Severe Accident Mitigation Alternatives (SAMA) and Appendix F SAMA Analysis, Letter, Benjamin, Exelon, to U. S. Nuclear Regulatory Commission. Application for Renewed Operating Licenses. January 3. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/dresden-quad.html

FPL 2000 FPL (Florida Power & Light). 2000. *Application for Renewed Operating Licenses; Turkey Point Units 3 & 4*. Appendix F Severe Accident Mitigation Alternatives Analysis. September. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/turkey-point/lra.pdf

GE 1994 GE (GE Nuclear Energy). 1994. *Technical Support Document for the ABWR.* 25A5680 Rev. 1. November.

HOLZ 1972 Holzworth, G. C., 1972. "Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution throughout the Contiguous United States," AP-101. U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.

NEI 2005 NEI (Nuclear Energy Institute). 2005. Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document. NEI 05-01. February.

NMC 2004 NMC (Nuclear Management Company, LLC). 2004. *Applicant's Environmental Report; Operating License Renewal Stage; Point Beach Nuclear Plant, Units 1 and 2*. Appendix F SAMA Analysis. Application for Renewed Operating Licenses. February. Available on U. S. Nuclear Regulatory Commission website at http://www.nrc.gov/reactors/operating/licensing/renewal/applications/point-beach/er.pdf

NRC 1976 NRC (U.S. Nuclear Regulatory Commission). 1976. *Flood Protection for Nuclear Power Plants.* Regulatory Guide 1.102. Office of Standards Development. Washington, D.C., September.

NRC 1977 NRC (U.S. Nuclear Regulatory Commission). 1977. *Design Basis Floods for Nuclear Power Plants.* Regulatory Guide 1.59. Office of Standards Development. Washington, D.C., August.

NRC 1987 NRC (U.S. Nuclear Regulatory Commission). 1987. *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants.* LWR Edition. NUREG-0800. Washington, D.C., June.

NRC 1989 NRC (U.S. Nuclear Regulatory Commission). 1989. *Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants*. NUREG-1150. Washington, D.C., June.

NRC 1997a NRC (U.S. Nuclear Regulatory Commission). 1997. *Regulatory Analysis Technical Evaluation Handbook*. NUREG/BR-0184.

NRC 1998a NRC (U.S. Nuclear Regulatory Commission). 1998a. *Code Manual for MACCS2: User's-Guide*. NUREG/CR-6613, Volume 1, SAND 97-0594. Chanin, D. and Young, M. May.

NRC 1998c NRC (U.S. Nuclear Regulatory Commission). 1998c. *WCGS Plant – Resolution of Unresolved Safety Issue (USI) A-46*, Verification of Seismic Qualification Of Equipment in Operating Plants. TAC NO. M69468, SER. September 25.

NRC 2003 NRC (U.S. Nuclear Regulatory Commission). 2003. *Sector Population, Land Fraction, and Economic Estimation Program.* SECPOP2000: NUREG/CR-6525, Washington, D.C., Rev. 1, August.

PPL 2006 PPL (PPL Susquehanna, LLC). 2006. Susquehanna Steam Electric Station Application for License Renewal. Environmental Report. Appendix E. August.

SCE&GC 2002 SCE&GC (South Carolina Electric and Gas Company). 2002. *Virgil C. Summer Nuclear Station Application for License Renewal*. Environmental Report. Appendix F. August.

SNOC 2000 SNOC (Southern Nuclear Operating Company). 2000. *Edwin I. Hatch Nuclear Plant Application for License Renewal, Environmental Report.* Appendix D, Attachment F. February.

USCB 1990 U.S. Census Bureau (USCB) 1990. General Population and Housing Characteristics: 1990. Data Set: 1990 Summary Tape File 1 (STF 1) – 100-Percent Data, , Available online at http://www.factfinder.census.gov, Accessed October 4, 2005.

USCB 2000 U.S. Census Bureau (USCB) 2000. Census 2000 Summary File 1 (SF 1) 100-Percent Data, Available online http://www.factfinder.census.gov, Accessed October 4, 2005.

USDA 1997 USDA (U.S. Department of Agriculture). 1997. *Usual Planting and Harvesting Dates for U.S. Field Crops.* National Agricultural Statistics Service. December. http://usda.mannlib.cornell.edu/reports/nassr/field/planting/uph97.pdf

USDA 1998 USDA (U.S. Department of Agriculture). 1998. *1997 Census of Agriculture.* National Agricultural Statistics Service. http://www.nass.usda.gov/census/census97/volume1/vol1pubs.htm

WCNOC 1992 WCNOC (Wolf Creek Nuclear Operating Corporation). 1992. *Individual Plant Examination Summary Report*. TR-92-0063 W01. September.

WCNOC 1995 WCNOC (Wolf Creek Nuclear Operating Corporation). 1995. *Individual Plant Examination for External Events*. June.

WCNOC 1996a WCNOC (Wolf Creek Nuclear Operating Corporation). 1996. Letter from Richard A. Muench to NRC. ET 96-0034. May 30.

WCNOC 1996b WCNOC (Wolf Creek Nuclear Operating Corporation). 1996. Letter from Richard A. Muench to NRC. ET 96-0068. September 13.

WCNOC 1996c WCNOC (Wolf Creek Nuclear Operating Corporation). 1996. *Wolf Creek Generating Station PSA Flooding Analysis*. Daniel R. Prichard. Calculation Number AN-96-126. December 20.

WCNOC 1997 WCNOC (Wolf Creek Nuclear Operating Corporation). 1997. *EPRI Safety Monitor Project PRA Fault Tree Modifications*. AN-97-050. Revision 0.

WCNOC 1998a WCNOC (Wolf Creek Nuclear Operating Corporation). 1998. *WCGS Fire Risk Evaluation Re-Analysis*. Calculation Number AN-98-023. March.

WCNOC 1998b WCNOC (Wolf Creek Nuclear Operating Corporation). 1998. *WCGS PSA Interfacing Systems LOCA Analysis*. Calculation Number AN-98-054. August.

WCNOC 2002 WCNOC (Wolf Creek Nuclear Operating Corporation). 2002. Wolf Creek Change Package 10203. Revision 2. September.

WCNOC 2003 WCNOC (Wolf Creek Nuclear Operating Corporation). 2003. *Gothic Model of EDG Room Temperature.* Calculation Number AN-02-010. Revision 0.

WCNOC 2005 WCNOC (Wolf Creek Nuclear Operating Corporation). 2005. *LERF Top Logic Development*. David B. Alford. PSA-05-0025. Revision 2.1.

WCNOC 2006a WCNOC (Wolf Creek Nuclear Operating Corporation). 2006. *Updated Safety Analysis Report*. Revision 19. March.

WCNOC 2006b WCNOC (Wolf Creek Nuclear Operating Corporation). 2006. *SAMA 2 Cost Estimate*. Letter Number LR 06-0002.

WCNOC 2006c WCNOC (Wolf Creek Nuclear Operating Corporation). 2006. *SAMA 15 Cost Estimate*. Letter Number LR 06-0003.

WCNOC 2006d WCNOC (Wolf Creek Nuclear Operating Corporation). 2006. *SAMA 13 Cost Estimate*. Letter Number LR 06-0004.

WEST 1999 WEST (Westinghouse). 1999. *Core Inventory Radiation Sources. SAP-99-145*. September 3.

ADDENDUM 1 TO ATTACHMENT F
SELECTED PREVIOUS INDUSTRY SAMAS

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to RCP Seal LOCAs (Loss of CC or SW)		
1	Cap downstream piping of normally closed component cooling water drain and vent valves.	SAMA would reduce the frequency of a loss of component cooling event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.
2	Enhance loss of component cooling procedure to facilitate stopping reactor coolant pumps.	SAMA would reduce the potential for reactor coolant pump (RCP) seal damage due to pump bearing failure.
3	Enhance loss of component cooling procedure to present desirability of cooling down reactor coolant system (RCS) prior to seal LOCA.	SAMA would reduce the potential for RCP seal failure.
4	Provide additional training on the loss of component cooling.	SAMA would potentially improve the success rate of operator actions after a loss of component cooling (to restore RCP seal damage).
5	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	SAMA would reduce effect of loss of component cooling by providing a means to maintain the centrifugal charging pump seal injection after a loss of component cooling.
6	Procedure changes to allow cross connection of motor cooling for residual heat removal service water (RHRSW) pumps.	SAMA would allow continued operation of both RHRSW pumps on a failure of one train of PSW.
7	Proceduralize shedding component cooling water loads to extend component cooling heatup on loss of essential raw cooling water.	SAMA would increase time before the loss of component cooling (and reactor coolant pump seal failure) in the loss of essential raw cooling water sequences.
8	Increase charging pump lube oil capacity.	SAMA would lengthen the time before centrifugal charging pump failure due to lube oil overheating in loss of CC sequences.
9	Eliminate the RCP thermal barrier dependence on component cooling such that loss of component cooling does not result directly in core damage.	SAMA would prevent the loss of recirculation pump seal integrity after a loss of component cooling. Watts Bar Nuclear Plant IPE said that they could do this with essential raw cooling water connection to RCP seals.
10	Add redundant DC control power for PSW pumps C & D.	SAMA would increase reliability of PSW and decrease CDF due to a loss of SW.
11	Create an independent RCP seal injection system, with a dedicated diesel.	SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of component cooling or SW or from a SBO event.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
12	Use existing hydro-test pump for RCP seal injection.	SAMA would provide an independent seal injection source, without the cost of a new system.
13	Replace ECCS pump motor with air-cooled motors.	SAMA would eliminate ECCS dependency on component cooling system (but not on room cooling).
14	Install improved RCS pumps seals.	SAMA would reduce probability of RCP seal LOCA by installing RCP seal O-ring constructed of improved materials
15	Install additional component cooling water pump.	SAMA would reduce probability of loss of component cooling leading to RCP seal LOCA.
16	Prevent centrifugal charging pump flow diversion from the relief valves.	SAMA modification would reduce the frequency of the loss of RCP seal cooling if relief valve opening causes a flow diversion large enough to prevent RCP seal injection.
17	Change procedures to isolate RCP seal letdown flow on loss of component cooling, and guidance on loss of injection during seal LOCA.	SAMA would reduce CDF from loss of seal cooling.
18	Implement procedures to stagger high-pressure safety injection (HPSI) pump use after a loss of SW.	SAMA would allow HPSI to be extended after a loss of SW.
19	Use FPS pumps as a backup seal injection and high-pressure makeup.	SAMA would reduce the frequency of the RCP seal LOCA and the SBO CDF.
20	Enhance procedural guidance for use of cross-tied component cooling or SW pumps.	SAMA would reduce the frequency of the loss of component cooling water and SW.
21	Procedure enhancements and operator training in support system failure sequences, with emphasis on anticipating problems and coping.	SAMA would potentially improve the success rate of operator actions subsequent to support system failures.
22	Improved ability to cool the residual heat removal (RHR) heat exchangers.	SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the FPS or by installing a component cooling water cross-tie.
23	8.a. Additional SW Pump	SAMA would conceivably reduce common cause dependencies from SW system and thus reduce plant risk through system reliability improvement.
24	Create an independent RCP seal injection system, without dedicated diesel	This SAMA would add redundancy to RCP seal cooling alternatives, reducing the CDF from loss of CC or SW, but not SBO.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to Heating, Ventilation, and Air Conditioning		
25	Provide reliable power to control building fans.	SAMA would increase availability of CR ventilation on a loss of power.
26	Provide a redundant train of ventilation.	SAMA would increase the availability of components dependent on room cooling.
27	Procedures for actions on loss of HVAC.	SAMA would provide for improved credit to be taken for loss of HVAC sequences (improved affected electrical equipment reliability upon a loss of control building HVAC).
28	Add a diesel building switchgear room high temperature alarm.	SAMA would improve diagnosis of a loss of switchgear room HVAC. Option 1: Install high temp alarm. Option 2: Redundant louver and thermostat
29	Create ability to switch fan power supply to DC in an SBO event.	SAMA would allow continued operation in an SBO event. This SAMA was created for reactor core isolation cooling (RCIC) system room at Fitzpatrick Nuclear Power Plant.
30	Enhance procedure to instruct operators to trip unneeded RHR/CS pumps on loss of room ventilation.	SAMA increases availability of required RHR/CS pumps. Reduction in room heat load allows continued operation of required RHR/CS pumps, when room cooling is lost.
31	Stage backup fans in switchgear (SWGR) rooms	This SAMA would provide alternate ventilation in the event of a loss of SWGR Room ventilation
Improvements Related to Ex-Vessel Accident Mitigation/Containment Phenomena		
32	Delay containment spray actuation after large LOCA.	SAMA would lengthen time of refueling water storage tank (RWST) availability.
33	Install containment spray pump header automatic throttle valves.	SAMA would extend the time over which water remains in the RWST, when full CS flow is not needed
34	Install an independent method of suppression pool cooling.	SAMA would decrease the probability of loss of containment heat removal. For PWRs, a potential similar enhancement would be to install an independent cooling system for sump water.
35	Develop an enhanced drywell spray system.	SAMA would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
36	Provide dedicated existing drywell spray system.	SAMA would provide a source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. This would use an existing spray loop instead of developing a new spray system.
37	Install an unfiltered hardened containment vent.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products not being scrubbed.
38	Install a filtered containment vent to remove decay heat.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products being scrubbed. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber
39	Install a containment vent large enough to remove ATWS decay heat.	Assuming that injection is available, this SAMA would provide alternate decay heat removal in an ATWS event.
40	Create/enhance hydrogen recombiners with independent power supply.	SAMA would reduce hydrogen detonation at lower cost, Use either 1) a new independent power supply 2) a nonsafety-grade portable generator 3) existing station batteries 4) existing AC/DC independent power supplies.
41	Install hydrogen recombiners.	SAMA would provide a means to reduce the chance of hydrogen detonation.
42	Create a passive design hydrogen ignition system.	SAMA would reduce hydrogen denotation system without requiring electric power.
43	Create a large concrete crucible with heat removal potential under the basemat to contain molten core debris.	SAMA would ensure that molten core debris escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through of the basemat.
44	Create a water-cooled rubble bed on the pedestal.	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.
45	Provide modification for flooding the drywell head.	SAMA would help mitigate accidents that result in the leakage through the drywell head seal.
46	Enhance FPS and/or standby gas treatment system hardware and procedures.	SAMA would improve fission product scrubbing in severe accidents.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
47	Create a reactor cavity flooding system (CFS).	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
48	Create other options for reactor cavity flooding.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
49	Enhance air return fans (ice condenser plants).	SAMA would provide an independent power supply for the air return fans, reducing containment failure in SBO sequences.
50	Create a core melt source reduction system.	SAMA would provide cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal form the vitrified compound would be facilitated, and concrete attack would not occur
51	Provide a containment inerting capability.	SAMA would prevent combustion of hydrogen and carbon monoxide gases.
52	Use the FPS as a backup source for the containment spray system.	SAMA would provide redundant containment spray function without the cost of installing a new system.
53	Install a secondary containment filtered vent.	SAMA would filter fission products released from primary containment.
54	Install a passive containment spray system.	SAMA would provide redundant containment spray method without high cost.
55	Strengthen primary/secondary containment.	SAMA would reduce the probability of containment overpressurization to failure.
56	Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur.	SAMA would prevent basemat melt-through.
57	Provide a reactor vessel exterior cooling system.	SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head could be submerged in water.
58	Construct a building to be connected to primary/secondary containment that is maintained at a vacuum.	SAMA would provide a method to depressurize containment and reduce fission product release.
59	Refill CST	SAMA would reduce the risk of core damage during events such as extended SBOs or LOCAs which render the suppression pool unavailable as an injection source due to heat up.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
60	Maintain ECCS suction on CST	SAMA would maintain suction on the CST as long as possible to avoid pump failure as a result of high suppression pool temperature
61	Modify containment flooding procedure to restrict flooding to below TAF	SAMA would avoid forcing containment venting
62	Enhance containment venting procedures with respect to timing, path selection and technique.	SAMA would improve likelihood of successful venting strategies.
63	1.a. Severe Accident EPGs/AMGs	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
64	1.h. Simulator Training for Severe Accident	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
65	2.g. Dedicated Suppression Pool Cooling	SAMA would decrease the probability of loss of containment heat removal. While PWRs do not have suppression pools, a similar modification may be applied to the sump. Installation of a dedicated sump cooling system would provide an alternate method of cooling injection water.
66	3.a. Larger Volume Containment	SAMA increases time before containment failure and increases time for recovery
67	3.b. Increased Containment Pressure Capability (sufficient pressure to withstand severe accidents)	SAMA minimizes likelihood of large releases
68	3.c. Improved Vacuum Breakers (redundant valves in each line)	SAMA reduces the probability of a stuck open vacuum breaker.
69	3.d. Increased Temperature Margin for Seals	This SAMA would reduce containment failure due to drywell head seal failure caused by elevated temperature and pressure.
70	3.e. Improved Leak Detection	This SAMA would help prevent LOCA events by identifying pipes which have begun to leak. These pipes can be replaced before they break.
71	3.f. Suppression Pool Scrubbing	Directing releases through the suppression pool will reduce the radionuclides allowed to escape to the environment.
72	3.g. Improved Bottom Penetration Design	SAMA reduces failure likelihood of RPV bottom head penetrations

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
73	4.a. Larger Volume Suppression Pool (double effective liquid volume)	SAMA would increase the size of the suppression pool so that heatup rate is reduced, allowing more time for recovery of a heat removal system
74	5.a/d. Unfiltered Vent	SAMA would provide an alternate decay heat removal method with the released fission products not being scrubbed.
75	5.b/c. Filtered Vent	SAMA would provide an alternate decay heat removal method with the released fission products being scrubbed.
76	6.a. Post Accident Inerting System	SAMA would reduce likelihood of gas combustion inside containment
77	6.b. Hydrogen Control by Venting	Prevents hydrogen detonation by venting the containment before combustible levels are reached.
78	6.c. Pre-inerting	SAMA would reduce likelihood of gas combustion inside containment
79	6.d. Ignition Systems	Burning combustible gases before they reach a level which could cause a harmful detonation is a method of preventing containment failure.
80	6.e. Fire Suppression System Inerting	Use of the FPS as a back up containment inerting system would reduce the probability of combustible gas accumulation. This would reduce the containment failure probability for small containments (e.g. BWR MKI).
81	7.a. Drywell Head Flooding	SAMA would provide intentional flooding of the upper drywell head such that if high drywell temperatures occurred, the drywell head seal would not fail.
82	7.b. Containment Spray Augmentation	This SAMA would provide additional means of providing flow to the containment spray system.
83	12.b. Integral Basemat	This SAMA would improve containment and system survivability for seismic events.
84	13.a. Reactor Building Sprays	This SAMA provides the capability to use firewater sprays in the reactor building to mitigate release of fission products into the Rx Bldg following an accident.
85	14.a. Flooded Rubble Bed	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.
86	14.b. Reactor Cavity Flooder	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
87	14.c. Basaltic Cements	SAMA minimizes carbon dioxide production during core concrete interaction.
88	Provide a core debris control system	(Intended for ice condenser plants): This SAMA would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and the containment shell.
89	Add ribbing to the containment shell	This SAMA would reduce the risk of buckling of containment under reverse pressure loading.
Improvements Related to Enhanced AC/DC Reliability/Availability		
90	Proceduralize alignment of spare diesel to shutdown board after LOOP and failure of the diesel normally supplying it.	SAMA would reduce the SBO frequency.
91	Provide an additional DG.	SAMA would increase the reliability and availability of onsite emergency AC power sources.
92	Provide additional DC battery capacity.	SAMA would ensure longer battery capability during an SBO, reducing the frequency of long-term SBO sequences.
93	Use fuel cells instead of lead-acid batteries.	SAMA would extend DC power availability in an SBO.
94	Procedure to cross-tie high-pressure core spray diesel.	SAMA would improve core injection availability by providing a more reliable power supply for the high-pressure core spray pumps.
95	Improve 4.16-kV bus cross-tie ability.	SAMA would improve AC power reliability.
96	Incorporate an alternate battery charging capability.	SAMA would improve DC power reliability by either cross-tying the AC busses, or installing a portable diesel-driven battery charger.
97	Increase/improve DC bus load shedding.	SAMA would extend battery life in an SBO event.
98	Replace existing batteries with more reliable ones.	SAMA would improve DC power reliability and thus increase available SBO recovery time.
99	Mod for DC Bus A reliability.	SAMA would increase the reliability of AC power and injection capability. Loss of DC Bus A causes a loss of main condenser, prevents transfer from the main transformer to off-site power (OSP), and defeats one half of the low vessel pressure permissive for low pressure coolant injection (LPCI)/CS injection valves.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
100	Create AC power cross-tie capability with other unit.	SAMA would improve AC power reliability.
101	Create a cross-tie for diesel fuel oil.	SAMA would increase diesel fuel oil supply and thus DG, reliability.
102	Develop procedures to repair or replace failed 4-kV breakers.	SAMA would offer a recovery path from a failure of the breakers that perform transfer of 4.16-kV non-emergency busses from unit station service transformers, leading to loss of emergency AC power.
103	Emphasize steps in recovery of OSP after an SBO.	SAMA would reduce HEP during OSP recovery.
104	Develop a severe weather conditions procedure.	For plants that do not already have one, this SAMA would reduce the CDF for external weather-related events.
105	Develop procedures for replenishing diesel fuel oil.	SAMA would allow for long-term diesel operation.
106	Install gas turbine generator.	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.
107	Create a backup source for diesel cooling. (Not from existing system)	This SAMA would provide a redundant and diverse source of cooling for the DGs, which would contribute to enhanced diesel reliability.
108	Use FPS as a backup source for diesel cooling.	This SAMA would provide a redundant and diverse source of cooling for the DGs, which would contribute to enhanced diesel reliability.
109	Provide a connection to an alternate source of OSP.	SAMA would reduce the probability of a LOOP event.
110	Bury OSP lines.	SAMA could improve OSP reliability, particularly during severe weather.
111	Replace anchor bolts on DG oil cooler.	Millstone Nuclear Power Station found a high seismic SBO risk due to failure of the diesel oil cooler anchor bolts. For plants with a similar problem, this would reduce seismic risk. Note that these were Fairbanks Morse DGs.
112	Change undervoltage (UV), AFW actuation signal (AFAS) block and high pressurizer pressure actuation signals to 3-out-of-4, instead of 2-out-of-4 logic.	SAMA would reduce risk of 2/4 inverter failure.
113	Provide DC power to the 120/240-V vital AC system from the Class 1E station service battery system instead of its own battery.	SAMA would increase the reliability of the 120-VAC Bus.
114	Bypass DG Trips	SAMA would allow D/Gs to operate for longer.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
115	2.i. 16 hour SBO Injection	SAMA includes improved capability to cope with longer SBO scenarios.
116	9.a. Steam Driven Turbine Generator	This SAMA would provide a steam driven turbine generator which uses reactor steam and exhausts to the suppression pool. If large enough, it could provide power to additional equipment.
117	9.b. Alternate Pump Power Source	This SAMA would provide a small dedicated power source such as a dedicated diesel or gas turbine for the feedwater or condensate pumps, so that they do not rely on OSP.
118	9.d. Additional DG	SAMA would reduce the SBO frequency.
119	9.e. Increased Electrical Divisions	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.
120	9.f. Improved Uninterruptible Power Supplies	SAMA would provide increased reliability of power supplies supporting front-line equipment, thus reducing core damage and release frequencies.
121	9.g. AC Bus Cross-Ties	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.
122	9.h. Gas Turbine	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.
123	9.i. Dedicated RHR (bunkered) Power Supply	SAMA would provide RHR with more reliable AC power.
124	10.a. Dedicated DC Power Supply	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).
125	10.b. Additional Batteries/Divisions	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).
126	10.c. Fuel Cells	SAMA would extend DC power availability in an SBO.
127	10.d. DC Cross-ties	This SAMA would improve DC power reliability.
128	10.e. Extended SBO Provisions	SAMA would provide reduction in SBO sequence frequencies.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
129	Add an automatic bus transfer feature to allow the automatic transfer of the 120V vital AC bus from the on-line unit to the standby unit	Plants are typically sensitive to the loss of one or more 120V vital AC buses. Manual transfers to alternate power supplies could be enhanced to transfer automatically.
Improvements in Identifying and Mitigating Containment Bypass		
130	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture (SGTR).	SAMA would enhance depressurization during a SGTR.
131	Improve SGTR coping abilities.	SAMA would improve instrumentation to detect SGTR, or additional system to scrub fission product releases.
132	Add other SGTR coping abilities.	SAMA would decrease the consequences of an SGTR.
133	Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	SAMA would eliminate direct release pathway for SGTR sequences.
134	Replace steam generators (SG) with a new design.	SAMA would lower the frequency of an SGTR.
135	Revise emergency operating procedures to direct that a faulted SG be isolated.	SAMA would reduce the consequences of an SGTR.
136	Direct SG flooding after a SGTR, prior to core damage.	SAMA would provide for improved scrubbing of SGTR releases.
137	Implement a maintenance practice that inspects 100% of the tubes in a SG.	SAMA would reduce the potential for an SGTR.
138	Locate RHR inside of containment.	SAMA would prevent intersystem LOCA (ISLOCA) out the RHR pathway.
139	Install additional instrumentation for ISLOCAs.	SAMA would decrease ISLOCA frequency by installing pressure of leak monitoring instruments in between the first two pressure isolation valves on low-pressure inject lines, RHR suction lines, and HPSI lines.
140	Increase frequency for valve leak testing.	SAMA could reduce ISLOCA frequency.
141	Improve operator training on ISLOCA coping.	SAMA would decrease ISLOCA effects.
142	Install relief valves in the CC System.	SAMA would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA.
143	Provide leak testing of valves in ISLOCA paths.	SAMA would help reduce ISLOCA frequency. At Kewaunee Nuclear Power Plant, four MOVs isolating RHR from the RCS were not leak tested.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
144	Revise EOPs to improve ISLOCA identification.	SAMA would ensure LOCA outside containment could be identified as such. Salem Nuclear Power Plant had a scenario where an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.
145	Ensure all ISLOCA releases are scrubbed.	SAMA would scrub all ISLOCA releases. One example is to plug drains in the break area so that the break point would be covered with water.
146	Add redundant and diverse limit switches to each containment isolation valve.	SAMA could reduce the frequency of containment isolation failure and ISLOCAs through enhanced isolation valve position indication.
147	Early detection and mitigation of ISLOCA	SAMA would limit the effects of ISLOCA accidents by early detection and isolation
148	8.e. Improved main steam isolation valve (MSIV) Design	This SAMA would improve isolation reliability and reduce spurious actuations that could be initiating events.
149	Proceduralize use of pressurizer vent valves during steam generator tube rupture (SGTR) sequences	Some plants may have procedures to direct the use of pressurizer sprays to reduce RCS pressure after an SGTR. Use of the vent valves would provide a back-up method.
150	Implement a maintenance practice that inspects 100% of the tubes in an SG	This SAMA would reduce the potential for a tube rupture.
151	Locate RHR inside of containment	This SAMA would prevent ISLOCA out the RHR pathway.
152	Install self-actuating containment isolation valves	For plants that do not have this, it would reduce the frequency of isolation failure.
Improvements in Reducing Internal Flooding Frequency		
153	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	SAMA would prevent flood propagation, for a plant where internal flooding from turbine building to safeguards areas is a concern.
154	Improve inspection of rubber expansion joints on main condenser.	SAMA would reduce the frequency of internal flooding, for a plant where internal flooding due to a failure of circulating water system expansion joints is a concern.
155	Implement internal flood prevention and mitigation enhancements.	This SAMA would reduce the consequences of internal flooding.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
156	Implement internal flooding improvements such as those implemented at Fort Calhoun.	This SAMA would reduce flooding risk by preventing or mitigating rupture in the RCP seal cooler of the component cooling system an ISLOCA in a shutdown cooling line, an AFW flood involving the need to remove a watertight door.
157	Shield electrical equipment from potential water spray	SAMA would decrease risk associated with seismically induced internal flooding
158	13.c. Reduction in Reactor Building Flooding	This SAMA reduces the Reactor Building Flood Scenarios contribution to core damage and release.
Improvements Related to Feedwater/Feed and Bleed Reliability/Availability		
159	Install a digital feedwater upgrade.	This SAMA would reduce the chance of a loss of main feedwater following a plant trip.
160	Perform surveillances on manual valves used for backup AFW pump suction.	This SAMA would improve success probability for providing alternative water supply to the AFW pumps.
161	Install manual isolation valves around AFW turbine-driven steam admission valves.	This SAMA would reduce the dual turbine-driven AFW pump maintenance unavailability.
162	Install accumulators for turbine-driven AFW pump flow control valves (CVs).	This SAMA would provide control air accumulators for the turbine-driven AFW flow CVs, the motor-driven AFW pressure CVs and SG power-operated relief valves (PORVs). This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP.
163	Install separate accumulators for the AFW cross-connect and block valves	This SAMA would enhance the operator's ability to operate the AFW cross-connect and block valves following loss of air support.
164	Install a new CST	Either replace the existing tank with a larger one, or install a back-up tank.
165	Provide cooling of the steam-driven AFW pump in an SBO event	This SAMA would improve success probability in an SBO by: (1) using the FP system to cool the pump, or (2) making the pump self cooled.
166	Proceduralize local manual operation of AFW when control power is lost.	This SAMA would lengthen AFW availability in an SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.
167	Provide portable generators to be hooked into the turbine driven AFW, after battery depletion.	This SAMA would extend AFW availability in an SBO (assuming the turbine driven AFW requires DC power)

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
168	Add a motor train of AFW to the Steam trains	For PWRs that do not have any motor trains of AFW, this would increase reliability in non-SBO sequences.
169	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate	This SAMA would be a back-up water supply for the feedwater/condensate systems.
170	Use FP system as a back-up for SG inventory	This SAMA would create a back-up to main and AFW for SG water supply.
171	Procure a portable diesel pump for isolation condenser make-up	This SAMA would provide a back-up to the city water supply and diesel FP system pump for isolation condenser make-up.
172	Install an independent DG for the CST make-up pumps	This SAMA would allow continued inventory make-up to the CST during an SBO.
173	Change failure position of condenser make-up valve	This SAMA would allow greater inventory for the AFW pumps by preventing CST flow diversion to the condenser if the condenser make-up valve fails open on loss of air or power.
174	Create passive secondary side coolers.	This SAMA would reduce CDF from the loss of Feedwater by providing a passive heat removal loop with a condenser and heat sink.
175	Replace current PORVs with larger ones such that only one is required for successful feed and bleed.	This SAMA would reduce the dependencies required for successful feed and bleed.
176	Install motor-driven feedwater pump.	SAMA would increase the availability of injection subsequent to MSIV closure.
177	Use Main feedwater pumps for a Loss of Heat Sink Event	This SAMA involves a procedural change that would allow for a faster response to loss of the secondary heat sink. Use of only the feedwater booster pumps for injection to the SGs requires depressurization to about 350 psig; before the time this pressure is reached, conditions would be met for initiating feed and bleed. Using the available turbine driven feedwater pumps to inject water into the SGs at a high pressure rather than using the feedwater booster alone allows injection without the time consuming depressurization.
Improvements in Core Cooling Systems		
178	Provide the capability for diesel driven, low pressure vessel make-up	This SAMA would provide an extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., FP system)

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
179	Provide an additional HPSI pump with an independent diesel	This SAMA would reduce the frequency of core melt from small LOCA and SBO sequences
180	Install an independent AC HPSI system	This SAMA would allow make-up and feed and bleed capabilities during an SBO.
181	Create the ability to manually align ECCS recirculation	This SAMA would provide a back-up should automatic or remote operation fail.
182	Implement an RWT make-up procedure	This SAMA would decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR.
183	Stop LPSI pumps earlier in medium or large LOCAs.	This SAMA would provide more time to perform recirculation swap over.
184	Emphasize timely swap over in operator training.	This SAMA would reduce HEP of recirculation failure.
185	Upgrade Chemical and Volume Control System to mitigate small LOCAs.	For a plant like the AP600 where the Chemical and Volume Control System cannot mitigate a Small LOCA, an upgrade would decrease the Small LOCA CDF contribution.
186	Install an active HPSI system.	For a plant like the AP600 where an active HPSI system does not exist, this SAMA would add redundancy in HPSI.
187	Change "in-containment" RWT suction from 4 check valves to 2 check and 2 air operated valves.	This SAMA would remove common mode failure of all four injection paths.
188	Replace 2 of the 4 safety injection (SI) pumps with diesel-powered pumps.	This SAMA would reduce the SI system CCF probability. This SAMA was intended for the System 80+, which has four trains of SI.
189	Align low pressure core injection or core spray to the CST on loss of suppression pool cooling.	This SAMA would help to ensure low pressure ECCS can be maintained in loss of suppression pool cooling scenarios.
190	Raise high pressure core injection/RCIC backpressure trip setpoints	This SAMA would ensure high pressure core injection/RCIC availability when high suppression pool temperatures exist.
191	Improve the reliability of the ADS.	This SAMA would reduce the frequency of high pressure core damage sequences.
192	Disallow automatic vessel depressurization in non-ATWS scenarios	This SAMA would improve operator control of the plant.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
193	Create automatic swap over to recirculation on RWT depletion	This SAMA would reduce the human error contribution from recirculation failure.
194	Proceduralize intermittent operation of high pressure coolant injection (HPCI).	SAMA would allow for extended duration of HPCI availability.
195	Increase available net positive suction head (NPSH) for injection pumps.	SAMA increases the probability that these pumps will be available to inject coolant into the vessel by increasing the available NPSH for the injection pumps.
196	Modify Reactor Water Cleanup (RWCU) for use as a decay heat removal system and proceduralize use.	SAMA would provide an additional source of decay heat removal.
197	Control Rod Drive (CRD) Injection	SAMA would supply an additional method of level restoration by using a non-safety system.
198	Condensate Pumps for Injection	SAMA to provide an additional option for coolant injection when other systems are unavailable or inadequate
199	Align EDG to CRD for Injection	SAMA to provide power to an additional injection source during loss of power events
200	Re-open MSIVs	SAMA to regain the main condenser as a heat sink by re-opening the MSIVs.
201	Bypass RCIC Turbine Exhaust Pressure Trip	SAMA would allow RCIC to operate longer.
202	2.a. Passive High Pressure System	SAMA will improve prevention of core melt sequences by providing additional high pressure capability to remove decay heat through an isolation condenser type system
203	2.c. Suppression Pool Jockey Pump	SAMA will improve prevention of core melt sequences by providing a small makeup pump to provide low pressure decay heat removal from the RPV using the suppression pool as a source of water.
204	2.d. Improved High Pressure Systems	SAMA will improve prevention of core melt sequences by improving reliability of high pressure capability to remove decay heat.
205	2.e. Additional Active High Pressure System	SAMA will improve reliability of high pressure decay heat removal by adding an additional system.
206	2.f. Improved Low Pressure System (Firepump)	SAMA would provide FPS pump(s) for use in low pressure scenarios.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
207	4.b. CUW Decay Heat Removal	This SAMA provides a means for Alternate Decay Heat Removal.
208	4.c. High Flow Suppression Pool Cooling	SAMA would improve suppression pool cooling.
209	8.c. Diverse Injection System	SAMA will improve prevention of core melt sequences by providing additional injection capabilities.
210	Alternate Charging Pump Cooling	This SAMA will improve the high pressure core flooding capabilities by providing the SI pumps with alternate gear and oil cooling sources. Given a total loss of Chilled Water, abnormal operating procedures would direct alignment of preferred Demineralized Water or the Fire System to the Chilled Water System to provide cooling to the SI pumps' gear and oil box (and the other normal loads).
Instrument Air/Gas Improvements		
211	Modify EOPs for ability to align diesel power to more air compressors.	For plants that do not have diesel power to all normal and back-up air compressors, this change would increase the reliability of IA after a LOOP.
212	Replace old air compressors with more reliable ones	This SAMA would improve reliability and increase availability of the IA compressors.
213	Install nitrogen bottles as a back-up gas supply for safety relief valves (SRVs).	This SAMA would extend operation of SRVs during an SBO and loss of air events (BWRs).
214	Allow cross connection of uninterruptible compressed air supply to opposite unit.	SAMA would increase the ability to vent containment using the hardened vent.
ATWS Mitigation		
215	Install MG set trip breakers in CR	This SAMA would provide trip breakers for the MG sets in the CR. In some plants, MG set breaker trip requires action to be taken outside of the CR. Adding control capability to the CR would reduce the trip failure probability in sequences where immediate action is required (e.g., ATWS).
216	Add capability to remove power from the bus powering the control rods	This SAMA would decrease the time to insert the control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has a rapid pressure excursion)
217	Create cross-connect ability for standby liquid control trains	This SAMA would improve reliability for boron injection during an ATWS event.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
218	Create an alternate boron injection capability (back-up to standby liquid control)	This SAMA would improve reliability for boron injection during an ATWS event.
219	Remove or allow override of low pressure core injection during an ATWS	On failure on high pressure core injection and condensate, some plants direct reactor depressurization followed by 5 minutes of low pressure core injection. This SAMA would allow control of low pressure core injection immediately.
220	Install a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	This SAMA would improve equipment availability after an ATWS.
221	Create a boron injection system to back up the mechanical control rods.	This SAMA would provide a redundant means to shut down the reactor.
222	Provide an additional instrument system for ATWS mitigation (e.g., ATWS mitigation scram actuation circuitry).	This SAMA would improve instrument and control redundancy and reduce the ATWS frequency.
223	Increase the SRV reseat reliability.	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.
224	Use CRD for alternate boron injection.	SAMA provides an additional system to address ATWS with SLC failure or unavailability.
225	Bypass MSIV isolation in Turbine Trip ATWS scenarios	SAMA will afford operators more time to perform actions. The discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities
226	Enhance operator actions during ATWS	SAMA will reduce human error probabilities during ATWS
227	Guard against SLC dilution	SAMA to control vessel injection to prevent boron loss or dilution following SLC injection.
228	11.a. ATWS Sized Vent	This SAMA would provide the ability to remove reactor heat from ATWS events.
229	11.b. Improved ATWS Capability	This SAMA includes items which reduce the contribution of ATWS to core damage and release frequencies.
Other Improvements		

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
230	Provide capability for remote operation of secondary side relief valves in an SBO	Manual operation of these valves is required in an SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability.
231	Create/enhance RCS depressurization ability	With either a new depressurization system, or with existing PORVs, head vents, and secondary side valve, RCS depressurization would allow earlier low pressure ECCS injection. Even if core damage occurs, low RCS pressure would alleviate some concerns about high pressure melt injection (HPME).
232	Make procedural changes only for the RCS depressurization option	This SAMA would reduce RCS pressure without the cost of a new system
233	Defeat 100% load rejection capability.	This SAMA would eliminate the possibility of a stuck open PORV after a LOOP, since PORV opening would not be needed.
234	Change CRD flow CV failure position	Change failure position to the "fail-safest" position.
235	Install secondary side guard pipes up to the MSIVs	This SAMA would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. This SAMA would also guard against or prevent consequential multiple SGTR following a Main Steam Line Break event.
236	Install digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (leak before break).
237	Increase seismic capacity of the plant to a high confidence, low pressure failure of twice the Safe Shutdown Earthquake.	This SAMA would reduce seismically -induced CDF.
238	Enhance the reliability of the demineralized water (DW) make-up system through the addition of diesel-backed power to one or both of the DW make-up pumps.	Inventory loss due to normal leakage can result in the failure of the CC and the SRW systems. Loss of CC could challenge the RCP seals. Loss of SRW results in the loss of three EDGs and the containment air coolers (CACs).
239	Increase the reliability of SRVs by adding signals to open them automatically.	SAMA reduces the probability of a certain type of medium break LOCA. Hatch evaluated medium LOCA initiated by an MSIV closure transient with a failure of SRVs to open. Reducing the likelihood of the failure for SRVs to open, subsequently reduces the occurrence of this medium LOCA.
240	Reduce DC dependency between high-pressure injection system and ADS.	SAMA would ensure containment depressurization and high-pressure injection upon a DC failure.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
241	Increase seismic ruggedness of plant components.	SAMA would increase the availability of necessary plant equipment during and after seismic events.
242	Enhance RPV depressurization capability	SAMA would decrease the likelihood of core damage in loss of HPCI scenarios
243	Enhance RPV depressurization procedures	SAMA would decrease the likelihood of core damage in loss of HPCI scenarios
244	Replace mercury switches on FPSs	SAMA would decrease probability of spurious fire suppression system actuation given a seismic event+D114
245	Provide additional restraints for CO_2 tanks	SAMA would increase availability of FP given a seismic event.
246	Enhance control of transient combustibles	SAMA would minimize risk associated with important fire areas.
247	Enhance fire brigade awareness	SAMA would minimize risk associated with important fire areas.
248	Upgrade fire compartment barriers	SAMA would minimize risk associated with important fire areas.
249	Enhance procedures to allow specific operator actions	SAMA would minimize risk associated with important fire areas.
250	Develop procedures for transportation and nearby facility accidents	SAMA would minimize risk associated with transportation and nearby facility accidents.
251	Enhance procedures to mitigate Large LOCA	SAMA would minimize risk associated with Large LOCA
252	1.b. Computer Aided Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.
253	1.c/d. Improved Maintenance Procedures/Manuals	SAMA will improve prevention of core melt sequences by increasing reliability of important equipment
254	1.e. Improved Accident Management Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.
255	1.f. Remote Shutdown Station	This SAMA would provide the capability to control the reactor in the event that evacuation of the MCR is required.
256	1.g. Security System	Improvements in the site's security system would decrease the potential for successful sabotage.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
257	2.b. Improved Depressurization	SAMA will improve depressurization system to allow more reliable access to low pressure systems.
258	2.h. Safety Related CST	SAMA will improve availability of CST following a Seismic event
259	4.d. Passive Overpressure Relief	This SAMA would prevent vessel overpressurization.
260	8.b. Improved Operating Response	Improved operator reliability would improve accident mitigation and prevention.
261	8.d. Operation Experience Feedback	This SAMA would identify areas requiring increased attention in plant operation through review of equipment performance.
262	8.e. Improved SRV Design	This SAMA would improve SRV reliability, thus increasing the likelihood that sequences could be mitigated using low pressure heat removal.
263	12.a. Increased Seismic Margins	This SAMA would reduce the risk of core damage and release during seismic events.
264	13.b. System Simplification	This SAMA is intended to address system simplification by the elimination of unnecessary interlocks, automatic initiation of manual actions or redundancy as a means to reduce overall plant risk.
265	Train operations crew for response to inadvertent actuation signals	This SAMA would improve chances of a successful response to the loss of two 120V AC buses, which may cause inadvertent signal generation.
266	Install tornado protection on gas turbine generators	This SAMA would improve onsite AC power reliability.