Omaha Public Power District

APPENDIX E
APPLICANT'S ENVIRONMENTAL REPORT
OPERATING LICENSE RENEWAL STAGE

FORT CALHOUN STATION UNIT 1

JANUARY 2002

CHAPTERS

1.0 PURPOSE OF AND NEED FOR ACTION

1.1 INTRODUCTION AND BACKGROUND

The Omaha Public Power District (OPPD) owns and operates Fort Calhoun Station Unit 1 (FCS), a single-unit nuclear power plant on the Missouri River, approximately 19 miles north of downtown Omaha, Nebraska. The U.S. Nuclear Regulatory Commission (NRC) authorized FCS to operate at full power with its issuance of Operating License DPR-40, effective August 9, 1973. This license, issued for a 40-year period, expires August 9, 2013 (Reference 1.1-1). The OPPD has prepared this environmental report (ER) in connection with its application to the NRC to renew the FCS operating license, as provided for by the following NRC regulations:

- Title 10, Energy, *Code of Federal Regulations*, 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, *Code of Federal Regulations*, Part 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions, Section 51.53, Post-Construction Environmental Reports, Subsection 51.53(c), Operating License Renewal Stage [10 CFR 51.53(c)]

1.2 STATEMENT OF PURPOSE AND NEED

OPPD adopts for this ER the following NRC general definition of purpose and need for the proposed action, as stated in the NRC's *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*, NUREG-1437 (Reference 1.2-1, Section 1.3; Reference 1.2-2, page 28472):

> 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.

FCS has a net summer capability rating of 476 megawatts and generates approximately 3.6 terawatt-hours of electricity annually. This energy is approximately one-third of OPPD's total generation and is enough to meet the needs of approximately 320,000 households in OPPD's service territory, which includes all or part of 13 counties in southeastern Nebraska (Reference 1.2-3, Exhibit 4.4-1; Reference 1.2-4, Attachment 1; Reference 1.2-5, Table 56A; Reference 1.2-6; Reference 1.2-7). The proposed action, renewal of the FCS operating license, would provide OPPD the option to operate this important source of electric power for an additional 20 years, through August 9, 2033.

1.3 ENVIRONMENTAL SCOPE AND METHODOLOGY

The 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, *Applicant's Environmental Report - Operating License Renewal Stage*. In determining what information to include in the FCS Environmental Report, OPPD relied on NRC regulations and the following supporting documents, which provide additional insight into the regulatory requirements:

- NRC supplemental information in the *Federal Register* (Reference 1.2-2; Reference 1.3-1; Reference 1.3-2; Reference 1.3-3)
- *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Reference 1.2-1; Reference 1.3-4)
- *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses* (Reference 1.3-5)
- *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* (Reference 1.3-6)

OPPD also obtained general guidance regarding format and content of the ER from the following NRC documents:

- *Supplement 1 to NRC Regulatory Guide 4.2, Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses* (Reference 1.3-7)
- Supplement 1 to NUREG-1555 Standard Review Plans for Environmental Reviews for Nuclear Power Plants (Operating License Renewal) (Reference 1.3-8)

Table 1.3-1, developed to verify conformance with regulatory requirements, indicates where the ER addresses each requirement of 10 CFR 51.53(c). For convenience, key excerpts from applicable regulations and supporting documents preface each responsive section of the ER.

TABLE 1.3-1
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	The Proposed Action
10 CFR 51.53(c)(2), Sentence 3	7.2.3	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 8.0	Alternatives to the Proposed Action Comparison of Environmental Impact 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 6.2 7.2.3 8.0	Environmental Consequences of the Proposed Action and Mitigating Actions Mitigation Environmental Impacts of Alternatives 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 6.3	Environmental Consequences of the Proposed Action and Mitigating Actions Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.1	Introduction
10 CFR 51.53(c)(3)(ii)(B)	4.2 4.3 4.4	Entrainment of Fish and Shellfish in Early Life Stages Impingement of Fish and Shellfish Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.1	Introduction
10 CFR 51.53(c)(3)(ii)(D)	4.1	Introduction
10 CFR 51.53(c)(3)(ii)(E)	4.5 4.6	Impacts of Refurbishment on Terrestrial Resources Threatened or Endangered Species

TABLE 1.3-1 (CONTINUED)
ENVIRONMENTAL REPORT RESPONSES TO LICENSE RENEWAL ENVIRONMENTAL REGULATORY REQUIREMENTS

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(3)(ii)(F)	4.7	Air Quality During Refurbishment (Nonattainment Areas)
10 CFR 51.53(c)(3)(ii)(G)	4.8	Impact on Public Health of Microbiological Organisms
10 CFR 51.53(c)(3)(ii)(H)	4.9	Electric Shock from Transmission Line-Induced Currents
10 CFR 51.53(c)(3)(ii)(I)	4.10 4.11 4.12 4.13	Housing Impacts Public Utilities: Public Water Supply Availability Education Impacts from Refurbishment Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.14	Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.15	Historic and Archaeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.16	Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0 6.2	Environmental Consequences of the Proposed Action and Mitigating Actions Mitigation
10 CFR 51.53(c)(3)(iv)	5.0	Assessment of New and Significant Information
10 CFR 51, Appendix B to Subpart A, Table B-1, Footnote 6	4.17	Environmental Justice

CFR = Code of Federal Regulations

1.4 REFERENCES

1.1-1 U.S. Atomic Energy Commission. *Omaha Public Power District (Fort Calhoun Station, Unit 1), Docket No. 50-285, Facility Operating License*, Washington, D.C., Issued August 9, 1973 [as revised through Amendment 184. February 3, 1998].

1.2-1 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants.* NUREG-1437. Office of Nuclear Regulatory Research. Washington, D.C., May 1996.

1.2-2 U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." *Federal Register.* 61, No. 109. (June 5, 1996): 28467-97.

1.2-3 Omaha Public Power District. *1997 Integrated Resource Plan* 1997-2016. Integrated Resource Planning Department. May 1997.

1.2-4 Omaha Public Power District. *2001 Integrated Resource Plan*. Memo: A. Ernie Parra to Distribution. October 31, 2000.

1.2-5 U.S. Department of Energy. *Electric Power Monthly April 2000 with Data for January 2000*. DOE/EIA-0226(00/04). Energy Information Administration. Washington, D.C., April 2000.

1.2-6 Omaha Public Power District. *Some Quick Facts about OPPD*. www.oppd.com/whoweare/quickfacts.htm. Copyright 2000. Accessed March 8, 2001.

1.2-7 Omaha Public Power District. *OPPD Service Territory Map*. www.oppd.com/whoweare/svcterritory.htm. Copyright 2000. Accessed March 8, 2001.

1.3-1 U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Correction." *Federal Register*. Vol. 61, No. 147. (July 30, 1996): 39555-6.

1.3-2 U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." *Federal Register*. Vol. 61, No. 244. (December 18, 1996): 66537-54.

1.3-3 U.S. Nuclear Regulatory Commission. "Changes to Requirements for Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Final Rules." *Federal Register*. Vol. 64, No. 171. (September 3, 1999): 48495-507.

1.3-4 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Section 6.3, Transportation and Table 9-1, Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants*. NUREG-1437, Vol. 1, Addendum 1. Office of Nuclear Reactor Regulation. Washington, D.C., August 1999.

1.3-5 U.S. Nuclear Regulatory Commission. *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses*. NUREG-1440. Office of Nuclear Regulatory Research. Washington, D.C., May 1996.

1.3-6 U.S. Nuclear Regulatory Commission. *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.* NUREG-1529. Office of Nuclear Regulatory Research. Washington, D.C., May 1996.

1.3-7 U.S. Nuclear Regulatory Commission. *Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses.* Supplement 1 to Regulatory Guide 4.2. Office of Nuclear Regulatory Research. Washington, D.C., September 2000.

1.3-8 U.S. Nuclear Regulatory Commission. *Standard Review Plans for Environmental Reviews for Nuclear Power Plants (Operating License Renewal).* NUREG-1555, Supplement 1. Office of Nuclear Reactor Regulations. Washington, D.C., October 1999.

2.0 SITE AND ENVIRONMENTAL INTERFACES

2.1 LOCATION AND FEATURES

Fort Calhoun Station Unit 1 (FCS) is located on the southwestern bank of the Missouri River at river mile 646, approximately 19 miles north-northwest of downtown Omaha, Nebraska, and approximately 10 miles north of the Omaha metropolitan area. The nearest municipality to the site is Blair, Nebraska, approximately 3 miles northwest.

Major features within the region (i.e., within approximately 50 miles) and the plant vicinity (i.e., within approximately 6 miles) are illustrated in Figures 2.1-1 and 2.1-2, respectively. Figure 2.1-3 shows the plant site and its immediate environs. General features in these areas of interest have undergone relatively little change since the 1970s when the plant began operation. The U.S. Nuclear Regulatory Commission (NRC) in its Final Environmental Statement for Fort Calhoun Station Unit 2 (FES Unit 2) (Reference 2.1-1)[1] provides a comprehensive summary description of the area at that time and a useful source of relevant information for this environmental report (ER).

2.1.1 REGIONAL FEATURES

Located in the dissected till plains of the central lowlands physiographic province, the site region encompasses portions of eastern Nebraska and western Iowa, which are characterized by a maximum relief of approximately 300 feet (Reference 2.1-1, Section 2.4.1). The main channel of the Missouri River prior to channelization defines the boundary between the two states in this area. The river, its associated flat bottomlands and flanking bluffs, and the dissected loess-covered till plains of western Iowa and drift hills of eastern Nebraska are defining natural features in the region.

The Missouri River is highly modified and controlled for most of its length as a result of numerous U.S. Army Corps of Engineers (COE) projects. A series of six dams and reservoirs, called the Missouri River Main Stem Reservoir System, is on the upper river north of Sioux City, Iowa. A 9-foot-deep by 300-foot-wide navigation channel is maintained from Sioux City to St. Louis. This reach of the river, on which FCS is located, has been modified through its entire length by a system of dikes and revetments designed to provide a continuous navigation channel without the use of locks and dams. Authorized channel dimensions are achieved through supplementary releases from upstream reservoirs and occasional dredging and maintenance. (Reference 2.1-1, Section 2.5.1; Reference 2.1-2, Sections 1.1 and 3.2). Section 2.2 provides pertinent details of river hydrology.

[1] Fort Calhoun Station Unit 2 was never built. However, an FES was prepared for the facility, which includes results of ecological studies in the site area and Missouri River that were not documented in the FES for Unit 1.

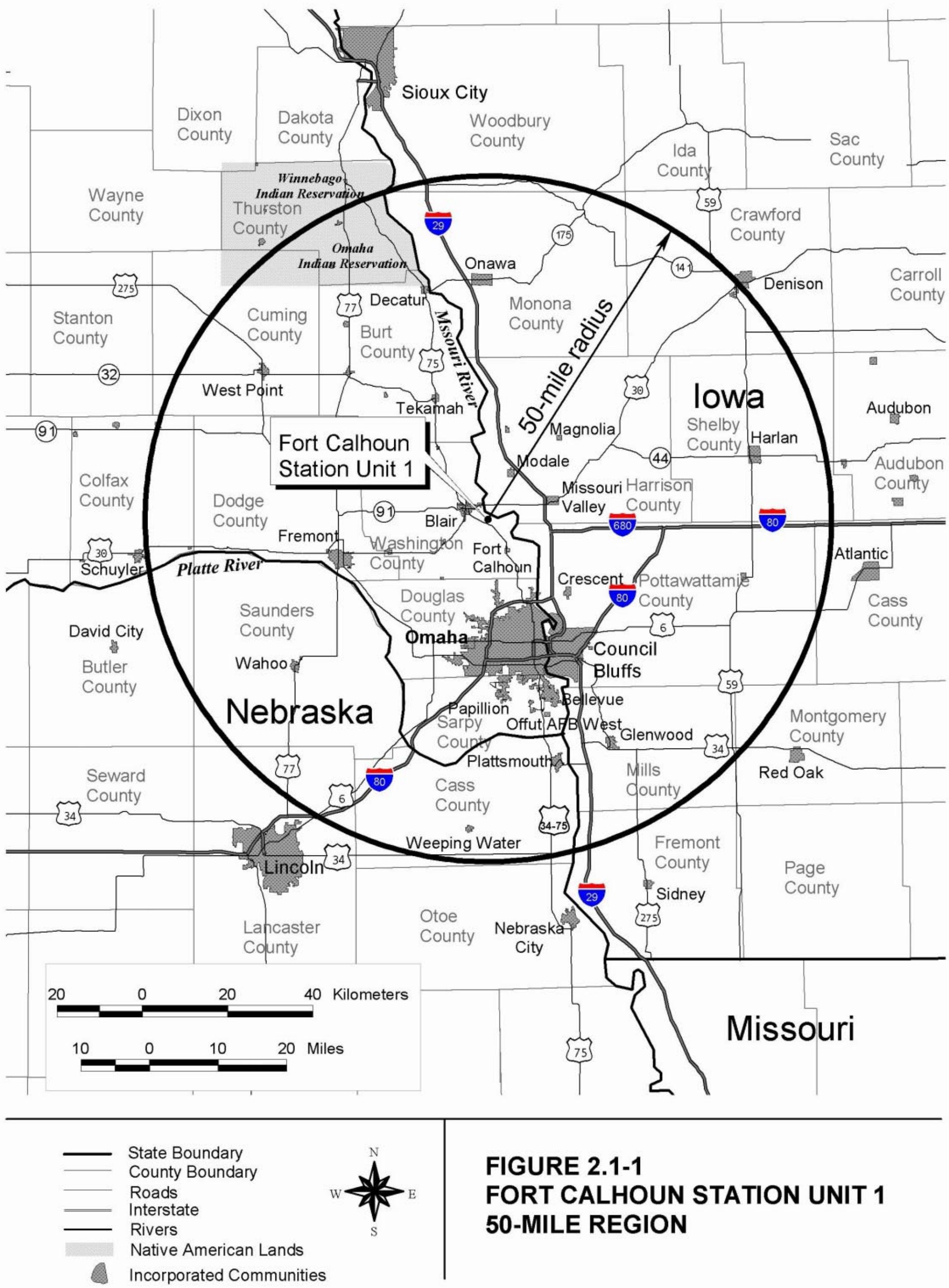


FIGURE 2.1-1
FORT CALHOUN STATION UNIT 1
50-MILE REGION

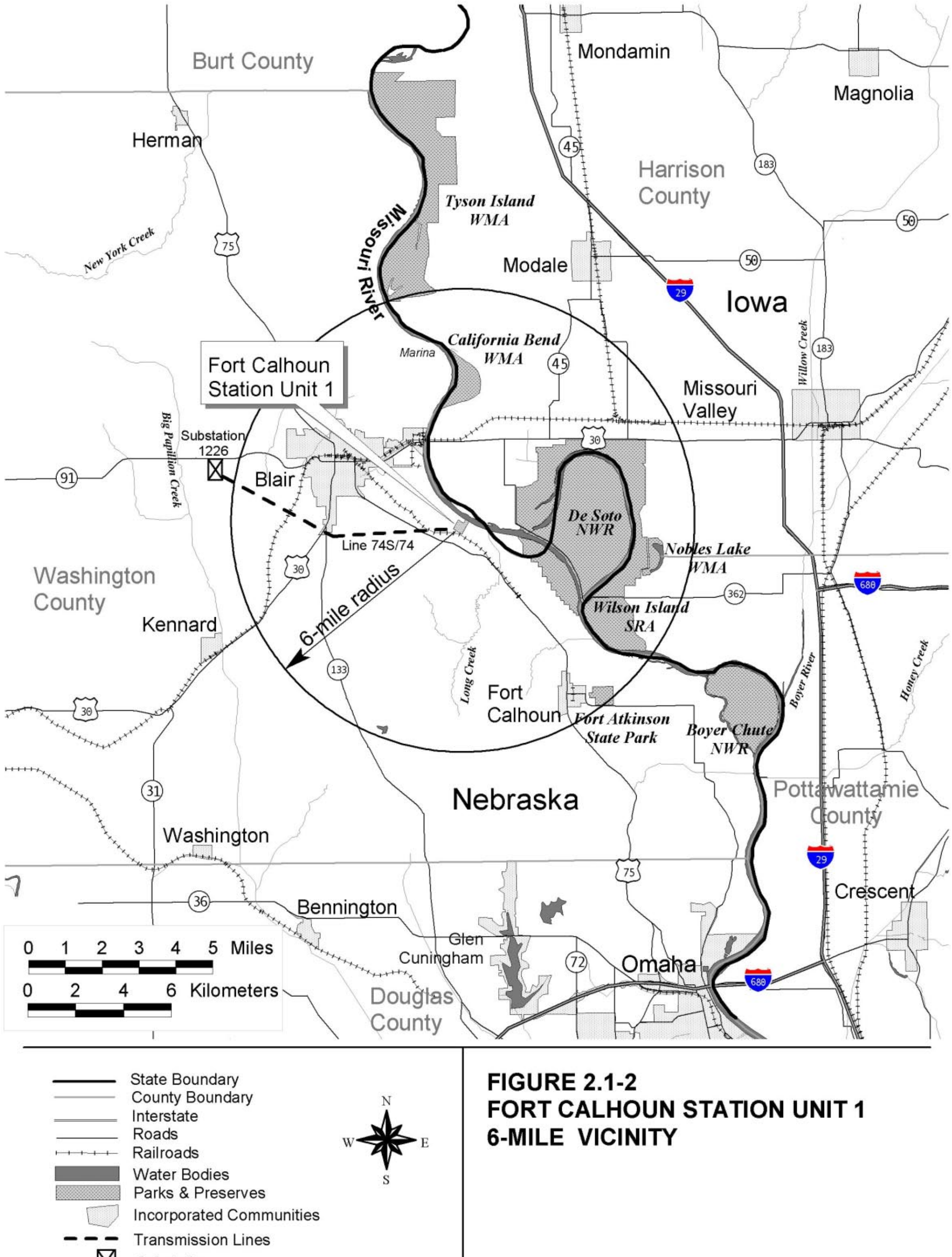


FIGURE 2.1-2
FORT CALHOUN STATION UNIT 1
6-MILE VICINITY

Note: Transmission line shown is that within the scope of license renewal.
See Section 3.1.4 for full description of transmission system.

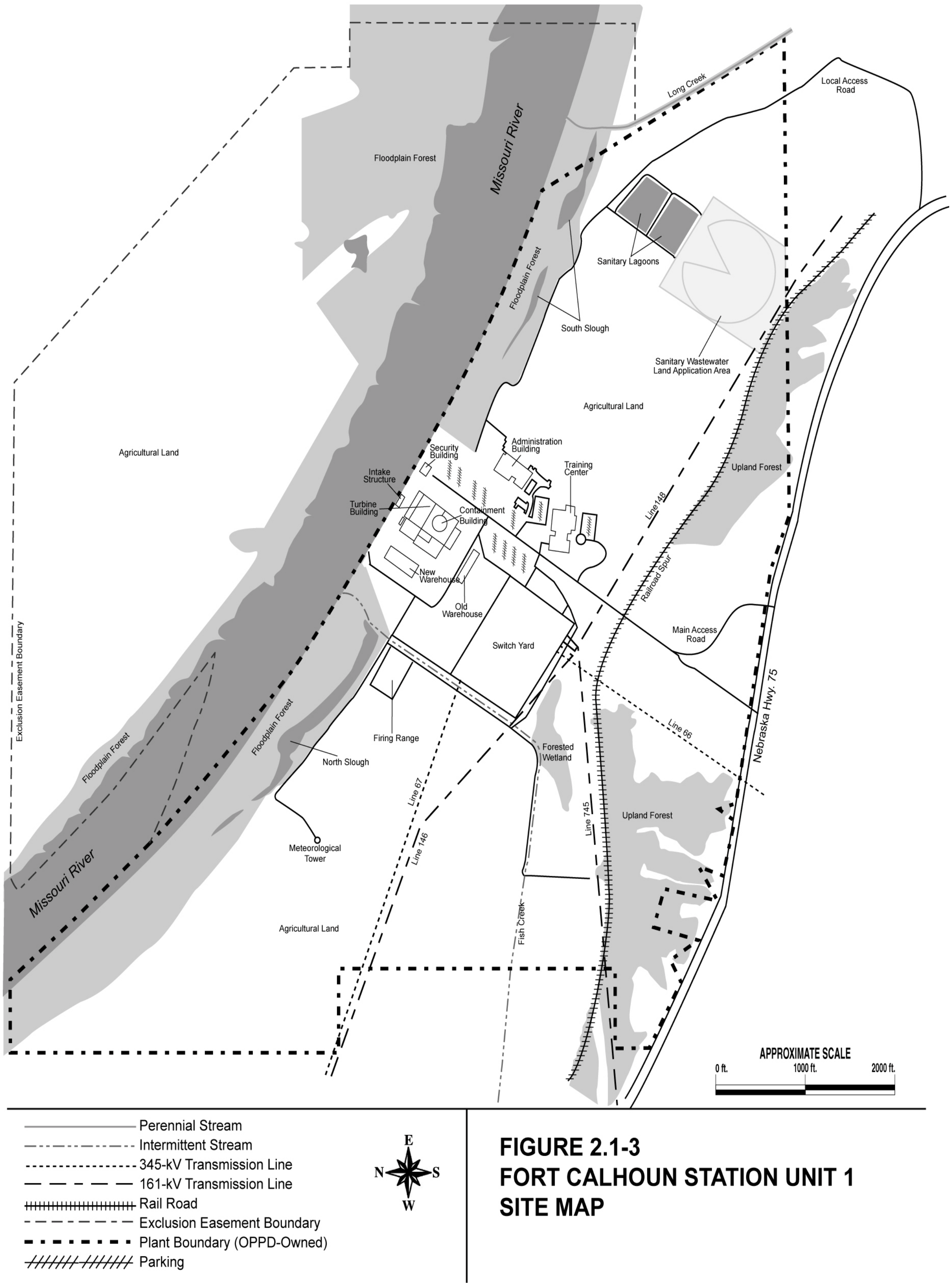


FIGURE 2.1-3
FORT CALHOUN STATION UNIT 1
SITE MAP

The river bottomlands at the plant site are approximately 10 miles wide, but vary in width from approximately 15 miles wide from Blair northward to approximately 3 miles in the vicinity of Omaha. (Reference 2.1-3, Section 2.6.1 and Figure 2.2-2; Reference 2.1-1, Section 2.4.1). These bottomlands are extensively developed in the Omaha Metropolitan Area. However, between Omaha and Sioux City, the valley is predominantly cultivated farmland and relatively sparsely developed, consisting most notably of the City of Onawa, Iowa, and several smaller communities, generally in the valley interior away from the river. Interstate Highway 29 runs along the river bottomlands in Iowa. Several areas in the valley, mostly on Missouri River bends and oxbow lakes, are dedicated to outdoor recreation, wildlife management, and related uses. Natural vegetation in the valley is most evident in these latter areas, along the Missouri River channel and smaller drainage courses, and in poorly drained areas unsuitable for cultivation.

Agriculture is also the predominant land use outside of incorporated areas in the upland region beyond the Missouri River bottomlands. The Platte River runs east before joining the Missouri River approximately 35 miles south of FCS. Large communities and other notable features within 50 miles include the Omaha Metropolitan Area (including the cities of Omaha, Bellevue, and Papillion, Nebraska; and Council Bluffs, Iowa) and Offutt Air Force Base to the south; Fremont, Nebraska, to the west; the Winnebago and Omaha Indian reservations and the cities of Blair and West Point, Nebraska, and Onawa, Iowa, to the north; and the city of Missouri Valley, Iowa, to the east (Figure 2.1-1).

2.1.2 FEATURES IN THE SITE VICINITY

The Missouri River bluffs lie in a northwest-southeast direction in the site vicinity. The Missouri River bottomlands east of the bluff line within six miles of FCS consist primarily of sparsely populated agricultural cropland and public lands dedicated to wildlife management, recreation, and historical preservation. Notable among these public lands in Nebraska are the DeSoto and Boyer Chute National Wildlife Refuges and the Fort Atkinson State Park. In Iowa, notable public lands include the Wilson Island State Recreation Area and Nobles Lake Wildlife Management Area, southward from the site, and the California Bend and Tyson Island Wildlife Management Areas northward from the site (Figure 2.1-2). One commercial marina operates on the Missouri River approximately 5 river miles upstream from FCS.

The largest municipalities within 6 miles of the site are Blair, approximately 3 miles northwest, and Fort Calhoun, approximately 5 miles south. Both municipalities lie near the river but largely above the floodplain on lands transitioning to the Missouri River bluffs. State Highway 133 and U.S. Highway 75 are the major north-south highways on the Nebraska side of the river in the site vicinity. Both highways intersect U.S. Highway 30, the main east-west route in the area, at or near Blair. The segment of U.S. Highway 75 north of Blair to Sioux City is the Lewis and Clark Byway, a state-designated scenic route.

Industrial development is limited in the site vicinity. The Cargill Facility, located on property adjacent to FCS to the northeast, employs approximately 450 persons. In operation since 1994, the facility uses a wet corn milling process to produce agricultural feed, corn sweeteners, and other products, including ethanol, lysine, and lactic acid. Cargill operations have several associated joint ventures that include Midwest Lysine, M&C Sweeteners, and Cargill-Dow. The facility has been expanded recently to include the Cargill-Dow joint venture to produce a lactic-acid-based polymer plastic. This new process will come on line in the fall of 2002. Purac, while not a joint venture, is co-located at the facility and processes the lactic acid end product to make lactic acid derivatives.

Several smaller industrial facilities are located in and near the Blair Industrial Park, located between the Cargill Facility and Blair. These include Terra Nitrogen, located near the Missouri River approximately 3 miles upstream in Blair, which maintains tanks and associated facilities for receipt (by rail), storage, and distribution of anhydrous ammonia. Two limestone quarry operations are within approximately 4 miles south of the plant. The remaining industrial development is largely in Blair and adjacent areas (Reference 2.1-4).

2.1.3 FORT CALHOUN SITE FEATURES

The FCS site consists of approximately 660 acres situated between U.S. Highway 75 (formerly U.S. Highway 73) and the Missouri River (Figure 2.1-3). Omaha Public Power District (OPPD) owns this land and holds perpetual easements on an additional 604 acres, consisting of cropland and natural vegetation, most of which is located across the Missouri River from the site. Together, this acreage comprises the exclusion area for the plant as defined by 10 CFR 100.3 and provides a minimum exclusion distance of 2,986 feet. The nearest residences are generally along U.S. Highway 75, 3,000 to 4,000 feet from the reactor and outside the exclusion area (Reference 2.1-3, Sections 1.2.1, 2.2, 2.8).

Approximately 85 percent of the site is on relatively level ground on the river bottomlands at an approximate elevation of 1,000 feet above mean sea level (msl). The remaining southern portion of the site rises sharply by approximately 60 feet to U.S. Highway 75, which traverses the lower slopes of the Missouri River bluff in this area. Access to the site is from U.S. Highway 75 (Reference 2.1-3, Sections 1.2.1, 2.3; Reference 2.1-5, Section II.D).

The plant operating facilities are in the bottomlands at a slightly higher elevation than most of the remaining lowlands on the site. The water surface elevation of the river at the site is less than 992 feet msl 70 percent of the time, and the design flood elevation for these facilities, corresponding to an annual occurrence probability of 0.1 percent (i.e., one chance in 1,000), is conservatively established at 1,006 feet msl. The plant can accommodate floods up to 1,007 feet msl without special provisions (Reference 2.1-3, Section 2.7.1.2, Figures 2.7-2, 2.7-3). Low-lying areas of the site have experienced flooding on rare occasions. However, river levels at these times have been much lower than 1,006 feet msl, and no plant shutdowns have been necessary as a result of such events.

Of the 660 acres on the site, approximately 135 are occupied by plant facilities or maintained as part of plant operations, including the power generation and ancillary facilities, switchyard, maintenance area, administration building, training building, firing range (for security staff), meteorological tower, closed water treatment sludge landfill, parking areas, roadways, and sanitary waste treatment lagoons and associated areas used to land-apply treated effluent from the lagoons to a center pivot irrigation system. Transmission lines connecting to the Fort Calhoun substation are prominent features on the site, but are largely coincident with other onsite land uses. These consist of a 345-kilovolt regional interconnection (Lines 66 and 67) and three 161-kilovolt lines: Line 146 northwestward to Substation 1298 serving the Cargill Plant, located on property adjoining the site; Line 148 southward to Substation 1297 at the City of Fort Calhoun, then southward to Omaha; and Line 74S/74 to Substation 1226, west of Blair. Section 3.1 describes pertinent details of plant facilities and transmission lines.

Approximately 345 acres is cropland, which OPPD leases to local farmers who grow predominantly corn and soybeans. Notable land uses on the remainder of the site (approximately 180 acres) include a railroad spur, natural vegetation, and drainage courses. The railroad spur is on a right-of-way easement to Union Pacific Railroad that follows the base of the bluff across the southern portion of the site (Figure 2.1-3) and continues northwestward to Blair, where it joins the main line. Built in 1994 to serve the neighboring Cargill Facility, the spur is coincident with the Chicago and Northwestern spur used for plant construction, which was subsequently abandoned and removed. Areas of natural vegetation on the site consist mostly of highly disturbed woodlands and shrub land on the steep slopes in the southern portion of the site and riparian woodlands along onsite sloughs bordering the Missouri River.

The Missouri River at the site is approximately 600 feet wide and 15 feet deep. The entire length of the river in this segment has been channelized. The banks are stabilized by filling dams along the east bank and riprap along the west cutting bank where plant facilities are located. Further evidence of this work is apparent on the site by remnants of a lateral slough formed when a segment of the river channel was cut off as a result of channelization. The central portion of this slough was filled for initial plant construction, resulting in the formation of what are now called the North Slough and South Slough, each of which is bordered by floodplain forest (Reference 2.1-5, Section II.D; Reference 2.1-1, Sections 2.5.1, 2.7.2). (See Figure 2.1-3 and Section 2.3.2.)

There are two streams on or adjacent to the site (Figure 2.1-3). Fish Creek, a small intermittent stream originating immediately south of U.S. Highway 30 in Blair, lies entirely within river bottomlands. This stream, which has been channelized for most of its length, consists essentially of a uniform channel, approximately 10- to 15-feet deep with grass-stabilized sloping banks, on the plant site. This stream outfalls to the North Slough, then to the Missouri River via a short drainage canal. Long Creek is a small Missouri River tributary that drains upland areas south of the site. The lower reach of this stream, in the bottomlands, occupies a steep, deeply incised channel, approximately 30 feet wide at the streambed. A narrow strip of riparian floodplain forest borders the channel. This reach of the stream coincides with a portion of the eastern site boundary and joins the downstream end of the South Slough at its outfall to the river (Reference 2.1-1, Section 2.7.2). (See Figure 2.1-3.) The upland reach of the stream, south of U.S. Highway 75, is smaller and steeper and formed from numerous small tributaries. Much of this drainage area, particularly the steeper slopes, is forested. Farmland and rural residential lots occupy the remainder of the area, where there are gentler slopes. General characteristics of the North and South Sloughs and Long Creek have undergone little apparent change from those the NRC described in 1978 (Reference 2.1-1, Section 2.7.2).

2.2 MISSOURI RIVER

The Missouri River has been extensively modified and is continuously maintained and managed for multiple uses by the COE, including power generation and fish and wildlife conservation. Controlled releases from the lowermost dam on the river (Gavins Point Dam), located upstream from FCS, largely determine the flow regime of the lower river. These releases substantially affect habitat conditions for fish and wildlife in the entire lower river, as well as availability and quality of cooling water for FCS and other power plants. OPPD presents selected information on river hydrology in this section as background for further discussion of habitat conditions, status of threatened or endangered species, and the FCS cooling water discharge in subsequent sections of this environmental report. The COE and the U.S. Fish and Wildlife Service (FWS) have developed extensive descriptions of Missouri River features of interest (Reference 2.1-2; Reference 2.1-1) that provide the basis for much of this information.

2.2.1 GENERAL DESCRIPTION

As noted by FWS, the Missouri River is the second longest river in the United States. Originating on the eastern slope of the Rocky Mountains near Three Forks, Montana, the river flows 2,321 miles through Montana, North Dakota, South Dakota, Iowa, Nebraska, Kansas, and Missouri to its confluence with the Mississippi River near St. Louis, Missouri. The Missouri River Basin drains approximately 529,350 square miles including 9,700 square miles in Canada; all of Nebraska; most of Montana, Wyoming, North Dakota, and South Dakota; approximately half of Kansas and Missouri; and smaller parts of Iowa, Colorado, and Minnesota. Main tributaries include the Yellowstone, Marias, Niobrara, James, Platte, and Kansas rivers. (Reference 2.2-1, pages 32-33).

As noted in Section 2.1-1, the COE has constructed and operates the Missouri River Main Stem Reservoir System, which consists of six integrated dams and reservoirs located in Montana, North Dakota, South Dakota, and Nebraska. Releases from the lowermost dam, at Gavins Point near Sioux City, Iowa, enter the lower river, which extends to its outfall to the Mississippi River. The six main stem dams and reservoirs are Fort Peck (Fort Peck Lake), Garrison (Lake Sakakawea), Oahe (Lake Oahe), Big Bend (Lake Sharpe), Fort Randall (Lake Francis Case), and Gavins Point (Lewis and Clark Lake). The COE completed construction of the main stem dams in 1964; the Reservoir System first filled to normal operating level in 1967 (Reference 2.2-1, page 33).

The Pick-Sloan Missouri River Basin Program, established under the Flood Control Act of 1944, directed the COE to construct all the main stem projects except Fort Peck, which Congress authorized in the River and Harbor Act of 1935. The Fort Peck Power Act of 1938 sanctioned construction of power facilities, while the Flood Control Act of 1944 sanctioned multiple-purpose regulation of this project similar to the other main stem projects. Congressionally authorized purposes of the Reservoir System are flood control, irrigation, navigation, recreation, fish and wildlife conservation, municipal water supply, water quality control, and power generation. The Pick-Sloan Program called for an efficient use of the waters of the Missouri River Basin for all purposes. A later amendment to the Flood Control Act of 1944 specified that navigation use is to be considered as long as it does not conflict with any beneficial consumptive use. The COE exercises discretion over operation of the Reservoir System for these congressionally authorized purposes (Reference 2.2-1, page 33).

The Reservoir System is operated using guidelines published in the Missouri River Main Stem Reservoir System Master Manual. The Master Manual, which has been subject to only minor revisions, the last in 1979, prescribes implementation protocols for Reservoir System storage and release functions to accommodate the multiple purposes described above. Although hydropower and water supply provide about 70 percent of the economic benefits, release criteria for Gavins Point Dam are currently influenced most by navigation considerations. The navigation considerations are overridden by the need to either cut back releases for downstream flood control or evacuate flood control storage space in the reservoirs (Reference 2.2-1, page 36).

Historically, the Master Manual has been the primary basis to guide day-to-day operational decisions. The COE has used its discretionary authority to adjust the specific numerical criteria contained in the Master Manual. For example, during floods on the lower river, Gavins Point Dam releases are reduced in response to established flood control constraints. Those reductions are tempered by the COE's judgment on whether a cutback in releases will affect the magnitude (peak discharge) or duration (number of days) of flooding on the lower river.

Based on prior experience and requirements that address federal legislation, long-term adjustments have been made in Reservoir System operations. The most significant long-term adjustment in Reservoir System operations criteria was made in response to a 1990 FWS Biological Opinion, which involved modification of summertime peak power releases from Fort Peck, Garrison, Fort Randall, and Gavins Point Dams to limit adverse impacts to two federally protected bird species, the Piping Plover (*Charadrius melodus*) (designated threatened) and the Least Tern (*Sterna antillarum*) (designated endangered), which have historically depended on exposed sandbars in the river for nesting (Reference 2.2-1, pages 50-51). (See Section 2.3.3.2.)

The Master Manual in conjunction with the Annual Operations Plan (AOP) guide the operation and management of the Reservoir System. A draft AOP is published by October of each year and the Final AOP is published in early January. The AOP falls under the framework of the Master Manual and provides flexibility for intrasystem management, including how water is released from reservoirs during navigation and non-navigation seasons. Consequently, actions involving these two guidance documents are not mutually exclusive but are often interrelated (Reference 2.2-1, page 36).

2.2.2 LOWER MISSOURI RIVER AT FORT CALHOUN STATION

FCS is located on the bank of the lower Missouri River at river mile 646, approximately 165 river miles south of Gavins Point Dam (Reference 2.1-3, Section 2.1). The flow of the Missouri River at FCS and Omaha is dominated by the releases from the Gavins Point Dam because no major tributary joins the Missouri River between the Dam and Omaha (Reference 2.2-1, page 37). Support for navigation on the Missouri River below Sioux City, including the river at the FCS site, is considered by the COE in the timing and flow rate for these releases. Under the current Master Manual, the COE has established target flows, corresponding approximately to Gavins Point Dam releases, of 25,000 cubic feet per second (cfs) and 31,000 cfs for minimum and full navigation services, respectively, downstream from the dam at both Sioux City and Omaha. These flows result in navigation channel depths of approximately 8 and 9 feet, respectively. The channel widths for minimum service and full-service navigation are 200 and 300 feet, respectively. The level of navigation service and navigation season length are determined on the basis of the amount of water in storage. A full-length navigation season consists of the eight-month period from March 23 to November 22 at Sioux City (Reference 2.2-1, Page 37-38; Reference 2.1-2, Section 2.1.2). The winter non-navigation target release also is determined on the basis of water in the Reservoir System storage. Approximate winter releases from Gavins Point Dam range from 12,000 cfs to 16,000 cfs, depending on the amount of water in storage. Minimum flow in the spring through fall period to provide water for intakes below the Reservoir System when water in storage is not sufficient to provide navigation flows is currently estimated to be 9,000 cfs (Reference 2.2-1, page 38). Daily releases from Gavins Point have ranged from a low of 6,000 cfs during April 1969, June 1983, March 1992, and March, April and July 1993, to a high of 70,000 cfs in October and November 1997. Daily average release during the navigation season for the period 1967-1997 has averaged 29,000 cfs with a standard deviation of 12,100 cfs from the annual mean discharge (Reference 2.2-2, page 40).

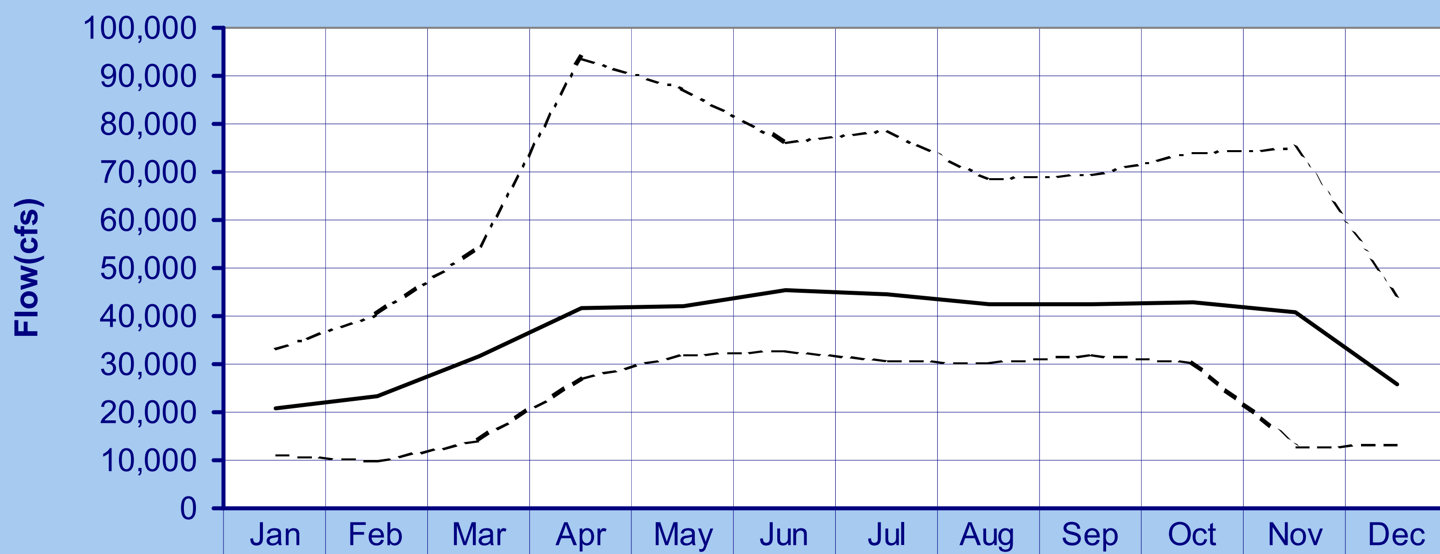
The United States Geological Survey (USGS) gaging stations along the Missouri River most relevant to characterizing river flows at FCS are located upstream at Sioux City, Iowa, and Decatur, Nebraska, and downstream at Omaha, Nebraska (Reference 2.2-3). The gages record the Missouri River stage, which is then converted to a flow rate. In addition to the stage and flow, measurements of water quality parameters such as nutrients, organics, major and trace inorganics, radiochemicals, sediments, and physical properties are obtained at the gaging stations.

The monthly average, minimum, and maximum flow rates for the gaging station at Omaha from 1967 through 2000, which provide an approximation of flow conditions at FCS, are illustrated in Figure 2.2-1. This period of record was selected because 1967 is when the Main Stem Reservoir System became completely operational and, thus, the data better represent existing conditions. As shown, monthly average river flows at Omaha typically have been 40,000 cfs to 45,000 cfs during the navigation season, and have been lower, typically 20,000 cfs to 26,000 cfs, during the winter months. Minimum and maximum monthly average flows have exhibited a similar pattern; for example, minimum monthly average flows have been 27,000 cfs to 30,000 cfs during the navigation season and typically 10,000 cfs to 13,000 cfs in the winter months (Reference 2.2-3).

2.2.3 FUTURE CHANGES IN RIVER MANAGEMENT

The navigation industry on the lower river has not grown as expected, while the recreation industry associated with the river reaches and reservoirs in the upper basin has grown significantly. In addition, the ecological impacts of the COE's Missouri River projects have become better known, and several affected species, most notably the Least Tern, Piping Plover, and pallid sturgeon (*Scaphirhyncus albus*), have been listed as threatened or endangered under the federal Endangered Species Act (see Section 2.3.3). These and other changes since the Main Stem Reservoir System was first authorized have prompted the COE to undertake a review and update of the Master Manual (Reference 2.2-1, page 36; Reference 2.1-2, Section 1.1). The objectives of the revision are to determine what best meets the current needs of the basin and to incorporate controls to appropriately meet those needs. These activities, which began in 1989, include development of an Environmental Impact Statement (EIS). In a Revised Draft EIS issued August 2001, FWS examines the impact of six alternatives for regulating flows in the Reservoir System. Issuance of the Final EIS and the revised Master Manual is expected by the end of 2002 (Reference 2.2-4).

The FWS has been working closely with the COE in the review and update of the Master Manual and related management practices for the Missouri River, and has issued a Biological Opinion (Reference 2.2-1) that addresses actions to protect and enhance federally listed populations of Least Tern, Piping Plover, and pallid sturgeon. This Opinion requires the COE to adopt an adaptive management approach to preclude jeopardy of these species. Specifically proposed actions include flow modifications in the lower river to restore and maintain nesting and foraging habitat for the Least Tern and Piping Plover, and to trigger spawning and enhance nursery habitat for the pallid sturgeon and other native fish species (see Section 2.3-3). The flow scenario specified by FWS as a starting point includes lowering target flows below Gavins Point Dam to 25,000 cfs from June 21 to July 15, 21,000 cfs from July 15 to August 15, and 25,000 cfs from August 15 to September 1 (Reference 2.2-1, p. 242-243). This altered flow regime is included among the options proposed by the COE in its Revised Draft EIS (Reference 2.2-4).



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Avg	20,982	23,252	31,604	41,835	42,186	45,405	44,496	42,679	42,666	42,949	40,658	25,930
Min	11,060	10,180	14,120	27,110	32,070	33,110	30,910	30,409	31,940	30,290	12,730	13,360
Max	33,260	40,410	54,660	93,840	87,620	76,120	78,560	68,890	69,770	74,070	75,040	44,260

Month

FIGURE 2.2-1

MONTHLY AVERAGE DISCHARGE FOR THE MISSOURI RIVER AT OMAHA, NEBRASKA. 1967 THROUGH 2000 (REFERENCE 2.2-3)

2.3 BIOLOGICAL RESOURCES

2.3.1 AQUATIC AND RIPARIAN ECOLOGICAL COMMUNITIES

FCS, with its associated cooling water intake and discharge structures, is on an outside (cutting) bend of the Missouri River approximately at river mile 646. The river at the site is approximately 600-feet wide and 15-feet deep. A continuous rock revetment protects the cutting bank for several miles upstream of the plant and approximately one mile downstream. Filling dikes are spaced along the inside of the river bend opposite the plant, providing the only shallow riverine habitat at the site. Mean current velocity in the river channel ranges between 3 and 5 feet per second during normal conditions, and may range up to 7 feet per second (Reference 2.1-1, Section 2.5.1.1). The mean annual flow for the period 1967-1999 is approximately 37,200 cfs at the USGS gaging station nearest to the site in Omaha (Reference 2.3-1).

Channelization and construction of dams, as described in Section 2.2, have reduced the surface area of the Missouri River by 50 percent. In addition, swift currents, bottom scour, increased turbidity, siltation, and shifting substrates have resulted from this channelization. Therefore, habitat is limited for many aquatic organisms, especially in the river channel. As noted by the NRC, slackwater areas behind wing dams and filling dams and sloughs, and stable structures such as dikes and revetments probably constitute the majority of suitable habitat for aquatic biota in the site vicinity (Reference 2.1-1, Section 2.7.2).

The lower reaches of Long Creek downstream from U.S. Highway 75 and the North and South Sloughs, which are hydraulically connected to the Missouri River (see Section 2.1.3 and Figure 2.1-3), provide slackwater areas on and adjacent to the site during high water periods, offering some spawning, nursery, and resting habitat for fish from the Missouri River. Fish Creek, the lowermost segment of which occurs on the Fort Calhoun Station site, provides little available aquatic habitat due to channelization, small size, and intermittent flow. The Fish Creek channel, onsite drainageways that outfall to Long Creek, and portions of the North and South Sloughs support wetland vegetation (see Section 2.3.2).

2.3.1.1 FISH

Ichthyoplankton monitoring in the Missouri River, conducted in the 1970s by OPPD and others as part of a comprehensive examination of the effects of power plants (including FCS), showed that the primary sources of recruitment of larval fish to the channelized Missouri River are Lewis and Clark Lake, the unchannelized Missouri River from Yankton, South Dakota, to Sioux City, Iowa, and tributaries. Freshwater drum, catostomids, cyprinids, and carp dominated (>94 percent) the larval drift. Other taxa collected and considered common were gizzard shad, goldeye, and *Stizostedion* sp. (sauger and walleye) (Reference 2.3-2). Field studies conducted at FCS and the Cooper Nuclear Station indicate that the seasonal highest abundance of fish larvae in the Missouri River occurs from May to July. Larvae of 13 species were collected from the

Missouri River at FCS; 69 percent were freshwater drum and river carpsucker (Reference 2.1-1, Section 2.7.2.7).

Results of studies OPPD reported in connection with the proposed FCS Unit 2 in the mid-1970s indicated the presence of 64 species of fish in the Missouri River and tributaries near FCS (Reference 2.1-1, Section 2.7.2.6). Twenty-three (36 percent) of these species were selected as important because of their commercial or recreational value, dominance in the ecosystem, or status determination as a rare, endangered, or otherwise threatened species. As the NRC summarized in the Unit 2 FES, common carp (*Cyprinus carpio*), freshwater drum (*Aplodinotus grunniens*), gizzard shad (*Dorosoma cepedianum*), and river carpsucker (*Carpiodes carpio*) were consistently the most abundant species collected (Reference 2.1-1, Section 2.7.2.6). Hesse et al. (Reference 2.3-3) reported the collection of 57 species of fish from the Missouri River (Sioux City, Iowa, to Rulo, Nebraska), of which 17.8 percent were game species, 33.9 percent were non-game species, and 48.3 percent were forage species. The 10 most abundant species collected near FCS by electroshocking and seining were gizzard shad *(Dorosoma cepedianum*), goldeye (*Hiodon alsoides*), carp (*Cyprinus carpio*), western silvery minnow (*Hybognathus argyritis*), silver chub (*Macrhybopsis storeriana*), emerald shiner (*Notropis atherinoides*), river shiner (*Notropis blennius*), red shiner (*Cyprinella lutrensis*), river carpsucker (*Carpiodes carpio*), and freshwater drum (*Aplodinotus grunniens*) (Reference 2.3-3).

Independent of the above studies, an Environmental Assessment issued in 2001 by the FWS for the DeSoto National Wildlife Refuge, immediately downriver from FCS, reports that 54 species may be found in the DeSoto Bend reach of the Missouri River based on 30 years of survey data obtained from the Nebraska Game and Parks Commission (Reference 2.3-4, Appendix E). All but five of the species reported by FWS were also collected during the monitoring studies of the 1970s discussed above (Reference 2.1-1). The five species not collected as part of FCS studies were either introduced species, difficult to sample for, or unsuited to riverine habitats available in the site vicinity.

Notable recent investigations of lower Missouri River fish populations include those Hesse reported in 1993 and 1994 (Reference 2.3-5; Reference 2.3-6; Reference 2.3-7; Reference 2.3-8; Reference 2.3-9; Reference 2.3-10). The investigators assessed the status of 13 selected fish species in the entire Missouri River reach bordering Nebraska, including paddlefish (*Polydon spathula*), burbot (*Lota lota*), channel catfish (*Ictalurus punctatus*), flathead catfish (*Pylodictis olivaris*), blue catfish (*Ictalurus furcatus*), sicklefin chub (*Macrhybopsis meeki*), sturgeon chub (*Macrhybopsis gelida*), silver chub (*Macrhybopsis storeriana*), speckled chub (*Macrhybopsis aestivalis*), flathead chub (*Platygobio gracilis*), plains minnows (*Hybognathus placitus*), western silvery minnow (*Hybognathus argyritis*), and sauger (*Stizostedion canadense*). Twenty-two years of sampling data in the Missouri River (1971-1992) were evaluated and presented for the selected species. The focus of the research centered on data regarding the absolute and relative abundance and commercial and recreational harvest.

In the 1993-1994 studies, Hesse reports that the decline in abundance of five of the species investigated--channel catfish, flathead catfish, blue catfish, sauger, and paddlefish--was evident in historical commercial harvest records and creel surveys and from fishery survey data collected 1971-1992. Commercial and recreational harvest of these five species was one of the factors cited in the studies as responsible for the observed decline in their populations. However, the studies also characterized all of these fish species as being adapted for survival in large unaltered rivers and the predominant factor for their decline was identified as the loss of suitable habitat, primarily due to channelization and impoundment of the river with consequent loss of seasonal flood pulses, altered temperature regimes, and loss of nutrient loadings from bordering floodplains.

The remaining eight species investigated by Hesse (burbot, sicklefin chub, sturgeon chub, silver chub, speckled chub, flathead chub, plains minnow, and western silvery minnow) also exhibited declines in abundance upon examination of the 22 years of Missouri River fishery survey data (Reference 2.3-5; Reference 2.3-9). Only the burbot was subject to a minor recreational fishery and was generally considered an incidental catch to the targeted fish species. All of these species are representative and indigenous to large unchannelized rivers. Again, the decline in abundance as found during the fishery surveys was attributed to loss of habitat resulting from channelization, impoundment of the river, loss of seasonal flood pulses, altered temperature regimes due to impoundment, and loss of nutrient loading from the floodplains.

The commercial harvest of channel catfish, flathead catfish, and blue catfish from the Missouri River was banned in 1992 due to over harvest of recruitment-size individuals. However, the commercial harvest of the common carp and buffalo fish (*Ictiobus* sp.) from the Missouri River still continues with the State of Nebraska issuing 80-90 permits annually (Reference 2.3-11). The recreational harvest of the three species of catfish from the Missouri River also continues to represent a valuable resource to the State of Nebraska.

2.3.1.2 PHYTOPLANKTON-PERIPHYTON

Studies the NRC summarized in the Unit 2 FES reported the collection of 103 taxa of phytoplankton in the Missouri River at FCS, dominated by 13 species that averaged 5 percent or more of the total population. Diatoms (Bacillariophyta) and green algae (Chlorophyta) dominated the plankton; other groups that occurred in smaller numbers included cryptomonads (Cryptophyta), golden-browns (Chrysophyta), blue-greens (Cyanophyta), euglenoids (Euglenophyta), and dino-flagellates (Pyrrophyta). A mean density of phytoplankton ranged from spring highs of 7.3×10^8 cells per cubic meter to winter lows of 9.9×10^7 cells per cubic meter (Reference 2.1-1, Section 2.7.2.1). The composition of the phytoplankton community at FCS is more representative of a reservoir than of a river ecosystem, and is primarily determined by discharges from Lewis and Clark Lake at Gavins Point Dam (Reference 2.3-12).

Diatoms comprised 58 percent to 95 percent of the total density of the sessile periphyton collected near FCS. The periphyton community near the station was represented by 166 taxa collected on plexiglass plates, pilings, brush, and logs (Reference 2.1-1, Section 2.7.2.1).

2.3.1.3 ZOOPLANKTON

The zooplankton community in the Missouri River at FCS is also characterized as a population of reservoir origin subject to minor additions from tributaries and backwaters. Mean zooplankton densities at the station were 4,729 per cubic meter of which 90 percent were copepods, and 10 percent were cladocerans (Reference 2.1-1, Section 2.7.2.2). Repsys and Rogers (Reference 2.3-13) reported the collection of 63 zooplankton taxa from the Missouri River at FCS.

2.3.1.4 MACROINVERTEBRATES

Studies of the Missouri River in the site vicinity have addressed three different macroinvertebrate communities: organisms in the drift, organisms attached to or closely associated with available solid substrates (aufwuchs), and organisms inhabiting bottom sediments (benthic macroinvertebrates). The drift and aufwuchs macroinvertebrate communities in the Missouri River at FCS were similar in that both were dominated almost exclusively by Tricoptera (caddisflies), Ephemeroptera (mayflies), and Chironomidae (midge fly larvae). The caddisfly *Hydropsyche orris*, and the mayfly *Stenonema* sp., dominated the drift and the aufwuchs communities which also included the caddisfly *Potamyia flava*, the mayfly *Caenis* sp., and the midge fly larvae *Rheotanytarsus* sp. Approximately 140 taxa were identified from the drift community, and 117 species were identified from the aufwuchs community (Reference 2.1-1, Sections 2.7.2.3, 2.7.2.4).

Benthic macroinvertebrates in the vicinity of FCS were represented by 100 taxa with a low density averaging 36.6 grams per square meter. Four groups were found to dominate the benthic community: Oligochaeta, Ephemeroptera, Tricoptera, and Chironomidae. The low densities of benthic macroinvertebrates observed near the station are attributable to unstable substrates created by channelization at the site resulting in shifting sand substrate and high currents (Reference 2.1-1, Section 2.7.2.5).

2.3.2 CRITICAL AND IMPORTANT TERRESTRIAL HABITATS

No areas within 50 miles of the Fort Calhoun Station site are designated as critical habitat for species listed as endangered or threatened under the Endangered Species Act (50 CFR 17.95, 50 CFR 17.96). As noted in Section 2.1.3, most of the 660-acre Fort Calhoun Station site consists of cropland, plant facilities, and other land maintained in support of plant operations. These areas occupy approximately 75 percent of the site. Portions developed for power plant and related support facilities consist mostly of impervious or graveled areas devoid of natural vegetation. Cultivated land is devoted primarily to corn and soybean production. Much of the remaining maintained area is planted in non-native grasses (e.g., *Fescue* sp.) that is periodically cut for hay. However, the area used for application of treated sanitary wastewater, approximately 13 acres, has been recently planted with a mixture of native prairie grasses. This project, if successful, would provide some prairie habitat on the site.

The remaining 25 percent of the site supports a predominance of natural vegetation in areas that have been subject to previous or ongoing disturbance. These plant communities represent common resources in the region. They include upland forest on slopes in the southern part of the site, and floodplain forest and wetlands on the Missouri River floodplain associated with onsite streams and sloughs (Figure 2.1-3). A detailed description of these habitats based on field studies conducted in the mid-1970s is provided in OPPD's Environmental Report submitted to the NRC in support of OPPD's license application for a second unit at the site (Reference 2.3-14), a summary of which the NRC provides in the FES for Unit 2 (Reference 2.1-1, Section 2.7). Based on limited land use changes on the site and field observations in June 2001, these descriptions continue to appropriately characterize these habitats. The following description highlights major terrestrial habitats on the site and observations of site conditions in June 2001.

Upland forest, occupying approximately 10 percent of the site, occurs on slopes between the railroad spur and U.S. Highway 75. Predominant tree species on this site, which has been subject to cutting and other disturbances in the past, include cottonwood (*Populus deltoides*), black locust (*Robinia psuedo-acacia*), red mulberry (*Morus rubra*), siberian elm (*Ulmus pumila*), and hackberry (*Celtis occidentalis*). Poison ivy (*Toxicodendron radicans*) and stinging nettle (*Urtica dioica*) are abundant in the understory.

Narrow bands of floodplain forest border the bank of the Missouri River, the North and South Sloughs, and the deeply incised Long Creek channel, comprising roughly 10 percent of the site. Green ash (*Fraxinus pennsylvanica*), cottonwood, boxelder (*Acer negundo*), silver maple (*Acer saccharinum*), and hackberry are among the dominant tree species in these areas. False indigo bush (*Amorpha fruticosa*) and rough dogwood (*Cornus drummondii*) predominate in the shrub layer. Giant ragweed (*Ambrosia trifida*), goldenrod (*Solidago* sp.), and milkweed (*Asclepias* sp.) are among the dominant species in the herbaceous layer.

Wetland communities, mostly associated with the North and South Sloughs, Fish Creek, and tributary drainageways to Long Creek, comprise 5 percent or less of the FCS site. The downstream ends of the North and South Sloughs are connected to the river, and water level in the sloughs therefore varies with river stage. Among the dominant emergent wetland species in the sloughs are narrow-leaved cattail (*Typha angustifolia*), reed canary grass (*Phalaris arundinacea*), milkweed, and black willow (*Salix nigra*).

Fish Creek, a small stream with low to intermittent base flow and an unconsolidated silt bottom, crosses the western boundary of the site and enters the downstream end of the North Slough. Most of the length of this stream, including the entire onsite segment, has been straightened and channelized to promote drainage. Grasses and other vegetation stabilize channel site slopes. Predominant wetland plant species that occur in and near the stream bottom include arrow arum (*Peltandra virginica*), sedges (*Carex* sp.), rushes (*Scirpus* sp.), willow (*Salix* sp.), and reed canary grass.

Long Creek, which flows into the Missouri River at the eastern boundary of the FCS site, drains the eastern portion of the site (Figure 2.1-3) via drainage ditches. One of these drainages originates as a seep near the parking lot of the Fort Calhoun Training Facility and flows, via a swale and ditch, through cultivated land to Long Creek. Sedges, rushes, spikerush (*Eleocharis* sp.), buckwheat (*Polygonum* sp.), willow, hemp (*Cannabis sativa*), and giant ragweed dominate the plant community in the drainageway. An additional drainage ditch, located adjacent to the railroad spur that runs along the southern portion of the site, exhibits similar plant species composition. Low-lying areas in the interior of cultivated fields in the eastern portion of the site exhibit standing water for extended periods after heavy precipitation, but do not support wetland plant communities due to their cultivation in years when conditions are suitable.

A small (approximately 3 acre) floodplain forest tract immediately west of the FCS Switch Yard (Figure 2.1-3) exhibits wetland characteristics on the basis of standing water and species composition. Cottonwood, rough dogwood, green ash, boxelder, slippery elm (*Ulmus rubra*), and reed canary grass dominate the plant community.

FCS transmission lines in the site vicinity primarily traverse cultivated farmland and the U.S. Highway 75 right-of-way. Line 74S/74, of particular concern to this application, traverses agricultural land for approximately six miles (see Figure 2.1-2 and Section 3.1.4). The remainder of this line, approximately one mile, occupies a 50- to 100-foot right-of-way through disturbed shrublands and upland forest on the Missouri River bluffs primarily upslope from U.S. Highway 75. Forested areas in this region have been subject to some clearing for rural residential development in recent years. The line crosses several small, intermittent streams, but no other surface waters or wetlands were encountered on the right-of-way when it was rebuilt in 1999.

2.3.3 ENDANGERED AND THREATENED SPECIES

The FWS has designated several species known to occur in Nebraska and Iowa as threatened or endangered at the federal level (50 CFR 17.11-12). Similarly, threatened and endangered species have been designated at the state level under programs administered by the Nebraska Game and Parks Commission (Reference 2.3-15) and by the Iowa Department of Natural Resources (Reference 2.3-16). As shown in Table 2.3-1, three fish species, eight bird species, and two plant species designated as endangered or threatened at the federal level or the state level in Nebraska or Iowa have some potential for occurrence in the vicinity of FCS, based on occurrence potential reported by the Nebraska Game and Parks Commission for Washington County, Nebraska (Reference 2.3-17) and by the FWS for the vicinity of the DeSoto National Wildlife Refuge (Reference 2.3-4, page 37). Pertinent information related to the status of these species and the potential for occurrence of these and selected other state-listed species on or near the FCS site is provided in the following sections.

2.3.3.1 AQUATIC SPECIES

As indicated in Table 2.3-1, three endangered or threatened fish species are considered to have reasonable likelihood of occurrence in the vicinity of FCS: the pallid sturgeon, listed as endangered at the federal level, and the lake sturgeon and sturgeon chub, which are listed at the state level. Of all of the designated endangered or threatened species currently listed for Nebraska and Iowa (Reference 2.3-15; Reference 2.3-16) only these three fish species are considered to be representative of and indigenous species to the Missouri River. However, due to channelization and main stem dam construction, their habitat requirements are no longer being met in the middle Missouri River. The Nebraska Game and Parks Commission specifically cites alterations to the natural hydrograph, channelization, and flow depletions as reasons for the decline of all three of these species (Reference 2.3-17). The FWS has issued a Biological Opinion that includes recommendations for changing the flow regime in the Missouri River (Reference 2.2-1) (see Section 2.2-3). These FWS recommendations are included as options by the COE in its Revised Draft EIS related to the Master Water Control Manual update and, if implemented, may improve the status of these species in the river.

The pallid sturgeon, once common in the Missouri River, is endangered throughout its historic range. Based on the FWS assessment for the neighboring DeSoto National Wildlife Refuge, its presence in the Missouri River near FCS is possible but unlikely (Reference 2.3-4, Chapter 3). This fish is often found near confluences, islands, and at the downstream end of sandbars (Reference 2.3-17). The closest of six sites on the Missouri River to FCS where pallid sturgeons have been most frequently reported since 1980 is at the mouth of the Platte River near Plattsmouth, Nebraska, approximately 52 river miles downstream (Reference 2.2-1, pages 155-156). It is believed that this fish spends some time in the Missouri River, and returns to the Platte River annually to spawn or possibly overwinter (Reference 2.3-18). Population estimates for pallid sturgeon in the Missouri River below Gavins Point Dam are considered subjective due to lack of mark and recapture data. Population estimates of pallid sturgeon based on frequency of sightings give an estimate of one to five pallid sturgeon per kilometer of river, or 1,303 to 6,516 individuals downstream of Gavins Point Dam to the Mississippi River. Approximately 511 pallid sturgeons were stocked in the Platte River in 1997, 1998, and 1999 to augment the existing population (Reference 2.2-1, pages 157-158).

Like the pallid sturgeon, the lake sturgeon was once common in the Missouri River. It is now rare in Nebraska and Iowa, but is common in parts of its historic range. It is not federally listed. It is believed that the lake sturgeon occupies habitats similar to those of the pallid sturgeon, but spends a greater portion of its time in the Missouri River than the Platte River (Reference 2.3-17). As for the pallid sturgeon, the paucity of suitable habitat in the site vicinity makes occurrence of the lake sturgeon in the Missouri River at FCS unlikely. Neither pallid sturgeon nor lake sturgeon was collected during monitoring studies conducted at FCS in the 1970s (Reference 2.3-3), and neither species is included in the Nebraska Game and Parks list of species collected near the Station in the DeSoto Bend reach of the Missouri River, based on 30 years of survey data (Reference 2.3-4, Appendix E).

TABLE 2.3-1
THREATENED AND ENDANGERED SPECIES WITH POTENTIAL FOR OCCURRENCE IN THE FORT CALHOUN SITE VICINITY[a]

Common Name	Scientific Name	Status[b]		
		Iowa	Nebraska	U.S.
Fish				
Pallid Sturgeon	*Scaphirhyncus albus*	E	E	E
Lake Sturgeon	*Acipenser fulvescens*	E	T	
Sturgeon Chub	*Macrhybopsis gelida*		E	
Birds				
Bald Eagle	*Haliaeetus leucocephalus*	E	T	T
Least Tern	*Sterna antillarum*	E	E	E
Piping Plover	*Charadrius melodus*	E	T	T
Northern Harrier	*Circus cyanus*	E		
Red-shouldered Hawk	*Buteo lineatus*	E		
Long-eared Owl	*Asio otus*	T		
Short-eared Owl	*Asio flammeus*	E		
Henslow's Sparrow	*Ammodramus henslowii*	T		
Plants				
American Ginseng	*Panax quinquifolium*		T	
Western Prairie Fringed Orchid	*Plantanthera praeclara*	T	T	T

a. Based on occurrence potential reported by the Nebraska Game and Parks Commission for Washington County, Nebraska, (Reference 2.3-17) and by the U.S. Fish and Wildlife Service for the vicinity of the DeSoto National Wildlife Refuge (Reference 2.3-4).

b. T = Threatened E = Endangered

The sturgeon chub is associated with fast flowing water and a gravel river bed but has been collected in side chutes and backwaters, which are thought to provide spawning habitat (Reference 2.3-17). In the 1970s, Hesse et al. (Reference 2.3-3) collected one sturgeon chub out of 90,379 fish sampled from the Missouri River in Nebraska during monitoring studies which included the FCS site vicinity. However, this individual was collected in the vicinity of Cooper Nuclear Station, approximately 114 river miles downstream from FCS. The sturgeon chub was a recent candidate for federal listing, but was not approved by the FWS because it was found to be common in 50 percent of its historical home range (Reference 2.3-18). However, it remains listed as endangered by the State of Nebraska.

An additional 17 species of fish are listed as either threatened or endangered at the state level in either Nebraska or Iowa (References 2.3-15, 2.3-16). Only one, the burbot (*Lota lota*), is likely to occur in the Missouri River. Hesse et al. (Reference 2.3-3) reported the collection of 18 burbots out of 90,379 fish collected from the Missouri River (1971-1977) in Nebraska. The burbot is common in the waters of the northern U.S. and Canada, and the Missouri River probably represents the southern limits of its range (Reference 2.3-19). The distribution of eight of the remaining 16 state-listed species (American brook lamprey, chestnut lamprey, black redhorse, weed shiner, freckled madtom, bluntnose darter, least darter, and western sand darter) is limited to the Mississippi River drainage or to the lower Missouri River within the Missouri state boundary (Reference 2.3-19). The remainder of the state-listed species (grass pickerel, Topeka shiner, pugnose shiner, blacknose shiner, northern redbelly dace, finescale dace, pearl dace, and orangethroat darter) would not be expected in the main stem Missouri River or lower portions of tributary streams on the basis of their habitat requirements. These species are restricted to small- to medium-sized streams characterized as being clear and silt free with no turbidity, conditions that are more common in the headwater reaches of tributaries to the middle Missouri River (Reference 2.3-20). OPPD knows of only one of these species, the burbot, that has been collected near the FCS site (Reference 2.3-3). None of these 17 species are included in the Nebraska Game and Parks Commission list of species collected near the FCS in the DeSoto Bend reach of the Missouri River, based on 30 years of survey data (Reference 2.3-4, Appendix E).

Table 2.3-1 indicates no mussels or other aquatic organisms having threatened or endangered status are expected to occur in the site vicinity. No mussels are listed as endangered or threatened by the State of Nebraska (Reference 2.3-21). The State of Iowa lists fourteen species of mussels as being either threatened or endangered, one of which (the Higgen's eye pearly mussel) is also considered to be endangered at the federal level. However, the Higgen's eye pearly mussel's habitat is the Mississippi River and some of its larger northern tributaries, in gravel or sand (Reference 2.3-22). The State of Iowa could not confirm that any of the listed identified mussels inhabit portions of Iowa in the vicinity of FCS or have ever been collected from the Missouri River (Reference 2.3-23). However, the habitat in the area of FCS on the outside (cutting) bank of the river is not conducive to colonization by mussels due to the channelization, swift current, high turbidity, and unstable substrates.

2.3.3.2 TERRESTRIAL SPECIES

Terrestrial species reported to have some potential for occurrence in the general FCS vicinity include eight bird species and two plant species (Table 2.3-1). Three of these bird species are listed as threatened or endangered at the federal level: the Bald Eagle and Piping Plover are listed as threatened and the Least Tern is designated as endangered. Of these, the Bald Eagle is most likely to occur on and near the FCS site.

The Bald Eagle was originally listed as endangered by the FWS in 1978. However, a national ban on DDT and other organochlorine pesticides in the mid-1970s, reduced use of lead shot for waterfowl hunting, and other measures have resulted in increasing populations of this species nationally. As a result, the Bald Eagle was downlisted to threatened in 1995, and is currently proposed for delisting (Reference 2.3-4, page 35; Reference 2.3-24; Reference 2.3-25). The outlook for the Bald Eagle in Nebraska is good. The federal recovery plan for the Bald Eagle in the northern Great Plains sets a target of 10 reproducing pairs in Nebraska. In 1998 there were 14 confirmed nests in the state with a total of 17 chicks confirmed fledged (Reference 2.3-25). Bald Eagles nest along the Missouri River, and there is some potential for occurrence of nests along the river in Washington County (Reference 2.3-17). Nesting attempts have been made at the DeSoto National Wildlife Refuge, however, these attempts have not been successful (Reference 2.3-4, page 35). No Bald Eagle nests exist on the FCS site, and OPPD is unaware of other nesting sites in the vicinity other than at the DeSoto National Wildlife Refuge.

Nebraska provides winter habitat for a sizable population of Bald Eagles at numerous locations throughout the state; wintering populations have exceeded 1,100 birds in recent years (Reference 2.3-24). The Nebraska Game and Parks Commission notes that several winter roosts exist along the river, and Bald Eagles are commonly found along the river during spring and fall migrations and throughout the winter where open water is present (Reference 2.3-17). The FWS (Reference 2.3-4, page 35) reports that this species is a common spring and fall visitor at the DeSoto National Wildlife Refuge, and that fall visitors remain as long as ducks and geese remain in the area or until DeSoto Lake freezes over. The maximum number of spring and fall visitors reported at the refuge are 120 and 143 individuals, respectively (Reference 2.3-4, page 35). Bald Eagles were observed in the FCS site vicinity during field surveys conducted in connection with licensing activities for FCS Unit 2 in 1975 (Reference 2.3-14, Section 2.2.1.2.2). No established Bald Eagle roosting sites exist on the site; however, the floodplain forest bordering the North and South Sloughs provides potentially attractive habitat, and small numbers of migrants or winter visitors are occasionally observed on and near the site. More than occasional occurrence of this species along transmission Line 74S/74, which traverses some upland forest west of the site, is unlikely considering the predominance of agricultural land, proximity of U.S. Highway 75, and nearby residential development.

The loss of sand bar nesting habitat due to river channelization and change in flow regime from construction of main stem dams has resulted in population declines for both the Least Tern and the Piping Plover along the Missouri River (Reference 2.3-17). As riverine nesting habitat became increasingly limited, Least Terns began to nest on bare spoil piles created by sand and gravel mining operations. Least Terns and Piping Plovers are often found nesting together on riverine sand bars and sand spoil piles (Reference 2.3-17; Reference 2.3-26). Both of these species once nested in the nearby DeSoto National Wildlife Refuge, but no nests have been observed since the 1970s, even though formerly used nesting areas have been maintained. Least Terns continue to be sporadically observed at the refuge, but the last Piping Plover observation at the refuge occurred in 1977 (Reference 2.3-4, page 35). The potential for occurrence of more than occasional individuals on or in the immediate vicinity of the site is considered very low due to the lack of exposed sandbars in this reach of the Missouri River. Neither species was sighted on or near the site during field surveys, which were conducted in support of the license application for FCS Unit 2 (Reference 2.3-14). The FWS has issued a Biological Opinion that includes recommendations for lowering river flows in summer to improve nesting and foraging habitat for these species (see Section 2.2-3). These recommendations are included as options in the COE's recently issued Revised Draft EIS related to the Master Water Control Manual and, if adopted, could improve the outlook for populations along the Missouri River.

Five additional bird species designated threatened or endangered by the State of Iowa are considered to have some potential for occurrence in the FCS site vicinity: Red-shouldered Hawk, Northern Harrier, Long-eared Owl, Short-eared Owl, and Henslow's Sparrow (Table 2.3-1). Information relative to occurrence potential for these species is summarized as follows (Reference 2.3-4, Appendix E; Reference 2.3-27; Reference 2.3-28):

- The Red-shouldered Hawk breeds in moist woodlands, often close to cultivated fields. Although it is relatively common in the eastern U.S., it is at the western end of its range in the site vicinity. This species has been observed in the site vicinity at the DeSoto National Wildlife Refuge. However, FWS considers its occurrence there to be "accidental" because the refuge is at the edge of its normal range.

- The Northern Harrier inhabits marshes and open fields. It is considered to be present at the DeSoto National Wildlife Refuge in spring and fall, and is occasionally (at 3- to 5-year intervals) observed at the refuge in summer. This species was observed on the FCS site during preoperational studies for OPPD's proposed Unit 2 (Reference 2.3-14).

- The Long-eared Owl occupies thick woodlands near open country. It has been observed rarely (less often than every five years), in winter, at the DeSoto National Wildlife Refuge.

- The Short-eared Owl inhabits open country over plains, sloughs, and marshes, and nests on the ground. Like the Long-eared Owl, this species has been observed rarely, in winter, at the DeSoto National Wildlife Refuge.

- Henslow's Sparrow is a rare and occasional inhabitant of wet shrubby fields and meadows. It has been observed rarely, in the fall, at the DeSoto National Wildlife Refuge.

The potential for occurrence on and near the FCS site and along transmission line 74S/74 for these five species is probably greatest for the Northern Harrier, considering observations reported by the FWS at the nearby DeSoto National Wildlife Refuge and by OPPD on the FCS site, as well as the presence of abundant open field habitat in the area. Floodplain forest in the vicinity of the North and South Sloughs offers habitat for the Red-Shouldered Hawk, but occurrence potential is limited by range conditions. Relatively little compatible habitat exists on site for the remaining three species; however, establishment of prairie grasses in the area used for sanitary waste application, if successful, could provide some suitable habitat in the future for the Henslow's Sparrow.

Considering the paucity of observations in more favorable habitat in the DeSoto National Wildlife Refuge, the probability of occurrence on the site or along transmission Line 74S/74 for these state-listed bird species is considered to be low with possible exception of the Northern Harrier. None of these five state-listed species, except the Northern Harrier, was reported to have been observed in field surveys conducted in support of OPPD's license application for FCS Unit 2 in 1975 (Reference 2.3-14).

The western prairie fringed orchid is the only federally listed plant species considered to have reasonable potential to occur in Washington County or the general vicinity of the site (see Table 2.3-1). This species normally inhabits mesic tallgrass prairie. Although it can be a colonizer species and grow in disturbed areas, it is found in greatest abundance in high-quality prairie (Reference 2.3-17). The potential for occurrence on or near the FCS site or along transmission Line 74S/74 is considered very low considering the lack of prairie habitat that would harbor or provide a propagation source for this species.

American ginseng, considered threatened in Nebraska, is an understory forb that grows in good-quality upland hardwood forest, often in association with stands of mature bur oak (Reference 2.3-17). This species is currently known to occur only in eastern Nebraska, where it is found on forested Missouri River bluffs. However, it is currently known to exist at only five sites ranging virtually the entire length of the state, from Richardson County north to Dixon County (Reference 2.3-17; Reference 2.3-25). Given the highly disturbed nature of upland forest on the site and adjacent to the transmission Line 74S/74 right-of-way, occurrence of this species is highly unlikely.

Neither of these plant species was noted in vegetation studies conducted on and near the site in support of OPPD's license application for FCS Unit 2 in 1975 or during field observations in June 2001 (Reference 2.3-14).

2.4 DEMOGRAPHY

In this section, OPPD descries demographic characteristics of the area within 50 miles of FCS. U.S. Bureau of Census data from the year 2000 census was not available at the census-tract level at the time of the analysis. Therefore, OPPD used 1990 census data for the population classification determination presented in Section 2.4.1 and the determination of minority and low-income populations presented in Section 2.4.2. Other population data cited in Section 2.4 and elsewhere in this Environmental Report are based on year 2000 census data.

2.4.1 GENERAL DEMOGRAPHY

The *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) presents a population classification method using degrees of "sparseness" and "proximity" to characterize the remoteness of the area surrounding a site. Sparseness measures population density and city size within 20 miles of a site; proximity measures population density and city size within 50 miles (Reference 2.4.1, Section C.1.4). The GEIS model for population by sparseness and proximity measures is shown below:

	Category	
Sparseness		
Most sparse	1.	Fewer 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 fewer 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

Category		
Proximity		
Not in close proximity	1.	No city with 100,000 or more persons and fewer 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 fewer than 190 persons per square mile within 50 miles
In close proximity	4.	Greater than 190 persons per square mile within 50 miles

Source: Reference 2.4-1, page C-159.

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

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 **Medium** **High**

Source: Reference 2.4-1, page C-6.

Using U.S. Census Bureau data, OPPD estimated 329,650 persons live within 20 miles of FCS (Reference 2.1-3, Table 2.8-1). Therefore, with a population density of 262 persons per square mile within 20 miles, FCS falls into Category 4 of the GEIS sparseness classification. There are an estimated 760,514 persons living within 50 miles of FCS (Reference 2.1-3, Table 2.8-1). This equates to a population density of 97 persons per square mile within 50 miles. Since Omaha is the largest city within 50 miles of the site and has a total population well over 100,000, FCS falls into Category 3 (one or more cities with 100,000 or more persons and fewer than 190 persons per square mile within 50 miles) of the GEIS proximity classification. According to the GEIS sparseness and proximity matrix, FCS's sparseness Category 4 and proximity Category 3 indicate that FCS is in a high population area.

All or parts of 12 counties in Nebraska are within 50 miles of FCS: Washington, Douglas, Sarpy, Cass, Lancaster, Saunders, Dodge, Colfax, Burt, Butler, Cuming, and Thurston. In Iowa, all or parts of 10 counties are within 50 miles of FCS: Monona, Woodbury, Crawford, Harrison, Shelby, Pottawattamie, Cass, Mills, Montgomery, and Fremont (Reference 2.1-3, Section 1.2).

Approximately one-half of the Winnebago and Omaha reservations in Thurston County fall within the 50-mile radius of FCS. According to U.S. Census Bureau year 2000 estimates, approximately 7,782 people reside on these tribal lands (Reference 2.4-2).

Offutt Air Force Base is south of Omaha, approximately 30 miles southeast of FCS, and has a year 2000 population of 8,901 (Reference 2.4-3).

The DeSoto National Wildlife Refuge, a 7,823-acre wildlife refuge approximately three miles from FCS, attracted an average of 295,000 visitors each year from 1990 to 1999 (Reference 2.3-4). Fort Atkinson State Park and the Boyer Chute National Wildlife Refuge fall within 10 miles of FCS and annually attract approximately 60,000 and 50,000 visitors, respectively (Reference 2.1-3, Section 2.8).

FCS is in largely rural and agricultural Washington County. Blair, the nearest municipality to FCS (3 miles to the northwest) and the largest in Washington County, has a population of 7,512 according to year 2000 U.S. Census Bureau estimates. Fort Calhoun lies approximately 5 miles to the southeast of the plant and has an estimated year 2000 population of 856. Missouri Valley, approximately 11 miles east of FCS, is the largest municipality in Harrison County, Iowa. It has an estimated year 2000 population of 2,992 (Reference 2.4-3).

Omaha lies approximately 19 miles south of FCS. It is the 45th largest city in the United States with a population of approximately 390,000, according to U.S. Census Bureau year 2000 estimates (Reference 2.4-4). Omaha is the 61st largest metropolitan statistical area (MSA) in the United States, with an estimated decennial population of 716,998 and an average annual growth rate of 1.2 percent between 1990 and 2000 (Reference 2.4-5). The Omaha MSA includes Washington, Douglas, and Sarpy counties, as well as Pottawattamie and Harrison counties in Iowa. Omaha's population is relatively young, with a median age of 33.8 years, as compared to the 35.4 years median age of the U.S. population (Reference 2.4-6). Future growth of the Omaha metropolitan area is expected to continue westward and southward, coinciding with Interstate 80 (Reference 2.1.3, Section 2.8).

Approximately 86 percent of FCS employees live in Washington, Douglas, and Sarpy counties (see Section 3.4.1 for workforce description). Table 2.4-1 presents estimated populations and annual growth rates for these three counties of interest.

2.4.2 MINORITY AND LOW-INCOME POPULATIONS

2.4.2.1 MINORITY POPULATIONS

The NRC guidance for performing environmental justice defines "minority" as: American Indian or Alaskan Native; Asian or Pacific Islander; Black not of Hispanic origin; and Hispanic (Reference 2.4-9, Attachment 4). The guidance indicates that a minority population exists if:

> <u>Exceeds 50 Percent</u> – the minority population of the environmental impact site exceeds 50 percent or
>
> <u>More than 20 Percent Greater</u> – the minority population percentage of the environmental impact site is significantly greater (typically at least 20 percent) than the minority population percentage in the geographic area chosen for comparative analysis

The NRC performed environmental justice analyses for the Calvert Cliffs Nuclear Power Plant and Oconee Nuclear Station license renewals (Reference 2.4-10, Section 4.4.6; Reference 2.4-11, Section 4.4.6). In doing so, the NRC used 50-mile radii as the potential environmental impact area and each state as the respective geographic area for comparative analysis. OPPD has adopted this approach in its FCS environmental justice analysis.

The NRC guidance calls for use of the most recent U.S. Census Bureau decennial census data. The U.S. Census Bureau provides updated annual population projections for selected portions of its demographic information; however, the update projections from the year 2000 census were not available at the census-tract level at the time of the analysis. Therefore, OPPD used 1990 U.S. Census Bureau data (Reference 2.4-12) to determine the percentage of the total population within Nebraska and Iowa for each minority category and to identify minority and low-income populations within 50 miles of FCS. OPPD used ArcView® software to combine U.S. Census Bureau tract data with Environmental Systems Research Institute tract-boundary spatial data to produce tract-by-tract data and maps. OPPD included census tracts if at least 50 percent of their area lay within 50 miles of FCS. The 50-mile radius (geographic area) includes 153 census tracts.

TABLE 2.4-1
ESTIMATED POPULATIONS AND AVERAGE ANNUAL GROWTH RATES IN WASHINGTON, DOUGLAS, AND SARPY COUNTIES FROM 1980 TO 2030

	Washington County		Douglas County		Sarpy County	
Year	Population	Percent	Population	Percent	Population	Percent
1980	15,508[a]	1.6	397,038[a]	0.2	86,015[a]	3.5
1990	16,607[a]	0.7	416,444[a]	0.5	102,583[a]	1.9
2000	18,780[a]	1.3	463,585[a]	1.1	122,595[a]	2.0
2010	20,829[a]	1.1	482,765[a]	0.4	145,494[a]	1.9
2020	22,653[a]	0.9	513,449[a]	0.6	171,386[a]	1.5
2030	24,239[b]	0.7	554,525[b]	0.8	190,239[b]	1.1

a. Source: Reference 2.4-7
b. Source: Reference 2.4-8

OPPD divided U.S. Census Bureau population numbers for each minority by the total population for Nebraska or Iowa to obtain the percentage of the total represented by each minority. Tables 2.4-2 and 2.4-3 show the results of this calculation and the threshold for determining whether a minority population exists for Nebraska and Iowa. Because the states' percentages are low, the "more than 20 percent greater" criterion is more encompassing than the "exceeds 50 percent" criterion. For example, if 40 percent of a Nebraska tract was Black, it would not contain a minority population under the "exceeds 50 percent" criterion. However, because 3.6 percent of the Nebraska population is Black, the tract would contain a minority population under the "more than 20 percent greater" criterion because 40 percent exceeds 23.6 percent (3.6 percent plus 20 percent).

For each of the 153 census tracts within 50 miles of FCS, OPPD calculated the percentage of the population in each minority category and compared the result to the corresponding threshold percentage to determine whether minority populations exist. These 153 census tracts are located in 10 counties in Nebraska (Burt, Cass, Cuming, Dodge, Douglas, Lancaster, Sarpy, Saunders, Thurston, and Washington) and six counties in Iowa (Crawford, Harrison, Mills, Monona, Pottawattamie, and Shelby). Tables 2.4-2 and 2.4-3 indicate how many census tracts within each county exceed the threshold for determining the presence of a minority population for Nebraska and Iowa, respectively.

TABLE 2.4-2
NEBRASKA MINORITY AND LOW-INCOME POPULATION CENSUS TRACTS

Category[a]	State Average (percent)[b]	Threshold for Minority Population (percent)[c]	Number of County Census Tracts Exceeding Threshold									
			Burt	Cass	Cuming	Dodge	Douglas	Lancaster	Sarpy	Saunders	Thurston	Washington
American Indian or Alaskan Native	0.8	20.8	0	0	0	0	0	0	0	0	1	0
Asian or Pacific Islander	0.8	20.8	0	0	0	0	0	0	0	0	0	0
Black (Non-Hispanic origin)	3.6	23.6	0	0	0	0	17	0	0	0	0	0
Hispanic	2.3	22.3	0	0	0	0	1	0	0	0	0	0
Low-Income	11.8	31.8	0	0	0	0	12	0	0	0	0	0

a. As defined by Reference 2.4-9, Attachment 4.
b. Source: U.S. Census Bureau website (Reference 2.4-12).
c. At least 20 percent greater than state average (Reference 2.4-9, Attachment 4).

TABLE 2.4-3
IOWA MINORITY AND LOW-INCOME POPULATION CENSUS TRACTS

Category[a]	State Average (percent)[b]	Threshold for Minority Population (percent)[c]	Number of County Census Tracts Exceeding Threshold					
			Crawford	Harrison	Mills	Monona	Pottawattamie	Shelby
American Indian or Alaskan Native	0.3	20.3	0	0	0	0	0	0
Asian or Pacific Islander	0.9	20.9	0	0	0	0	0	0
Black (Non-Hispanic origin)	1.7	21.7	0	0	0	0	0	0
Hispanic	1.2	21.2	0	0	0	0	0	0
Low-Income	11.9	31.9	0	0	0	0	1	0

a. As defined by Reference 2.4-9, Attachment 4.
b. Source: U.S. Census Bureau website (Reference 2.4-12).
c. At least 20 percent greater than state average (Reference 2.4-9, Attachment 4).

Based on the “more than 20 percent greater” criterion, the only Nebraska counties with minority population tracts in the 50-mile radius are Douglas County and Thurston County. Douglas County has Black minority populations in 17 tracts and a Hispanic minority population in one tract. There are no tracts with American Indian minority populations or Asian minority populations in Douglas County. Thurston County has an American Indian minority population in one tract and no tracts with Black minority populations, Asian minority populations, or Hispanic minority populations. In Iowa, none of the counties in the 50-mile radius surrounding FCS has tracts with American Indian minority populations, Asian minority populations, Black minority populations, or Hispanic minority populations.

Figure 2.4-1 depicts the locations of the American Indian or Alaskan Native minority populations. Figure 2.4-2 depicts the locations of Black minority populations, and Figure 2.4-3 depicts the locations of Hispanic minority populations.

Tracts are designated as American Indian and Alaska Native minority population if the percentage of the American Indian and Alaska Native population is at least 20 percent greater than the American Indian and Alaska Native percentage of 0.8 for Nebraska or 0.3 for Iowa

FIGURE 2.4-1
AMERICAN INDIAN AND ALASKA NATIVE MINORITY POPULATION WITHIN 50 MILES OF FORT CALHOUN STATION UNIT 1

50-mile radius

1990 Black Minority Population

County

N W E S

Tracts are designated as Black minority population if the percentage of the Black population is at least 20 percent greater than the Black percentage of 3.6 for Nebraska or 1.7 for Iowa

**FIGURE 2.4-2
BLACK MINORITY POPULATION WITHIN 50 MILES OF FORT CALHOUN STATION UNIT 1**

Tracts are designated as Hispanic minority population if the percentage of the Hispanic population is at least 20 percent greater than the Hispanic percentage of 2.3 for Nebraska or 1.2 for Iowa

FIGURE 2.4-3
HISPANIC MINORITY POPULATION WITHIN 50 MILES OF FORT CALHOUN STATION UNIT 1

2.4.2.2 LOW-INCOME POPULATIONS

NRC guidance defines “low-income” using U.S. Census Bureau statistical poverty thresholds (Reference 2.4-9, Attachment 4). The guidance indicates that a low-income population is present if the percentage of households below the poverty level in an environmental impact site is significantly greater (typically at least 20 percent) than the low-income population percentage in the geographical area chosen for comparative analysis. U.S. Census Bureau data (Reference 2.4-13) characterizes 11.8 percent of Nebraska households as low-income and 11.9 percent of Iowa households as low-income. Applying the NRC criterion (at least 20 percent greater than the state), 12 Douglas County, Nebraska census tracts and one Pottawattamie County, Iowa census tract have low-income populations (see Tables 2.4-2 and 2.4-3). Figure 2.4-4 shows locations of the low-income population census tracts.

**FIGURE 2.4-4
LOW-INCOME HOUSEHOLDS
WITHIN 50 MILES OF FORT CALHOUN
STATION UNIT 1**

2.5 AREA ECONOMIC BASE

This section focuses on Washington, Douglas and Sarpy counties because 86 percent of FCS employees reside in these counties. All three counties are in the Omaha MSA.

The Omaha MSA has experienced steady growth in recent years. The employed work force in Omaha increased 25.7 percent between 1990 and 1999, which compares favorably to the national growth rate of 17.6 percent (Reference 2.5-1). Services is the largest employment sector, accounting for 33.1 percent of total employment in the Omaha MSA. Trade accounts for approximately 24.1 percent of total employment, while the government and manufacturing sectors account for approximately 12.1 percent and 9.5 percent, respectively (Reference 2.4-6).

In 2000, the Omaha MSA had an estimated labor force of 400,049, with an unemployment rate of 2.5 percent. For the past decade, unemployment rates in the region have been much lower than the national average and comparable to the Nebraska average. The median household in Omaha had an estimated effective buying income of $46,575. Nationally, the estimated effective buying income of the median household was $37,233 (Reference 2.5-1).

U.S. Interstates 80 and 29, as well as 12 other U.S. and state highways, intersect in the Omaha MSA. This extensive highway network gives the region access to east-west and north-south corridors. The region's transportation network also includes rail and trucking terminals, the Eppley airfield and four other local airports, and two barge lines that are capable of transporting large volumes of commodities on the Missouri River (Reference 2.5-2).

Agriculture contributes significantly to the regional economy, particularly in more rural Washington County. Principal crops in the region include corn, soybeans, and hay (Reference 2.1-3, Table 2.9-2). According to the U.S. Department of Agriculture's 1997 Census of Agriculture, receipts from all agricultural products contributed $92.5 million to Washington County's economy. Livestock sales alone accounted for 51 percent of the market value of agricultural product sales. By comparison, agricultural sales contributed only $44.1 million and $57.2 million to the economies in Douglas and Sarpy counties, respectively (Reference 2.5-3).

2.6 TAXES

The Nebraska State Constitution Article VIII, Section 11 (1958), stipulates:

> Every corporation and political subdivision organized primarily to provide electricity… shall annually make the same payments in lieu of taxes as it made in 1957, which payments shall be allocated in the same proportion to the same public bodies or their successors as they were in 1957. The legislature may require each such public corporation to pay to the treasurer of any county in which may be located any incorporated city or village, within the limits of which such

public corporation sells electricity at retail, a sum of five percent of the annual gross revenue. (Reference 2.6-1)

OPPD is a publicly owned electric utility with a total generation capability as of July 31, 2001, of 2,203,000 kilowatts from its five power stations. OPPD leases an additional 6,600 megawatts from the Tecumseh Municipal Utility (Reference 2.6-2). As a political subdivision responsible for the production and distribution of electricity within its 13-county service area, OPPD is exempt from paying state occupational taxes, personal property, and real estate taxes. Instead, OPPD makes six payments in lieu of taxes each year to the municipalities and 12 Nebraska counties (Burt, Cass, Colfax, Dodge, Douglas, Johnson, Nemaha, Otoe, Richardson, Sarpy, Saunders, and Washington) in which OPPD sold power in 1957. In addition, each county receives 5 percent of the total gross revenues OPPD receives from electricity sales from within the county, minus the amount already paid to the incorporated area of the county. Payments are made to the counties and municipalities within the service area irrespective of whether the power is purchased from another generator or produced at OPPD power plants. The counties and municipalities then distribute the money to the appropriate cities, school districts, and agencies.

From 1996 to 2000, approximately 80 percent of OPPD's total annual in-lieu payments have been paid to Douglas County, the largest consumer of OPPD electricity. In 2000, OPPD's in-lieu payments totaled $17.6 million, $15 million of which was paid to Douglas County and its constituent municipalities. By comparison, OPPD made in-lieu payments totaling approximately $1.79 million and $330,000 to the county governments and constituent municipalities in Sarpy and Washington counties, respectively.

2.7 SOCIAL SERVICES AND PUBLIC FACILITIES

2.7.1 PUBLIC WATER SUPPLY

FCS acquires potable water through the City of Blair's Department of Utilities. Current plant usage averages 10 million gallons per month (an average of approximately 321,000 gallons per day) for FCS with no restrictions on supply (Reference 2.7-1). Discussion of public water systems focuses on Washington, Douglas, and Sarpy counties because approximately 86 percent of FCS employees reside in these counties (see Section 3.4 for work force description). Local municipalities and private water companies provide public potable water service to residents who do not have individual onsite wells. These providers are subject to regulation under the Federal Safe Drinking Water Act, as implemented by the Nebraska Department of Health.

According to Nebraska Department of Natural Resources 1995 estimates, approximately 42 percent of Washington County residents use on-site wells to obtain potable water, while only 13 percent and 21 percent of residents use on-site wells in Douglas and Sarpy counties, respectively. Additionally, water use for irrigation is substantially greater in

Washington County than in Douglas and Sarpy counties. Total domestic water use in 1995, from both public water supply systems and private groundwater wells, equaled an estimated 66.63 million gallons per day in the combined-county region of Washington, Douglas, and Sarpy counties (Reference 2.7-2).

The lack of a public water supply system in unincorporated portions of Washington County has hindered development in the county. The largest public water supplier in Washington County is the City of Blair's Department of Utilities. The City of Blair Municipal Water Plant services approximately 8,500 residents in Blair and surrounding areas in Washington County. In addition, the city serves industrial customers such as FCS and the neighboring Cargill agricultural product plant. The water treatment plant has a permitted capacity of 8 million gallons per day, and the plant is scheduled to increase its capacity to 14 million gallons per day by the end of 2001. Source water is obtained from the Missouri River. The plant is operating near capacity, as actual daily demand averages 7.5 million gallons per day with a peak demand of approximately 8 million gallons per day (Reference 2.7-3).

The Omaha Metropolitan Utilities District (the District) serves more than 170,000 customers in Douglas and Sarpy counties, including Omaha, Bellevue, Offutt Air Force Base, Elkhorn, Waterloo, LaVista, and Carter Lake. The District also supplies water to the Papio-Missouri River Natural Resources District, which provides potable water supplies to the township of Fort Calhoun. The District operates two water plants with a combined average daily demand of approximately 95 million gallons of water per day. The combined permitted capacity of the two plants is 234 million gallons per day. Source water for the plants is obtained from the Missouri and Platte rivers, as well as several groundwater peaking wells. The District estimates that peak demand could approach or reach the permitted capacity levels in the summer. In 1998, the Nebraska Department of Water Resources approved the first two in a series of permits to begin construction of a third water treatment plant using groundwater wells for source water. This third water treatment plant is projected to increase the permitted capacity of the water system to 100 million gallons per day and meet water demands of the service area until at least 2030 (Reference 2.7-4).

The City of Papillion Public Works Department is the other primary public potable water service provider in Sarpy County. The Department serves approximately 17,000 customers in Papillion and surrounding areas in Sarpy County. The water treatment plant has a permitted capacity of 12 million gallons per day. Actual daily demand averages 5.5 million gallons per day during the winter and 7.5 million gallons per day during the summer, with a peak demand of approximately 9 million gallons per day (Reference 2.7-5).

2.7.2 TRANSPORTATION

The U.S. Transportation Research Board has developed a commonly used indicator, called "level of service" (LOS), to measure roadway traffic volume. LOS is a qualitative assessment of traffic flow and how much delay the average vehicle might encounter during peak hours. Table 2.7-1 presents the LOS definitions used by local and state agencies, as well as by the NRC in the GEIS (Reference 2.4-1, Section 3.7.4.2).

Road access to FCS is via U.S. Highway 75, a two-lane highway running north-south near the Nebraska-Iowa state boundary. In the vicinity of the site, from Blair to Fort Calhoun, the Nebraska Department of Roads estimates that U.S. Highway 75 carries an LOS designation of 'B', based on 1998 data (Reference 2.7-6).

TABLE 2.7-1
LEVEL OF SERVICE DEFINITIONS

Level of Service	Conditions
A	Free flow of the traffic stream; users are unaffected by the presence of others.
B	Stable flow in which the freedom to select speed is unaffected, but the freedom to maneuver is slightly diminished.
C	Stable flow that marks the beginning of the range of flow in which the operation of individual users is significantly affected by interactions with the traffic stream.
D	High-density, stable flow in which speed and freedom to maneuver are severely restricted; small increases in traffic will generally cause operational problems.
E	Operating conditions at or near capacity level causing low, but uniform, speeds and extremely difficult maneuvering that is accomplished by forcing another vehicle to give way; small increases in flow or minor perturbations will cause breakdowns.
F	Defines forced or breakdown flow that occurs wherever the amount of traffic approaching a point exceeds the amount that can traverse the point. This situation causes the formation of queues characterized by stop-and-go waves and extreme instability.

Source: Reference 2.4-1, Section 3.7.4.2.

2.8 LAND USE PLANNING

This section focuses on Washington, Douglas, and Sarpy counties because 86 percent of FCS employees reside in these three counties (see Section 3.4 for work force description).

Nebraska State Statute Section 23-114 stipulates "the County Board shall have power to create a planning commission with the powers and duties set forth in this act; make, adopt, amend, extend, and implement a county comprehensive development plan; and adopt a zoning resolution, which shall have the force and effect of law" (Reference 2.8-1). In order to accommodate and regulate growth and development, Washington, Douglas, and Sarpy counties have developed comprehensive growth management plans characterizing current conditions and setting standards, regulations, and goals for land development. Douglas County's plan was adopted August 7, 1998, and Sarpy County's plan was adopted May 1993 (Reference 2.8-2; Reference 2.8-3). The City of Omaha adopted a comprehensive master plan in 1996 (Reference 2.8-4). Washington County's plan is currently being updated (Reference 2.8-5).

Washington, Douglas, and Sarpy counties have adopted land use planning regulations, such as zoning, to manage future growth and development. Planning agencies in Washington, Douglas, and Sarpy counties encourage growth in existing urban areas and limit business activities in agricultural areas to those supporting agricultural production. Zoning regulations restrict growth in areas susceptible to flooding. Each county planning agency supports the goal of protecting environmentally sensitive lands, natural resources, rural and agricultural land uses, historic and archaeological resources, and habitats for threatened and endangered species. There are no growth control measures in place to restrict development (Reference 2.8-2; Reference 2.8-3; Reference 2.8-5).

The vast majority of land area in Douglas County is incorporated. Aggressive annexation by constituent municipalities such as Omaha and Elkhorn have significantly decreased Douglas County's planning jurisdiction. In 1997, Douglas County's planning jurisdiction totaled approximately 80 square miles, or 23.9 percent of the county's total land area. The majority of this land is in the western portion of Douglas County. Agricultural and open land is the largest land use component in the unincorporated portion of Douglas County, followed by residential use (Reference 2.8-2).

Residential and commercial land uses are predominant in the eastern and central portions of both Douglas and Sarpy counties. Development is strong along the Missouri River, and has largely spread out from Omaha. By comparison, land uses in western portions of both counties are largely rural and agricultural (Reference 2.8-4).

Washington County is more rural in character, with a larger emphasis on agricultural and open land uses. More than 16,419 acres of land are used for agriculture in Washington County (Reference 2.1-3, Section 2.9). More than 59 percent of Washington County's population lives in rural areas, while only 4 percent of Douglas County's population and 14 percent of Sarpy County's population live in rural areas (Reference 2.4-7). Commercial and urban development in Washington County centers on the City of Blair and smaller municipalities where public services, such as public water service, are available.

2.9 HISTORIC AND ARCHAEOLOGICAL RESOURCES

The construction of FCS in the 1970s did not significantly impact any known historic or archaeological resources of significance. Prior to construction of Fort Calhoun Station Unit 1, a representative of the Nebraska State Historical Society conducted a field investigation at the site location and concluded the area held little historical interest. A society representative was also present during initial site grading and earth excavation, and no significant historical artifacts were found (Reference 2.9-1, page 2-11a).

An archaeological survey, performed in 1975, of the area for the proposed Fort Calhoun Station Unit 2, identified two potential archaeological sites in the southern portion of the generating facility 110 to 451 feet away from the center of the main access road. Both archaeological sites contained material likely to be remnants attributable to the historic DeSoto Township, although one of the sites contained evidence of possible prehistoric origin. Laboratory analysis was unable to conclusively show that any of the recovered artifacts resulted from prehistoric human activity. Considering the value of the artifacts recovered and disturbances to the area resulting from years of agricultural use and various construction activities in the area, the state historic preservation officer concluded that the historical DeSoto Township did not meet requirements to warrant nomination to the National Register of Historic Places (Reference 2.1-1, Section 2.3). The Nebraska State Historical Society has erected a roadway marker near the entrance of FCS to show the historical significance of the DeSoto Township, the cost of which it shared with OPPD (Reference 2.9-1, page 2-11a).

The National Register of Historic Places lists nine historic sites within 10 miles of FCS. Seven of the nine sites are historic buildings in Blair: the Blair High School (circa 1899), Abraham Castetter House (circa 1876), Congregational Church of Blair (circa 1874), C. C. Crowell Jr. House (circa 1910), Long Creek School, Trinity Seminary Building, and the Washington County Courthouse (circa 1891) (Reference 2.9-2; Reference 2.9-3). The reconstructed Fort Atkinson, which was the only U.S. military base west of Missouri from 1820-1827, is approximately 5.5 miles southeast of FCS. The Bertrand site, the wreck of a Missouri River steamer that sank in the DeSoto bend, in 1865, on its maiden voyage upstream with cargo for the Montana goldfields, is 2.5 miles east of FCS in the DeSoto National Wildlife Refuge (Reference 2.3-14, Section 2.6.2.1).

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3.0 PROPOSED ACTION

NRC

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

Omaha Public Power District (OPPD) proposes that the U.S. Nuclear Regulatory Commission (NRC) renew the Fort Calhoun Station Unit 1 (FCS) operating license for an additional 20-year period, through August 9, 2033. Renewal would provide OPPD and the State of Nebraska the option of relying on FCS to meet the state's future needs for electricity generation. Section 3.1 provides a general description of selected plant design and operating features. Sections 3.2 through 3.4 address potential changes that could be required to support renewed operating licenses.

3.1 GENERAL PLANT INFORMATION

3.1.1 MAJOR FACILITIES

FCS is a single unit plant, consisting of a nuclear steam supply system, steam and power conversion systems, and related facilities. At the currently licensed thermal power level of 1,500 megawatt-thermal, electrical power output is 509.8 megawatts-electrical and the net generating capability of the plant (i.e., electric power supplied to the grid) is 476 megawatts (summer rating) (Reference 3.1-1, Table 1.2-1; Reference 3.1-2, Exhibit 4.4-1).

As discussed in Section 2.1.3, FCS facilities occupy approximately 135 acres of the site. The principal power generation and direct support facilities are within the fenced Protected Area [i.e., restricted area as defined in 10 CFR 20.3(a)] and are accessed via portals at the Security Building and Warehouse (Reference 3.1-1, Section 1.2; Reference 3.1-3, page 4). Major facilities in the Protected Area and their associated functions are described below and depicted in Figure 2.1-3. The *Fort Calhoun Station Updated Safety Analysis Report* (Reference 3.1-1) provides additional details. Public information literature OPPD developed provides general descriptions (e.g., Reference 3.1-3).

Containment Building – a vertical cylindrical structure with a domed roof constructed of steel-reinforced concrete that houses the reactor, steam generators, reactor coolant pumps, other nuclear steam supply system (NSSS) components, and equipment for refueling and other operations that do not require visual observation or direct attention by the operator during power operation. The Containment Building provides a highly reliable, essentially leak-tight barrier against the escape of radioactive material that might be released from the reactor system in the event of an accident. Featuring walls approximately 4 feet thick with a ¼-inch-thick carbon steel inner liner, the structure is designed to readily withstand impact from objects tornadoes propel and to tolerate an internal pressure of 60 pounds per square inch, the maximum pressure that would be created in the unlikely event of a rupture of the largest primary pipe in the Reactor Cooling System. As with other Class I safety-related buildings at the plant, e.g., the Auxiliary Building and the Intake Structure, the Containment Building is designed to withstand earthquakes. It is constructed on a large, reinforced concrete mat supported on steel piles driven into bedrock approximately 70 feet below grade. With a diameter of approximately 120 feet and a height of approximately 140 feet, the Containment Building is the most visually prominent building on the site.

Auxiliary Building – a heavily reinforced concrete, safety-related structure adjacent to the Containment Building. It houses fuel storage and handling facilities, the spent fuel pool, radioactive waste treatment facilities, emergency diesel generators, the control room, and other related support facilities.

Turbine Building – a Class II structure with a reinforced concrete base mat and structural steel superstructure. It houses the turbine generator, condensers, condensate and feedwater pumps, feedwater heaters, and other turbine heat cycle components.

Service Building – a facility adjacent to the Turbine Building that contains offices, an auxiliary boiler, and facilities originally used to produce demineralized water for the plant. Production of demineralized water has been replaced with a vendor-operated water treatment system, discussed below. However, these former production facilities continue to be used for storage and distribution of process water obtained from the City of Blair Municipal Water System.

Intake Structure – a Class I safety-related structure on the Missouri River bank featuring heavily reinforced concrete construction below grade and a structural steel superstructure above grade. This structure houses the equipment needed to pump water from the river to condense steam, exiting the turbine, in the main condensers and to cool various plant equipment. Section 3.1.3 discusses this structure in more detail.

Radioactive Waste Processing Building – a building adjacent to the Auxiliary Building that houses facilities for decontaminating equipment and sorting, treating, storing, and preparing low-level radioactive waste for shipment to approved offsite treatment and disposal facilities. Processing capabilities include dry active waste compaction and liquid waste filtration, ion exchange, and solidification.

Chemical and Radiation Protection Facility (CARP) – a facility that houses the Technical Support Center, chemistry laboratories, radiological control facilities, lockers, showers, and a cafeteria.

Maintenance Shop – a building adjacent to the Service Building that houses facilities for maintenance and repair of plant facilities and equipment.

Warehouse – a facility that receives, inspects, stores, and issues routine shipments of material for use at the site. An alternate security entrance to the Restricted Area is provided at the warehouse.

Major plant facilities outside of the Protected Area include the following (see Figure 2.1-3):

Switchyard – comprises transformers and related equipment to transmit power from the main transformer of the plant to the electric grid, and to transmit power from the grid to the plant for startup. Located in a separate, fenced area southwest of the Protected Area, the switchyard comprises two substations: OPPD Substation 3451, which provides interconnection with a 345-kilovolt (kV) transmission line; and OPPD Substation 1251, which provides connection for three 161-kV lines from the switchyard (see Section 3.1.4).

Old Warehouse Building – borders the Protected Area and houses the vendor-owned Ionics Reverse Osmosis Unit, which supplies demineralized water for various plant uses (see Section 3.1.3).

Firing Range – located west of the Protected Area, the firing range is surrounded by an earthen berm on three sides and is used for training plant security personnel.

Administration Building – houses administrative offices and related support facilities. It was constructed in 1991.

Training Center – houses training facilities (since 1989), the control room simulator, the environmental monitoring laboratory, and related facilities.

Sanitary Lagoons – treat sanitary wastes generated at the plant in two lagoons east of the main plant complex. Treated wastewater is land-applied using a center pivot irrigation system.

3.1.2 NUCLEAR STEAM SUPPLY SYSTEM

The FCS nuclear steam supply system consists of a pressurized water reactor and its associated coolant system supplied by Combustion Engineering (Reference 3.1-1, Sections 1.2, 1.3, 3.1, 10.2; Reference 3.1-3). The NSSS is designed as two closed loops, each of which includes two reactor coolant pumps and a steam generator connected parallel to the reactor. Highly purified water, to which chemicals are added to control corrosion and to moderate the nuclear reaction, circulates under high pressure through the reactor and the tube side of the steam generators in these closed loops, called the primary system. Heat from the reactor is transferred to highly purified, treated water in the shell side of the steam generators to produce high-pressure saturated steam that is routed through the steam turbines, condensed back to water in the main condensers, and pumped back to the steam generators, thus making up a secondary cooling loop isolated from the primary system.

The reactor was initially licensed to operate at a maximum power level of 1,420 megawatts-thermal. On the basis of additional safety and environmental evaluations, however, the NRC issued a license amendment (Amendment No. 50), August 15, 1980, to allow operation at the system's full-rated power level of 1,500 megawatts-thermal (Reference 3.1-1, Section 3.2.1; Reference 3.1-4).

The FCS reactor is licensed for uranium dioxide fuel that has a maximum enrichment of 5.0 percent by weight uranium-235 (Reference 3.1-1, Section 9.5.3.3). Maximum fuel enrichment to date, through loading for Fuel Cycle 20 which began April 2001, is 4.66 percent by weight uranium-235.

The reactor core comprises fuel rods fabricated with cylindrical, uranium-dioxide pellets enclosed in 128-inch-long cylindrical, zircaloy tubes with welded end plugs. The 176 fuel rods are fabricated into 14 x 14 array fuel assemblies with end fittings and grids to support and limit motion of the tubes. There are 133 of these fuel assemblies in the reactor core. The core also contains boron carbide absorber rods, arranged in 49 control element assemblies, to control the nuclear reaction.

OPPD regularly replaces about one-third of the fuel assemblies in the reactor core at approximately 18-month intervals. The approximate maximum average burn-up for a fuel sub-batch discharged from the reactor core is less than 53,300 megawatt-days per metric ton uranium.

All spent fuel from the reactor core is stored in the Auxiliary Building's spent fuel pool. It is anticipated that the maximum capacity of the spent fuel pool will be reached in 2007. OPPD is currently considering construction of a dry cask storage facility to support plant operations beyond 2007, when spent fuel can be shipped to a permanent repository.

3.1.3 COOLING AND AUXILIARY WATER SYSTEMS

3.1.3.1 WATER USE OVERVIEW

Water used for FCS operation consists of once-through, noncontact cooling water from the Missouri River and filtered, chlorinated water from the City of Blair Municipal Water System for potable and service water use, discussed in Sections 3.1.3.2 and 3.1.3.3, respectively. Groundwater use at the plant is limited to small amounts withdrawn from two onsite wells for occasional water level adjustment in the Sanitary Lagoons and occasional flushing of the center-pivot irrigation system used to land-apply treated effluent from the Sanitary Lagoons.

3.1.3.2 COOLING WATER SYSTEMS

Cooling water for FCS is obtained from the Missouri River at the Intake Structure, a reinforced concrete building that extends approximately 80 feet along the riverbank at river mile 645.85, immediately north of the Service Building (see Figure 2.1-3). Most of the water withdrawn at the structure is associated with the Circulating Water System, which employs three pumps operating at 120,000 gallons per minute to supply once-through cooling water to remove heat from the main (turbine) condensers, and other turbine plant heat exchangers used to cool turbine bearings, lubricating oil, and related equipment (Reference 3.1-1, Section 10.2.3; Reference 3.1-5, Section 4.0).

Water is also withdrawn at the Intake Structure by the Raw Water System, which provides once-through cooling water to component cooling water heat exchangers to remove heat from various auxiliary systems, the spent fuel pool, ventilation equipment, pump components, and other equipment. This system includes four 5,325 gallon per minute pumps to withdraw the river water. For normal plant operation, only one pump operates. Two pumps may be operated during the summer, when river temperatures are higher (Reference 3.1-1, Section 9.8).

Maximum water withdrawal for the plant during normal operation, therefore, amounts to approximately 371,000 gallons per minute (827 cubic feet per second or 534 million gallons per day).

The Intake Structure and Circulating Water System for the plant remain essentially as the U.S. Atomic Energy Commission [AEC (predecessor agency to the NRC)] described in the Final Environmental Statement (FES) for the plant (Reference 3.1-6, Section III.D.1) and OPPD's approved Clean Water Act Section 316(b) demonstration report (Reference 3.1-5, Section 4.0), both issued in the 1970s. The temperature increase of cooling water flowing through the main condensers, however, is approximately 5 deg F higher (i.e., approximately 23 deg F) at the currently authorized maximum power level of 1,500 megawatts (thermal), than the AEC indicated in the FES. In addition, in the early 1980s, OPPD constructed a sheet pile wall with rock backfill along the shoreline at the upstream side of the Intake Structure to further stabilize the bank. This project, completed under the authority of a U.S. Army Corps of Engineers (COE) permit, effectively extended the bank further into the river (Reference 3.1-7). OPPD also obtains COE authorization to occasionally dredge sand and other accumulated riverbed materials from in front of the intake, an operation last performed in approximately 1990.

Water enters the Intake Structure through six separate inlet bays. Vertical trash racks, constructed of 12-foot-long steel bars with 3-inch spacing between the bars, are in each bay at the river interface to prevent large debris from entering the system. Debris that accumulates on the trash racks is removed periodically by isolating the outer portion of the inlet bay and backwashing, and by using the Surface Sluice System, which directs a stream of water away from the racks on the surface of the river. The Surface Sluice System operates as necessary to divert floating debris. In the winter, ice flows away from the Intake Structure inlet bays (Reference 3.1-5, Section 4.0).

A curtain wall is within each inlet bay, approximately 5-½ feet beyond the trash rack, to allow isolation of individual bays to maintain and repair equipment and to backwash the trash rack. A 6-foot-wide by 8-foot-high sluice gate at the base of the wall separates the bays. Water entering each bay flows through the sluice gate opening and through traveling screens approximately 8 feet beyond the gate. The traveling screens, each 8 feet wide and constructed of 3/8-inch stainless steel mesh, prevent small debris from entering the system. The screens are periodically rotated and backwashed using nozzles in the upper screen splash housing. Debris washed from the screens is directed to a screen wash trough, which discharges to the river at the downstream end of the Intake Structure (Reference 3.1-5, Section 4.0).

At river surface elevations greater than 978 feet (corresponding to an extreme low-level condition), the average velocity of intake water through sluice gate openings in the curtain walls is approximately 2.8 feet per second. Estimated average approach velocities to the traveling screens are 0.7 and 1.1 feet per second at river surface elevations of 992 feet and 983 feet, which approximately correspond to normal and low river level conditions, respectively (Reference 3.1-5, Section 4.0).

Water passing through the intake screens enters three pump cells, two inlet bays per cell, which can be isolated from one another by cross-connect sluice gates. Both the Circulating Water System and the Raw Water System pumps take suction from this area of the Intake Structure. The three Circulating Water System pumps, all of which are normally in operation, transfer water from the pump cells to the intake tunnel and through the main condensers and turbine plant heat exchangers. Side streams from the intake tunnel provide water for backwashing the trash racks and traveling screens and for supplying the Surface Sluice System.

Nominal temperature rise for the cooling water as it passes through the main condensers is 23 deg F at 100-percent reactor power. The warm water leaving the condensers and heat exchangers is directed to a below-grade reinforced concrete discharge tunnel, which outfalls to the river at the shoreline approximately 40 feet downstream from the Intake Structure. At its outfall to the river, the discharge tunnel is rectangular in cross-section, 33 feet wide and 14 feet high, and is submerged at normal river flow conditions. The top of the tunnel, at elevation 992 feet, terminates at the shoreline. The walls slope to the floor of tunnel, which extends approximately 25 feet further riverward (Reference 3.1-5, Figure 4.1-3).

During the winter, when ice forms in the river, some of the warm water from the discharge tunnel is diverted through a reinforced concrete recirculation tunnel and is discharged back to the river immediately upstream from the inlet bays to prevent ice forming on the trash racks, traveling screens, and other vulnerable equipment (Reference 3.1-5, Section 4.6). The temperature of the water flowing into the Intake Structure in this mode is raised by approximately 8-9 deg F. Therefore, the nominal temperature differential between the ambient river and the circulating water discharge is raised from approximately 23 deg F to 31-32 deg F during the winter.

OPPD operates the Circulating Water System in compliance with applicable provisions of National Pollutant Discharge Elimination System (NPDES) Permit NE0000418 for FCS (Reference 3.1-8). This permit includes a maximum temperature limit of 110 deg F for the circulating water discharge. However, the permit also conditionally provides for a discharge temperature of 112 deg F under the terms of a Consent Order that OPPD has entered into with the Nebraska Department of Environmental Quality (NDEQ) (Reference 3.1-9). The Consent Order was executed to allow for continued full-power operation of FCS under unusually high ambient river temperatures that have been experienced in recent years (see Section 4.4 and Appendix 2). The NPDES permit also includes limits for the use and discharge of chlorine for biofouling control in the once-through cooling water systems. However, high sediment concentrations in the river water have been effective in preventing biofouling, and to date no biocides have been needed or used in these systems. OPPD may require chlorination or other methods of control in the future if biofouling organisms, such as zebra mussels, become established in the Missouri River at the site and present a potential impediment to station operation.

3.1.3.3 MUNICIPAL WATER SUPPLY

FCS uses approximately 10 million gallons per month (0.3 million gallons per day) of filtered, chlorinated water from the City of Blair Municipal Water System for potable water, service water, and other uses (Reference 3.1-10). Principal uses of this water, which is provided via an 8-inch supply line to the plant, include the following:

- Potable water and the Fire Protection System supply to the Administration Building and Training Center.

- Feedwater to the vendor-owned Ionics Reverse Osmosis Unit in the Old Warehouse Building. This system, which replaced the plant's original deionized water plant in the Service Building in the mid-1990s, supplies demineralized water for various plant uses, including makeup to the reactor primary and secondary water systems, spent fuel pool, stator cooling water system, and auxiliary boiler. Brine generated from reverse osmosis is pumped to the circulating water system discharge tunnel and discharged in accordance with the NPDES permit.

- Makeup to the plant's Potable Water Storage Tank in the Auxiliary Building. Water from this tank supplies potable water to buildings in the Protected Area and the Old Warehouse Building, and provides a backup source of seal water to the circulating water and raw water pumps.

- Supply to the Service Water System, which provides seal water to the circulating water, raw water, and screen wash pumps in the Intake Structure; water for the vacuum priming pumps in the Turbine Building; and water for pressurizing the fire main header via the fire protection jockey pump.

3.1.4 POWER TRANSMISSION SYSTEMS

The following transmission lines, illustrated in Figures 2.1-2 and 3.1-1, connect to the FCS Switchyard, designated by OPPD as Substation 3451/1251 (Reference 3.1-11):

1. Transmission lines installed as a direct result of FCS construction, startup, and operation and evaluated by the AEC in its permit review for continued construction and operation of the plant (Reference 3.1-6, Section III.B):

    - Approximately ¼ mile of single-circuit 161-kV line, on three-pole steel angle structures, from the FCS Substation to the FCS plant proper, for plant startup use. This line has not been modified since initial plant construction and lies entirely on developed portions of the FCS site property.

    - Approximately ½ mile of 345-kV line, on steel lattice towers, from the FCS generator/main transformer to the FCS Substation. This line has not been modified since initial plant construction, and lies entirely on developed portions of the FCS site property.

    - Approximately 7 miles of 161-kV line from the FCS Substation westward to Substation 1226, approximately 3 miles west of Blair, Nebraska (Line 74S, a ½-mile long single-circuit line on a 50-foot-wide right-of-way; connecting to Line 74, a 6-½ mile long double-circuit line on a 100-foot right-of-way to Substation 1226). This line was originally constructed, in 1969, as a single-circuit on wooden pole H-frames for initial plant construction and startup, and provided a connection to the transmission grid once the plant became operational. It was entirely reconstructed, February 1999, to single steel poles. Line 74N, a 161-kV single-circuit from Cargill (Substation 1298), joins Line 74S from the FCS Substation.

2. Other transmission lines connecting to the FCS Substation:

    - A 345-kV line from near Sioux City, Iowa, connecting through the FCS Substation and continuing southward to near Rulo, Nebraska. The segments connecting to the FCS Substation typically occupy a 150-foot-wide right-of-way, and include Line 67 to the north, a single-circuit on wooden pole H-frames, and Line 66 (extending to Lines 65, 59, and 60) to the south, a double-circuit on steel lattice towers. This line provides the main connection of FCS with the transmission grid. Its construction, completed May 1970, was roughly concurrent with FCS construction. However, the line was built to provide interconnection with the Iowa Public Service Company, Nebraska Public Power District (NPPD), and others, and the decision to construct the line predates the FCS construction decision (Reference 3.1-6, Section III.B). It continues to serve as a major interconnection with other utilities in the Mid-Continent Area Power Pool (MAPP), including Mid-American Energy Company, NPPD, and others (Reference 3.1-12).

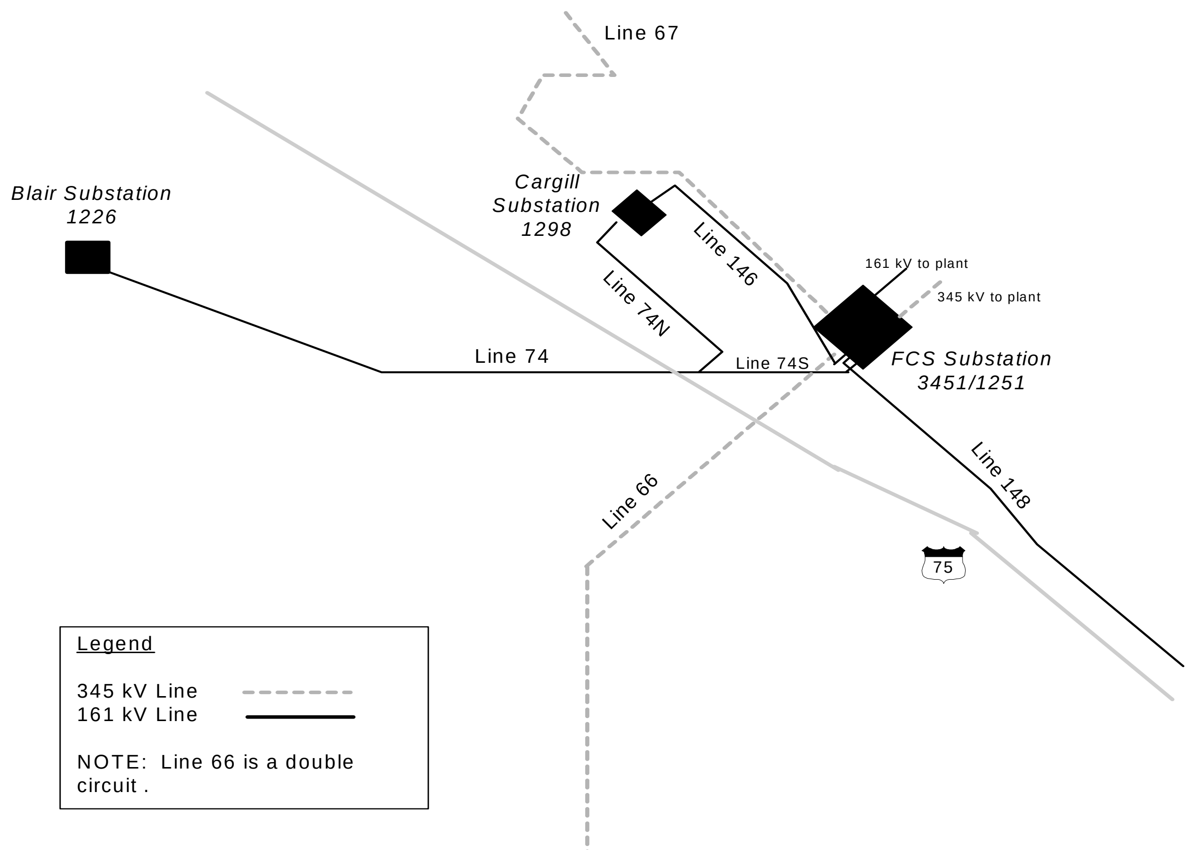

FIGURE 3.1-1 - OPPD TRANSMISSION LINES ASSOCIATED WITH FORT CALHOUN STATION UNIT 1

- A single-circuit 161-kV line on single metal poles (Line 148) from FCS Substation 3451/1251 southward approximately 8 miles to Substation 1297 at the city of Fort Calhoun, then (as Line 147) approximately 10 miles to Substation 1250, approximately 3 miles northwest of OPPD's North Omaha Station. This line, constructed in 1994, is on highway right-of-way most of its length. Segments on private property occupy a 50-foot-wide right-of-way.

- A single-circuit 161-kV line (Line 146) from the FCS Substation northwestward approximately 1.5 miles to the Cargill Facility (Substation 1298), then back southward (as Line 74N) approximately ¾ mile to join a single-circuit 161-kV line (Line 74) from FCS Substation, as described above. Lines 146 and 74N (single steel poles) and Substation 1298 were constructed January 1995 to serve the Cargill Facility, northeast of FCS on adjoining property. Offsite portions of these lines are on a 50-foot-wide right-of-way.

As at the construction permit stage, the transmission corridor of concern for license renewal is that which was constructed between the plant Switchyard and its connection to the existing transmission system (Reference 3.1-13, Section 4.5, page 4-59; Reference 3.1-14, Section 4.13). As indicated above, the 345-kV line providing the primary connection (via Lines 66/67) was not expressly built for FCS, and is therefore not subject to review under this application. The only other transmission line originally constructed in connection with FCS, currently designated 74S/74 (operating at 161 kV), was totally reconstructed in 1999. This line was reconstructed to the 1997 National Electrical Safety Code® (NESC®) requirements that were in effect at the time.

Leaving the FCS Substation and leading west, this 161-kV line (Line 74S/74) traverses (for approximately one mile) disturbed shrublands and woodlands, primarily on the hilly upland terrain of the Missouri River bluffs in the vicinity of U.S. Highway 75. For the remaining six miles or so to the Blair Substation, this line is routed across agricultural cropland. The line crosses several small intermittent streams, but no other surface waters or wetlands were encountered on the right-of-way when it was rebuilt in 1999. Land use adjacent to the right-of-way has undergone little change since initial construction; however, some additional development has occurred along U.S. Highway 30 near the line crossing, and new rural residential development has occurred along the north side of line for approximately ¾ mile in the bluff area just west of U.S. Highway 75.

OPPD makes annual flight inspections of its transmission line rights-of-way to ensure nonencroachment by structures. OPPD also conducts routine vegetation maintenance of its transmission line rights-of-way approximately every three years to ensure continued reliability of the lines and, as appropriate to existing land use, promote shrub and forest edge habitats conducive to wildlife. Maintenance includes removal or trimming of woody vegetation as necessary to ensure adequate line clearance in accordance with OPPD's *Tree Clearance Guidelines* (Reference 3.1-15) and to allow vehicular access along the rights-of-way. Large woody vegetation that can interfere with conductors is mechanically trimmed or removed, and stumps are treated with approved herbicides. Small woody vegetation is manually removed or controlled by basal application of approved herbicides. Low-growing woody vegetation, including sumac, chokecherry, wild plum, and other species having substantial value for wildlife, are not trimmed or removed except as needed for vehicular access. OPPD does not employ mowing or broadcast application of herbicides, and does not use herbicides in or near wetlands and stream crossings. OPPD requires applicators to be certified in accordance with Nebraska Pesticide Regulations in the Nebraska Administrative Code (NAC), Title 25, Chapter 2.

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: (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…." (Reference 3.1-17, Section 2.6.3.1, page 2-41.) ["SMITTR" defined at GEIS Section 2.4, page 2-30 as surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping.]

The GEIS (Reference 3.1-13, Section 3.1 and Appendix B, Table B.2) identifies refurbishment activities that utilities might perform for license renewal. Performing such major refurbishment activities would necessitate changing administrative control procedures and modifying the facility. The GEIS analysis assumed that an applicant would begin any major refurbishment work shortly after the NRC granted a renewed license and would complete the activities during five outages, including one major outage at the end of the 40th year of operation. The GEIS refers to this as the refurbishment period.

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

The FCS Integrated Plant Assessment that OPPD has conducted under 10 CFR 54 and included as part of this application has not identified the need to undertake any refurbishment or replacement actions to maintain the functionality of important systems, structures, and components during the FCS license renewal period. Therefore, no refurbishment would be conducted that would directly affect the environment or plant effluents.

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…." (Reference 3.1-17, Section 2.6.3.1, page 2-41.) ["SMITTR" defined at GEIS Section 2.4, page 2-30 as surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping]

In accordance with NRC regulation 10 CFR 54, OPPD has performed an FCS aging management review and has included in the FCS license renewal application an integrated plant assessment that identifies how OPPD would manage the effects of aging on systems, structures, and components. In some cases, existing FCS programs adequately address aging effects with no license renewal modification. In other cases, OPPD has identified necessary modifications to existing programs, or development and implementation of new programs.

Appendix A of the FCS Unit 1 License Renewal Application is a supplement to the Updated Safety Analysis Report. In accordance with NRC requirements [10 CFR 54.21(d)], the supplement contains a description of the programs and activities for managing the effects of FCS aging. In addition to describing existing programs, the supplement describes proposed modifications (enhancements) to existing programs and proposed programs and activities.

3.4 EMPLOYMENT

3.4.1 CURRENT WORK FORCE

OPPD employs at FCS a permanent work force of approximately 632 employees and approximately 140 contractors, a number that is within the range of 600 to 800 personnel per reactor unit that the NRC estimates in the GEIS (Reference 3.1-13, Section 2.3.8.1). Approximately 23 percent of the employees live in Washington County, 56 percent live in Douglas County, and 7 percent live in Sarpy County. All three counties are located within the Omaha Metropolitan Statistical Area (MSA), which also includes Pottawattamie and Harrison counties in Iowa. The remaining employees live in various other locations.

OPPD refuels FCS at 18-month intervals. During refueling outages, site employment increases by as many as 600 workers for temporary (30 to 40 days) duty. These numbers are within the GEIS range of 200 and 900 additional workers per reactor outage.

3.4.2 LICENSE RENEWAL INCREMENT

Performing the license renewal surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping (SMITTR) activities discussed in Section 3.3 would necessitate increasing FCS staff workload by some increment, the size of which would be a function of the schedule within which OPPD must accomplish the work and the amount of work involved.

In the GEIS the assumption is that the NRC would renew a nuclear power plant license for a 20-year period plus the remaining duration of the current license, and that the NRC would issue the renewal approximately 10 years prior to license expiration. Therefore, the renewed license would be effective for 30 years. The GEIS stipulates that the utility would initiate SMITTR activities at the time of issuance and would conduct license renewal SMITTR activities throughout the remaining 30-year life of the plant, sometimes during full power operation (Reference 3.1-13, Section B.3.1.3), but mostly during normal refueling, and during 5-year and 10-year in-service inspections during refueling outages (Reference 3.1-13, Table B.4).

OPPD has determined that the GEIS scheduling assumptions are reasonably representative of FCS incremental license renewal workload scheduling. Many SMITTR activities that Section 3.3 refers to would have to be performed during outages. Although some FCS 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 estimate is that no more than 60 additional personnel per reactor would be needed to perform license renewal SMITTR activities during the 3-month duration of a 10-year in-service refueling. Having established this upper value for what would be a single event in 20 years, the NRC uses this number in the GEIS as the expected number of additional permanent workers needed per unit attributable to license renewal. GEIS Section C.3.1.2 was written using this approach in order to "...provide a realistic upper bound to potential population-driven impacts…."

OPPD expects that existing "surge" capabilities for routine activities such as outages will enable OPPD to perform the increased SMITTR workload without adding FCS staff. For the purpose of performing its own analyses in this environmental report, OPPD is adopting the GEIS approach. OPPD license renewal plant modifications would be SMITTR activities that would be performed mostly during outages. Therefore, as a reasonably conservative high estimate, OPPD is assuming that FCS would require no more than 60 additional permanent workers to perform license renewal SMITTR activities.

Adding full-time employees to the plant work force for operating during the license renewal period would have the indirect effect of creating additional jobs and related population growth in the community. Using RIMS II (Regional Input-Output Modeling System), the U.S. Bureau of Economic Analysis calculated a regional employment multiplier appropriate for the electric services (utilities) sector for the Omaha MSA. OPPD used this value (4.0387) to estimate the number of direct and indirect jobs supported by additional FCS employees that might be needed during the license renewal period (Reference 3.4-1). Applying the multiplier, a total of 242 (60 × 4.0387) new jobs would be created in the area with a U.S. Census Bureau year 2000 labor force of 400,049 workers. These 242 new direct and indirect jobs represent less than 1 percent of current total employment in the Omaha MSA (Reference 3.4-2). In summary, OPPD is assuming that 60 additional permanent direct workers during the license renewal period would create an additional 182 indirect jobs in the community.

These 242 new jobs (60 direct and 182 indirect) could result in a population increase of 603 in the area [242 jobs multiplied by 2.49 average number of persons per household in the state of Nebraska (Reference 3.4-3)]. This increase represents approximately 0.1 percent of the Census Bureau's estimated population in year 2000 (604,960) for the combined area of Washington, Douglas, and Sarpy counties.

3.5 REFERENCES

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4.0 ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION AND MITIGATING ACTIONS

NRC

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 51.53(c)(2)

4.1 INTRODUCTION

Chapter 4 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of the Fort Calhoun Station Unit 1 (FCS) operating license. The U.S. Nuclear Regulatory Commission (NRC) has identified and analyzed 92 environmental issues that it considers to be associated with nuclear power plant license renewal and has designated the issues as Category 1, Category 2, or Not Applicable (NA). The NRC designated issues Category 1 if, after 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; and
- A single significance level (i.e., small, moderate, or large) has been assigned to the impacts (except for collective offsite radiological impacts from the fuel cycle and from high-level-radioactive 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 not to be sufficiently beneficial to warrant implementation.

If the NRC analysis concluded that one or more of the Category 1 criteria could not be met, the NRC designated the issue as Category 2. The NRC requires plant-specific analyses for Category 2 issues. The NRC designated two issues NA, signifying that the categorization and impact definitions do not apply to these issues. NRC rules do not require analyses of Category 1 issues that the NRC has resolved using the generic findings (10 CFR 51, Subpart A, Appendix B, Table B-1) derived from its *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Reference 4.1-1). An applicant may reference the generic findings or GEIS analyses for Category 1 issues.

Appendix 1 of this report lists the 92 issues, their respective category, and the environmental report (ER) and GEIS sections that address each issue. For those issues not applicable to FCS, a notation gives the basis for that designation. The issues are numbered in the same order in which they are listed in Table B-1 of Appendix B to Subpart A of 10 CFR 51, for ease of reference.

4.1.1 CATEGORY 1 LICENSE RENEWAL ISSUES

NRC

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

"…absent new and significant information, the analysis for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal…." (61 Federal Register, page 28483).

Omaha Public Power District (OPPD) has determined that of the 69 Category 1 issues, 12 do not apply to FCS because they apply to design, operational, or location features that do not exist at the facility. These features are intake and discharge from a lake or canal, cooling towers, and groundwater withdrawal. In addition, because OPPD does not plan to conduct any refurbishment activities, the NRC findings for the seven Category 1 issues that apply only to refurbishment do not apply. OPPD has reviewed the NRC findings and has not identified or become aware of any new and significant information that would make the NRC findings inapplicable to FCS. Therefore, OPPD adopts by reference the NRC findings for the 50 Category 1 issues that OPPD determined to be applicable to FCS.

4.1.2 CATEGORY 2 LICENSE RENEWAL ISSUES

NRC

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

"The report must contain a consideration of alternatives for reducing adverse impacts, as required by § 51.45(c), for all Category 2 license renewal issues…." 10 CFR 51.53(c)(3)(iii)

The NRC designated 21 issues as Category 2. As in the case of Category 1 issues, some Category 2 issues (five) do not apply to design, operational, or location features of FCS. These issues and the basis for exclusion are listed as follows:

Issue	Basis for Exclusion
13. Water use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	Not applicable because FCS is not equipped with cooling ponds or cooling towers.
33. Groundwater use conflicts (potable, service, and dewatering; plants that use>100 gallons per minute)	Not applicable because FCS uses <100 gallons per minute of groundwater (no dewatering; potable and service water are from municipal supply; groundwater use is limited to occasional withdrawals for maintaining water level in Sanitary Lagoons and flushing of center pivot irrigation system).
34. Groundwater use conflicts (plants using cooling towers withdrawing makeup water from a small river)	Not applicable because FCS is not equipped with cooling towers.
35. Groundwater use conflicts (Ranney wells)	Not applicable because FCS does not use Ranney wells.
39. Groundwater quality degradation (cooling ponds at inland sites)	Not applicable because FCS is not equipped with cooling ponds.

Sections 4.2 through 4.16 address the Category 2 issues applicable to FCS and the issues that apply to refurbishment activities. Each section begins with a statement of the issue and explains why the NRC was not able to generically resolve the issue. If an issue does not warrant detailed analysis, the section explains the basis.

The sections present details resulting from OPPD's analyses for the fifteen Category 2 issues determined to be applicable to FCS. These analyses include conclusions regarding the significance of the impacts relative to renewal of the FCS operating license and discuss potential mitigative alternatives, when applicable, and to the extent required. OPPD has identified the significance of the impacts associated with each issue as either small, moderate, or large, consistent with the following criteria the NRC established in 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3:

> 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 NRC has concluded that those impacts that do not exceed permissible levels in the NRC'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 (NEPA) practice, OPPD considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are small receive less mitigative consideration than impacts that are large).

4.1.3 NA LICENSE RENEWAL ISSUES

The NRC determined that its categorization and impact finding definitions did not apply to two issues. Regarding the first issue, the NRC noted that applicants currently do not need to submit information on chronic effects from electromagnetic fields (10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 5). For the other NA issue, environmental justice, the NRC does not require information from applicants but noted that environmental justice will be addressed in individual license renewal reviews (10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 6). To support NRC's evaluation, OPPD has included an environmental justice analysis in Section 4.17, along with supporting demographic information in Section 2.4.2.

4.2 ENTRAINMENT OF FISH AND SHELLFISH IN EARLY LIFE STAGES

NRC

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

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

The NRC made impacts on fish and shellfish resources resulting from entrainment a Category 2 issue because it could not assign a single significance level (small, moderate, or large) to the issue. In support of its categorization of this issue, the NRC specifically noted that impacts of entrainment are small at many plants, but they may be moderate or large impacts at some plants. The NRC further indicated that environmental restoration efforts at a site could increase the number of fish susceptible to intake effects during the license renewal period (Reference 4.1-1, Section 4.2.2.1.2). Information to be ascertained include: (1) type of cooling system (whether once-through or cooling pond); and (2) current Clean Water Act Section 316(b) determination or equivalent state documentation.

As Section 3.1.3 indicates, FCS has a once-through heat dissipation system. The Nebraska Department of Environmental Control (NDEC), the predecessor agency of the Nebraska Department of Environmental Quality (NDEQ), included requirements for a Clean Water Act Section 316(b) demonstration report for FCS as a condition of the initial National Pollutant Discharge Elimination System (NPDES) permit for the station issued December 27, 1974 (Reference 4.2-1 Part III; Reference 4.2-2). These requirements mandated that OPPD submit an intake monitoring program plan to NDEC for approval and implementation within 45 days and 90 days of permit receipt, respectively. The requirements also mandated that OPPD prepare a final monitoring report, developed on the basis of U.S. Environmental Protection Agency (EPA) guidance regarding best technology available for minimizing adverse environmental impacts of cooling water intake structures, and submit the report to the NDEC within 18 months of permit receipt for their evaluation with regard to Section 316(b).

OPPD submitted its intake monitoring plan to the NDEC on February 24, 1975 (Reference 4.2-3). The plan consisted of continuing OPPD's ongoing intake monitoring program being conducted in accordance with the FCS operating permit, and included monitoring of fish impingement on FCS traveling screens, fish larvae in the ambient Missouri River, and fish larvae entrained through the plant cooling water systems. The NDEC approved OPPD's intake monitoring plan on March 25, 1975, concluding that the plan fulfilled the general requirements of the Section 316(b) guidelines (Reference 4.2-4).

OPPD submitted the FCS Intake Monitoring Report (Reference 4.2-5) to the NDEC, in accordance with the NPDES permit conditions, on July 1, 1976 (see Appendix 2.0). The report included the results of OPPD's monitoring of fish larvae in 1974 and 1975, and an assessment of entrainment impacts. The study concluded that, based on the small percentage of fish larvae entrained, the fish taxa collected, and the high natural mortality of fish during early life stages, entrainment at FCS would have minimal adverse effects on the fish populations in this stretch of the Missouri River. The NDEC reviewed and approved this report on January 19, 1977 (see Appendix 2.0, pages 2-51 through -53), concluding that losses due to entrainment at FCS were within the acceptable range.

In its approval of the FCS Intake Monitoring Report, the NDEC indicated its interest in any additional information OPPD developed concerning larval fish entrainment and other topics related to assessing associated impacts. OPPD continued to conduct fish larvae entrainment studies at FCS through 1977, and summarized results of the entire program, which spanned the period 1973 through 1977, in a comprehensive report (Reference 4.2-6, Section IV). These results were also reported in the context of a more general assessment of entrainment effects that included monitoring results for both FCS and the Cooper Nuclear Station (Reference 4.2-7, Chapter 8).

Renewals and modifications of the NPDES permit for FCS issued since the initial NPDES permit for the station, including the current permit (see Appendix 2.0), have not included entrainment monitoring or assessment requirements, and neither the NDEQ nor its predecessor agency has raised concerns regarding FCS entrainment impacts. OPPD considers approval of the Intake Monitoring Report and the current NPDES Permit No. NE0000418 as evidence of a determination by the State of Nebraska that FCS is currently in compliance with applicable provisions of the Clean Water Act Section 316(b). Given this determination, OPPD concludes that entrainment impacts from continued operation of FCS in the license renewal period are SMALL, and that further mitigation would be unwarranted.

4.3 IMPINGEMENT OF FISH AND SHELLFISH

NRC

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

"The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems...." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 26

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

As indicated in Section 4.2, FCS has a once-through heat dissipation system, and the NDEC included requirements for a Clean Water Act Section 316(b) demonstration report for FCS as a condition of issuing the initial NPDES permit for the station December 27, 1974. OPPD conducted fish impingement monitoring at FCS in accordance with an NDEC-approved plan that called for continuance of monitoring that was being conducted in accordance with the FCS operating permit. The final monitoring report (Reference 4.2-5), developed on the basis of EPA Section 316(b) guidance, was submitted to the NDEC on July 1, 1976 (see Section 4.2 and Appendix 2.0). The report included the results of OPPD's fish impingement monitoring from May 1973 through December 1975, and an assessment of impingement impacts. The study concluded that, because impingement involved few adult fish and because most small fish impinged would have been lost due to natural mortality, the overall effect of impingement on fish populations in the vicinity of FCS appeared to be minimal. The NDEC reviewed and approved this report on January 19, 1977 (see Appendix 2.0, pages 2-51 through -53), concluding that losses due to impingement at FCS were within the acceptable range.

In its approval of the FCS Intake Monitoring Report, the NDEC indicated its interest in any additional information OPPD developed concerning compensatory mechanisms and fish recruitment potential in the Missouri River. OPPD continued to conduct monitoring of fish impingement at FCS and monitoring of juvenile and adult fish at nearby sampling locations in the Missouri River through 1977. Results of these programs, which spanned the period 1973 through 1977, were summarized in a comprehensive report (Reference 4.2-6, Section IV). These results were also reported in the context of a more general assessment of power station impacts on Missouri River fish populations that included impingement monitoring results for both FCS and the Cooper Nuclear Station (Reference 4.2-7, Chapter 9).

Renewals and modifications of the NPDES permit for FCS issued since the initial NPDES permit for the station, including the current permit (see Appendix 2.0), have not included impingement monitoring or assessment requirements, and neither the NDEQ nor its predecessor agency has raised concerns regarding FCS impingement impacts. OPPD considers approval of the Intake Monitoring Report and the current NPDES Permit No. NE0000418 as evidence of a determination by the State of Nebraska that FCS is currently in compliance with applicable provisions of the Clean Water Act Section 316(b). Given this determination, OPPD concludes that impingement impacts from continued operation of FCS in the license renewal period are SMALL, and that further mitigation would be unwarranted.

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 (b) determinations and, if necessary, a 316(a) variance in accordance with 40 CFR Part 125, or equivalent State permits and supporting documentation. If the applicant can not provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock …." 10 CFR 51.53(c)(3)(ii)(B)

"Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants...." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 27

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

As indicated in Section 3.1.3, FCS has a once-through heat dissipation system. OPPD has consistently operated FCS in compliance with thermal discharge limits the NDEQ, or its predecessor agency, the NDEC, established for the plant, and no formal Clean Water Act Section 316(a) variance has been needed or sought for the facility. Thermal discharge limits (maximum allowable effluent temperatures), which have been included in the NPDES permit for the plant since the NDEC initially issued it on December 27, 1974, (Reference 4.2-1; Reference 4.2-2), have been established based on comprehensive studies of thermal discharge effects to ensure continued compliance with water quality standards and an acceptable level of impact to aquatic biota.

These studies were conducted in response to numerous stakeholder interests including NEPA requirements associated with initial licensing of the plant, monitoring requirements established in the operating license technical specifications, and NDEC requirements set forth in a State of Nebraska Certificate of Compliance for FCS issued October 13, 1972, prior to initial operation (Reference 4.4-1). The Certificate of Compliance indicated that there was reasonable assurance that FCS operation would be in compliance with applicable water quality standards. However, the certificate also required that OPPD undertake a study to determine the effects of the thermal discharge upon the physical, chemical, and biological aspects of the Missouri River; monitor cooling water discharge and intake and discharge temperatures; and conduct thermal plume mapping during operation.

These thermal effects investigations were conducted in the context of long-term, comprehensive ecological studies being undertaken to better determine the effects on the Missouri River and associated biota of FCS and the Cooper Nuclear Station. The Missouri River Study Group, comprised of OPPD, the Nebraska Public Power District (NPPD), consultants, academic institutions, and regulators, including the NDEC, performed the studies as a coordinated effort. The FCS Five Year Report (Reference 4.2-6) summarizes results of the studies conducted in the vicinity of FCS, which include operational phase monitoring from initial plant startup in 1973 through 1977. Results of broader studies that examined power station effects and monitoring results for both FCS and the Cooper Nuclear Station are reported by the Missouri River Study Group in a separate report (Reference 4.2-7, Chapter 3).

FCS was initially authorized to operate at a maximum power level of 1,420 megawatts (thermal) [MW(t)], and a maximum daily temperature limit of 105 deg F was established for the FCS cooling water discharge in the initial NPDES permit on the basis of initial operational monitoring results (Reference 4.2-1; Reference 4.2-2). On August 18, 1980, the NRC amended the FCS operating license to increase the maximum authorized power level to 1,500 MW(t) (Reference 4.4-2). This increase was supported by an OPPD environmental assessment report (Reference 4.4-3) that used results of thermal plume modeling and monitoring studies and other relevant information presented in the FCS Five Year Report (Reference 4.2-6).

This OPPD environmental assessment report indicated that the thermal plume dimensions resulting from the anticipated increase in discharge temperature of 5 deg F would be bounded by projections the U.S. Atomic Energy Commission (AEC) originally reported in the Final Environmental Statement for the plant (Reference 4.4-4, Part V), and that impacts to aquatic biota would be small. On the basis of its review, the NDEC agreed that the increase in maximum daily discharge temperature to 110 deg F would not adversely affect the Missouri River and would comply with Nebraska Water Quality Standards (Reference 4.4-5). On August 28, 1980, the NDEC issued a corresponding modification to the NPDES permit for the plant.

Appendix 2.0 of this report includes copies of the current NPDES permit for FCS and the associated Fact Sheet the NDEQ issued. As indicated by the permit, the maximum daily discharge limits for cooling water discharges from the plant (Outfalls 001 and 005) remain at 110 deg F. As shown in the Fact Sheet, the NDEQ established these discharge limits according to the Clean Water Act Section 316(a).

OPPD is seeking to permanently increase FCS's NPDES daily maximum temperature limit to 112 deg F to better ensure that the plant can operate at full power under the unusually high ambient river temperatures such as have been experienced in recent summers. In the interim period until the NDEQ acts on the permit modification request, OPPD has entered into a Consent Order with the NDEQ that allows a daily maximum temperature limitation of 112 deg F (see Appendix 2.0). This Consent Order, which the current NPDES permits acknowledges, requires that OPPD submit water quality information that evaluates the impacts of this temperature increase and enables the NDEQ to verify that instream water quality criteria are being met.

OPPD is participating in a cooperative effort with the EPA and the NDEQ to obtain information required under terms of the Consent Order. This study, which includes thermal modeling, will focus on power plants and other industries discharging to the lower Missouri River, and will address potential effects of historically high ambient river temperatures. It is also expected that this study will assist OPPD and the NDEQ in assessing the implications of reduced river flows in summer such as those being considered by the U.S. Army Corps of Engineers in the context of revisions to the Missouri River Master Manual and the associated U.S. Fish and Wildlife Service (FWS) Biological Opinion (see Section 2.2.3). The study was begun in the fall of 2001, and OPPD expects that the final report regarding FCS thermal discharges will be completed in 2002 or early 2003.

Subsequent to the release of the report, the NDEQ is expected to make a final determination to issue or deny the requested permit modification. In any event, OPPD would continue to comply with NDEQ thermal discharge standards through the duration of the current operating license and the license renewal term.

On the basis of these considerations, OPPD concludes that heat shock impacts from continued operation of FCS in the license renewal period would continue to be SMALL and, because the standard-setting process provides for minimizing environmental impact, further mitigation to support operations through the license renewal period would not be warranted.

4.5 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, Appendix B, Table B-1, Issue 40

"…If no important resources would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant…." (Ref. 4.1-1, Section 3.6, page 3-6)

The NRC made impacts of refurbishment on terrestrial resources a Category 2 issue because the significance of ecological impacts cannot be determined without considering site-specific and project-specific details (Reference 4.1-1, Section 3.6). Aspects of the site and the 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 habitat.

Detailed analyses are not required for this issue, because, as Section 3.2 discusses, OPPD has no plans for major refurbishment or other license renewal-related construction activities at FCS.

4.6 THREATENED OR ENDANGERED SPECIES

NRC

"All license renewal applicants shall assess the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened and endangered species in accordance with the Endangered Species Act." 10 CFR 51.53(c)(3)(ii)(E)

"Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected."
10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 49

The NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed, and a 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 (Reference 4.1-1, Sections 3.9 and 4.1).

Section 2.3 describes aquatic and terrestrial habitats on and in the vicinity of the FCS site and along transmission line rights-of-way of concern. Section 2.3.3 provides a discussion of those species listed as threatened or endangered at the federal level or the state level (in Nebraska or Iowa) that have the greatest likelihood of occurrence in the general vicinity of FCS. This section presents an assessment of the environmental consequences to these species from future plant refurbishment activities and continued operation of the plant.

As discussed in Section 3.2, OPPD has no plans to conduct major refurbishment or construction activities at FCS for continued operations during the license renewal period. Therefore, there would be no refurbishment-related impacts to protected species, and no further analysis of refurbishment-related impacts is required.

Section 2.3.3 presents information that indicates the potential for occurrence of any threatened or endangered aquatic species in the immediate vicinity of the site is very limited based on habitat and range considerations. Potential for impact from station operation on these species is reduced accordingly. In particular, the Missouri River in the site vicinity is distant from the confluence of major tributaries, islands, or sandbars that would provide potentially attractive habitat for the pallid sturgeon and lake sturgeon. Lack of a gravel river bed and limited backwater habitat contribute to a low likelihood of occurrence of the sturgeon chub. Habitat for mussels is also limited in the Missouri River at the site area, particularly along the cutting bank of the Missouri River such as occurs downstream from the thermal discharge from the plant. The only aquatic species currently listed as threatened or endangered that was collected during FCS monitoring studies was the burbot, which is at the southern edge of its range in the site vicinity.

Similarly, Section 2.3.3 presents information that indicates, except for the Bald Eagle and Northern Harrier, habitat conditions or range contribute to a low likelihood of occurrence and impact potential for terrestrial animal species on the FCS site or along the right-of-way for transmission Line 74S/74, which extends from FCS to west of Blair, Nebraska. Migrating or wintering Bald Eagles are likely to occur on or near the site, particularly in floodplain forest adjacent to the Missouri River and onsite sloughs; however, this species is unlikely to nest on or near the site or along the transmission line given the proximity to human activity and relatively more hospitable conditions on the nearby DeSoto National Wildlife Refuge. Given the lack of nesting habitat along the Missouri River on the site, potential for impact on the Least Tern or Piping Plover is remote. Among the other bird species of concern, potentially suitable habitat may be present for the Red-shouldered Hawk and Northern Harrier; however, the Red-shouldered Hawk is at the edge of its range at the site.

Section 2.3.3 notes habitat conditions on the FCS site and on the right-of-way for transmission Line 74/74S are not conducive to the presence of either the western prairie fringed orchid or American ginseng, the threatened plant species noted as having occurrence potential in the general plant vicinity. There are no known occurrences of these species on the site and transmission line rights-of-way of concern.

In addition to lack of suitable habitat in areas of concern, potential for adverse impact on threatened and endangered species from continued plant operation is highly unlikely on the basis of plant operational history. In particular, there has been no demonstrated impact on the population of any threatened or endangered species during the 30-year operation of FCS.

OPPD has initiated contacts with the FWS, the Nebraska Game and Parks Commission, and the Iowa Department of Natural Resources regarding FCS license renewal. Appendix 3.0 includes copies of the contact letters and agency responses. Based on the considerations presented above and the results of correspondence with these agencies, OPPD concludes that impact to threatened and endangered species from continued operation of FCS in the license renewal period would be SMALL, and further mitigation would be unwarranted.

4.7 AIR QUALITY DURING REFURBISHMENT (NONATTAINMENT AREAS)

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

The NRC made impacts to air quality during refurbishment a Category 2 issue because vehicle exhaust emissions could be cause for some concern, and a general conclusion about the significance of the potential impact could not be drawn without considering the compliance status of each site and the number of workers expected to be employed during the outage (Reference 4.1-1, Section 3.3). Information needed would include (1) the attainment status of the plant-site area and (2) number of vehicles added as a result of refurbishment activities.

FCS is not in or near a nonattainment or maintenance area. Detailed analysis is not required for this issue because, as Section 3.2 discusses, OPPD has no plans for major refurbishment at FCS.

4.8 IMPACT ON PUBLIC HEALTH OF MICROBIOLOGICAL ORGANISMS

> **NRC**
>
> **"If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow rate of less than $3.15 \times 10^{12} ft^3$/year ($9 \times 10^{10} m^3$/year), an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided." 10 CFR 51.53(c)(3)(ii)(G)**
>
> **"These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 57**

The NRC designated impacts to public health from thermophilic organisms a Category 2 issue, requiring plant-specific analysis, because the magnitude of the potential public health impacts associated with thermal enhancement of such organisms, particularly *Naegleria fowleri,* could not be determined generically. The NRC noted in the GEIS that impacts of nuclear power plant cooling towers and thermal discharges are considered to be of small significance if they do not enhance the presence of microorganisms that are detrimental to water quality and public health (Reference 4.1-1, Section 4.3.6). Information to be ascertained includes: (1) thermal conditions for the enhancement of *Naegleria fowleri*; (2) thermal characteristics of the Missouri River; (3) thermal discharge temperature; and (4) impacts to public health.

The NRC requires [10 CFR 51.53(c)(ii)(G)] an assessment of the potential impact of thermophilic organisms in receiving waters on public health if a nuclear power plant uses cooling ponds, cooling lakes, or cooling canals or discharges to a river with an average annual flow rate of less than 3.15 x 10^{12} cubic feet per year. Because the average Missouri River discharge in the vicinity of FCS is approximately 1.2 x 10^{12} cubic feet per year (Section 2.3.1), the NRC considers it a small river, making this issue applicable to FCS.

The Missouri River in the vicinity of the plant is confined to a sinuous artificial channel. Water flow is regulated to meet the needs of barge traffic, flood control, irrigation, and pollution control. Based on river traffic, currents, and shoreline characteristics, swimming in the vicinity of FCS is unlikely. However, recreational use (boating, fishing) may occur and sampling in the river by OPPD employees may be performed, creating the potential for human exposure.

Thermophilic bacteria generally occur at temperatures of 77 deg F to 178 deg F, with maximum growth at 122 deg F to 140 deg F. Bacteria pathogenic to humans typically have optimum temperatures of approximately 99 deg F (Reference 4.8-1). Populations of the pathogenic amoeba *Naegleria fowleri* can be enhanced in thermally altered water bodies at temperatures ranging from 95 deg F to 106 deg F or higher, but this organism is rarely found in water cooler than 95 deg F based on studies reviewed and coordinated by Tyndall et al. (Reference 4.8-2).

The ambient temperatures of the Missouri River near OPPD vary from freezing (approximately 32 deg F) in the winter to 85 deg F in the summer (Reference 4.4-3, Section 4.1). Therefore, ambient river conditions would not support the thermophilic organisms of concern.

Based on FCS discharge monitoring data submitted to the NDEQ for the period December 1997 to March 2001, the mean monthly average temperature of the discharge at the outfall was 76.8 deg F, and the maximum daily temperature was 107 deg F. Monthly average discharge temperatures at or above 95 deg F occurred only during July and August in this period, except for September 1998. The highest monthly average discharge temperatures for 2000, 101 deg F (July) and 103 deg F (August), were typical of that observed in 1998 and 1999. Organisms inhabiting sediments or other substrates on the river bottom or immersed banks that are exposed to the highest temperatures would only be likely in a small zone near the plant (<500 feet downstream from the outfall) due to the rapid mixing characteristics of the discharge in the Missouri River (Reference 4.4-3, Section 4.1).

Thermophilic organisms occurring in the water column, if any, that might be of concern are expected to be limited to those entrained in the condenser cooling water. These organisms would be subjected to a rapid temperature rise through the condenser followed by relatively rapid cooling as the discharge plume mixes with the ambient river water. Residence time in those areas of the plume with temperatures greater than 95 deg F would be short because of mixing in the plume and river flow (average velocity is approximately 5 feet per second) which rapidly moves the discharged water and entrained organisms downstream to areas of reduced temperature. The ensuing decline in temperature would create an adverse environment for thermophilic microbes. Based on the average temperature of the discharge and receiving water, species such as *Naegleria fowleri* and *Legionella* sp. would not be expected to proliferate in the vicinity of FCS.

Given these poor conditions for supporting populations of thermophilic organisms, such organisms in the FCS discharge do not constitute a significant public health issue. In addition, no pathway for significant human exposure exists because there is no mechanism for inhalation exposure from aerosol production (such as spray nozzles), and it is unlikely that swimming and fishing will occur in the immediate vicinity of the discharge stream, precluding both direct contact and ingestion routes.

OPPD has initiated contacts with the Nebraska Department of Public Health and Human Services and the Iowa Department of Public Safety regarding FCS license renewal. Appendix 6.0 includes copies of the contact letters. Based on the evaluation presented above, OPPD concludes that impacts on public health from thermophilic microbiological organisms are not likely to occur as a result of license renewal, and there would be no impacts to mitigate. Because the definition of “small” includes impacts that are not detectable, the appropriate characterization of the impact on public health of microbiological organisms from continued operation of FCS in the license renewal period is SMALL, and further mitigation is unwarranted.

4.9 ELECTRIC SHOCK FROM TRANSMISSION LINE-INDUCED CURRENTS

NRC

“If the applicant’s transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electrical Safety Code (NESC) for preventing electric shock from induced currents, an assessment of the impact of the proposed action on the potential shock hazard from the transmission lines must be provided.” 10 CFR 51.53 (c)(3)(ii)(H)

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

The NRC made the impact 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®) criteria, the NRC could not determine the significance of the electrical shock potential. The regulation at 10 CFR 51.53(c)(3)(ii)(H) does not define the phrase "transmission line," but the GEIS indicates that transmission lines use voltages of about 115/138 kilovolts and higher, and that, in contrast, distribution lines use voltages below the 115/138-kilovolt level (Reference 4.4-1, Sections 2.2.7 and 4.5.1). The GEIS also indicates that the transmission line of concern is between the plant Switchyard and the intertie to the transmission system. Information to be ascertained includes: (1) change in line use and voltage since last analysis; (2) conformance with current NESC® standards; and (3) the potential change in land use along the transmission lines since the initial NEPA review.

The NESC® (Reference 4.9-1) specifies minimum vertical clearances to the ground for electric lines. For electric lines operating at voltages exceeding 98 kilovolts alternating current (AC) to ground (Reference 4.9-2), the clearance provided must limit the steady-state current[1] to 5 milliamperes due to electrostatic effects if the largest anticipated vehicle were short-circuited to ground.

As described in Section 3.1.4, the 161-kilovolt line connecting FCS to the Blair Substation (Line 74S/74) is the only transmission line specifically constructed to connect FCS with the existing transmission system and reviewed as part of the construction permit. It is, therefore, within the scope of the license renewal environmental review. This line was entirely reconstructed, in February 1999, to the NESC® code requirements for minimum clearances that were in effect at the time.

Lower voltage lines, such as 161 kilovolts, do not generate ground-level electric fields that are high enough to cause induced-shock effects when the NESC® minimum ground clearances are utilized. A 161-kilovolt line (phase-to-phase) equates to 93 kilovolts to ground, which is below the threshold for the NESC® requirement related to potential induced-shock hazard. Therefore, an analysis of the potential shock hazard for this line is not required. OPPD concludes that the potential impact from continued operation of FCS in the license renewal period from electrical shock is SMALL, and mitigation is not warranted.

[1]The National Electrical Safety Code® and the GEIS use the phrase "steady-state current", whereas 10 CFR 51.53 (c)(3)(ii)(H) uses the phrase "induced current." The phrases have the same meaning here.

4.10 HOUSING IMPACTS

NRC

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

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

"…small impacts result when no discernible change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and no housing construction or conversion occurs." (Ref. 4.1-1, Section 4.7.1.1)

The NRC made housing impacts a Category 2 issue because impact magnitude depends on local conditions the NRC could not predict for all plants at the time of the GEIS publication (Reference 4.1-1, Section 3.7.2). 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 impact housing due to increased staffing. As Section 3.2 describes, OPPD does not plan to perform major refurbishment activities. OPPD concludes that there would be no refurbishment-related impacts to area housing and, therefore, no analysis is required. Accordingly, the following discussion focuses on impacts of continued operations on local housing availability.

As Section 2.4 describes, FCS is in a high population area. Washington, Douglas, and Sarpy counties, as Section 2.8 notes, are not subject to growth control measures that limit housing development. In 10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 63), the NRC concludes that impacts to housing are expected to be of small significance at plants in high population areas where growth control measures are not in effect. Therefore, OPPD expects housing impacts to be small.

A site-specific housing analysis supports this conclusion. The maximum impact to area housing is calculated using the following assumptions: (1) all direct and indirect jobs would be filled by immigrating residents; (2) the residential distribution of new residents would be similar to current worker distribution; and (3) each new job created (direct and indirect) represents one housing unit. As Section 3.4 describes, approximately 86 percent of the FCS employees reside in Washington, Douglas, and Sarpy counties. Therefore, the focus of the housing impact analysis is on these three counties. As Section 3.4 describes, OPPD's conservative estimate of 60 license renewal employees could generate the demand for 242 housing units (60 direct and 182 indirect jobs). If it is assumed that 86 percent of the 242 new workers would locate in the Washington, Douglas, and Sarpy combined-county area, consistent with current employee trends, an additional 208 new housing units would be needed. In an area with a population of more than 600,000 and vacancy rates in excess of 6 percent (Reference 4.10-1), this would not create a discernible change in housing availability, change rental rates and housing values, or spur housing construction or conversion. Given the magnitude of the impact on housing from continued operation of FCS in the license renewal period, which is SMALL, mitigative measures would not be necessary.

4.11 PUBLIC UTILITIES: PUBLIC WATER SUPPLY AVAILABILITY

NRC
The environmental report must contain "…an assessment of the impact of population increases attributable to the proposed project on the public water supply." 10 CFR 51.53(c)(3)(ii)(I)
"An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 65
"Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (Ref. 4.1-1, Section 3.7.4.5)

The NRC made public utility impacts a Category 2 issue because water shortages may occur in conjunction with plant demand and plant-related population growth (Reference 4.1-1, Section 4.7.3.5). Local information needed would be a description of water shortages experienced in the area and an assessment of the public water supply system's available capacity.

The NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. As Section 3.2 discusses, OPPD plans no major refurbishment, so major refurbishment activities would not affect plant demand.

The impact to the local water supply systems from plant-related population growth can be determined by calculating the amount of water that would be required by these individuals. As Section 3.4 describes, OPPD's conservative estimate of 60 license renewal employees could generate a total of 242 new jobs. This could increase population in the area by 603 [242 jobs multiplied by 2.49 average number of persons per household in the state of Nebraska (Reference 4.11-1)]. The average American uses between 50 and 80 gallons per day for personal use (Reference 4.11-2, page 2). Using this consumption rate, the plant-related population increase would require approximately

30,150 to 48,240 additional gallons per day. This amount represents less than 0.1 percent of the 66.63 million gallons per day that the Nebraska Department of Natural Resources estimated was consumed in 1995 in the combined region of Washington, Douglas, and Sarpy counties. Therefore, the impacts resulting from plant-related population growth to the public water supply from continued operation of FCS in the license renewal period would be SMALL, requiring no increase in allocations and not warranting mitigation.

4.12 EDUCATION IMPACTS FROM REFURBISHMENT

NRC

The environmental report must contain "An 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, Appendix B, Table B-1, Issue 66

"…small impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts are associated with 4 to 8 percent increases in enrollment, and if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service…. Large impacts are associated with enrollment increases greater than 8 percent…." (Ref. 4.1-1, Section 3.7.4.1)

The NRC made impacts to education a Category 2 issue because site-specific and project-specific factors determine the significance of impacts (Reference 4.1-1, Section 3.7.4.1). Local factors to be ascertained include (1) project-related enrollment increases and (2) status of the student/teacher ratio.

As Section 3.2 describes, OPPD does not plan to perform major refurbishment activities at FCS. OPPD concludes, there would be no refurbishment-related impacts to education; therefore, no analysis is required.

4.13 OFFSITE LAND USE

4.13.1 REFURBISHMENT

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)

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

"…if plant-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile, and at least one urban area with a population of 100,000 or more within 50 miles…." (Ref. 4.1-1, Section 3.7.5)

The NRC made impacts to offsite land use from 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 of at least 100,000 residents.

As Section 3.2 describes, OPPD does not plan to perform major refurbishment activities at FCS. OPPD concludes, there would be no refurbishment-related impacts to offsite land use; therefore, no analysis is required.

4.13.2 OFFSITE LAND USE: LICENSE RENEWAL TERM

NRC

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

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

"…if plant-related population growth is less than five percent of the study area's total population, off-site land-use changes would be small…" (Ref. 4.1-1, Section 3.7.5)

"If the plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development." (Ref. 4.1-1, Section 4.7.4.1)

The NRC made impacts to offsite land use during the license renewal term a Category 2 issue because land use changes may be perceived to be beneficial by some community members and adverse by others. Therefore, the NRC could not assess the potential significance of site-specific offsite land-use impacts (Reference 4.1-1, Section 4.7.4.1). Site-specific factors to consider in an assessment of new tax-driven land-use impacts include (1) the size of plant-related population growth compared to the area's total population, (2) the size of the plant's tax payments relative to the community's total revenue, (3) the nature of the community's existing land-use pattern, and (4) the extent to which the community already has public services in place to support and guide development.

The GEIS presents an analysis of population-driven and tax-driven impacts on offsite land use for the renewal term (Reference 4.1-1, Section 4.7.4.1). Based on the GEIS case study analysis, the NRC concludes that all new population-driven land-use changes during the license renewal term at all nuclear power 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 represented by operations-related growth (Reference 4.1-1, Section 4.7.4.2)].

As Section 2.6 describes, OPPD is exempt from paying state occupational, personal property, and real estate taxes. Instead, as mandated in the Nebraska Constitution, OPPD makes payments in lieu of taxes each year to the municipalities and 12 Nebraska counties in which OPPD sold power in 1957. The in-lieu payments are based upon the gross revenues OPPD receives from electricity sales from within the applicable counties, regardless of where the power is generated, and are not anticipated to change significantly during the license renewal period. The magnitude of the in-lieu payments relative to the receiving county's total revenues is not relevant in assessing new tax-driven land-use impacts. Therefore, OPPD concludes that there would be no tax-driven land-use impacts related to license renewal activities at FCS.

4.14 TRANSPORTATION

NRC

The environmental report must contain an assessment of "…the impact of the proposed project on local transportation during periods of license renewal refurbishment activities." 10 CFR 51.53(c)(3)(ii)(J)

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

Level of Service (LOS) "A and B are associated with small impacts because the operation of individual users is not substantially affected by the presence of other users." LOS A is characterized by "free flow at the traffic stream; users are unaffected by the presence of others." LOS B is characterized by "stable flow in which the freedom to maneuver is slightly diminished." (Ref. 4.1-1, Section 3.7.4.2)

The NRC made impacts to transportation a Category 2 issue because road conditions existing at the time of the project, which the NRC could not forecast for all plants (Reference 4.1-1, Section 3.7.4.2), primarily determines impact significance. Local road conditions to be ascertained are (1) level of service (LOS) conditions and (2) incremental increase in traffic associated with refurbishment activities and license renewal staff.

As Section 3.2 describes, OPPD does not plan to perform major refurbishment activities at FCS. OPPD concludes there would be no refurbishment-related impacts to local transportation; therefore, no analysis is required.

As Section 2.7.2 notes, access to FCS is via U.S. Highway 75. In the vicinity of the site, the highway carries an LOS designation of "B" from the City of Blair to Fort Calhoun. The NRC concluded in the GEIS that impacts to roads with LOS designations of "A" or "B" are small (Reference 4.1-1, Section 3.7.4.2).

The current FCS work force is approximately 772 employees (OPPD and contractors). Each refueling outage, which occurs every 18 months and lasts about 30 days, adds approximately 600 temporary workers. The OPPD conservative projection of 60 additional employees associated with operating through the license renewal term for FCS represents approximately an 8-percent increase in the current number of employees and an even smaller percentage of the employees present on site during periodic refueling. Given these employment projections and an LOS designation of "B" for the access road to FCS, impacts to transportation from continued operation of FCS in the license renewal period would be SMALL and mitigative measures would not be necessary, a conclusion that is consistent with the GEIS.

4.15 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 Office (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about the character; and (3) if the conditions associated with moderate impacts do not occur." (Ref. 4.1-1, Section 3.7.7)

The 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 determination of impacts must be made through consultation with the State Historic Preservation Officer (SHPO) (Reference 4.1-1, Section 4.7.7.3).

As Section 3.2 describes, OPPD does not plan to perform land-disturbing refurbishment activities at FCS. Therefore, OPPD concludes that there would be no refurbishment-related impacts to historic and archaeological resources; therefore, no analysis is required.

As described in Section 2.9, no known archaeological or historic sites of significance were threatened or impacted by construction of FCS in the 1970s. No known archaeological or historic sites of significance have been identified along the transmission line rights-of-way. Therefore, continued use of transmission lines and rights-of-way are projected to cause little or no impact.

OPPD has initiated discussions regarding FCS license renewal with the SHPO. Appendix 4.0 includes copies of the contact letter and the SHPO response**.** Based on the considerations above and response by the SHPO, OPPD concludes that continued operation of FCS would have no adverse impacts to historic resources; hence, there would be no impacts to mitigate. Because the definition of “small” includes impacts that are not detectable, the appropriate characterization of the impact on historic and archaeological resources from continued operation of FCS in the license renewal period is SMALL.

4.16 SEVERE ACCIDENT MITIGATION ALTERNATIVES

NRC

The environmental report must contain a consideration of alternatives to mitigate severe accidents “ . . . [i]f the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environmental assessment . . . .” 10 CFR 51.53(c)(3)(ii)(L)

“The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives.” 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 76

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

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

The NRC concluded in its generic license renewal rulemaking that the unmitigated environmental impacts from severe accidents met the Category 1 criteria, but the NRC made consideration of mitigation alternatives a Category 2 issue because ongoing regulatory programs related to mitigation (i.e., Individual Plant Examination and Accident

Management) have not been completed for all plants[2]. Since these programs have identified plant programmatic and procedural improvements (and, in a few cases, minor modifications) as cost-effective in reducing severe accident and risk consequences, the NRC thought it premature to draw a generic conclusion as to whether severe accident mitigation would be required for license renewal.

Site-specific information to be presented in the environmental report includes: (1) potential SAMAs; (2) benefits, costs, and net value of implementing potential SAMAs; and (3) sensitivity of the analysis to changes to key underlying assumptions. This section of the environmental report is a synopsis of key site-specific SAMA information. Additional details, as called out in the following sections, are provided in Appendix 5.0.

4.16.1 METHODOLOGY OVERVIEW

The methodology used to perform the FCS SAMA cost-benefit analysis is based primarily on the handbook used by the NRC to analyze the benefits and costs of its regulatory activities, NUREG/BR-0184 (Reference 4.16-5), subject to FCS-specific considerations.

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

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

- Establish the Base Case – Use NUREG/BR-0184 and the current FCS probabilistic risk assessment (PRA) model at the time of evaluation to evaluate the following severe accident impacts:

  - Offsite exposure costs – Monetary value of consequences (dose) to offsite population:

    Use the FCS PRA model to determine the total accident frequency, which is a function of core damage and containment release frequencies. Use the Melcor Accident Consequence Code System (MACCS) to convert release input to public dose, and the methodology described in NUREG/BR-0184 to convert dose to present-worth dollars based on valuation of $2,000 per person-rem and present-worth discount factor.

[2]OPPD has completed the requirements of Generic Letter 88-20 (Reference 4.16-1, Reference 4.16-2, Reference 4.16-3, Reference 4.16-4).

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

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

- Onsite exposure costs – Monetary value of dose to workers:

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

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

  Use NUREG/BR-0184 best estimate cleanup, decontamination, and replacement power costs; then apply the NUREG/BR-0184 methodology to convert onsite property damage estimate to present-worth dollars.

• SAMA Identification – Identify potential SAMAs from the following sources:

  Severe Accident Mitigation Design Alternative (SAMDA) analyses submitted in support of original licensing activities for other operating nuclear power plants and advanced light water reactor plants; SAMA analyses submitted in support of license renewal activities for other nuclear power plants; NRC and industry documentation discussing potential plant improvements; and insight provided by plant staff.

• Preliminary Screening – Eliminate obviously non-viable candidates.

• Final Disposition of Remaining SAMAs – Eliminate candidates based on cost-benefit analysis:

  - SAMA impacts – Calculate impacts (i.e., onsite/offsite dose and damages) by manipulating the plant model to simulate revised plant risk following implementation of each individual SAMA.

  - SAMA benefits – Calculate benefits for each SAMA in terms of averted consequences. Averted consequences are the arithmetic differences between the calculated impacts for the base case and the revised impacts following implementation of each individual SAMA.

  - Cost estimate – Estimate the cost of implementing each SAMA. The detail of the cost estimate must be commensurate with the benefit; if a benefit is low, it is not necessary to perform a detailed cost estimate to determine that the SAMA is not cost beneficial and engineering judgment can be applied.

- Sensitivity Analysis – Determine the effect that changing the discount rate would have on the cost-benefit calculation.
- Conclusions – Identify SAMAs that are cost beneficial, if any, and implementation plans or bases for not implementing.

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

4.16.2 ESTABLISHING THE BASE CASE

The purpose of establishing the base case is to provide the baseline for determining the risk reductions (benefits) that would be attributable to the implementation of potential SAMAs. The primary source of data relating to the base case is the FCS PRA model. Severe accident risk is calculated through use of the FCS PRA model, Level 2 partitioning spreadsheets, and the MACCS2 Level 3 model. OPPD used Revision 3 of the FCS PRA model for the SAMA evaluation that uses PRA techniques to:

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

The FCS PRA model includes internal events (e.g., loss of feedwater event, loss-of-coolant accident). The model has been upgraded since completion of the Individual Plant Examination and Individual Plant Examination for External Events (Reference 4.16-1; Reference 4.16-2), and it has been significantly modified to accommodate risk-important plant design and procedural changes implemented since 1993. The model also explicitly includes the dominant seismic scenarios. Impact of high winds, tornadoes, and transportation accidents were found to have minimal impact on risk and are not treated explicitly. However, the factors applied in the economic assessments bound any uncertainty associated with these events. The FCS PRA model is integrated into plant operations and updated periodically. As such, it is considered a “living” plant risk model. The FCS PRA model updates occur as a result of:

- Changes in Equipment Performance – As data collection progresses, estimated failure rates and system unavailability periodicities change.

- Plant Configuration Changes – A time lag exists between changes to the physical plant and incorporation of those changes into the FCS PRA model.

- Modeling Changes – The FCS PRA model is continually refined to incorporate the latest state of knowledge. For example, changes have been made to more realistically address large loss-of-coolant accident initiating event frequencies and improved reactor coolant pump (RCP) seal failure models.

The FCS PRA model describes the results of the first two levels of the FCS PRA for the plant. These levels are defined as follows: Level 1 determines core damage frequencies based on system analyses and human-factor evaluations; and Level 2 evaluates the impact of severe accident phenomena on radiological releases and quantifies the condition of the containment and the characteristics of the release of fission products to the environment. The scope of plant challenges considered in the FCS PRA model includes only internal events (e.g., turbine trips, loss of main feedwater, internal floods). The Level 1 core damage states are mapped into containment status end states. Appendix Section 5.1 provides information regarding the FCS PRA model and the modeling approaches used in the SAMA analyses.

Using the results of these analyses, the next step is to perform a Level 3 PRA analysis, which calculates the hypothetical impacts of severe accidents on the surrounding environment and members of the public. The MACCS2 computer code is used for determining the offsite impacts for the Level 3 analysis, whereas the magnitude of the onsite impacts (in terms of cleanup and decontamination costs and occupational dose) are based on information provided in NUREG/BR-0184. The principal phenomena analyzed are: atmospheric transport of radionuclides; mitigating actions (i.e., evacuation, condemnation of contaminated crops and milk) based on dose projection; dose accumulation by a number of pathways, including food and water ingestion; and economic costs. Input for the Level 3 analysis includes the reactor core radionuclide inventory, FCS plant source terms (as applied to the FCS PRA model), site meteorological data, projected population distribution (within a 50-mile radius) for the year 2030, emergency response evacuation modeling, and economic data. Appendix Section 5.2 describes the MACCS input data, assumptions, and results.

4.16.2.1 OFFSITE EXPOSURE COSTS

The Level 3 base case analysis shows an annual offsite exposure risk of 10.15 person-rem. This calculated value is converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem. This monetary equivalent is then discounted to present value using the NRC standard formula (Reference 4.16-5):

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

where:

W_{pha} = monetary value of public health risk after discounting ($)

C = $[1 - \exp(-rt_f)]/r$

where:

t_f = years remaining until end of facility life = 20 years

r = real discount rate (as fraction) = 0.07

Z_{pha} = monetary value of public health (accident) risk per year before discounting ($/year)

Using a 20-year period for remaining plant life and a 7 percent discount rate results in a value of approximately 10.76 for C. Therefore, calculating the discounted monetary equivalent of public health risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value, approximately 10.76. The resulting monetary equivalent is $218,000.

4.16.2.2 OFFSITE ECONOMIC COSTS

The Level 3 analysis shows that the offsite property loss factor multiplied by accident frequency yields an annual offsite economic risk of $15,427. Calculated values for offsite economic costs caused by severe accidents are also discounted to present value. Discounting is performed in the same manner as for the Offsite Exposure Costs discussed above. The resulting monetary equivalent is $166,000.

4.16.2.3 ONSITE EXPOSURE COSTS

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

IMMEDIATE DOSE

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

Equation (1):

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

where:

W_{IO}	=	monetary value of accident risk avoided due to immediate occupational dose, after discounting ($)
R	=	monetary equivalent of unit dose ($/person-rem)
F	=	accident frequency (events/year)
D_{IO}	=	immediate occupational dose (person-rem/event)
s	=	subscript denoting status quo (current conditions)
A	=	subscript denoting after implementation of proposed action
r	=	real discount rate
t_f	=	years remaining until end of facility life

The values used in the analysis are:

R	=	$2,000/person-rem
r	=	0.07
D_{IO}	=	3,300 person-rem/accident (best estimate)
t_f	=	20 years

Assuming F_A is zero for the base case, the monetary value of the immediate dose associated with FCS's accident risk is:

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

$$= 3300 * F * \$2000 * \frac{1 - e^{-.07*20}}{.07}$$

The core damage frequency (CDF) for the base case is 2.48E-05 per year; therefore,

$$W_{IO} = \$2,000$$

LONG-TERM DOSE

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

Equation (2):

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

where:

W_{LTO}	=	monetary value of accident risk-avoided long-term doses, after discounting ($)
F	=	accident frequency (events/year)
s	=	subscript denoting status quo (current conditions)
A	=	subscript denoting after implementation of proposed action
t_f	=	years remaining until end of facility life
r	=	real discount rate
R	=	monetary equivalent of unit dose ($/person-rem)
D_{LTO}	=	long-term occupational dose (person-rem/event)
m	=	years over which long-term doses accrue

The values used in the analysis are:

R	=	\$2,000/person-rem
r	=	0.07
D_{LTO}	=	20,000 person-rem/accident (best estimate)
m	=	“as long as 10 years”
t_f	=	20 years

Assuming F_A is zero for the base case, the monetary value of the long-term dose associated with the plant accident risk is:

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

$$= \left(F_S \times 20000\right) \$2000 * \frac{1-e^{-.07*20}}{.07} * \frac{1-e^{-.07*10}}{.07*10}$$

The CDF (F) for the base case is 2.48E-05 per year; therefore,

$$W_{LTO} = \$7,000$$

TOTAL OCCUPATIONAL EXPOSURES

Combining Equations (1) and (2) above and using the above numerical values, the long-term accident related onsite (occupational) bounding dose (W_O) is equivalent to:

$W_O = W_{IO} + W_{LTO} = \$9,000$

4.16.2.4 ONSITE ECONOMIC COSTS

Onsite economic costs are considered to include costs associated with cleanup/ decontamination, replacement power, and repair/refurbishment. Each of these factors is discussed in the following sections.

CLEANUP AND DECONTAMINATION

The total undiscounted cost estimate of cleanup and decontamination of a power facility subsequent to a severe accident is estimated by the NRC, in NUREG/BR-0184, at $1.5E+09. Assuming the $1.5E+09 estimate is spread evenly over a 10-year period for cleanup and applying a 7 percent real discount rate, the cost translates into a net present value of $1.1E+09 for a single event. This quantity is derived from the following equation:

$$PV_{CD} = \left(\frac{C_{CD}}{m}\right)\left(\frac{1 - e^{-rm}}{r}\right)$$

where:

PV_{CD}	=	present value of the cost of cleanup/decontamination ($)
C_{CD}	=	total cost of the cleanup/decontamination effort ($1.5E+09)
m	=	cleanup period (10 years)
r	=	real discount rate (7 percent)

Therefore:

$$PV_{CD} = \left(\frac{\$1.5E + 09}{10}\right)\left(\frac{1 - e^{-.07*10}}{.07}\right)$$

$$PV_{CD} = \$1.079E + 09$$

This cost is integrated over the license renewal period as follows:

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

where:

U_{CD}	=	net present value of cleanup/decontamination over the life of the plant ($)
t_f	=	years remaining until end of facility life

Based upon the values previously assumed:

$U_{CD} = \$1.61E{+}10$

REPLACEMENT POWER

Replacement power costs, U_{RP}, are an additional contributor to onsite costs. These are calculated in accordance with NUREG/BR-0184, Sections 5.7.6.4 and 5.6.7.2. Since replacement power will be needed for the time period following a severe accident, and for the remainder of the expected generating plant life, long-term replacement power calculations have been used. Values used in the calculations are based on the 910 megawatt (electric) [MW(e)] reference plant.

$$PV_{RP} = \left(\frac{\$1.2E+08}{r}\right)\left(1 - e^{-rt_f}\right)^2$$

where:

PV_{RP}	=	present value of the cost of replacement power for a single event
t_f	=	years remaining until end of facility life
r	=	real discount rate

This equation was developed per NUREG/BR-0184 for discount rates between 5 percent and 10 percent only. It was developed using the constant $1.2E+08, which has no intrinsic meaning, but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a “generic” reactor after an event.

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

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

where:

U_{RP}	=	present value of the cost of replacement power over the life of the facility ($)

Based upon values previously assumed:

U_{RP} = \$7.89E+09

Applying the correction for a 478 MW(e) FCS versus 910 MW(e) for the “generic” reactor,

U_{RP} = \$4.14E+09

REPAIR AND REFURBISHMENT

OPPD has no plans for major repair/refurbishment following a severe accident; therefore, there is no contribution to averted onsite costs from this source.

TOTAL ONSITE ECONOMIC COST

The total onsite economic cost is the sum of the cleanup/decontamination cost (U_{CD}) and the replacement power cost (U_{RP}) multiplied by the CDF (2.48E-05/year). Therefore, the total onsite economic cost is \$391,000.

4.16.2.5 MAXIMUM ATTAINABLE BENEFIT

The present-dollar value equivalent for severe accidents at FCS is the sum of the offsite exposure costs, offsite economic costs, onsite exposure costs, and onsite economic costs. Table 4.16-1 lists each of these values for the base case as calculated in the previous sections. As shown, the monetized value of severe accident risk is approximately \$784,000.

**TABLE 4.16-1
ESTIMATED PRESENT-DOLLAR VALUE EQUIVALENT
FOR SEVERE ACCIDENTS AT FORT CALHOUN STATION**

Parameter	Present Dollar Value
Onsite Economic Costs	$391,000
Offsite Economic Costs	$166,000
Onsite Exposure Costs	$9,000
Offsite Exposure Costs	$218,000
Total	**$784,000**

The maximum theoretical benefit is based upon the elimination of all plant risk and equates to the base case severe accident risk described above. Therefore, the maximum attainable benefit is $784,000.

4.16.3 SAMA IDENTIFICATION AND SCREENING

The NRC and the nuclear power industry have documented analyses of methods to mitigate severe accident impacts for existing and new plant designs and for in-system evaluations. Appendix Section 5.3 lists documents from which OPPD gathered descriptions of candidate SAMAs. In addition, OPPD considered insights into possible FCS-specific improvements gained through the preparation and use of the FCS PRA model over the past decade. Finally, the top 100 cutsets of the Level 1 PRA update were examined to identify the important contributors to plant risk (both plant equipment and operator actions) and to ensure that the important contributors were addressed by one or more SAMA. These cutsets included dominant risk contributors associated with external flooding and seismic events. Shutdown related improvements are not addressed explicitly. However, SAMAs that affect structures, systems, and components that may enhance mitigation functions during both at-power and shutdown conditions are addressed.

Table 5.3-1 of Appendix Section 5.3 lists the 190 candidate SAMAs that OPPD identified for analysis and identifies the source of the information. The first step in the analysis was to eliminate non-viable SAMAs through preliminary screening.

4.16.3.1 PRELIMINARY SCREENING

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were obviously not viable for implementation at FCS. Screening criteria include:

- SAMA improvements that modify features not applicable to FCS;
- SAMA improvements that have already been implemented at FCS;
- SAMA improvements that are duplicates and could be consolidated with one or more other SAMA improvement(s);
- SAMA improvements that involve major plant design and/or structural change or component purchase that clearly identifies the cost of the item well in excess of the maximum attainable benefit; or
- SAMA improvements that would have a minimal risk reduction based on review of system risk reduction worth values, other plant metrics, or previous system review results.

Table 5.3-1 of Appendix Section 5.3 provides a brief discussion of each candidate SAMA and its disposition. Based on this preliminary screening, 57 candidate SAMAs were not applicable, 8 were duplicates and combined into other SAMAs, 31 were prohibitively expensive, 24 resulted in minimal risk reduction, 50 were already implemented, and 20 were designated for further analysis.

4.16.3.2 FINAL SCREENING/COST-BENEFIT ANALYSIS

The final screening involved developing FCS-specific SAMA descriptions and cost-benefit analyses for the viable candidate SAMAs. OPPD refined the generic conceptual SAMAs by developing plant-specific descriptions for each, including details on site-specific implementation. This step provided a basis for bounding benefit and cost estimates. Each redefined SAMA provides the analysts with a detailed description that can be compared with the current plant configuration and processes. Appendix Section 5.4 provides a description for each candidate SAMA.

OPPD estimated the costs of implementing each SAMA through the application of engineering judgment, estimates from other licensee submittals, and site-specific cost estimates (if necessary). Conservatively, the cost estimates included neither the cost of replacement power during extended outages required to implement the modifications, nor the contingency costs associated with unforeseen implementation obstacles. Estimates were presented in terms of dollar values at the time of implementation or estimation, and were not adjusted to present-day dollars.

The benefits resulting from the bounding estimates presented in the benefit analysis are, in general, rather low. In most cases the benefits are so low that it is obvious that the implementation costs would exceed the benefit, even without a detailed cost estimate. In many cases, plant staff judgment was applied in assessing whether the benefit approached the estimated implementation costs. A detailed cost estimate was only applied in those situations in which the benefit is significant and application of judgment might be questioned.

Screening based on level of benefit achieved was carried out in two steps. The first step involved using the maximum attainable benefit that could possibly be provided by any one SAMA or combination of SAMAs. As shown in Table 4.16-1, the monetized value of this risk is approximately $784,000. Therefore, any SAMA having an estimated cost of implementation exceeding this value was not considered cost beneficial and was screened from further consideration.

The next step involved performing a benefits analysis on the remaining SAMAs. Section 4.16.2 discusses maximum benefit calculations in more detail. The methodology for determining if a SAMA is beneficial consists of determining whether the benefit provided by implementation of the SAMA exceeds the expected cost of implementation. Where the benefits of the SAMAs are small, engineering judgment was used as the basis for costs. The benefit is defined as the sum of the reductions in the dollar equivalents for each severe accident impact (offsite exposure costs, offsite economic costs, occupational exposure costs, and onsite economic costs) resulting from the implementation of a SAMA. In general, if the expected cost exceeded twice the calculated benefit, the SAMA was considered not to be cost beneficial. Comparison of the expected cost with twice the benefit calculated from consideration of only internal events was undertaken to recognize and account for the potential contribution to risk from external events.

The result of implementation of each SAMA would be a change in the FCS severe accident risk (i.e., a change in frequency or consequence of severe accidents)[3]. The methodology for calculating the magnitude of these changes is straightforward. First, the FCS severe accident risk after implementation of each SAMA was calculated using the same methodology as for the base case. A spreadsheet was then used to combine the results of the Level 2 model with the Level 3 model to calculate the post-SAMA risks. The results of the benefit analysis for each of the SAMAs are presented in Section 4.16.4.

Each SAMA evaluation was performed in a bounding fashion. Bounding evaluations are performed to address the generic nature of the initial SAMA concepts. Such bounding calculations overestimate the benefit and, thus, are conservative calculations. For example, SAMA No. 9 considers installation of an additional service water pump to reduce the potential for loss of cooling to the RCP seals. This SAMA was evaluated

[3] Frequency x consequence = risk.

using a bounding calculation that assumed the benefit of the additional service water pump would eliminate all core damage events associated with a loss of component cooling. Such a calculation obviously overestimates the benefit. However, if the inflated benefit indicated that the SAMA is not cost-beneficial, then the purpose of the analysis is satisfied.

Two types of evaluations were used in determining the benefit of the SAMAs; model and cutset requantification. Requantified PRA results were used to establish both the CDF change and its impact on the change in the various fission product classes. These results were combined with MACCS2 release class impacts to determine the change in offsite exposure risk.

An example of such an evaluation is the assessment as to whether to add accumulators to the Safety Injection Refueling Water Tank (SIRWT) bubblers. These devices are used to monitor SIRWT inventory. Premature low-level indication by these components can result in a premature switch of the high-pressure safety injection suction source from the SIRWT to a potentially dry containment sump. This SAMA was evaluated in a bounding manner by assuming the SAMA change would make the SIRWT bubblers 100 percent available. Offsite exposure and economic impacts were based on mapping the lost CDF sequences into the appropriate release categories.

Other SAMAs were more quickly evaluated simply by examining the contribution of specific components or human actions to the CDF. For example, enhancing external flood procedures was assumed to have a benefit of reducing CDF associated with the Ohae Dam break by 50 percent. Offsite exposure and economic impacts were based on reducing the frequency for the associated release categories. Appendix Section 5.4 describes the SAMA-specific modeling approaches used for the evaluation.

As described above for the base case, values for avoided public and occupational health risk (benefits) were converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem (Reference 4.16-5) and discounted to present value. Values for avoided offsite economic costs were also discounted to present value. The formula used for calculating net value for each SAMA is as follows:

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

where:

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

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA, and the SAMA would not be considered cost-beneficial. The projected cost of each SAMA (COE) was derived by utilizing applicable cost estimates published in NRC submittals from other licensees or expert judgment by knowledgeable plant staff. If these previous submittals contained costs for a specific SAMDA, the SAMDA description was reviewed to determine if the cost estimate could reasonably be applied to FCS based on plant design, current licensing basis, and knowledge of implementing plant modifications. If the previous licensee submittals did not contain cost estimates or if these cost estimates could not be applied, knowledgeable staff reviewed the benefit to determine whether the SAMA could be implemented for a cost equivalent to two times the calculated benefit. If the SAMA could not be screened using this criterion, a plant-specific cost estimate was prepared. Specific descriptions of the SAMA cost estimates are provided in Appendix Section 5.4.

4.16.4 RESULTS

OPPD analyzed 190 conceptual alternatives for mitigating FCS severe accident impacts. Preliminary screening eliminated 170 SAMAs from further consideration based on inapplicability to FCS's design, prohibitive expense far in excess of any benefit, minimal risk reduction, duplication, or applicability to features that have already been incorporated into FCS's current plant design, procedures, and programs. During final screening, the remaining 20 SAMA candidates were subjected to detailed cost-benefit analyses. Table 4.16-2 presents the percentage of CDF reduction and the results of the cost-benefit analyses for each SAMA evaluated.

The cost-benefit evaluation indicates six candidate SAMAs are potentially cost beneficial for mitigating the consequences of a severe accident. These include:

- Expand guidance on refilling the Refueling Water Storage Tank (SAMA No. 92);
- Enhance the guidance on SIRWT bubblers and recirculation valves (SAMA No. 181);
- Add capability for steam generator level indication (SAMA No. 182);
- Provide 480 volts alternating current power supply to open the power-operated relief valve (SAMA No. 183);
- Add capability to flash the field on the emergency diesel generator to enhance station blackout event recovery (SAMA No. 184); and
- Add manual steam relief capability (SAMA No. 186).

In NUREG/BR-0184, the NRC recommends using a 7 percent real (i.e., inflation-adjusted) discount rate for value-impact analyses and notes that a 3 percent discount rate should be used for sensitivity analyses to indicate the sensitivity of the results to the choice of discount rate. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. With a 3 percent discount rate used in the sensitivity analyses, the magnitude of the net values change, and two additional SAMA candidates were determined to be potentially cost beneficial:

- Implement procedure and operator training enhancements to anticipate problems and cope with events that lead to loss of cooling to RCP seals (SAMA No. 4); and

- Add independent power supply to charge batteries (SAMA No. 54).

In the GEIS, the NRC concluded that the probability-weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to groundwater, and societal and economic impacts of severe accidents are of small significance for all plants. OPPD concurs with that conclusion and addressed site-specific measures to mitigate severe accidents in this analysis. OPPD determined that the potentially cost-beneficial SAMAs identified do not relate to adequately managing the effects of aging and, therefore, are not required to be implemented pursuant to 10 CFR 54.

However, OPPD has historically identified and implemented various cost-beneficial enhancements at FCS to reduce the consequences of postulated accidents. Accordingly, OPPD plans to implement 7 of the cost-beneficial SAMAs listed above (SAMA Nos. 4, 92, 181, 182, 183, 184, and 186). The implementation of these SAMAs reduces the benefit of SAMA No. 54 sufficiently to make it not cost-beneficial. Based on current resource utilization planning, OPPD expects the SAMA implementation to be completed by the end of 2005. OPPD considers the implementation of the SAMAs to be voluntary enhancements, not regulatory commitments.

TABLE 4.16-2
DISPOSITION OF SAMAs RELATED TO FORT CALHOUN STATION

SAMA No.	Potential Enhancement	CDF Reduction	Estimated Benefit	Estimated Cost of Enhancement	Screening Result and Discussion
4	Implement procedure and operator training enhancements for support-system failure sequences, with emphasis on anticipating problems and coping with events that could lead to loss of cooling to reactor coolant pump seals.	5%	$27,000	>$30K	Negative net value. Would potentially improve mitigation of loss of reactor coolant pump seal cooling events. OPPD will continue to monitor Combustion Engineering Owners Group developments for further consideration.
9	Install an additional service water pump.	3%	$17,000	>>2xbenefit	Negative net value. Would install a service water swing pump that automatically aligns to the service water header without an operating pump.
10	Install the improved N 9000 reactor coolant pump seals.	5%	$27,000	>>2xbenefit	Negative net value.
41	Use the Fire Protection System as a back up source for the Containment Spray System.	0	$23,000	>2xbenefit	Negative net value. Would upgrade the Fire Protection System and hard-pipe a connection to the Containment Spray System so it is available even in an SBO scenario.
52	Provide additional DC battery capacity.	16%	$111,000	>>2xbenefit	Negative net value. Additional batteries would extend 125 VDC battery life to 24 hours.
54	Incorporate an alternate battery charging capability.	16%	$111,000	>$150K	Negative net value. Modification reduces the likelihood of battery depletion during SBO events.

TABLE 4.16-2 (CONTINUED)
DISPOSITION OF SAMAS RELATED TO FORT CALHOUN STATION

SAMA No.	Potential Enhancement	CDF Reduction	Estimated Benefit	Estimated Cost of Enhancement	Screening Result and Discussion
56	Increase/improve DC busload shedding.	16%	$111,000	>$160K	Negative net value. Modification improves 125 VDC busload management, allowing the 125 VDC batteries to last for 24 hours. The likelihood of managing battery load to 24 hours is very small. When the probability of success is applied to the estimated benefit, implementation costs are expected to well exceed the benefit.
60	Develop procedures to repair or replace failed 4-kilovolt breakers.	0	0	NA	Negative net value. Would mitigate the failure of breakers that transfer 4.16-kilovolt non-emergency buses from unit station service transformers to system station service transformers.
88	Ensure all interfacing system loss-of-coolant accident releases are scrubbed.	0	$35,000	>>2xbenefit	Negative net value. Would ensure that every possible interfacing system loss-of-coolant accident path will undergo scrubbing.
92	Conserve/makeup Borated Water Storage Tank inventory post accident.	25%	$165,000	<$30K	Positive net value. Conservation of the Borated Water Storage Tank during steam generator tube ruptures is already implemented. This SAMA would involve expanding the existing guidance on refilling the Borated Water Storage Tank (i.e. the Safety Injection Refueling Water Tank) to increase long-term injection capability.

TABLE 4.16-2 (CONTINUED)
DISPOSITION OF SAMAS RELATED TO FORT CALHOUN STATION

SAMA No.	Potential Enhancement	CDF Reduction	Estimated Benefit	Estimated Cost of Enhancement	Screening Result and Discussion
181	Add accumulators or implement training on Safety Injection Refueling Water Tank bubblers and recirculation valves.	17.2%	$78,000	<$30K	Positive net value. Prevents premature recirculation actuation signal resulting from depletion of bubbler air supply. Cost of hardware modification would exceed the estimated benefit. This SAMA would enhance the existing guidance to increase operator awareness regarding the available time before recirculation actuation signal.
182	Add capability for steam generator level indication during an SBO.	17.2%	$76,000	<$30K	Positive net value. Upgrade enhances the ability to feed the steam generators following an SBO.
183	Add 480 VAC power supply to open the power-operated relief valve.	0	$32,000	<$25K	Positive net value. Provides capability to depressurize RCS following a severe accident. Opening a power-operated relief valve during a core damage event would reduce the potential for a thermally induced tube rupture, lower RCS pressure while potentially averting a high-pressure melt ejection, and retain RCS fission products within containment.
184	Add capability to flash the field on the emergency diesel generator to enhance SBO recovery.	27%	$118,000	<$30K	Positive net value. Increases the likelihood of recovery from long-term SBOs due to emergency diesel generator failure.

TABLE 4.16-2 (CONTINUED)
DISPOSITION OF SAMAs RELATED TO FORT CALHOUN STATION

SAMA No.	Potential Enhancement	CDF Reduction	Estimated Benefit	Estimated Cost of Enhancement	Screening Result and Discussion
185	Remove SI-2C from auto-start.	10%	$44,000	>2xbenefit	Negative net value. Removes a common mode failure mechanism by uncoupling the standby and spare high-pressure safety injection pumps. This item will be considered further by OPPD for economic or other improvements outside of the SAMA analysis.
186	Add manual steam relief capability and associated procedures.	3%	$62,000	<$40K	Positive net value. Modification increases cooldown capability for responding to steam generator tube ruptures and potentially isolable interfacing system loss-of-coolant accidents.
187	Enhance operation of FW-54.	3%	$14,000	>2xbenefit	Negative net value. Enhances SBO coping capability.
188	Enhance external flood procedures.	17% of flooding CDF	$16,000	>2xbenefit	Negative net value. Enhance procedures and hardware for coping with a potential failure of the Oahe Dam.
189	Add trisodium phosphate into Auxiliary Building.	0%	$17,000	>>2xbenefit	Negative net value. Trisodium phosphate controls the pH of sump water in the Auxiliary Building during severe accident scenarios, which increases retention of iodines and so reduces offsite exposure.

TABLE 4.16-2 (CONTINUED)
DISPOSITION OF SAMAs RELATED TO FORT CALHOUN STATION

SAMA No.	Potential Enhancement	CDF Reduction	Estimated Benefit	Estimated Cost of Enhancement	Screening Result and Discussion
190	Enhance Emergency Operating Procedures to provide guidance to operators to better avert thermally induced steam generator tube ruptures.	0%	$20,000	>$30K	Negative net value. Adds actions to Emergency Operating Procedures that minimize the potential for post-accident thermally induced steam generator tube ruptures. Related benefit achieved through implementation of SAMA No. 183. OPPD will continue to follow Combustion Engineering Owners Group developments in this area.

AC = alternating current
CDF = core damage frequency
DC = direct current
K = thousand
NA = not applicable
OPPD = Omaha Public Power District
RCS = Reactor Coolant System
SAMA = severe accident mitigation alternative
SBO = station blackout
VAC = volts alternating current
VDC = volts direct current

4.17 ENVIRONMENTAL JUSTICE

NRC
"The need for and the content of an analysis of environmental justice will be addressed in plant-specific reviews." 10 CFR 51, Appendix B to Subpart A, Table B-1

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations" (Reference 4.17-1), requires executive agencies to identify and address, as appropriate, "disproportionately high and adverse human health or environmental effects" from their programs, policies, and activities on minority and low-income populations. The Presidential Memorandum that accompanied Executive Order 12898 emphasized the importance of using existing laws, including NEPA, to identify and address environmental justice concerns, "including human health, economic, and social effects, of Federal actions."

Although the NRC is not subject to Executive Order 12898, it has voluntarily committed to conducting environmental justice reviews of actions under its jurisdiction and has issued procedural guidance (Reference 4.17-2, Attachment 4). The guidance does not provide a standard approach or formula for identifying and addressing environmental justice issues. Instead, it offers general principles for conducting an environmental justice analysis under NEPA. The NRC guidance makes clear that if no significant impacts are anticipated from the proposed action, then "…no member of the public will be substantially affected" and, as a consequence, "…there can be no disproportionate high and adverse effects or impacts on any member of the public including minority or low income populations."

OPPD has reviewed and adopted by reference NRC findings for Category 1 issues that OPPD determined are applicable to FCS (see Section 4.1.1 and Appendix 1.0). The NRC had concluded that environmental impacts for each of these issues would be small. OPPD has addressed each Category 2 issue and has performed required analyses for those that OPPD determined are applicable to FCS (see Sections 4.2 through 4.16). For each applicable Category 2 issue, OPPD has concluded that the environmental impacts from continued operation of FCS in the license renewal period would be small. These include:

- Aquatic resources (entrainment, impingement, and heat shock)
- Threatened and endangered species
- Public health impacts from microbiological organisms
- Electric shock from transmission line-induced currents
- Housing, public water supply, offsite land use, and transportation

- Historic and archaeological resources

Based on the OPPD review, FCS license renewal would result in no significant impact. No member of the public would be substantially affected and, as a consequence, there would be no disproportionately high and adverse impacts on any member of the public, including minority and low-income populations. In such instances, a qualitative review of potential environmental justice impacts is adequate, and no mitigation measures need to be described.

4.18 REFERENCES

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4.10-1 Nebraska Department of Economic Development. *The Nebraska Databook and Economic Trends.* www.info.neded.org. Accessed May 1, 2001.

4.11-1 U.S. Census Bureau. *Table DP-1. Profile of Demographic Characteristics for Nebraska: 2000.* http://blue.census.gov/Press-Release/www/2001/tables/redist_ne.html. Accessed June 13, 2001.

4.11-2 Fetter, Jr., C. W. *Applied Hydrogeology*. Charles E. Merrill Publishing Co./Bell & Howell Co. Columbus, Ohio, 1980.

4.16-1 Gates, W.G. (OPPD) letter to the Document Control Desk (NRC), "NRC Generic Letter 88-20 Submittal for Fort Calhoun Station 'Individual Plant Examination for Severe Accident Vulnerabilities.' Omaha, Nebraska, December 1, 1993.

4.16-2 Patterson, T. L. (OPPD) letter to Document Control Desk (NRC), "Phase II Response to Generic Letter 88-20, Supplement 4 Individual Plant Examination of External Events." Omaha, Nebraska, June 30, 1995.

4.16-3 Letter from Wharton, L.R. (NRC) to S.K. Gambhir (OPPD), "Review of Fort Calhoun Station Individual Plant Examination of External Events (IPEEE)." Washington, D.C., May 6, 1996.

4.16-4 Letter from Wharton, L.R. (NRC) to T.L. Patterson (OPPD), "Fort Calhoun Station Unit No. 1 - Review of Individual Plant Examination (IPE) Submittal - Internal Events." Washington, D.C., December 9, 1996.

4.16-5 U.S. Nuclear Regulatory Commission. *Regulatory Analysis Technical Evaluation Handbook.* NUREG/BR-0814. Office of Nuclear Regulatory Research. Washington, D.C., January 1997.

4.17-1 The President. "Executive Order 12898, Federal Actions to Address Environmental Justice in Minority and Low Income Populations." *Federal Register*. Vol. 59, No. 32. February 16, 1994.

4.17-2 U.S. Nuclear Regulatory Commission. "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues." Rev. 2. Office of Nuclear Reactor Regulation. Washington, D.C., September 21, 1999.

5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

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

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

While NRC regulations do not require an applicant's ER 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 the NRC staff to such information so that the staff can determine whether to seek the NRC's approval to waive or suspend application of the Rule with respect to the affected generic analysis. The NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of its *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) conclusions (Reference 5.1-1, page C9-13, Concern Number NEP.015).

Omaha Public Power District (OPPD) assumes new and significant information would be the following:

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

The NRC does not define the term "significant." For the purpose of its review, OPPD used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act (NEPA) authorizes the CEQ to establish implementing regulations for federal agency use. The NRC requires license renewal applicants to provide the NRC with input, in the form of an ER that the NRC will use to meet NEPA requirements as they apply to license renewal (10 CFR 51.10). CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), to focus on significant environmental issues (40 CFR 1502.1), and to eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of “significantly,” which requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). OPPD assumed that moderate or large impacts, as the NRC defines, would be “significant.” Section 4.1.2 presents the NRC definitions of “moderate” and “large” impacts.

OPPD is aware of no new and significant information regarding the environmental impacts of Fort Calhoun Station Unit 1 (FCS) license renewal.

5.1 REFERENCES

5.1-1 U.S. Nuclear Regulatory Commission. *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*. NUREG-1529. Office of Nuclear Regulatory Research. Washington, D.C., May 1996.

6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

Omaha Public Power District (OPPD) has reviewed the environmental impacts associated with renewing the Fort Calhoun Station Unit 1 (FCS) operating license and has concluded that all of the impacts would be small and would not require mitigation. This environmental report documents OPPD's basis for this conclusion. In Section 4.1, OPPD incorporates by reference the U.S. Nuclear Regulatory Commission's (NRC's) findings for the 50 Category 1 issues that apply to FCS, all of which have impacts that are SMALL (see Appendix 1.0). Chapter 4, Sections 4.2 through 4.16, presents OPPD's analysis of the 15 Category 2 issues that apply to FCS. Results of these analyses indicate that impacts would be SMALL for all applicable Category 2 issues not related to refurbishment. OPPD studies indicate that no refurbishment would be required for license renewal, so no impacts would be associated with Category 2 refurbishment issues. Table 6.1-1 summarizes impacts that FCS license renewal would have on resources associated with Category 2 issues.

TABLE 6.1-1
ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL OF FORT CALHOUN STATION UNIT 1

No.	Issue	Environmental Impact
	Surface Water Quality, Hydrology, and Use (for all plants)	
13	Water-use conflicts (plants using cooling ponds or cooling towers using makeup water from a small river with low flow)	NONE. The issue is not applicable because FCS does not use cooling ponds or cooling towers.
	Aquatic Ecology (for all plants with once-through and cooling pond heat dissipation systems)	
25	Entrainment of fish and shellfish in early life stages	SMALL. OPPD has a current NPDES permit, which constitutes compliance with CWA Section 316(b) requirements to provide best available technology to minimize entrainment.
26	Impingement of fish and shellfish	SMALL. OPPD has a current NPDES permit, which constitutes compliance with CWA Section 316(b) requirements to provide best available technology to minimize impingement.
27	Heat shock	SMALL. Thermal discharge from FCS complies with Nebraska Water Quality Standards without recourse to a CWA Section 316(a) variance.

TABLE 6.1-1 (CONTINUED) ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL OF FORT CALHOUN STATION UNIT 1

No.	Issue	Environmental Impact
		Groundwater Use and Quality
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use more than 100 gpm)	NONE. The issue is not applicable because FCS uses fewer than 100 gpm (no dewatering; potable and service water are from municipal supply). Groundwater use is limited to occasional small withdrawals to fill the Sanitary Lagoons and flush the center pivot irrigation system.
34	Groundwater use conflicts (plants using cooling towers withdrawing makeup water from a small river)	NONE. The issue is not applicable because FCS does not use cooling towers.
35	Groundwater use conflicts (Ranney wells)	NONE. The issue is not applicable because FCS does not use Ranney wells.
39	Groundwater quality degradation (cooling ponds at inland sites)	NONE. The issue is not applicable because FCS does not use cooling ponds.
		Terrestrial Resources
40	Refurbishment impacts to terrestrial resources	NONE. OPPD has no plans for major refurbishment at FCS.
		Threatened or Endangered Species
49	Threatened or endangered species	SMALL. Species of concern have a low potential for occurrence in habitats affected by plant operation and lack of observed impacts during operational monitoring.
		Air Quality
50	Air quality during refurbishment (nonattainment and maintenance areas)	NONE. OPPD has no plans for major refurbishment at FCS.
		Human Health
57	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	SMALL. FCS operations have had no known impact on public health due to pathenogenic organisms. Risk of human health is low due to poor conditions for supporting populations of pathogenic organisms in the Missouri River, including areas affected by the thermal discharge and low potential for exposure of public in the thermally affected zone.
59	Electromagnetic fields, acute effects (electric shock)	SMALL. All circuits meet National Electrical Safety Code® requirements for limiting induced shock.

TABLE 6.1-1 (CONTINUED)
ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL OF FORT CALHOUN STATION UNIT 1

No.	Issue	Environmental Impact
		Socioeconomics
63	Housing impacts	SMALL. No impacts are anticipated because no additional employees are expected. A bounding analysis, which assumes 60 additional employees are required during the license renewal term, indicates the need for an additional 242 housing units in an area with a population greater than 600,000. This impact would be small.
65	Public services: public utilities	SMALL. No impacts are anticipated because no additional employees are expected. A bounding analysis assumes the license renewal term requires 60 additional employees indicating as many as 603 new residents could move to Douglas, Washington, and Sarpy counties. This would result in an increased demand of approximately 42,000 gallons of water per day on water systems in the three counties. This would be less than 0.1 percent of the total domestic water use in the three counties.
66	Public services: education (refurbishment)	NONE. OPPD has no plans for major refurbishment at FCS.
68	Offsite land use (refurbishment)	NONE. OPPD has no plans for major refurbishment at FCS.
69	Offsite land use (license renewal term)	NONE. OPPD is exempt from paying state occupational taxes, personal property taxes, and real estate taxes related to FCS operations, and the magnitude of OPPD payment in lieu of taxes relative to the receiving county's total revenues is not relevant in assessing new tax-driven land use impacts.
70	Public services: transportation	SMALL. No impacts are anticipated because no additional employees are expected, and the LOS designation for the road that provides access to FCS, U.S. Highway 75, is currently "B." Impact from adding as many as 60 employees during the license renewal period would be small.
71	Historic and archaeological resources	SMALL. No impacts to historic or archaeological resources were identified.
76	Severe accidents	SMALL. OPPD identified 7 potentially cost-beneficial SAMAs; however, none were related to aging. OPPD plans to implement these as voluntary enhancements.
		Environmental Justice
92	Environmental justice	SMALL. No disproportionately high or adverse impacts to minority or low-income populations were identified.

TABLE 6.1-1 (CONTINUED)
ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL OF FORT CALHOUN STATION UNIT 1

No.	Issue	Environmental Impact

CWA = Clean Water Act
FCS = Fort Calhoun Station Unit 1
gpm = gallons per minute
LOS = level of service
NPDES = National Pollutant Discharge Elimination System
OPPD = Omaha Public Power District

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)

All impacts of license renewal at FCS are either beneficial or small and, in either case, would not require additional mitigation. Ecological studies assessing impacts on aquatic ecology in the Missouri River during the first five years of plant operations concluded that impacts from operations were small (see Sections 4.2, 4.3, and 4.4). Current operations include environmental monitoring activities that would continue during the license renewal term. These activities include the radiological environmental monitoring program, radiological effluents control program, and National Pollutant Discharge Elimination System (NPDES) discharge monitoring.

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 51.53(c)(2)

OPPD adopts by reference for this environmental report the NRC findings stated in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) for applicable Category 1 issues (see Appendix 1.0), including discussions of any unavoidable adverse impacts. In Chapter 4.0, OPPD examined the 21 Category 2 issues the NRC identified in the GEIS and the environmental justice issue, and identified the following unavoidable adverse impacts of renewing the operating license for FCS:

- The cooling water system would cause some early life stages of fish to be lost by entrainment during plant operation. Operational monitoring conducted at FCS has indicated that 2.6 percent to 5.3 percent of the larvae passing through the site, predominantly freshwater drum and several species of sucker, may be lost to entrainment by the plant. Considering the small percentage of larvae entrained, their species composition, and the naturally high mortality of these early life stages, it was concluded that entrainment losses from FCS operation have minimal adverse effects on fish populations in this stretch of the Missouri River (see Section 4.2).

- Some fish would be lost due to impingement on the traveling screens at FCS. During operational monitoring at FCS, impinged fish consisted predominantly of freshwater drum, gizzard shad, channel catfish, black bullhead, white bass, white crappie, and bluegill; approximately 70 percent of fish impinged were young of the year. Results of these studies indicated that the overall effect of impingement on Missouri River fish populations in the vicinity of FCS were minimal (see Section 4.3).

- OPPD does not expect to add staff for the license renewal period. However, for purpose of analysis, OPPD assumed that license renewal could necessitate adding as many as 60 staff. The assumed addition of 60 direct workers to Douglas, Sarpy, and Washington counties, where approximately 86 percent of the FCS employees reside, could result in small impacts to housing availability, public water supplies, offsite land use, and transportation infrastructure (see Sections 4.10, 4.11, 4.13.2, 4.14).

6.4 IRREVERSIBLE OR 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 51.53(c)(2)

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

- Nuclear fuel, which is utilized in the reactor and converted to radioactive waste,
- Land required to permanently store or dispose of this spent nuclear fuel and low-level radioactive wastes generated from plant operations,
- Elemental materials that will become radioactive, and
- Materials used for the normal industrial operations of the plant that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

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

NRC

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

The current balance between short-term use and long-term productivity of the environment at the FCS site was set in 1973 when the unit began operating. The U.S. Atomic Energy Commission (AEC) documented its evaluation of this balance in its final environmental statement (FES) for FCS (Reference 6.5-1). Of particular note in this evaluation was the conversion of approximately 20 acres of land, about 10 acres of agricultural land and 10 acres of riparian habitat, to electric power generation facilities. Since construction, additional land within the site boundary has been converted from agricultural use to plant operations use. The AEC noted that, upon decommissioning, much of the facility could be dismantled and restored to its original condition for the long term.

OPPD notes that the current balance is now well established and can be expected to remain essentially unchanged by renewal of the operating license and extended operation of FCS. Extended operation of the unit would postpone restoration of the site and its potential availability for uses other than electric power generation. It would also result in other short-term impacts on the environment, all of which have been determined to be small on the basis of the NRC's evaluation in the GEIS and OPPD's evaluation in this environmental report.

6.6 REFERENCES

6.5-1 U.S. Atomic Energy Commission. *Final Environmental Statement Related to Operation of Fort Calhoun Station Unit No. 1; Omaha Public Power District*. Docket No. 50-285. Directorate of Licensing, Washington, D.C., August 1972.

7.0 ALTERNATIVES TO THE PROPOSED ACTION

NRC

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

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

"While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable.…" (Reference 7.0-1, Section 8.1)

"…The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area.…" (Reference 7.0-2, Section II.H, page 66541)

The National Environmental Policy Act (NEPA) requires the U.S. Nuclear Regulatory Commission (NRC) to consider the environmental impacts of the proposed action (i.e., license renewal) as well as its alternatives when deciding whether to approve license renewal. Omaha Public Power District (OPPD) identifies in this chapter a range of alternatives to renewal of the Fort Calhoun Station Unit 1 (FCS) operating license and presents its evaluation of associated environmental impacts. This chapter also describes alternatives OPPD considered but determined to be unreasonable, and provides the supporting rationale.

Section 7.1 addresses the "no-action" alternative and focuses on the potential environmental impacts of not renewing the FCS operating license independent of any actions OPPD might take to meet its obligations regarding system generation needs. Section 7.2 is a discussion of how OPPD meets its generation planning obligations and identifies feasible and reasonable alternative actions that could be taken to fulfill them, which in effect constitute elements of the no-action alternative. Section 7.2.3 presents OPPD's environmental impact evaluations of these alternatives.

The environmental impact evaluation presented in this environmental report (ER) is not intended to be exhaustive. Rather, the level of detail and analysis relies on the NRC's decision-making standard for license renewal, as follows:

> "…the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that pre-

serving the option of license renewal for energy planning decision makers would be unreasonable.” [10 CFR 51.95(c)(4)].

Therefore, analyses were generally scoped to provide enough information to support NRC decision-making by demonstrating whether an alternative would have a smaller, comparable, or greater environmental impact than the proposed action. Additional detail or analysis was not considered useful or necessary if it would identify only additional adverse impacts of license renewal alternatives; i.e., information beyond that necessary for decision based on the standard quoted above. This approach is consistent with the Council on Environmental Quality (CEQ) regulations, which provide that the consideration of alternatives (including the proposed action) be adequately addressed so reviewers may evaluate their comparative merits [40 CFR 1502.14(b)].

In characterizing environmental impacts in this chapter, OPPD uses the same definitions of “SMALL,” “MODERATE,” and “LARGE” that the NRC used in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) which are presented in Section 4.1 of this ER. Chapter 8.0 presents a summary comparison of environmental impacts of the proposed action and alternatives.

7.1 NO-ACTION ALTERNATIVE

The no-action alternative considered in this ER denotes a scenario in which the NRC does not renew the FCS operating license, and OPPD decommissions the facility and takes appropriate actions to meet system-generating needs created by discontinued operation of the plant. OPPD addresses the impacts of decommissioning in this section.

The NRC, in its GEIS (i.e., NUREG-1437), defines decommissioning as the safe removal from service of a nuclear facility and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. The decommissioning options that the NRC evaluated in the GEIS include immediate decontamination and dismantlement (DECON) and safe storage of the stabilized and defueled facility (SAFSTOR), followed by decontamination and dismantlement. Regardless of the option chosen, decommissioning must be completed within 60 years after operations cease (10 CFR 50.82). In the event the NRC does not renew the FCS operating license, OPPD currently plans to operate the plant until the current license expires, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of a reactor larger than FCS (the pressurized-water, 1,175-MW Trojan Nuclear Plant). That description bounds the decommissioning activities OPPD would conduct at FCS.

As indicated in the GEIS, the NRC has evaluated environmental impacts associated with decommissioning. The impacts the NRC evaluated include occupational and public dose; impacts of waste management; and impacts to air, water, ecological, and socioeconomic resources. The NRC has indicated that the decommissioning 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 (Reference 7.1-1, page 4-15). OPPD adopts by reference the NRC's conclusions regarding environmental impacts of decommissioning as presented in the GEIS.

Decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. OPPD is required to decommission FCS regardless of the NRC decision on license renewal; renewal would merely postpone decommissioning for another 20 years. In the GEIS, the NRC established that the timing of decommissioning operations does not substantially influence the environmental impacts of decommissioning. OPPD adopts by reference the NRC findings to the effect that delaying decommissioning until after the renewal term would have small environmental impacts (10 CFR 51, Subpart A, Appendix B, Table B-1, Decommissioning). The discriminators between the proposed action and the no-action alternative lie within the choice of generation replacement options that compose the no-action alternative. Section 7.2.3 presents OPPD's analysis of the impacts from these options.

OPPD concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those the NRC identified in the GEIS as the impacts that would occur following license renewal. 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

As Section 1.2 indicates, FCS has a net summer capability rating of 476 megawatts (MW) and generates approximately 3.6 terawatt-hours of electricity annually, approximately one-third of OPPD's total generation. In the event the FCS operating license is not renewed, OPPD would be required to build new generating capacity, purchase power, or reduce power requirements through demand reduction to ensure it meets the electric power needs of its customers. Comprehensive integrated resource planning would determine these actions.

OPPD and other utilities in the state are obligated under Nebraska Statute 66-1060 to utilize integrated resource planning and include least-cost options when evaluating alternatives for providing energy supply and managing energy demand in the state. This planning includes evaluation of new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources in order to provide adequate and reliable service to electric customers while minimizing life-cycle system costs, including adverse environmental effects (Nebraska Statute 66-1060). OPPD develops integrated resource plans annually and provides input to statewide planning as a member of the Nebraska Power Association (NPA). The NPA develops, at approximate 5-year intervals, coordinated long-range (20-year) power supply plans and research and conservation reports describing programs related to demand-side management, renewable energy sources, and related topics. The NPA prepares these documents under oversight of the Nebraska Power Review Board, which is directly responsible for these activities under Nebraska law (Statutes 70-1024 through 70-1026). As a preference customer of the Western Area Power Administration (WAPA), OPPD also implements integrated resource planning in accordance with requirements of the Energy Policy Act of 1992 (Reference 7.2-1, Section 1.0; Reference 7.2-2, page 7). These planning efforts are designed to project future energy demands and provide the basis for action necessary to meet anticipated baseload, intermediate load, and peak load conditions with appropriate margins that ensure system reliability, including the 15 percent reserve-capacity obligation OPPD has as a member of the Mid-Continent Area Power Pool (MAPP) (Reference 7.2-2, Section 4.7).

As Figure 7.2-1 shows, coal-fired and nuclear power plants represent most of the generating capability of Nebraska utilities. These sources of power are used to a greater degree, relative to available capability, than gas- or oil-fueled generation. This condition reflects the relatively low cost of coal and nuclear fuels relative to gas and oil, and the suitability of coal-fired and nuclear plants for baseload application. Energy production by hydroelectric sources is similarly preferred from a cost standpoint, but capacity is limited and utilization can vary substantially depending on water availability (Reference 7.2-1, Section 1.0; Reference 7.2-2, Exhibit 4.4-6).

As Figure 7.2-2 shows, OPPD has no hydroelectric generating capability of its own, but does purchase a small amount of hydroelectric capability from WAPA (approximately 80MW). Similar to the state as a whole, OPPD relies heavily on coal and nuclear fuels to supply energy to its customers and preferentially uses this capacity relative to oil- or gas-fired units. OPPD’s other fossil-fired capacity consists primarily of natural gas-fired combustion turbines designed to meet system peak loads (Reference 7.2-2, Section 4.4, exhibit 4.4-6).

Figure 7.2-1: NEBRASKA UTILITY GENERATION AND CAPABILITY (1998) (REFERENCE 7.2-3)

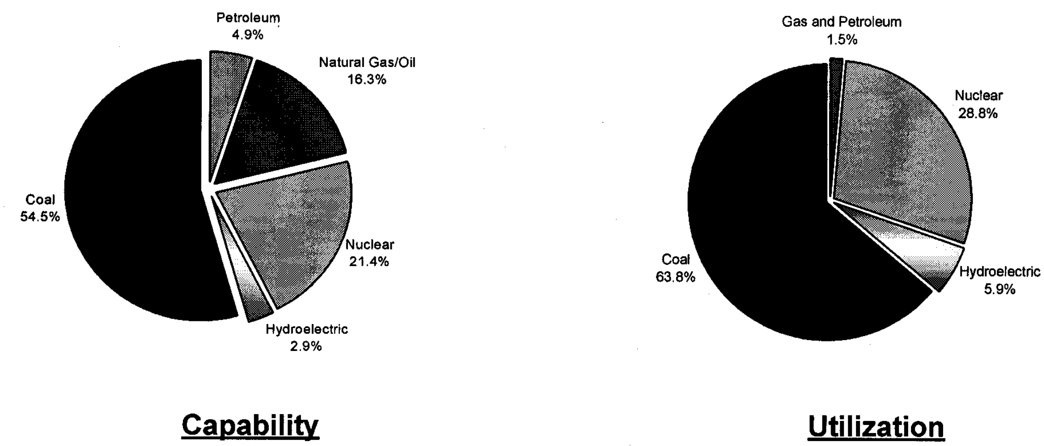
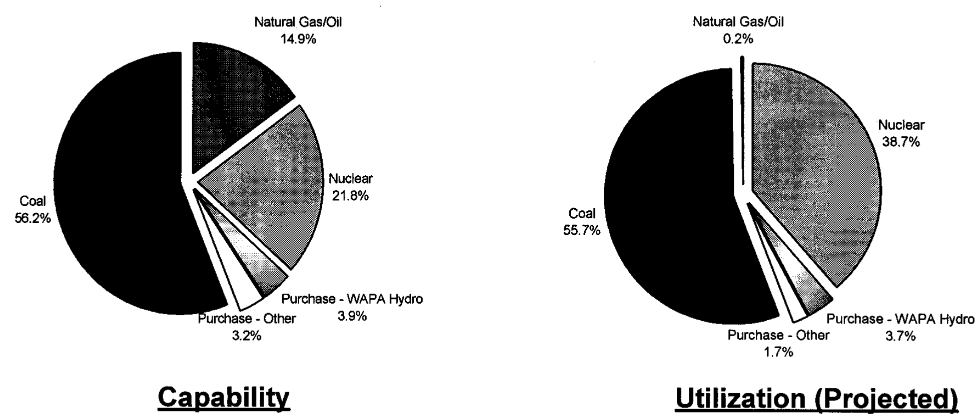


Figure 7.2-2: OPPD GENERATION UTILIZATION (1997) (REFERENCE 7.2-2)



OPPD's integrated resource planning in recent years includes consideration of demand-side management options, power purchases, and the range of generation technologies expected to be available through 2016, including conventional power supplies, emerging technologies, storage technologies, and renewables (Reference 7.2-2; Reference 7.2-3; Reference 7.2-4). Generation technologies are evaluated in categories based on feasibility for baseload, intermediate, and peaking applications at appropriate capacity factors (e.g., 65-80 percent, 20-30 percent, and 5 percent, respectively). Baseload options have typically included three coal technologies (pulverized coal, integrated gasification combined cycle, and fluidized bed), one natural gas technology (combined cycle), advanced nuclear technology, and three renewable technologies (landfill gas/ internal combustion, wood, and municipal solid waste). Wind, natural gas combined cycle, repowering with natural gas combustion turbines and combined-cycle units, solar photovoltaic, and solar central receiver technologies have been evaluated for intermediate load applications. Technologies evaluated for peaking application have included combustion turbines, fuel cells, diesel internal combustion, and storage technologies (Reference 7.2-2, Sections 5.0 and 6.0; Reference 7.2-4).

OPPD has used these integrated resource-planning results as input to the selection of alternatives to FCS license renewal it considers in this ER. OPPD addresses feasible alternatives in Section 7.2.1; and presents other alternatives considered in Section 7.2.2.

7.2.1 FEASIBLE ALTERNATIVES

Results of OPPD's integrated planning since the late-1990s indicate that pulverized coal is preferred over other baseload technology options considered, including other coal-fueled options, and that cumulative projected demand including potential loss of FCS capacity would require approximately 600 MW of additional baseload capacity by year 2013 (Reference 7.2-2, page v; Reference 7.2-4). OPPD conducted a specific, detailed study, in 1999, to determine the optimum size, timing, and technology for this additional capacity (Reference 7.2-5). This study, which considered a range of scenarios for both pulverized coal and natural gas-fired combined-cycle units, confirmed that the addition of a 600-MW pulverized coal plant in 2013 remained the optimal plan. However, the study also indicated that installation of two 300-MW pulverized coal-fired plants or two 300-MW combined-cycle units, one unit each in 2009 and 2013, could be optimal from a rate impact perspective, depending on financing assumptions (Reference 7.2-5, Section 5.0). OPPD continues to evaluate options for developing this additional baseload capacity on the basis of its *2001 Integrated Resource Plan* (Reference 7.2-4). Consistent with these studies, OPPD considers that both pulverized coal and natural gas combined cycle are reasonable and feasible technology alternatives for the evaluation purposes of this ER.

OPPD does not plan to purchase additional baseload capacity to replace the loss of FCS capability in 2013. Currently, plans are to obtain as much as 280 MW of capacity under firm purchase contracts extending through 2009, but only 80 MW of such capacity from 2010-2015 (Reference 7.2-4, Attachments 1-3). However, OPPD routinely considers long-term power purchases in its integrated resource planning; that capacity possibly could be developed elsewhere in the U.S. or Canada (e.g., by other members of MAPP or independent producers). OPPD therefore considers power purchase as a feasible alternative for the purposes of this analysis.

7.2.1.1 REPRESENTATIVE COAL-FIRED GENERATION

As indicated above, OPPD would likely develop 600 MW of capacity to meet anticipated system needs in 2013. However, OPPD has considered for this analysis a representative 500-MW pulverized coal plant. A plant of this size, which has an approximate net capability of 475 MW, is consistent with standard unit sizes available and more closely matches the capacity need (476 MW) that would result from discontinuing FCS operations. A unit of this size is thus economical and provides a more normalized basis for comparing impacts among the alternatives.

OPPD assumes for this analysis that the representative plant would be located at its existing Nebraska City Station site. While OPPD may choose to build a replacement unit elsewhere (i.e., a greenfield site), the Nebraska City site is a primary candidate location for a replacement coal-fired unit on the basis of OPPD’s recent integrated resource plans. In addition, this alternative would generally result in less environmental impact than would development of a comparable plant at a greenfield site. This has the advantage for this analysis of better ensuring that adverse environmental impacts of the coal-fired alternative are not biased in favor of relicensing FCS. OPPD has constructed only one generating unit at the site, Nebraska City Unit 1, a 650-MW nominal pulverized coal plant, which has been in operation since 1979. However, the site was located and planned as a multi-unit baseload generating facility, and the infrastructure for coal delivery, storage, and handling; stormwater management; ash handling and disposal; plant access; and administrative support for multiple units is currently in place. OPPD prepared an environmental assessment for the plant, which uses once-through cooling water from the Missouri River, in connection with a U.S. Army Corps of Engineers (COE) permit for the facility in 1975 (Reference 7.2-6).

The Nebraska City site consists of approximately 1587 acres on river bottomlands bordering the Missouri River in rural Otoe County, Nebraska, approximately 5 miles southeast of Nebraska City, Nebraska (year 2000 population – 7,228; Reference 7.2-7), as Figure 2.1-1 shows. The incorporated areas of Omaha (year 2000 population - 390,007) and Lincoln, Nebraska (year 2000 population - 225,581), are approximately 35 miles north and 50 miles west of the site, respectively (Reference 7.2-7). Access to the site is via a rural secondary road from U.S. Highway 75, approximately 3 miles west. The eastern boundary of the site borders the Missouri River. The western boundary of the site coincides with a rail line that is dedicated to serving the Nebraska City Station. This rail line, which OPPD owns, splits from the Burlington Northern Santa Fe main line in Lincoln, Nebraska, runs eastward to Nebraska City, and terminates at the site. A major 345-kilovolt (kV) transmission north-south intertie (OPPD Line 60) and a 161-kV transmission line connect through the Nebraska City Station Substation. A levee protects areas of the site occupied by plant facilities and adjacent plant expansion areas, which consist predominantly of cropland OPPD leases for farming. Most of the natural vegetation on the site occurs near the river and along Fourmile Creek, a small Missouri River tributary, north and riverward of the levee in areas that would not be subject to plant expansion. The area surrounding the site is predominantly sparsely populated agricultural land.

Table 7.2-1 is a summary of basic characteristics and environmental impact parameters and associated rationale for the representative coal-fired generation alternative that OPPD has assumed for purposes of this analysis. OPPD does not know what specific air emission controls would be required in 2013 for a plant of this type. However, a new coal-fired unit of this size built today would be required to conform to New Source Performance Standards (NSPS; 40 CFR 60, Subpart Da), which would require a minimum of a 99-percent reduction of particulates and a 90-percent reduction of sulfur dioxide (SO_2) from uncontrolled levels. The application of best available control technology (BACT) under Prevention of Significant Deterioration Rules (40 CFR 51.166) could require additional or more stringent controls, including specific emission controls for nitrogen oxides (NO_x). In addition, recent OPPD integrated resource planning studies indicate that replacement of FCS with coal-fired generation in 2013, assumed to be 600 MW of capacity in consideration of other system needs, would require OPPD to purchase additional SO_2 allowances or achieve SO_2 emission reductions by other means (Reference 7.2-2, Section 10.4.2; Reference 7.2-4, page 10 and Attachment 9), which could include additional SO_2 emission controls on the new coal-fired unit beyond those NSPS mandated. In view of uncertainties in emission controls that would be required and as a conservative measure to avoid overstating impacts of FCS license renewal alternatives, OPPD has, for this analysis, generally assumed application of best technology available for control of sulfur oxides (SO_x), NO_x, and particulates, based on U.S. Environmental Protection Agency (EPA) information (Reference 7.2-8). OPPD estimates that approximately 75 miles of new transmission line may be required. OPPD assumes that the plant would feature a closed-cycle cooling system with cooling towers at this site based on regulatory considerations. Cooling tower makeup water would be obtained from the Missouri River or onsite wells. Cooling tower blowdown would be to the Missouri River.

OPPD notes that a 500-MW pulverized coal plant could be located at a greenfield site or possibly at the FCS site. Although additional transmission lines would not be required, location of the plant at the FCS site would require substantial acreage for development of coal and limestone delivery, storage, and handling facilities, which would not be required for the representative plant. In addition, the limited buildable acreage at the FCS site could necessitate the acquisition of additional land to achieve a reasonable coal-fired plant configuration there. The advantages of onsite infrastructure noted above for a representative plant at the Nebraska City site would not be realized at a greenfield site. In addition, as much as 150 miles of new transmission could be required at a greenfield site. In Section 7.2.3.1, OPPD notes the key environmental impact differences from the representative plant that would be associated with these siting options.

TABLE 7.2-1
REPRESENTATIVE COAL-FIRED GENERATION ALTERNATIVE

Characteristic	Basis/Detail
Number of units: 1 Unit size: 500 MW (gross) 475 MW (net)	Standard size (OPPD experience): approximately equivalent to FCS net capacity. Approximate net capacity = 0.95 x gross capacity (OPPD experience).
Location: Nebraska City site	Site designed to accommodate minimum of three 650-MW units; only one unit currently at site; economical by maximizing use of existing staff and infrastructure (e.g., coal storage, handling; ash handling, disposal); tends to maximize land-use compatibility and minimize land disturbance for construction.
Capacity factor: 0.8	Typical for baseload plant (OPPD experience).
Firing mode: subcritical, tangential or wall-fired, dry-bottom pulverized coal	Widely demonstrated, reliable, economical (OPPD experience). Relatively low NO_x emissions (Reference 7.2-8, Table 1.1-3).
Fuel type: Wyoming sub-bituminous	Typical low-sulfur coal used at existing OPPD plants.
Fuel heating value: 8,500 Btu/lb	Average for coal burned in Nebraska (Reference 7.2-9).
Heat rate: 10,000 Btu/kWh	Approximate annual average for new pulverized coal-fired steam turbine generators (OPPD experience).
Fuel ash content by weight: 6 percent (approximately 80 percent fly ash and 20 percent bottom ash)	Typical for coal used at existing OPPD plants; total ash content comparable to Nebraska average (Reference 7.2-9); fly ash:bottom ash ratio typical for OPPD plants.
Fuel sulfur content by weight: 0.34 percent	Typical for coal used at Nebraska City Unit 1 (Reference 7.2-9, Table 31).
Uncontrolled SO_x emissions: 11.9 lb/ton of coal	EPA emission factor for pulverized coal, tangential-fired, dry-bottom boiler. Calculated as 35 x percent of sulfur in coal (Reference 7.2-8, Table 1.1-3).
Uncontrolled NO_x emissions: 8.4 lb/ton of coal	EPA emission factor for pulverized coal, tangential-fired, dry-bottom boiler (Reference 7.2-8, Table 1.1-3).
Uncontrolled CO emissions: 0.5 lb/ton of coal	EPA emission factor for pulverized coal, tangential-fired, dry-bottom (Reference 7.2-8, Table 1.1-3).

TABLE 7.2-1 (CONTINUED)
REPRESENTATIVE COAL-FIRED GENERATION ALTERNATIVE

Characteristic	Basis/Detail
Uncontrolled PM emissions: 60 lb/ton of coal	EPA emission factor for pulverized coal, tangential-fired, dry-bottom boiler. Calculated as 10 x percent of ash in coal (Reference 7.2-8, Table 1.1-4).
Uncontrolled PM_{10} emissions: 14 lb/ton of coal	EPA emission factor for pulverized coal, tangential-fired, dry-bottom boiler. Calculated as 2.3 x percent of ash in coal (Reference 7.2-8, Table 1.1-4).
NO_x control: low NO_x burners, overfire air, selective catalytic reduction (95 percent reduction)	Best available for minimizing NO_x emissions (Reference 7.2-8, Table 1.1-2).
Particulate control: fabric filter (99.9 percent removal)	Best available for minimizing particulate emissions (Reference 7.2-8, Section 1.1.4.1).
SO_x control: Wet limestone flue gas desulfurization (90 percent removal)	Best available for minimizing SO_x emissions (Reference 7.2-8, Table 1.1-2).
Ash and flue-gas desulfurization sludge disposal: Onsite landfill	Existing Nebraska City method for ash.
Cooling water system: closed cycle with cooling towers	Regulatory considerations by OPPD.
Cooling water withdrawal rate and source: 6,100 gpm from Missouri River or groundwater	OPPD estimate.
Cooling tower blowdown rate and receiving water: 600 gpm to Missouri River	OPPD estimate.
Coal and limestone delivery: rail (unit trains of 120 rail cars/train, 100 tons/rail car assumed for coal)	Consistent with current delivery method for coal at Nebraska City Station.
Onsite acreage requirement for power facilities (power block, switchyard, cooling towers, related facilities): 50 acres	OPPD estimate based on existing Nebraska City Station.
Approximate stack height: 650 feet	OPPD estimate based on Nebraska City Unit 1 Boiler Building height of 265 feet and consideration of EPA Good Engineering Practice Stack Height [40 CFR 51.100(ii)].
Offsite transmission requirements: 75 miles of 345-kV line on 100-foot right-of-way	Anticipated OPPD system load requirements and transmission infrastructure.
Construction period: 5 years	OPPD estimate.

TABLE 7.2-1 (CONTINUED)
REPRESENTATIVE COAL-FIRED GENERATION ALTERNATIVE

Characteristic	Basis/Detail
Construction work force: 1,200 (peak), 450 (average)	OPPD estimate; consistent with GEIS estimate of 1,200-2,500 peak workforce for 1,000-MW plant (Reference 7.0-1, Table 8.1).
Additional operating staff: 15	OPPD estimate; operations and support work force would already be in place at Nebraska City Station.

Btu = British thermal unit
CFR = Code of Federal Regulations
CO = carbon monoxide
EPA = U.S. Environmental Protection Agency
FCS = Fort Calhoun Station Unit 1
gpm = gallons per minute
GEIS = *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*
kV = kilovolt(s)
kWh = kilowatt-hour
lb = pound
MW = megawatts
NO_x = nitrogen oxides
PM = filterable particulate matter
PM_{10} = filterable particulates with diameter less than 10 microns
OPPD = Omaha Public Power District
ROW = right-of-way
SO_x = sulfur oxides

7.2.1.2 NATURAL GAS-FIRED GENERATION

For the same reasons discussed in Section 7.2.1.1 for the coal-fired alternative, OPPD has considered for this analysis a representative 480-MW (net capability) combined-cycle natural gas-fired plant, which corresponds to a standard unit size and closely matches the capacity that would be needed to make up for discontinued FCS operations. OPPD assumes for this analysis that the representative plant would be at its existing Cass County Station site. This multi-unit site is being developed for combustion turbine peaking units with eventual conversion of some units to combined-cycle operation with the addition of heat recovery steam generators and steam turbines. The current site design accommodates six 160-MW combustion turbines, four with associated 160-MW heat recovery steam generators and steam turbines, on approximately 90 acres. Initial planned site development consists of two 160-MW combustion turbines at the site in 2003, with conversion of these units to combined-cycle operation in 2009 (Reference 7.2-4).

The Cass County site consists of 237 acres on gently rolling uplands in rural Cass County, Nebraska, approximately 6-1/2 miles west of the Missouri River and 5 miles southwest of Plattsmouth (year 2000 population - 6,887) (Reference 7.2-7) (see Figure 2.1-1). Other small population centers in the area consist of the Village of Murray (year 2000 population - 481), 2 miles southeast of the site; and the unincorporated community of Mynard, 3 miles northeast of the site (Reference 7.2-7). The metropolitan areas of Omaha (year 2000 population - 390,007) and Lincoln, Nebraska (year 2000 population - 225,581) are approximately 15 miles north and 35 miles west of the site, respectively (Reference 7.2-7).

Access to the site is via a rural secondary road from U.S. Route 75 approximately 2-1/2 miles east of the site. The entire predeveloped site consisted of cultivated agricultural land bisected by a narrow strip of riparian woodlands and a few acres of maintained conservation buffer border, an upper reach of Fourmile Creek, which runs northward through the eastern portion of the site. Fourmile Creek originates approximately 3 miles south of the site and outfalls to the Platte River approximately 4 miles northwest of Plattsmouth. Seven large natural gas-supply pipelines, belonging to Enron Gas Company and Natural Gas Pipeline Company, lie within 1 mile of the site, two of which traverse the site property. A major 345-kV transmission intertie (OPPD Line 60) lies 3-1/2 miles west of the site. The area surrounding the site is predominantly agricultural land and is sparsely populated with farmsteads. Natural vegetation in the surrounding area is essentially limited to narrow riparian woods bordering the small streams that drain the area.

Table 7.2-2 is a summary of basic characteristics and environmental impact parameters for the representative natural gas-fired generation alternative assumed for purposes of this analysis, with associated rationale. Emissions of criteria pollutants designated under national ambient air quality standards (40 CFR 50) for this generation technology, except for NO_x, are low enough that emission controls are typically not needed. As is true for the coal-fired alternative, specific air emission controls that would be required in 2013 for NO_x, and potentially other emissions currently unregulated (e.g., CO_2) are not known. In view of this uncertainty, and to avoid overstating the impact of this alternative relative to license renewal, OPPD has generally assumed application of best technology currently available to control NO_x, based on information the EPA provided (Reference 7.2-10). The facility would not require new gas pipelines. However, approximately 75 miles of new 345-kV transmission line may be required between the plant and other points in the transmission system (e.g., Omaha and Lincoln load centers). Makeup water for cooling would be obtained either from onsite wells or from a municipal water source (e.g., rural water district), which could require construction of a new pipeline assumed to be 5 miles long. Cooling tower blowdown would be discharged to Fourmile Creek.

As noted above for the coal-fired generation alternative, a 480-MW natural gas-fired combined-cycle plant could be located at FCS or at a greenfield site. However, location of the plant at the FCS site would require installation of a new gas supply pipeline, which would not be required for the representative plant. Similarly, the advantages of onsite, and potentially offsite, infrastructure noted above for a representative plant at the Cass County site would not be realized at a greenfield site. In Section 7.2.3.2, the key environmental impact differences from the representative plant that would be associated with these siting options are discussed.

TABLE 7.2-2
REPRESENTATIVE GAS-FIRED GENERATION ALTERNATIVE

Characteristic	Basis
Number and type of unit: 1 combined-cycle unit Consists of 2 x 160-MW combustion turbines 1 x 160-MW HRSG/ST Total capability: 480 MW (net) 490 MW (gross)	Standard size (OPPD experience): approximately equivalent to FCS net capacity. Approximate gross capability: 1.02 x net capability (OPPD experience).
Location: Cass County site	Site designed for six 160-MW combustion turbines and addition of HRSG/STs. Initial site development consists of two 160-MW combustion turbines to be on line in 2003; existing staff and infrastructure. Total site acreage: 234, of which 90 acres are planned for power development.
Capacity factor: 0.8	Typical for baseload plant (OPPD experience).
Fuel type: natural gas	Typical fuel for CC baseload application; low emissions.
Fuel heating value: 1,000 Btu/scf	Typical for natural gas in Nebraska (Reference 7.2-9, Table 28).
Fuel sulfur content: 0.2 grains/100 scf (0.00068 wt%)	Typical for pipeline quality natural gas (Reference 7.2-11, Section 1.4.3).
Heat rate: 7,000 Btu/kWh	Typical for gas-fired CC units (OPPD experience).
Uncontrolled SO_2 emissions: 0.00064 lb/MMBtu	EPA emission factor for natural gas-fired turbines (Reference 7.2-10, Table 3.1-2a). Calculated as 0.94 x percent of sulfur in gas.
Dry-low NO_x combustor (NO_x emissions: 9.9E-02 lb/MMBtu; CO emissions: 1.5E-02 lb/MMBtu)	EPA emission factor for best available NO_x combustion control (Reference 7.2-10, Table 3.1-1).
NO_x post-combustion control: selective catalytic reduction (90 percent reduction)	EPA emission factor for best available NO_x post-combustion control (Reference 7.2-10, Section 3.1.4.3).
Uncontrolled PM emissions (all PM_{10}): 1.9E-03 lb/MMBtu	EPA emission factor (Reference 7.2-10, Table 3.1-2a).
Closed-cycle cooling water system (cooling towers)	Environmental impact and regulatory considerations by OPPD.

TABLE 7.2-2 (CONTINUED)
REPRESENTATIVE GAS-FIRED GENERATION ALTERNATIVE

Characteristic	Basis
Onsite acreage requirement for power facilities (power block, switchyard, cooling towers, related facilities): 25 acres	OPPD estimate based on Cass County site plans.
Onsite acreage requirement for infrastructure and support facilities: 0 acres	Facilities will already exist at Cass County site.
Approximate stack height: 250 feet	OPPD estimate based on an approximate HRSG/ST height of 100 feet (Reference 7.2-12) and consideration of EPA Good Engineering Practice Stack Height [40 CFR 51.100(ii)].
Offsite transmission requirements: 75 miles of 345-kV line on 100-foot right-of-way	Anticipated OPPD system load requirements and transmission infrastructure.
Offsite gas supply pipeline requirements: none for Cass County	Seven high-capacity natural gas pipelines lie on or within 1 mile of the site.
Cooling water withdrawal rate and source: 2,438 gpm from municipal source or onsite groundwater	OPPD estimate.
Cooling tower blowdown rate and receiving water: 200 gpm to Fourmile Creek	OPPD estimate.
Construction period: 2-3 years	OPPD estimate; industry experience.
Construction work force: 450 (peak), 200 (average)	OPPD estimate.
Additional operating staff: 10	OPPD estimate; substantial work force will already be in place at Cass County Station.

Btu = British thermal unit
CC = combined cycle
CO = carbon monoxide
EPA = U.S. Environmental Protection Agency
FCS = Fort Calhoun Station Unit 1
gpm = gallons per minute
HRSG/ST = heat recovery steam generator and steam turbine
kV = kilovolt
kWh = kilowatt-hour
lb = pound
MM = million
MW = megawatt
NO_x = nitrogen oxides
OPPD = Omaha Public Power District
PM = filterable particulate matter
PM_{10} = filterable particulates with diameter less than 10 microns
scf = standard cubic foot
SO_2 = sulfur dioxide
wt. = weight

7.2.1.3 PURCHASED POWER

Any discussion of the potential sources of purchased power to replace FCS capacity at a future date is conjectural. Out-of-state utilities (e.g., members of MAPP) and independent power producers represent potential sources of such power. Nebraska has been a net exporter of electricity in recent years (Reference 7.2-3; Reference 7.2-13), suggesting that power also could be available from instate sources. If present conditions persist, these potential instate sources would be limited to other utilities. Nebraska is unique in that it is the only state in the country served entirely by publicly owned power entities, which include public power districts such as OPPD, cooperatives, and municipalities. In view of the relatively low-cost power and nonprofit services from these consumer-owned systems, Nebraska's utility industry remains regulated, and the state is pursuing a "condition certain" approach to deregulation. Under this framework, Nebraska would continue to monitor industry deregulation in the nation and wholesale market prices, and would implement a public process to assess and adopt retail competition in the event that a deregulated market is determined to offer assured benefits and protections to Nebraska consumers (Reference 7.2-14). Non-utility generating capability in Nebraska amounted to only 16 MW in 1999, and no additions are planned through 2004 (Reference 7.2-15).

Any predictions regarding the technologies that would be used to generate purchased power at a future date are similarly speculative and conjectural. However, OPPD assumes one or more of the technologies the NRC evaluated in the GEIS would be used, and considers the GEIS descriptions of these technologies to be appropriately representative.

It is similarly unclear at present what, if any, additional transmission infrastructure would be required in the event OPPD purchased power to replace FCS capacity. The transmission system in eastern Nebraska is inherently secure and stable because approximately 80 percent of the state's electrical load is there. The bulk 345-kV transmission system in this area has sufficient redundancy, and strong electrical ties exist between major load centers in eastern Nebraska (Reference 7.2-1, Section 8.1.2). Import of power from the west would be relatively more likely to require additional transmission. Western Nebraska is characterized by low local area loads, high baseload generation, and no synchronous ties to the Western interconnected system of the U.S. This mismatch creates a heavy reliance on the transmission system to transport power to load centers in eastern Nebraska (Reference 7.2-1, Section 8.1.2). In any event, importing power could result in the need for additional transmission facilities (Reference 7.2-1, Section 8.2.3), although supply from multiple diverse sources would minimize the amount of transmission needed. OPPD assumes for this option that 35 miles of new 345-kV transmission line could be required on a 100-foot right-of-way, and that this line would be routed according to the results of an appropriate routing study to minimize potential environmental impacts, including land use incompatibilities.

7.2.2 OTHER ALTERNATIVES CONSIDERED

OPPD describes in this section alternatives other than coal and natural gas-fired generation that were considered to ensure system energy needs are met in the event that the FCS operating license is not renewed. The discussion includes the reasons why OPPD does not consider these alternatives to be reasonable or feasible for purposes of this evaluation.

7.2.2.1 GENERATION ALTERNATIVES

In addition to coal-fired and natural gas-fired generation, representative examples of which are identified as feasible alternatives in Section 7.2.1, the NRC evaluated several other generation technologies in the GEIS (Reference 7.0-1, Chapter 8.0). OPPD has also considered most of these options in its integrated resource planning, which involves identifying potentially viable technologies, categorizing them by potential application (i.e., baseload, intermediate, peaking), and performing an economic analysis. In addition, OPPD participates with the NPA in supporting research and development of alternative generation technologies, including wind and other renewable energy sources. Table 7.2-3 provides a list of the alternative generation technologies OPPD considered, its basis for not including them as reasonable and feasible alternatives for replacement of FCS capability, and an indication of OPPD and NPA efforts to research selected technologies.

7.2.2.2 DELAYED RETIREMENT

As the NRC noted in the GEIS (Reference 7.0-1, Section 8.3.13), 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. OPPD has considered this option, but does not consider it to be a reasonable alternative to license renewal for FCS. OPPD currently has only two non-nuclear baseload facilities, both of which are coal fired: the Nebraska City Station, a single unit having a 631-MW net summer capability, placed in service in 1979; and the North Omaha Station, consisting of five units totaling 663 MW of net summer capability, placed in service in the 1950s and 1960s (Reference 7.2-1, Section 4.4; Reference 7.2-4, Attachment 1). OPPD expects to operate the Nebraska City Station for the foreseeable future. In addition, OPPD has undertaken measures to maximize the generating life of North Omaha Units 1-5 under the Life Optimization, Maintenance and Repair Project (Reference 7.2-2, Section 5.1.1) and its current capital expenditure plan. As a result of these efforts, OPPD expects all of its existing non-nuclear baseload units to remain in service until at least 2020. Their associated generating capability is formally accounted for in OPPD’s integrated resource planning projections, which currently extend through 2016 (Reference 7.2-2, Sections 4.4, 5.1.1; Reference 7.2-4, Attachments 1 and 2).

TABLE 7.2-3
OTHER GENERATION TECHNOLOGY OPTIONS CONSIDERED

Alternative	Considerations/Reasons for Not Evaluating Further
Wind	OPPD has evaluated wind technology as a 50- and 100-MW capacity addition for intermediate load and baseload applications. Results indicate that this option may be an attractive option for intermediate load service; however, capacity factor for a wind turbine would be approximately 30 percent, substantially below that needed for baseload service (Reference 7.2-2, Sections 5.1.5, 6.1; Reference 7.2-4, page 6 and Attachment B). However, OPPD continues to explore this option for intermediate load application. OPPD participated with the NPA in conducting a 4-year wind speed monitoring study in Nebraska. Results indicate that annual average wind speeds at the study sites (14.4-16.4 miles/hour) are technically sufficient for commercial wind farm development. However, wind speeds are lowest in the summer when Nebraska experiences peak loads as a result of air conditioning and irrigation activities (Reference 7.2-16, pages 1-3, 18, Figure 5, Table 4; Reference 7.2-3, page 5). As the NRC indicates, capacity factors for this option are currently too low for baseload application of this technology, and land requirements would be large (Reference 7.0-1, Section 8.3.1).
Solar Photovoltaic	OPPD has evaluated solar photovoltaic technology as a 100-MW facility for intermediate and peak load applications (Reference 7.2-2, Sections 5.1.5, 6.1; Reference 7.2-4, Attachment B). Results indicate this option would be expensive. OPPD participated in solar insulation monitoring conducted during an NPA wind speed monitoring study in Nebraska (Reference 7.2-16, page 18). Average annual solar insulation for the eight monitoring sites ranged from 4.07 to 4.24 kWh/m^2/day. NPA used data from the first year of this study to evaluate two 10-MW photovoltaic plants using variations of this technology: a fixed-flat plate system and a solar concentrating system. The range of annual capacity factors for the sites was 13.1-15.1 percent. NPA indicated that solar photovoltaic technologies are too expensive for bulk power applications, but noted increasing use for small distributed applications (Reference 7.2-1, Section 7.2). Modest solar resource availability in Nebraska, intermittency of this resource, and expense of energy storage results in capacity factors too low for practical baseline generation, and land requirements would be very large for 500 MW of capacity (Reference 7.0-1, Section 8.3.2).

TABLE 7.2-3 (CONTINUED)
OTHER GENERATION TECHNOLOGY OPTIONS CONSIDERED

Alternative	Considerations/Reasons for Not Evaluating Further
Solar Central Receiver	OPPD has evaluated solar central receiver technology as a 100-MW facility for intermediate and peak load applications (Reference 7.2-2, Sections 5.1.5, 6.1; Reference 7.2-4, Attachment B). Results indicate this option would be expensive. Modest solar resource availability in Nebraska, intermittency of this resource, and expense of energy storage results in capacity factors too low for practical baseline generation, and land requirements would be large for 500-MW capacity (Ref 7.0-1, Section 8.3.3).
Hydroelectric	OPPD has evaluated hydroelectric technology only as pumped storage for peaking application (Reference 7.2-2, Sections 5.1.5 and 6.1; Reference 7.2-4, Attachment B). Although the upper Missouri River is currently developed for hydroelectric power, the potential for development of hydroelectric power on the lower Missouri River in or near the OPPD service territory is limited by topography (Section 2.1) (Reference 7.2-17, Section 3.1). Hydroelectric generating capability in Nebraska amounted to only 167 MW (approximately 2.9 percent of total utility generating capability) in 1998, slightly below capacity available in 1988 (Reference 7.2-3). As the NRC indicated, a relatively low capacity factor, a large land-use requirement (e.g., inundation of approximately 500,000 acres or more could be required for a 500-MW plant), and substantial ecological impacts would be associated with this option (Reference 7.0-1, Section 8.3.4).
Geothermal	Potentially developable geothermal resources are not present in eastern Nebraska (Reference 7.0-1, Section 8.3.5).
Wood and Other Energy Crops	OPPD has evaluated wood fuel as a 100-MW unit for baseload application (Reference 7.2-2, Sections 5.1.5, 6.1; Reference 7.2-4, Attachment B). Results indicate this option would be expensive. OPPD, in conjunction with other utilities in the NPA, is monitoring the development of Whole Tree Technology^{TM}, a steam cycle generating technology, and use of switchgrass or other energy crops (e.g., alfalfa stems) as fuel for gasification/combined-cycle generation technology (Reference 7.2-1, Sections 7.3, 7.4). At this stage of development, OPPD does not consider these technologies to have progressed sufficiently to provide economical and reliable baseload service.

TABLE 7.2-3 (CONTINUED)
OTHER GENERATION TECHNOLOGY OPTIONS CONSIDERED

Alternative	Considerations/Reasons for Not Evaluating Further
Municipal Solid Waste	OPPD has evaluated this technology as a 40-MW unit for baseload application. Results indicate this option would be expensive. As noted by the NRC (Reference 7.0-1, Section 8.3.7) and NPA (Reference 7.2-1, Section 7.5), use of this option is primarily a waste management decision, and tipping fees, availability of landfill space (which is not in short supply in Nebraska), and reduced heat content of the waste stream due to segregation and recycling of high heat content components (e.g., wood, paper, plastics) affects economic viability. NPA also notes as factors affecting viability of this option the potential presence of toxic substances in municipal solid waste ash and the fact that this technology is not qualified to receive the 1.5-cent/kWh renewable energy production incentive available under the Energy Policy Act of 1972. OPPD has determined that recovery of landfill gas and use as fuel to produce electricity is a feasible and cost-effective renewable energy technology and plans to develop a landfill gas-to-energy facility at the Douglas County, Nebraska, municipal solid waste landfill (Reference 7.2-4, pages 5-6). Initial operation of the facility, consisting of multiple-unit internal combustion engine/generators, is planned for 2002. Ultimate development of this resource is uncertain, but OPPD believes the landfill has a potential to support approximately 30 MW of baseload generation capacity. However, this technology option would not provide sufficient capacity to replace FCS.
Oil	OPPD has evaluated this technology in recent integrated resource plans only as a 5-MW internal combustion diesel-powered unit for peaking purposes. Results indicate this option would be expensive. The relative viability of oil-fired generation in Nebraska compared to other fuels is indicated by the fact that it represents a small fraction of generation capability in the state and has a low utilization rate relative to other sources (see Figure 7.2-1).
Advanced Nuclear Reactor	OPPD has evaluated this technology as a 600-MW unit for baseload application. Results indicate this option would be expensive. Although positive interest in the development of new nuclear power plants has been expressed recently by members of both industry and government, substantial political uncertainty remains regarding this option. In addition, the Energy Information Administration indicates in recent projections that no nuclear power plants are expected to be constructed by 2020 (Reference 7.2-18, page 5).

FCS = Fort Calhoun Station Unit 1
kWh = kilowatt hour
m^2 = square meter
MW = megawatt
NPA = Nebraska Power Association
NRC = Nuclear Regulatory Commission
OPPD = Omaha Public Power District

7.2.2.3 DEMAND-SIDE MANAGEMENT

As part of its integrated resource planning process, OPPD annually reviews demand-side management measures that could be taken to influence customer use of OPPD-supplied electricity, which in turn would reduce overall demand and make more efficient use of existing generating capacity. To the extent these measures reduce system demand, they can offset or delay the need for new generation capability, and the NRC thus considered them an alternative to license renewal in the GEIS (Reference 7.0-1, Section 8.3.14). OPPD has implemented the following demand-side management programs, and has included associated changes in net demand into its projected baseload forecast (Reference 7.2-2, Section 5.2; Reference 7.2-4, page 7):

- Residential Energy Conservation Program (RECP) – OPPD's RECP is designed to conserve energy and save money throughout the year by providing energy credit refunds and/or special rates to customers who install high-efficiency heat pumps or high-efficiency electric heating and cooling systems.

- Curtailable Rates – OPPD offers five rate schedules wherein it can conditionally discontinue or reduce service to customers during periods of high demand, thus reducing system peak loads.

- Load Curtailment/Standby Generation Agreements – OPPD has agreements with several customers to use their own onsite generation sources to reduce or eliminate load at OPPD's request, which acts to reduce OPPD system peak loads.

- Commercial Heating, Ventilation, and Air Conditioning (HVAC) – OPPD offers rebates to commercial and industrial customers who install a water-source or air-source heat pump. Additional incentives are offered with the installation of an electric boiler as a backup heat source. This measure results in off-peak (winter) load building and reduction in peak (summer) demand.

OPPD has screened additional demand-side management programs, and is currently considering implementation of the following measures, with program impact and potential system demand reductions as indicated upon full implementation (Reference 7.2-4, page 7):

Proposed Program	Program Impact	Target Demand Reduction (MW)
Air Conditioner (A/C) Cycling	Peak Clipping	100.0
A/C Setback Thermostat	Peak Clipping/Conservation	39.5
A/C Tune-Up/Cleaning	Peak Clipping/Conservation	15.8
Commercial Efficient Lights	Conservation	4.9
Total		160.2

OPPD has achieved and continues to pursue substantial load reductions through the use of demand-side management efforts. However, as noted above, currently implemented measures are already credited into OPPD's load forecast and are not available to offset generating capability attributable to FCS. While OPPD intends to achieve additional demand reductions of approximately 160 MW in the next few years, OPPD considers these potential reductions a contingency to its overall resource plans. In any event, the potential reductions would be insufficient to replace FCS capacity. On the basis of its annual screening of potentially viable demand-side measures, OPPD is unaware of additional viable opportunities. Based on these considerations, OPPD does not consider demand-side management measures to be a feasible alternative to renewal of the FCS operating license.

7.2.3 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

The following sections are discussions of OPPD's evaluations of environmental impacts for the feasible generation alternatives. Sections 7.2.3.1 and 7.2.3.2, respectively, discuss impacts associated with OPPD's coal-fired and natural gas-fired representative alternatives. These plants would not be constructed to operate for only the FCS extended operation period; therefore, OPPD assumes for this analysis a typical design life of 40 years for the coal-fired plant and 25 years for the combined-cycle natural gas-fired plant, and that these plants would be constructed on a schedule that would allow them to be in service when FCS shuts down. OPPD focused its evaluation of these alternatives on its representative plant locations (Nebraska City site and Cass County site) as identified in Section 7.2.1. However, key differences in impact that could be expected as a result of locating these plants at FCS or at a greenfield site are noted. OPPD presents its discussion of environmental impacts of the purchased power alternative in Section 7.2.3.3. Chapter 8.0 presents a summary comparison of environmental impacts of license renewal and alternatives discussed in this section.

7.2.3.1 COAL-FIRED GENERATION

LAND USE

Based on current site configuration and expansion plans, OPPD estimates that development of the representative coal-fired alternative at the Nebraska City site would require approximately 50 acres for the power block, cooling towers, and related support facilities, which would be dedicated to industrial use for the life of the plant. Onsite disposal of ash and flue gas desulfurization waste (i.e., scrubber sludge; see Waste Management discussion, below) would require an estimated 90 acres of the site, which is currently active cropland. Assuming no use is ever found for this waste, farming and other land uses that could compromise the integrity of the landfill once it is closed and levitated would be precluded. Most of the onsite acreage that this alternative would affect is currently farmed. However, these land-use changes would be consistent with planned incremental development of the site, which presently supports a coal-fired power plant, ash disposal landfill, and related infrastructure. The permanent land-use changes to the 90 acres needed for waste disposal would be noticeable, but would not destabilize land use in the area, a characteristic of moderate impact.

OPPD expects that an additional 75 miles of 345-kV transmission line would be required off site to transmit additional power produced at the Nebraska City Station, probably to load centers Omaha and Lincoln, Nebraska. OPPD would typically acquire easements for a 100-foot right-of-ways for the line. The predominant land use in the area is cultivated farmland; the area is sparsely populated. OPPD would route this line based on the results of an appropriate routing study that evaluates how best to minimize environmental impacts, including land-use conflicts. Agricultural use, which would be most affected, could continue in areas not occupied by tower footings. On this basis, impacts on land use are likely to be small to moderate. Considering the permanent land-use change that would result from waste disposal, overall land-use impact for this alternative is considered to be moderate.

No offsite development (e.g., for transmission lines) would likely be needed for the development of a 500-MW coal-fired plant at FCS. However, OPPD estimates that, in addition to 50 acres required for the power block and cooling towers (assuming a closed-cycle cooling mode), a minimum of 200 acres would be needed to reconfigure the existing rail spur and construct necessary facilities for coal, limestone, and ash storage and handling. An additional 90 acres is estimated to be required for waste disposal; this is discussed in more detail below.

Although agricultural land and other potentially developable land on the FCS site total more than 345 acres (see Section 2.1.3), it may be necessary to acquire additional acreage to efficiently configure the site to accommodate the plant. OPPD also expects that additional land disturbance would be required to recontour the site to ensure protection from flood flows. Much of the site land surface is at an approximate elevation of 1,000 feet above mean sea level (msl) and the 100-year flood stage for the site is approximately 1,001 feet msl (Reference 7.2-19, Section 2.7.1.2). This condition would likely require raising base land surface elevations for the power block and ash-scrubber sludge landfill, perhaps using fill excavated from higher areas near the southern portion of the site or from offsite areas. In particular, Nebraska Department of Environmental Quality (NDEQ) regulations [Nebraska Administrative Code (NAC), Title 132, Chapter 4, prohibit locating ash disposal landfills in a 100-year floodplain unless it can be demonstrated that facility integrity would be assured and the facility would not restrict flood flows or reduce temporary water storage capacity. Potentially affected onsite acreage is predominantly cropland or land currently maintained as part of current plant operations, although the southern portion of the site potentially useful for fill supports natural vegetation. The potential for offsite land-use conflicts may exist as a result of rural residential development along and near U.S. Highway 75 bordering the site. However, industrial development is being encouraged in this general area, as evidenced by the establishment of the nearby Blair Industrial Park and Cargill Facility (see Section 2.1.2). In view of the above considerations, land-use impact would be clearly noticeable.

Assuming the site could be recontoured to accommodate an ash-scrubber sludge landfill operating in compliance with regulations, the impact would not be considered destabilizing, and therefore characterized as moderate. If this accommodation could not be made, impact could be considered large, and this waste would have to be disposed of elsewhere.

Development of a 500-MW coal-fired plant at a greenfield site would require development of more land than either the Nebraska City or FCS options would require in order to provide for such facilities as a switchyard, support facilities, roads and other infrastructure, and an appropriate buffer zone. OPPD estimates that a maximum of 850 acres would be required, half of the site acreage requirement the NRC cited for a 1,000-MW coal-fired plant (Reference 7.0-1, Table 8.1). An estimated 150 miles of offsite transmission lines (three lines) would also likely be required. Depending on location, land-use impacts could theoretically range from moderate to large, but could be maintained at moderate levels with appropriate planning.

WATER USE AND QUALITY

Development of onsite and offsite facilities for a 500-MW coal-fired power plant at the Nebraska City site or other location could result in some localized and temporary degradation of surface water quality (e.g., from introduction of sediments) during construction. Introduction of sediment or contaminants from spills (e.g., via stormwater) creates potential sources of impact during both construction and operation. However, National Pollutant Discharge Elimination System (NPDES) stormwater permit restrictions, associated pollution prevention plans, and related requirements would limit these impacts. Similarly, sanitary and process waste streams and leachate from the ash and scrubber waste landfill would be appropriately treated, and discharges would meet the limitations established in the NPDES permit. The ash and scrubber waste landfill would be located, designed, permitted, operated, and monitored in compliance with applicable regulations to ensure protection of groundwater (e.g., NAC Title 132, Chapter 4). Therefore, the potential for associated adverse impacts from these sources on surface water and groundwater resources is considered to be small.

Impacts on water use and quality from power plant operation, which are potentially of greatest concern from an environmental standpoint, are associated with the cooling water system which, like that existing at FCS, cools and condenses steam in the main condensers of the plant (see Section 3.1.3). Unlike FCS and the existing coal-fired plant at Nebraska City, which feature a once-through circulating water system that withdraws from and discharges to the Missouri River, OPPD's representative coal-fired alternative at the Nebraska City site is assumed to have a closed-cycle cooling system using cooling towers.

Both the Missouri River and onsite groundwater are potential sources of makeup water. However, the impact of these withdrawals would be small. Net withdrawal from the river [5,500 gpm or 12 cubic feet per second (cfs)] would amount to only 0.1 percent of the Missouri River minimum monthly average flow of approximately 14,000 cfs, observed at

Nebraska City from 1970-1999 (Reference 7.2-20). Groundwater at the site maintains a direct hydraulic connection to the Missouri River at all times of the year, and the yield from wells established in the area for irrigation are large, e.g., 700-2,000 gpm (Reference 7.2-6, Appendix Section 2.1.7.2). OPPD would obtain required state water appropriation permits for any surface and groundwater withdrawals, which are designed to ensure availability of these resources to other users. Cooling tower blowdown would be discharged to the Missouri River and would be characterized primarily by an increased temperature, dissolved solids relative to the river, and possibly intermittent low concentrations of biocides (e.g., chlorine). However, these discharges are estimated to amount to only 600 gpm (1.3 cfs) and would be subject to the strict limitations of an NPDES permit. Considering also the large flow volume of the river, overall changes in surface water quality characteristics would be minor. OPPD therefore considers overall impact to water use and quality for the representative plant to be small.

OPPD assumes that the cooling water system for a coal-fired alternative plant at FCS would withdraw from and discharge to the Missouri River. This site offers the potential flexibility of using either cooling towers or maximizing use of the existing circulating water intake and discharge structure in a once-through (i.e., open-cycle) cooling mode. As noted above for the representative plant, net water withdrawal from the river to make up for evaporative losses from cooling towers (closed-cycle cooling mode) would be small. In addition, because a coal-fired plant has a higher thermal efficiency than a comparably sized nuclear power plant (Reference 7.0-1, Table 8.2), lower cooling water flows than FCS uses would also be expected in a once-through cooling mode. Since FCS has a small impact on water use and quality, impact of the coal-fired alternative would also be small.

Impact on water use and quality from an alternative coal-fired plant at a greenfield site is dependent on the characteristics of the source water and receiving water body and is, therefore, less quantifiable. However, given the protection required water appropriation permits and wastewater discharge permits provide, impacts would likely range from small to moderate.

AIR QUALITY

Potential adverse impacts to air quality from a coal-fired power plant are substantially different from those of a nuclear power plant as a result of the fuel used and the combustion process. Emissions of greatest concern include sulfur oxides (SO_x), nitrogen oxides (NO_x), particulate matter, and carbon monoxide (CO)--all of which are regulated pollutants--and carbon dioxide (CO_2), an unregulated “greenhouse gas.” SO_x, generally expressed as equivalent concentrations of sulfur dioxide (SO_2), and NO_x are important contributors to acid rain. NO_x contributes to ozone formation, a major component of smog, and particulates are a main source of haze. All of these regulated pollutants are of concern from a health risk standpoint, particularly for their potential for adverse effects on the respiratory system. Emissions of CO_2, formed as a primary product of the combustion process, have been raised as a concern with respect to global warming

(Reference 7.0-1, Section 8.3.9). As Section 7.2.1 indicates, OPPD has assumed a plant design that includes control technologies to effectively minimize emissions of regulated air pollutants. Based on emission factors and estimated efficiencies for these emission controls cited by the EPA, and assumed design parameters (see Table 7.2-1), approximately 2,061,000 tons of coal would be consumed annually, resulting in the following annual air emissions for these pollutants[1]: SO_x = 1,230 tons; NO_x = 430 tons; CO = 520 tons; total particulates (filterable) = 62 tons; and particulates having a diameter of less than 10 microns (PM_{10}) = 14 tons.

Air quality in Nebraska and Iowa currently complies with national ambient air quality standards (10 CFR 50) for the above pollutants. With the exception of a portion of Omaha currently designated a nonattainment area for lead, and Muscatine County in eastern Iowa, formerly in nonattainment for SO_2, the EPA lists no areas in Nebraska or Iowa as currently or formerly in nonattainment with ambient air quality standards for any of the criteria air pollutants (Reference 7.2-21). OPPD has conducted a screening level modeling study of new coal-fired units at Nebraska City (Reference 7.2-22), which focused on SO_2, the criteria pollutant considered most likely to be limiting with respect to ambient air quality standards and prevention of significant deterioration requirements (40 CFR 51.166). Results of this study suggest that while changes in SO_2 levels may be detectable, these changes would be small and would not affect the current ambient air quality compliance status and would be well within allowable prevention of significant deterioration concentration increments. However, considering the public health risks and potential concerns related to acid rain and global warming associated with air emissions from coal combustion the NRC cites (Reference 7.0-1, Section 8.3-9), OPPD considers the potential impacts on air quality to be moderate for the coal-fired alternative, regardless of its location at sites considered in this analysis.

WASTE MANAGEMENT

The coal-fired generation alternative would annually consume approximately 2,061,000 tons of coal having an ash content of 6 percent, of which 80 percent is fly ash and 20 percent is bottom ash (see Table 7.2-1). OPPD currently sells approximately 50 percent of the fly ash it produces at its coal-fired plants for beneficial use, and assumes sufficient additional demand will be identified in the future to maintain this percentage. Some or all scrubber sludge from the assumed flue-gas desulfurization process (gypsum) also represents a potentially usable product. However, considering the relatively large volume of this waste and uncertainties in future demand, OPPD has ignored this potential in evaluating the impact for this alternative.

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[1] Annual emissions of regulated air pollutants calculated as follows from amount of coal combusted and estimates of uncontrolled air emissions and removal efficiencies (all necessary parameters are listed in Table 7.2-1): Coal Combusted (tons/yr) = Total Gross Capability (MW) x Heat Rate (Btu/kW-hour) x 1000 (kW/MW) x Fuel Heat Value (lb/MMBtu) x 0.0005 (ton/lb) x Capacity Factor (80%) x 8,760 hr/yr = 2,061,000 tons/yr. Pollutant Emissions (tons/yr) = Coal Combusted (tons/yr) x Uncontrolled Emissions (lb/ton) x 0.0005 (ton/lb) x [100 – removal efficiency (%)]. Removal efficiency for carbon monoxide is assumed to be zero.

Consistent with the above assumptions and current operations at the Nebraska City Station, OPPD assumes that all of the bottom ash and approximately 50 percent of the fly ash the coal-fired alternative would generate, amounting to approximately 74,000 tons per year, would be disposed of in an onsite landfill. In addition, approximately 23,000 tons of limestone would be used annually for flue-gas desulfurization, generating approximately 36,000 tons of dry scrubber sludge that would also be disposed of on site. OPPD currently disposes of ash in landfills at the Nebraska City site in essentially above-grade cells. Consistent with this practice and assuming an average waste depth of 30 feet in the landfill, it is estimated that ash and scrubber waste disposal over the 40-year plant life would occupy approximately 90 acres. OPPD would design, operate, close, and monitor the landfill in accordance with applicable requirements specified in the facility permit and associated regulations. After closure and revegetation of the disposal facility, the land could be made available for other noninvasive uses (e.g., recreation).

The coal-fired alternative plant would also generate relatively small quantities of the spent catalyst used for NO_X control at the plant. OPPD assumes this waste would be disposed of in accordance with applicable regulations at a permitted offsite disposal facility, regardless of the plant's location.

Based on these considerations, the impact of waste management operations for OPPD's representative plant would be clearly noticeable, but destabilization of groundwater quality or other resource attributes would not be expected. Therefore, OPPD believes that waste management impacts for the coal-fired generation alternative at the Nebraska City site would be moderate.

Theoretical impacts from waste management for a coal-fired alternative at FCS could be moderate to large depending on the feasibility of developing the ash disposal facility in compliance with Nebraska location standards for the facility, as previously discussed under land use impacts.

For a greenfield site, OPPD would select a location for a coal-fired plant on the basis of the results of an appropriate siting study, which would ensure that site characteristics are suitable for waste disposal in accordance with applicable environmental regulations. On this basis, associated impacts are assumed to be comparable to those described above for the representative plant.

ECOLOGICAL RESOURCES

Development of the coal-fired alternative plant at the Nebraska City site would affect only marginal onsite terrestrial species habitat, consisting of approximately 140 acres in areas modified for industrial use or cultivation. OPPD therefore considers impact to onsite terrestrial resources to be small. Transmission lines for the plant, consisting of approximately 75 miles of 345-kV line on a 100-foot right-of-way, would be located based on the results of an appropriate routing study that would seek to avoid high-value habitat and, based on current land-use patterns, would most likely traverse active agricultural land for most of its length. In addition, shrub habitat, which has substantial wildlife value, would be promoted and maintained on the right-of-way in rural areas where existing uses (e.g., agriculture) are not conflicting, in accordance with OPPD's current practices (see Section 3.1.4). Therefore, the impact to ecological resources along the transmission line would also likely be small.

Impacts to ecological resources from operation of the coal-fired alternative that are potentially of greatest concern are associated with the cooling water system for the plant. OPPD would use cooling towers with water from the Missouri River or groundwater for makeup and would discharge blowdown to the Missouri River. The cooling system would be designed and operated in compliance with the Clean Water Act (CWA), most notably provisions of Sections 316(a) and 316(b), respectively related to thermal discharge impact and cooling water intake effects (e.g., impingement and entrainment of aquatic organisms). Intake and discharge flows, and thermal loading to the Missouri River would be much lower than for the existing Nebraska City Station, which uses once-through cooling. Associated impacts on Missouri River biota from this plant have been demonstrated to be acceptably low on the basis of approved CWA Section 316(a) and 316(b) studies and operation-phase monitoring. On the basis of these considerations, OPPD expects that the impact on aquatic biota from operation of the representative coal-fired alternative would be small. Given the considerations discussed above, OPPD believes that the overall impact to ecological resources for the representative plant would be small.

Terrestrial habitat potentially affected by construction of the coal-fired alternative at FCS consists predominantly of agricultural land and areas maintained as part of current site operations, which are of marginal value for wildlife. Regrading of the site to ensure protection from flood flows could eliminate as much as approximately 40 acres of upland woods and shrubland on slopes between U.S. Highway 75 and the onsite rail spur (see Figure 2.1-3) or a similar offsite habitat, depending on the borrow area location. These onsite forest and shrub habitats are essentially isolated and highly disturbed. Although they represent a substantial proportion of natural terrestrial habitat on the site, their loss would not noticeably affect overall availability of such habitat in the general site vicinity. Impact of current FCS operations on aquatic biota is considered to be small (see Chapter 4.0), and intake and discharge flows and thermal loading to the Missouri River from operation of the coal-fired alternative are expected to be less than for the current plant, regardless of the choice of cooling system (e.g., once-through or cooling towers). In view of these considerations, OPPD considers the impact to ecological resources from this option to be small.

Projections of the ecological impacts resulting from locating the plant at a greenfield site are conjectural, but likely would be low to moderate. A relatively low-quality ecological habitat predominates in the area, and large water bodies for cooling water (e.g., Platte River, Missouri River) are relatively accessible. In addition, OPPD would locate the site and associated transmission lines and other infrastructure (e.g., rail) with appropriate consideration of ecological resources.

SOCIOECONOMICS

Major sources of potential socioeconomic impacts from the coal-fired generation alternative include:

- temporary increases in jobs, economic activity, and demand for housing and public services in communities surrounding the site during the construction period, and

- changes in permanent jobs and economic activity attributable to coal-fired plant operation and shutdown of FCS.

As noted in Table 7.2-1, OPPD estimates that the representative 500-MW coal-fired plant would be constructed in approximately five years with an average work force of 450 and a peak work force of 1,200. Large labor pools in the metropolitan areas of Omaha and Lincoln, Nebraska, are within approximately 40 miles and 50 miles of the site, respectively. Therefore, it is expected that most workers would commute and relatively few would temporarily relocate to Nebraska City or other small communities in the area. OPPD estimates the following work force breakdown for construction of the additional plant at the existing Nebraska City Station (Reference 7.2-6, Appendix Section 3.1.3), expressed as approximate percentages of average construction work force levels: 10 percent local hires (i.e., from Otoe County, Nebraska or Fremont County, Iowa); 5-10 percent temporary relocations; and 80-85 percent commuters from outside the two-county area (85 percent daily commuters, 15 percent weekly commuters). Assuming similar estimates for an average construction work force of 450, a maximum of 45 workers would temporarily relocate and approximately 60 workers would commute weekly. The corresponding increase in demand for housing and public services in Nebraska City (year 2000 population – 7,228) (Reference 7.2-7) and other smaller communities near the site due to the temporary relocation of workers and their families might be noticeable, but could be readily accommodated. The resulting impact is therefore considered to be small to moderate. These communities would realize temporary economic benefits during construction, including increased jobs and expenditures for the plant. OPPD expects that only 15 additional workers would be required to operate the representative coal-fired alternative plant, with correspondingly small positive and negative impacts to neighboring communities.

Implementation of this alternative would result in the eventual net loss of jobs and associated economic activity attributable to shutdown of FCS. Approximately 740 workers are currently employed at FCS, of which approximately 56 percent reside in Douglas County, which includes Omaha (see Section 3.4). Considering the large population and labor force in Douglas County and the Omaha area, loss of these jobs would have a minor impact on these communities. However, approximately 23 percent of plant employees (approximately 170 workers) reside in Washington County (year 2,000 population - 18,780), many of these in Blair (year 2000 population – 7,512) (see Section 2.4.1). In addition, OPPD is a major employer in Washington County. It is expected that the loss of these jobs and reduction of general economic activity resulting from FCS shutdown would be noticeable, but would not destabilize local economies, particularly considering potential job opportunities in the Omaha area, which is within commuting distance. OPPD therefore considers the overall socioeconomic impact of this alternative to be small to moderate.

Location of the coal-fired alternative at FCS is likely to have only a small impact on surrounding communities during construction, considering its proximity to the Omaha metropolitan area. The operating work force for the new plant is expected to be 250 or fewer based on the estimate for a 1,000-MW coal-fired plant cited by the NRC (Reference 7.0-1, Table 8.2). Work force requirements for the new plant would act to offset direct loss of jobs resulting from the shutdown of FCS. For the same reasons discussed above for the representative plant, the net loss of 500 jobs would likely represent a small to moderate impact to local communities.

In view of the above considerations and the fact that virtually all of OPPD's service territory is within commuting distance to large population centers (e.g., Omaha and Lincoln, Nebraska, and Sioux City, Iowa), the overall socioeconomic impact from development of a coal-fired plant at a greenfield site also would be expected to be small to moderate.

TRANSPORTATION

Potential impacts on transportation from the coal-fired alternative stem primarily from increased rail traffic for delivery of coal and limestone to the plant and increased vehicular traffic by plant employees. The plant is expected to use approximately 2,061,000 tons of coal and 23,000 tons of limestone annually, as stated in the prior discussions of air quality and waste management impacts. Consistent with current Nebraska City Station operations, it is assumed that delivery of coal would be by unit trains of 120 cars with an approximate capacity of 100 tons per car. Limestone delivery is also assumed to be rail. This amounts to three to four additional trains per week in addition to the three to four trains per week that support current plant operations. Cumulative round-trips on this line would therefore be approximately one per day. OPPD owns the rail line from Lincoln that is used for this delivery; it is used exclusively to serve Nebraska City Station. In addition, overpasses are provided for major thoroughfares that intersect this line, including U.S. Highway 75 and State Highway 2 in Nebraska City. Considering the low traffic on this line and crossing improvements, the resulting impact would be small. Construction of the plant would result in a temporary increase in traffic caused by construction workers; however, plant operation is expected to require only 15 additional permanent employees (see Table 7.2-1). Assuming an average and maximum construction work force of 450 and 1,200, respectively (see Table 7.2-1) and 2.1 workers per vehicle (Reference 7.2-6, Appendix Section 3.1.3.6), increased traffic would amount to approximately 210-570 round-trips per day. OPPD expects that few, if any, additional control measures would be required to accommodate this additional traffic on the rural secondary road providing interconnection to the major thoroughfares (U.S. Highway 75, State Highway 2). These thoroughfares are major highways that bypass downtown Nebraska City. Resultant impacts are, therefore, considered to be small.

Location of the coal-fired alternative at FCS would increase train traffic (three to four round-trips per week) on the rail spur from the plant to the main line in Blair, Nebraska, and on the main line through Blair. This would be a small increase, and neither the spur nor the main line includes at-grade crossings of main thoroughfares in Blair (U.S. Highways 30 and 75). Considering the near proximity of the site to the Omaha metropolitan area, the number of workers carpooling may be fewer than would occur at the Nebraska City site (e.g., 600-800 round-trips per day). Appropriate staggering of shifts would readily accommodate the associated increase in U.S. Highway 75 traffic in the site vicinity given its current level of service designation of "B." Overall, the impact from this option on transportation is therefore considered to be small.

The projection of transportation impacts at a greenfield site is conjectural, but OPPD assumes that with appropriate infrastructure accommodations transportation impacts would be small to moderate.

HUMAN HEALTH

In the GEIS, the NRC cites risk of accidents to workers and public risks (e.g., cancer, emphysema) from the inhalation of toxics and particulates associated with air emissions as potential risks to human health associated with the coal-fired generation alternative (Reference 7.0-1). OPPD assumes that regulatory requirements imposed on facility design and operations under the authority of the Occupational Safety and Health Act (OSHA), Clean Air Act (CAA), and related statutes are designed to provide an appropriate level of protection to workers and the public with respect to these risks, and that compliance with those requirements would result in small, if any, impacts on human health, regardless of plant location.

AESTHETICS

Potential aesthetic impacts of construction and operation of a coal-fired plant include visual impairment resulting from the presence of a large industrial facility, which includes a boiler building, a 650-foot high exhaust stack, cooling towers with associated condensate plumes, coal storage and handling facilities, and a waste disposal facility. Noise from plant operations presents a potential for annoyance to nearby residents. Development of the coal-fired alternative plant at the Nebraska City site would involve an incremental addition to an existing similar facility that is remotely located relative to major thoroughfares and residential developments. Based on existing land use in the region, the associated transmission line would likely be routed overland through sparsely populated areas. On this basis, OPPD contends that the aesthetic impacts from the representative coal-fired alternative would be small.

Location of the plant at FCS would also represent development at an existing industrial site. However, development of the plant would consume a large area of the site that is presently agricultural land, and the boiler building, stack, cooling towers, and coal storage areas would be visually prominent to passers-by on U.S. Highway 75 and residents along and near this highway in the site vicinity. It is expected that offsite noise from plant operations (e.g., cooling towers, waste disposal operations, rail delivery of coal and limestone) would also be apparent. Potential impacts, though noticeable, would not be destabilizing in consideration of the present industrial status of the plant site and the adjacent Cargill Facility. The impact is therefore considered to be small to moderate. A projection at this time regarding the aesthetic impact of the coal-fired alternative at a greenfield site is conjectural, and the impact could range from small to large, depending on location.

CULTURAL RESOURCES

The area developed for the coal-fired generating plant at the Nebraska City site would be located on previously disturbed areas, primarily agricultural land. In addition, no archaeological or historic sites are known to exist in these areas on the plant property, based on studies conducted in 1975 in connection with Unit 1 construction (Reference 7.2-6, Appendix Section 3.1.3.7.2). OPPD would route offsite transmission lines with consideration of archaeological and historical resources, and would take appropriate measures to recover any such resources discovered during onsite or offsite construction. On this basis, OPPD considers the potential adverse impact on cultural resources from this alternative to be small.

Similarly, OPPD would locate a greenfield site and associated offsite facilities (e.g., transmission lines) with appropriate consideration of known archaeological and historical resources, and would make appropriate recovery measures in cases where construction jeopardized resources. The potential adverse impacts to cultural resources for this option are therefore considered to be small.

Location of the coal-fired plant at FCS could result in the excavation of upland areas at the southern part of the site in the general location where material likely to be remnants of the historic community of DeSoto have been found (see Section 2.9). However, the prior disturbance of the area, the probable low value of artifacts recovered from this area, and the minimal potential for recovery of any valuable artifacts suggests that the impacts to cultural resources of this option would be small.

7.2.3.2 GAS-FIRED GENERATION

OPPD's impact evaluation of the gas-fired generation alternative is presented below. In view of the similarities of this evaluation to that presented previously, the following impact discussion is abbreviated, with frequent reference to corresponding topics addressed for the coal-fired generation alternative.

LAND USE

OPPD estimates that development of a 480-MW (net) combined-cycle natural gas-fired plant at the Cass County site would require approximately 25 acres of the total 90 acres planned for development on the 237-acre site. This land-use change would represent an incremental expansion of an existing, planned industrial site, as would be the case for the coal-fired alternative at the Nebraska City site. However, unlike the coal-fired alternative, no onsite waste disposal facility and associated long-term land use restrictions would result from implementing this option. Major natural gas supply pipelines pass through or near the site, eliminating the potential for land-use conflicts associated with bringing fuel to the site. OPPD expects that an additional 75 miles of 345-kV transmission line would be required off site to transmit additional power produced at the station. In the event onsite wells are not used to supply water, OPPD expects to use water from a municipal source (e.g., rural water district), which may be required to construct an additional water supply pipeline to the site. OPPD assumes that this line would be approximately 5 miles long. As is the case for the coal-fired alternative at Nebraska City, the predominant land use in the area surrounding the Cass County site is sparsely populated cultivated farmland, which could continue within the acquired transmission line right-of-way. OPPD would route the transmission line to minimize environmental impacts, including land-use conflicts. It is assumed that the water supply pipeline, if needed, would be routed along existing road and utility rights-of-way. On the basis of these considerations, the impacts on land use from this alternative are considered to be small.

Development of the gas-fired alternative at FCS is expected to have onsite acreage requirements comparable to the representative plant at Cass County, assuming the plant is configured to take advantage of the existing Switch Yard and other support infrastructure. Some impact to offsite land use would result from construction of a pipeline to bring fuel to the plant. The nearest major natural gas supply pipelines to FCS are those noted above as passing through or near the Cass County site. These pipelines are located approximately 40 miles from FCS (Reference 7.2-23). OPPD has not closely examined potential natural gas supply sources for this option, but considering the predominance of agricultural land use in the region, assumes that a supply pipeline could be routed and constructed to ensure that resultant land-use impacts would be small to moderate.

Locating the gas-fired alternative at a greenfield site would require additional onsite acreage for supporting infrastructure and an appropriate buffer area. For example, the NRC estimates that approximately 110 acres may be required for a 1,000-MW facility (Reference 7.0-1, Table 8.1). Impacts on land use from development of the gas-fired alternative at a greenfield site could range from small to moderate assuming it is located according to the findings of an appropriate siting study.

WATER USE AND QUALITY

For the same reasons as those discussed in Section 7.2.3.1 for the coal-fired alternative, the potential for impairment of onsite and offsite surface water resources during construction of the gas-fired alternative would be small, and the impacts on water use and quality that are of greatest potential concern during operation are associated with the cooling water system. As for the coal-fired plant at the Nebraska City site, OPPD would use a closed-cycle cooling system with mechanical draft cooling towers for the representative combined-cycle gas-fired plant at the Cass County site. However, water-use requirements would be substantially smaller because only one-third of the power from the gas-fired unit would be obtained from a steam cycle, while the remaining power would come from combustion turbines. An estimated 2,438 gpm (5.4 cfs) of water would be required to make up for cooling tower evaporation losses and to replace water discharged from the system to maintain dissolved solids at an acceptable concentration. This makeup would be obtained either from onsite wells or from a municipal water source (e.g., rural water district) which would, in turn, likely obtain its water from high-capacity wells, the Missouri River, or the Platte River. This additional water demand is modest, and water withdrawals from either surface water or groundwater would be subject to state approval to preclude potential conflicts with other users. OPPD therefore considers water use impacts to be small.

Cooling tower blowdown, amounting to approximately 200 gpm (0.4-0.5 cfs), would be discharged to Fourmile Creek. Observed flows in this creek range from 3-181 cfs and dissolved solids concentrations are moderate. Cooling tower blowdown would be characterized by elevated temperature and dissolved solids relative to the creek, and could contain intermittent low concentrations of biocides (e.g., chlorine), depending on biofouling potential and controls that are applied. This discharge would be subject to strict NPDES permit limitations to ensure that state water quality standards are met, and the discharge would normally comprise less than approximately 15 percent of stream flow. OPPD therefore expects the overall impact to water use and quality for the representative plant to be small.

The cooling system impacts on water use and quality for a gas-fired plant located at the FCS site would be similar to those for the coal-fired unit discussed in Section 7.2.3.1. However, cooling water requirements and discharge flows would be substantially less. Therefore, for reasons previously cited in Section 7.2.3.1, the impacts on water use and quality for the gas-fired plant at FCS would be small.

The discussion of impacts on water use and quality from an alternative gas-fired plant at a greenfield site is conjectural. However, there are numerous locations in OPPD's service territory that present conditions similar to those described for the Cass County site, and the impacts would likely be small for the same reasons noted for the representative plant.

AIR QUALITY

Like the coal-fired alternative, power for the gas-fired alternative is derived from the combustion of fossil fuel, and therefore results in substantial emissions of CO_2, an unregulated greenhouse gas. However, natural gas contains very little sulfur and other contaminants that are present in coal, and is inherently a cleaner burning fuel. As a result, gas-fired plants release similar types of emissions as do coal-fired plants of comparable capacity, but generally in much smaller quantities. Differences in actual emissions are affected by the emission controls that are applied. Table 7.2-2 specifies OPPD's annual emission estimates for criteria pollutants from the gas-fired generation alternative as follows[2]: SO_x = 8 tons; NO_x = 120 tons; CO = 180 tons; and particulates (filterable) = 23 tons (all which are PM_{10}). Except for PM_{10}, these air emissions are much lower than those estimated for the coal-fired alterative described in Section 7.2.3.1, particularly for SO_x. The higher values for PM_{10}, which are nonetheless low, are attributable to the postcombustion controls assigned to the coal-fired alternative, but which are not typically used for a gas-fired plant. OPPD considers the potential adverse impacts on air quality for the gas-fired alternative to be small to moderate, regardless of site location.

WASTE MANAGEMENT

Operation of the gas-fired alternative would generate only small quantities of waste, including some spent catalyst that is used for NO_x control, which would be disposed of in accordance with applicable regulations at a permitted offsite disposal facility, regardless of the plant's location. This alternative would avoid the relatively large quantities of ash and scrubber waste the coal-fired alternative would generate. OPPD concludes that the gas-fired generation waste management disposal impacts would be small.

ECOLOGICAL RESOURCES

Development of the gas-fired alternative plant at the Cass County site would affect only marginal onsite terrestrial species habitat, consisting of approximately 25 acres of land in cultivation or already modified for industrial use. Transmission lines for the plant, consisting of approximately 75 miles of line on a 100-foot right-of-way, would be located based on the conclusions of an appropriate routing study that would have among its bases avoidance of high-value habitat. Also, based on current land use patterns, the route would most likely traverse active agricultural land for most of its length. Shrub habitat, which has substantial wildlife value, would be promoted and maintained on the right-of-way in rural areas where existing uses (e.g., agriculture) are not conflicting. Therefore, the impacts to terrestrial ecological resources from this alternative are considered to be small.

The cooling system for the plant would be designed and operated in compliance with the CWA, including limitations for physical and chemical parameters of potential concern. Compliance with CWA Section 316(a) provisions, in particular, would ensure that thermal discharges would be controlled as necessary to maintain a balanced aquatic community in Fourmile Creek. Therefore, only minor localized changes in stream flora and fauna,

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[2] Annual emissions of regulated air pollutants calculated as follows from natural gas heat input and estimates of uncontrolled air emissions and removal efficiencies (Table 7.2-2 lists all necessary parameters): Natural Gas Heat Input (MMBtu/yr) = Total Gross Capability (MW) x Heat Rate (Btu/kW-hour) x 1,000 (kW/MW) x Capacity Factor (80%) x 8,760 hr/yr x 10E-06 MMBtu/Btu = 24,037,000 MMBtu/yr. Pollutant Emissions (tons/yr) = Natural Gas Heat Input (MMBtu/yr) x Uncontrolled Emissions (lb/MMBtu) x 0.0005 (ton/lb) x [100 – removal efficiency (%)]. Removal efficiencies for SOx, CO, and filterable particulates are assumed to be zero. Total Natural Gas Consumed = Natural Gas Heat Input (MMBtu/yr) x Heat Value (MMBtu/scf) = 24,037,000,000 scf/yr.

e.g., species composition and distribution, would be expected to result from discharge of cooling tower blowdown to the stream. The impact to aquatic communities and the overall impact to ecological resources from this alternative are therefore expected to be small.

In view of the lower acreage requirements and cooling water system flows needed for the gas-fired plant compared to the coal-fired alternative, the impact to ecological resources from the development of the gas-fired alternative at FCS is considered to be low for the same reasons cited in Section 7.2.3.1 for the coal-fired plant. On the same basis, the ecological resources impacts resulting from location of the plant at a greenfield site are likely to be low to moderate.

SOCIOECONOMICS

As noted in Table 7.2-2, OPPD estimates that the representative gas-fired plant would be constructed in 2-3 years with an average work force of 200 and a maximum work force of 450. Considering the nearness of the site to the Omaha metropolitan area, few workers are likely to relocate to Plattsmouth or other smaller communities in the area, and little, if any, increased demand for housing and public services would occur. Local communities are likely to derive some limited benefits in the form of increased job opportunities and economic activity during the construction period. As OPPD notes in Section 7.2.3.1 for the coal-fired alternative at the Nebraska City site, implementation of this alternative would result in the eventual loss of approximately 740 jobs and the associated economic activity from the shutdown of FCS, an associated small to moderate impact.

As OPPD indicates in Section 7.2.3.1 for the coal-fired option, location of the gas-fired plant at FCS would likely have little impact on Blair and other local communities during the construction phase, considering the nearness of the site to the Omaha metropolitan area. The operating work force at the gas-fired plant is expected to be fewer than 150 workers, based on estimates the NRC provided for a 1,000-MW gas-fired plant (Reference 7.0-1, Table 8.2). These new jobs offer only a modest offset to the approximately 740 jobs that would be lost at the nuclear power plant. As discussed in Section 7.2.3.1, related impacts on the Blair and other surrounding communities would likely be small to moderate.

In view of the above considerations and the fact that virtually all of OPPD's service territory is within commuting distance to large population centers (e.g., Omaha and Lincoln, Nebraska and Sioux City, Iowa), the overall socioeconomic impact from development of the gas-fired plant at a greenfield site would likely be small to moderate.

TRANSPORTATION

The potential for adverse impacts on transportation from implementation of the gas-fired alternative relates primarily to increased vehicular traffic from commuting workers during the peak construction period. OPPD estimates that the maximum construction work force would number approximately 450. Assuming only moderate use of carpooling, maximum vehicle round-trips per day would be expected to be approximately 300. The Cass County site is readily accessible to a major north-south thoroughfare (U.S. Highway 75) and east-west highway (Nebraska Highway 1) within 2-3 miles via a rural two-lane road, which would be able to readily accommodate this increased traffic. The associated impact is, therefore, considered to be small.

Location of the gas-fired alternative at FCS would result in increased traffic on U.S. Highway 75 during construction, which is expected to be readily accommodated and have an associated small impact.

Projections concerning transportation impacts at a greenfield site are conjectural, but OPPD assumes that with appropriate infrastructure accommodations, the transportation impacts from development of a gas-fired plant would be small.

HUMAN HEALTH

The NRC cites workplace accidents and inhalation of toxics and particulates associated with air emissions as potential human health risks from gas-fired generation (Reference 7.0-1, Tables 8.1, 8.2). As discussed for the coal-fired alternative in Section 7.2.3.1, OPPD assumes that regulatory requirements related to occupational safety and health and air emissions are designed to protect human health and that compliance with those requirements would ensure that any associated impacts would be small.

AESTHETICS

The potential aesthetic impacts from construction and operation of a gas-fired plant include visual impairment and offsite noise, as discussed in Section 7.2.3.1 for the coal-fired alternative. As is the case for the representative coal-fired plant at the Nebraska City site, the gas-fired representative plant would represent an incremental addition to an existing plant with similar characteristics that is remotely located relative to major thoroughfares and residential developments. Based on existing land use in the region, the associated transmission line would likely be routed overland through sparsely populated areas. The associated aesthetic impacts are therefore considered to be small.

Location of the plant at FCS would also represent development at an existing industrial site. In addition, the boiler building and stack, assumed to be approximately 250 feet high, and cooling tower plumes would be less prominent than for the coal-fired plant alternative. Potential noise impacts from coal handling and waste disposal would not occur, and substantially more acreage would remain as visual and noise buffers for the passers-by on U.S. Highway 75 and nearby residents. Considering also the presence of other industry in the area (i.e., the Cargill Facility), the potential aesthetics impacts would be small.

Any discussion of the potential aesthetics impact of the gas-fired alternative at a greenfield site is conjectural, and the impact could range from small to large, depending on location.

CULTURAL RESOURCES

The area developed for the gas-fired generating plant at the Cass County site would be located on previously disturbed areas, primarily agricultural land, and no archaeological or historic sites are known to exist on the plant property. OPPD would route offsite transmission lines with consideration of known cultural resources, and would take appropriate measures to recover any such resources discovered during onsite or offsite construction. On this basis, OPPD considers the potential adverse impact on cultural resources from this alternative to be small.

The potential impacts to cultural resources from the FCS and the greenfield siting options are also considered to be small for reasons similar to those discussed for the coal-fired alternative in Section 7.2.3.1.

7.2.3.3 PURCHASED POWER

As discussed in Section 7.2.3.1, OPPD assumes that the generating technology employed under the purchase, power alternative would be one of those that the NRC analyzed in the GEIS. OPPD is adopting by reference the NRC analysis of the environmental impacts from those technologies. Therefore, under the purchased power alternative, environmental impacts would still occur, but would be located elsewhere in the region, the United States, or Canada.

OPPD estimates that the purchased power alternative may require construction of 35 miles of 345-kV transmission line on a 100-foot right-of-way to transmit power to meet the demand in eastern Nebraska that FCS currently satisfies, with associated land use, ecological resource, aesthetic, and related impacts. Considering land use in the region, OPPD assumes that the transmission line would be routed predominantly through rural agricultural land or other previously disturbed land, or along existing transmission line rights-of-way, and would be in compliance with an appropriate routing study that would seek to minimize potential adverse impacts to land use, ecological resources, aesthetics, and related resources. On this basis, OPPD concludes that the associated impacts of the transmission line would be small to moderate.

7.3 REFERENCES

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7.1-1 U.S. Nuclear Regulatory Commission. *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities*. NUREG-0586. Office of Nuclear Regulatory Research. Washington, D.C., August 1988.

7.2-1 Nebraska Power Association. *Statewide Integrated Resource Planning Coordination Report (1997-2016).* Nebraska Power Association Integrated Planning Task Force and Transmission Task Force. Lincoln, Nebraska, October 1996.

7.2-2 Omaha Public Power District. *1997 Integrated Resource Plan 1997-2016*. OPPD Integrated Resource Planning Department. May 1997.

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7.2-4 Omaha Public Power District. *2001 Integrated Resource Plan*. Memo: A. Ernie Parra to Distribution. October 31, 2000.

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7.2-7 U.S. Census Bureau. *2000 Census Of Population and Housing Characteristics*. Http://factfinder.census.gov. Accessed June 8, 2001.

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7.2-11 U.S. Environmental Protection Agency. *Compilation of Air Emission Factors. AP-42 Vol. 1, Stationery Point Area Sources*. Chapter 1, "External Combustion Sources," Section 1.4, "Natural Gas Combustion." Washington, D.C., July 1998.

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7.2-13 Nebraska Energy Office. *Nebraska Energy Statistics 1960-1997.* www.nol.org/home/neo/stat.htm. Accessed March 8, 2001.

7.2-14 Ridley & Associates. *Nebraska's Electric Utility Industry, Summary of Final Report to the Nebraska Legislature, L.R. 455 Phase II Study. December 1999*. www.nol.org/home/neo/lr455final/index.html. Accessed March 8, 2001.

7.2-15 Energy Information Administration. *Inventory of Non-utility Electric Power Plants in the United States, 1999,* Table 6. "Existing Capacity and Planned Capacity Additions at U.S. Non-Utilities by Energy Source and State, 1999." Office of Coal, Nuclear, Electric and Alternate Fuels. November 2000. www.eia.doe.gov.cneaf/electricity/ipp/ipp2.pdf. Accessed June 10, 2001.

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8.0 COMPARISON OF ENVIRONMENTAL IMPACT 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)

The Omaha Public Power District (OPPD) presents its evaluations of the environmental impacts associated with Fort Calhoun Station Unit 1 (FCS) operating license renewal (the proposed action) and those associated with the selected alternatives in Chapter 4.0 and Chapter 7.0, respectively. In this chapter, OPPD provides a comparative summary of these impacts. The environmental impacts comparison addresses Category 2 issues associated with the proposed action and issues the Nuclear Regulatory Commission (NRC) identifies in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Reference 8.0-1, Section 8.1) as major considerations in an alternatives analysis. For example, the NRC concluded in the GEIS that air impacts from the proposed action would be small (Category 1), but indicated that there is a potential for major human health concerns associated with air emissions from fossil-fuel generation alternatives (see Section 7.2.3.1). OPPD provides a comparative summary of its conclusions regarding these issues in Table 8.0-1, and a more detailed comparison in Table 8.0-2.

TABLE 8.0-1
IMPACTS COMPARISON SUMMARY

Impact	Proposed Action (License Renewal)	No-Action Alternative			
		Base (Decom-missioning)	With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Land Use	SMALL	SMALL	MODERATE	SMALL	All impacts are dependent on generation technologies used and location.
Water Use and Quality	SMALL	SMALL	SMALL	SMALL	
Air Quality	SMALL	SMALL	MODERATE	SMALL to MODERATE	
Waste Management	SMALL	SMALL	MODERATE	SMALL	
Ecological Resources	SMALL	SMALL	SMALL	SMALL	
Socioeconomics	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE	
Transportation	SMALL	SMALL	SMALL	SMALL	
Human Health	SMALL	SMALL	SMALL	SMALL	
Aesthetics	SMALL	SMALL	SMALL	SMALL	
Cultural Resources	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.
LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource (10 CFR 51, Subpart A, Appendix B, Table B-1, footnote 3).

TABLE 8.0-2
IMPACTS COMPARISON DETAIL

	No-Action Alternative			
Proposed Action (License Renewal) [a]	**Base (Decommissioning) [a]**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With Purchased Power**
		Description		
FCS license renewal for 20 years, followed by decommissioning (Chapter 3).	Decommissioning following expiration of current FCS license. Adopting by reference NRC description in the GEIS, as bounding FCS decommissioning, GEIS description (see Section 7.1).	New construction at Nebraska City site with 75 miles of 345-kV transmission line. Plant characteristics as follows (see Sections 7.2.1.1, 7.2.3.1): One 475-MW (net) tangentially fired, dry bottom unit; capacity factor 0.8. Closed-cycle cooling; mechanical draft cooling towers. Pulverized bituminous coal; 8,500 Btu/pound; 10,000 Btu/kWh; 6.0% ash; 0.34% sulfur; 2,061,000 tons coal/yr.	New construction at Cass County site with 75 miles of 345-kV transmission line. Plant characteristics as follows (see Sections 7.2.1.2, 7.2.3.2): One 480-MW (net) unit; consisting of two 160-MW combustion turbines and a 160-MW heat recovery boiler; capacity factor 0.8. Closed-cycle cooling; mechanical draft cooling towers. Natural gas, 1,000 Btu/scf; 7,000 Btu/kWh; 24,037,000,000 scf gas/yr.	Construct 35 miles of 345-kV transmission line. Could involve construction of new generation capacity out of state. Adopting by reference NRC description in the GEIS of alternate technologies (Section 7.2.1.3).

TABLE 8.0-2 (CONTINUED)
IMPACTS COMPARISON DETAIL

	No-Action Alternative			
Proposed Action (License Renewal) [a]	**Base (Decommissioning)** [a]	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With Purchased Power**
		Description (Continued)		
		Low NO_x burners, overfire air, selective catalytic reduction (95% NO_x removal efficiency). Wet limestone flue gas desulfurization (90% SO_x removal efficiency); 23,000 tons limestone/yr. Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency). Construction work force: 450 average, 1,200 peak. Additional operating work force: 15.	Dry-low NO_x combustor; selective catalytic reduction (90% NO_x removal efficiency). Construction work force: 200 average, 450 peak. Additional operating work force: 10.	
		Land Use Impacts		
SMALL – Adopting by reference applicable NRC findings for GEIS Category 1 issues (Issues 52, 53).	SMALL – Not an impact evaluated in the GEIS (Reference 8.0-1, Section 7.3).	MODERATE – 140 acres of agricultural land converted to industrial use at existing plant site, including 90 acres for waste disposal (subject to prevalent land-use restrictions) and 50 acres for plant facilities. 75 miles of new transmission line, over mostly agricultural land. (see Section 7.2.3.1).	SMALL – 25 acres of agricultural land converted to industrial use at existing plant site. 75 miles of new transmission line, over mostly agricultural land (see Section 7.2.3.2).	Impact dependent on generation technology and location. Adopting by reference NRC description in the GEIS of land use impacts from alternate technologies (Reference 8.0-1, Section 8.3). 35 miles of new transmission line, mostly over agricultural land (see Section 7.2.3.3).

TABLE 8.0-2 (CONTINUED)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal) [a]	No-Action Alternative: Base (Decommissioning) [a]	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Water Use and Quality Impacts				
SMALL – Adopting by reference applicable NRC findings for GEIS Category 1 issues (Issues 3, 6-12, 32). No applicable Category 2 water-use and quality issues.	SMALL – Adopting by reference applicable NRC finding for GEIS Category 1 issue (Issue 89). No Category 2 issues.	SMALL – Construction impacts minimized by use of best management practices. Operation impacts minimized by using closed-cycle cooling, regulatory controls, and discharge to Missouri River (see Section 7.2.3.1).	SMALL – Construction impacts minimized by use of best management practices. Operation impacts minimized by using closed-cycle cooling and regulatory controls (see Section 7.2.3.2).	Impact dependent on generation technology and location. Adopting by reference NRC description in the GEIS of water quality impacts from alternate technologies (Reference 8.0-1, Section 8.3).
Air Quality Impacts				
SMALL – Adopting by reference applicable NRC finding for GEIS Category 1 issue (Issue 51). No applicable Category 2 issues.	SMALL – Adopting by reference applicable NRC finding for GEIS Category 1 issue (Issue 88). No Category 2 issues.	MODERATE – • 1,230 tons SO_x/yr • 430 tons NO_x/yr • 520 tons CO/yr • 62 tons TSP/yr • 14 tons PM_{10}/yr (see Section 7.2.3.1).	SMALL to MODERATE - • 8 tons SO_x/yr • 120 tons NO_x/yr • 180 tons CO/yr • 23 tons TSP/yr (all PM_{10}) (see Section 7.2.3.2).	Impact dependent on generation technology and location. Adopting by reference NRC description in the GEIS of air quality impacts from alternate technologies (Reference 8.0-1, Section 8.3).
Waste Management Impacts				
SMALL – Adopting by reference applicable NRC finding for GEIS Category 1 issue (Issues 77-84). No Category 2 issues.	SMALL – Adopting by reference applicable NRC finding for GEIS Category 1 issue (Issue 87). No Category 2 issues.	MODERATE – 74,000 tons ash and 36,000 tons scrubber sludge generated annually (see Section 7.2.3.1).	SMALL –Relatively low waste generation (see Section 7.2.3.2).	Impact dependent on generation technology and location. Adopting by reference NRC description in the GEIS of waste management impacts from alternate technologies (Reference 8.0-1, Section 8.3).

TABLE 8.0-2 (CONTINUED)
IMPACTS COMPARISON DETAIL

	No-Action Alternative			
Proposed Action (License Renewal) [a]	**Base (Decommissioning) [a]**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With Purchased Power**
		Ecological Resource Impacts		
SMALL – Adopting by reference applicable NRC findings for GEIS Category 1 issues (Issues 15-24, 45-48). OPPD has a current NPDES permit, which constitutes compliance with CWA Section 316(b) requirements to provide best available technology to minimize entrainment and impingement (see Section 4.2, Issue 25; Section 4.3, Issue 26). Thermal discharge from FCS complies with Nebraska Water Quality Standards without recourse to a CWA Section 316(a) variance (see Section 4.4, Issue 27.)Impacts to threatened and endangered species expected to be small due to low potential for occurrence in habitats affected by plant operation and lack of observed impacts during operational monitoring (see Section 4.6, Issue 49).	SMALL – Adopting by reference applicable NRC finding for GEIS Category 1 issue (Issue 90). No Category 2 issues.	SMALL - Loss of 140 acres of previously disturbed terrestrial habitat; potential impacts to aquatic ecology minimized by using closed-cycle cooling, regulatory controls, and discharge to Missouri River (see Section 7.2.3.1).	SMALL - Loss of 25 acres of previously disturbed terrestrial habitat; potential impacts to aquatic ecology minimized by closed-cycle cooling and regulatory controls (see Section 7.2.3.2).	Impact dependent on generation technology and location. Adopting by reference NRC description in the GEIS of ecological resource impacts from alternate technologies (Reference 8.0-1, Section 8.3). 35 miles of new transmission line, mostly over agricultural land (see Section 7.2.3.3).

TABLE 8.0-2 (CONTINUED)
IMPACTS COMPARISON DETAIL

	No-Action Alternative			
Proposed Action (License Renewal) [a]	**Base (Decommissioning)** [a]	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With Purchased Power**
Socioeceonomic Impacts				
SMALL – Adopting by reference applicable NRC findings for GEIS Category 1 issues (Issues 64, 67). Location in area of high population minimizes potential for housing impacts (see Section 4.10, Issue 63). No tax-driven land-use impacts because OPPD is exempt from paying state occupational, personal property, and real estate taxes, and magnitude of the in-lieu payments relative to the receiving county's total revenues is not relevant in assessing new tax-driven land-use impacts (see Section 4.13.2, Issue 69). Capacity of public water supply minimizes potential for related impacts (see Section 4.11, Issue 65).	SMALL – Adopting by reference applicable NRC finding for GEIS Category 1 issue (Issue 91). No Category 2 issues.	SMALL to MODERATE – Increased demand for public services from nearby communities during construction and net loss of jobs in Washington County and associated reduction in economic activity from shutdown of FCS may result in noticeable, but not destabilizing, impacts (see Section 7.2.3.1).	SMALL to MODERATE – Net loss of jobs in Washington County and associated reduction in economic activity from shutdown of FCS may result in noticeable, but not destabilizing impacts (see Section 7.2.3.2).	Impact dependent on generation technology and location. Adopting by reference NRC description in the GEIS of socioeconomic impacts from alternate technologies (Reference 8.0-1 Section 8.3).

TABLE 8.0-2 (CONTINUED)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal) [a]	No-Action Alternative: Base (Decommissioning) [a]	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Transportation Impacts				
SMALL - Adopting by reference applicable NRC finding for GEIS Category 1 issue (Issue 85.) Capacity of U.S. Highway 75 minimizes potential for related impacts (see Section 4.14, Issue 70).	SMALL – Not an impact evaluated in the GEIS (Reference 8.0-1, Section 7.3).	SMALL – Temporary increase in traffic of 210-570 vehicle round-trips per day during construction; increase of 15 permanent employees for plant operations. Increase of 3-4 train round-trips per week on low-volume rail lines. (see Section 7.2.3.1).	SMALL - Temporary increase in traffic of 300 (maximum) vehicle round-trips per day during construction (see Section 7.2.3.2).	Impact dependent on generation technology and location. Not an impact evaluated in the GEIS.
Human Health Impacts				
SMALL –Adopting by reference applicable NRC findings for GEIS Category 1 issues (Issues 56, 58, 61, 62). Risk from thermophilic microbiological organisms minimal due to poor conditions for supporting populations of pathogenic organisms in the Missouri River, including areas affected by the thermal plume, and low potential for exposure of public in thermally affected zone (see Section 4.8, Issue 57).	SMALL – Adopting by reference applicable NRC finding for GEIS Category 1 issue (Issue 86). No Category 2 issues.	SMALL– Some risk of cancer and emphysema from air emissions and risk of accidents to workers, as the NRC notes in the GEIS Regulatory controls assumed to reduce risks to acceptable levels (see Section 7.2.3.1).	SMALL – Same as for coal-fired alternative (see Section 7.2.3.2).	Impact dependent on generation technology and location. Adopting by reference NRC description in the GEIS of human health impacts from alternate technologies (Reference 8.0-1, Section 8.3).

TABLE 8.0-2 (CONTINUED)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal) [a]	No-Action Alternative			
	Base (Decommissioning) [a]	With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Human Health Impacts (Continued)				
FCS operations have had no known impact on public health from pathogenic organisms. Risk due to transmission-line induced currents minimal due to conformance with National Electric Safety Code® criteria (see Section 4.9, Issue 59).				
Aesthetic Impacts				
SMALL – Adopting by reference applicable NRC findings for GEIS Category 1 issues (Issues 73,74). No Category 2 issues.	SMALL – Not an impact evaluated in the GEIS (Reference 8.0-1, Section 7.3).	SMALL – Incremental development at existing power plant site remote from major thoroughfares in sparsely populated rural area (see Section 7.2.3.1).	SMALL – Same as coal-fired alternative (see Section 7.2.3.2).	Impact dependent on generation technology and location. Adopting by reference NRC description in the GEIS of aesthetic impacts from alternate technologies (Reference 8.0-1, Section 8.3).

TABLE 8.0-2 (CONTINUED)
IMPACTS COMPARISON DETAIL

	No-Action Alternative			
Proposed Action (License Renewal) [a]	**Base (Decommissioning) [a]**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With Purchased Power**
Cultural Resource Impacts				
SMALL – Lack of cultural resources and SHPO consultation minimize potential for impact (see Section 4.15, Issue 71).	SMALL – Not an impact evaluated in the GEIS (Reference 8.0-1, Section 7.3).	SMALL – No known cultural resources in affected onsite areas; preservation measures, if necessary, would minimize impact (see Section 7.2.3.1).	SMALL – Same as coal-fired alternative (see Section 7.2.3.2).	Impact dependent on generation technology and location. Adopting by reference NRC description in the GEIS of cultural resource impacts from alternate technologies (Reference 8.0-1, Section 8.3).

a. See Appendix Table 1.0-1 for a list of issues and applicability.

Impact definitions:

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.
LARGE – For the issue, environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.
(10 CFR 51, Subpart A, Appendix B, Table B-1, footnote 3.)

Btu = British thermal unit
CO = Carbon monoxide
CWA = Clean Water Act
FCS = Fort Calhoun Station Unit 1
gal. = gallon
GEIS = *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (Ref. 8.0-1)
kV = kilovolt
kWh = kilowatt hour
lb = pound
MM = million
MW = megawatt
NO_X = nitrogen oxide(s)
NPDES = National Pollutant Discharge Elimination System
OPPD = Omaha Public Power District
PM_{10} = filterable particulates having diameter less than 10 microns
scf = standard cubic foot
SHPO = State Historic Preservation Officer
SO_x = sulfur oxide(s)
TSP = total suspended particulates
yr = year

8.1 REFERENCES

8.0-1 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437. Office of Nuclear Regulatory Research. Washington, D.C., May 1996.

9.0 STATUS OF COMPLIANCE

9.1 PROPOSED ACTION

NRC

"The environmental report shall list all Federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with these requirements. The environmental report shall also include a discussion of the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection." 10 CFR 51.45(d), as required by 10 CFR 51.53(c)(2)

9.1.1 GENERAL

Table 9.1-1 lists Omaha Public Power District's (OPPD's) environmental authorizations for current Fort Calhoun Station Unit 1 (FCS) operations. These "authorizations" include permits, licenses, approvals, and other entitlements required for plant operations and related activities. OPPD expects to continue to renew these authorizations as needed during the current license period and through the license renewal period, and will continue to operate FCS in compliance with the provisions of these authorizations and applicable environmental standards and requirements.

Table 9.1-2 lists additional environmental authorizations and consultations that would be required prior to U.S. Nuclear Regulatory Commission (NRC) renewal of the FCS operating license. As indicated, OPPD anticipates that relatively few such authorizations and consultations would be needed. Sections 9.1.2 through 9.1.5 provide more detailed discussions of key authorizations and compliance issues.

As Table 9.1-2 shows, OPPD anticipates that the only state environmental authorizations or consultations required specifically for FCS license renewal are from Nebraska authorities. However, as Section 2.1 notes, the Missouri River roughly follows the Nebraska-Iowa boundary, and OPPD maintains easements on land across the river in Iowa as part of the plant exclusion zone. Considering the potential for impact on shared resources, in particular the Missouri River, OPPD has made efforts to inform potentially affected state agencies in both Nebraska and Iowa about its intent to seek renewal of the FCS operating license. In addition, OPPD has specifically sought consultation from relevant agencies in both states regarding threatened and endangered species and potential for human health impacts from thermophilic microbes (see Appendices 3.0 and 6.0, respectively).

TABLE 9.1-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT FORT CALHOUN STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
Federal Authorizations						
U.S. Nuclear Regulatory Commission	Atomic Energy Act [42 USC 2011, et seq.], 10 CFR 50.10	License to operate	DPR-40	5/24/73 (allowed 20% power). Full power license issued 8/9/73	8/9/2013	Operation of FCS
State and Local Authorizations						
Nebraska Department of Environmental Quality	Federal Clean Water Act, Section 402 [33 USC 1251, et seq.]. NAC Title 119, Chapter 2	Industrial Wastewater Facility Permit	NPDES Permit No. NE0000418	4/1/2001	3/31/2006	Wastewater treatment and effluent discharge via outfalls 001-008. Nebraska Department of Environmental Quality considers the permit to certify compliance with state water quality standards for purposes of the Federal Clean Water Act, Section 401.
Nebraska Department of Environmental Quality	Nebraska Statute 81-1513	Consent Order In the Matter of Omaha Public Power District – Fort Calhoun Nuclear Station	Case No. 2206	7/27/99	To be determined as conditions are met.	Increases maximum discharge temperature limits from 110 deg F to 112 deg F. Requires thermal modeling study to determine compliance with state water quality standards.

TABLE 9.1-1 (CONTINUED)
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT FORT CALHOUN STATION OPERATIONS

Agency	Authority	Authorization	Number	Issue Date	Expiration	Activity Covered
Nebraska Game and Parks Commission	Nebraska Statute 37-418	Scientific Collecting Master Permit	Master Permit No. 168	4/16/2001	12/31/2001	Collection of fish species (for radiological environmental monitoring programs).
Nebraska Department of Natural Resources	NAC Title 457	Surface water authorization permits	D-1083 D-1100	12/17/81 8/20/92	Indefinite	Permits withdrawal of water from the Missouri River. Approval for up to approximately 370,000 gpm.
Nebraska Department of Natural Resources	NAC Title 456, Chapter 12	Groundwater well registrations	G-109801A-E G-109802 G-109803 G- 110639	4/30/2001 4/30/2001 4/30/2001 6/29/2001	Indefinite	One-time registration of onsite groundwater wells. Well numbers G-109801A-E and G- 110639 are used for groundwater monitoring.[a] G-109802 and G-109803 supply small amounts of water for operation of sanitary wastewater treatment facilities.

a. Monitoring wells G-109801A through E are associated with post-closure care monitoring of 1.3-acre wastewater treatment sludge landfill, certified closed on August 5, 1997, in accordance with NAC Title 132, Chapter 3. Post-closure plan under review by Nebraska Department of Environmental Quality as of September 2001.

CFR = Code of Federal Regulations
FCS = Fort Calhoun Station Unit 1
gpm = gallons per minute
NAC = Nebraska Administrative Code
NPDES = National Pollutant Discharge Elimination System
USC = U.S. Code

TABLE 9.1-2
ENVIRONMENTAL AUTHORIZATIONS FOR FORT CALHOUN STATION LICENSE RENEWAL[a]

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License renewal application	Environmental report submitted in support of license renewal application.
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires Federal agency issuing a license to consult with U.S. Fish and Wildlife Service (see Appendix 3.0).
Nebraska Department of Environmental Quality	Clean Water Act Section 401 (33 USC 1341)	Certification	Requires Federal agency issuing a license to obtain certification from State that the action complies with state water quality standards.
Nebraska 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 (see Appendix 4.0).

USC = United States Code
a. No renewal-related requirements identified for local or other agencies.

9.1.2 THREATENED AND ENDANGERED SPECIES CONSULTATION

The Endangered Species Act, Section 7 (16 USC 1531 et seq.), requires Federal agencies to ensure that an agency action is not likely to jeopardize any species that is listed or threatened. For actions that may adversely affect such species or their habitats in Nebraska, the act requires consultation with the U.S. Fish and Wildlife Service (FWS). Procedural regulations for the consultation process are set forth at 50 CFR 402, Subpart B. FWS maintains the list of threatened and endangered species at 50 CFR 17.

As discussed in Section 4.6, OPPD does not expect continued operations of FCS to impact the population of any threatened or endangered species, although some listed species have habitats that include the lower Missouri River and elsewhere in the region of FCS. In preparation for the NRC's consultation process, and in consideration of potential impacts to species having special status at the state level, OPPD invited comment from FWS, the Nebraska Game and Parks Commission, and the Iowa Department of Natural Resources regarding potential effects that FCS license renewal might have on species of concern. Appendix 3.0 includes copies of OPPD contact letters and responses.

9.1.3 HISTORIC PRESERVATION CONSULTATION

Section 106 of the National Historic Preservation Act (16 USC 470 et seq.) requires Federal agencies to take into account the effect of activities they license on historic properties, and to afford the Advisory Committee on Historic Preservation an opportunity to comment on the undertaking. Committee regulations provide for establishing an agreement with any State Historic Preservation Officer (SHPO) to substitute State review for Council review (35 CFR 800.7). Although federal law or NRC regulation does not require it, OPPD has chosen to invite comment by the Nebraska SHPO. Appendix 3.0 includes copies of OPPD correspondence with the SHPO. Based on the OPPD submittal, the SHPO concurred with OPPD's conclusion that FCS license renewal would not affect known historic or archaeological resources.

9.1.4 COMPLIANCE WITH NPDES THERMAL DISCHARGE LIMITS

Under authorization from the U.S. Environmental Protection Agency (EPA), the Nebraska Department of Environmental Quality (NDEQ) administers the National Pollutant Discharge Elimination System (NPDES) program in Nebraska. The current NPDES permit for FCS (see Appendix 2.0) authorizes a daily maximum temperature of 110 deg F for cooling water discharges from the plant. OPPD is seeking to permanently increase FCS's NPDES daily maximum temperature limit to 112 deg F to better ensure that the plant can operate at full power under the unusually high ambient river temperatures that have been experienced in recent summers. In the interim period until the NDEQ acts on OPPD's NPDES permit modification request, OPPD has entered into a Consent Order with the NDEQ that allows a daily maximum temperature of 112 deg F (see Appendix 2.0).

This Consent Order requires that OPPD submit water quality information to evaluate the impacts of this temperature increase to verify that instream water quality criteria would be met. OPPD is participating in a cooperative effort with the EPA and the NDEQ to obtain this information. This study, which includes thermal modeling, focuses on power plants and other industrial facilities that discharge to the lower Missouri River and will address potential effects of historically high river temperatures. It is also expected that this study will assist OPPD and the NDEQ to assess the implications of reduced river flows in summer such as those being considered by the U.S. Army Corps of Engineers (see Section 2.2.3).

This study was initiated in the fall of 2001, and it is expected that the final report regarding FCS thermal discharges will be completed in 2002 or early 2003. Subsequent to the release of the report, the NDEQ is expected to make a final determination to issue or deny the requested permit modification. In any event, OPPD would continue to comply with NDEQ thermal discharge standards through the duration of the current operating license and the license renewal term.

9.1.5 WATER QUALITY (401) CERTIFICATION

The Federal Clean Water Act (CWA) Section 401, requires that an applicant for a federal license or permit to conduct an activity that might result in a discharge into navigable waters obtain from the state having jurisdiction certification that the discharge will comply with applicable CWA standards (33 USC 1341). OPPD is applying to the NRC for a license (i.e., license renewal) to continue FCS operations.

The State of Nebraska has EPA authorization to implement the NPDES program in Nebraska for facilities such as FCS. Pursuant to state authority and the EPA authorization, the NDEQ has issued an NPDES permit for FCS (see Appendix 2.0). Title 119, Chapter 59, Section 001.03 of the NDEQ Rules and Regulations requires that the NDEQ review of an application for reissuance of a NPDES permit be sufficiently detailed to ensure that the applicant's discharge is "consistent with existing applicable effluent standards and limitations, water quality standards, best management practices, and other legally applicable requirements" (Reference 9.1-1). It is OPPD's understanding that the NPDES permit issued by the NDEQ constitutes CWA Section 401 certification by the State of Nebraska for the continued operations covered by that permit.

9.2 FEASIBLE 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 45(d) as required by 10 CFR 51.53(c)(2)

It is OPPD's judgment that the representative coal- and gas-fired generation alternatives and purchased power alternative, presented in Section 7.2.1, probably could be constructed and operated to comply with all applicable environmental quality standards and requirements. Although construction and operation details for the purchased power alternative (Section 7.2.1.3) are not known, it is reasonable to assume that any facility offering power for purchase would be in compliance.

9.3 REFERENCES

9.1-1 Nebraska Department of Environmental Quality. Title 119, Chapter 59. www.deq.ne.us/ruleandr.nfs/pages/119-ch59. Accessed June 20, 2001.

APPENDIX 1.0 DISCUSSION OF NRC LICENSE RENEWAL NATIONAL ENVIRONMENTAL POLICY ACT ISSUES

Omaha Public Power District (OPPD) has prepared this *Applicant's Environmental Report - Operating License Renewal Stage; Fort Calhoun Station Unit 1* in accordance with the requirements of the U.S. Nuclear Regulatory Commission (NRC) regulation at 10 CFR 51.53. The NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants. Table 1.0-1 lists these 92 issues with their assigned classifications, i.e., categories, and identifies where Fort Calhoun Station Unit 1 (FCS) addresses each issue in the environmental report (ER). The table also provides a cross-reference to the section in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) containing the NRC's generic analysis. For expediency, OPPD has assigned a number to each issue and uses the issue numbers throughout the ER.

TABLE 1.0-1
FORT CALHOUN STATION ENVIRONMENTAL REPORT
DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
1. Impacts of refurbishment on surface water quality	1	NA[c]	
2. Impacts of refurbishment on surface water use	1	NA[c]	
3. Altered current patterns at intake and discharge structures	1	4.1	4.2.1.2.1/4-4
4. Altered salinity gradients	1	NA[d]	
5. Altered thermal stratification of lakes	1	NA[e]	
6. Temperature effects on sediment transport capacity	1	4.1	4.2.1.2.3/4-6
7. Scouring caused by discharged cooling water	1	4.1	4.2.1.2.3/4-6
8. Eutrophication	1	4.1	4.2.1.2.3/4-6
9. Discharge of chlorine or other biocides	1	4.1	4.2.1.2.4/4-10
10. Discharge of sanitary wastes and minor chemical spills	1	4.1	4.2.1.2.4/4-10

TABLE 1.0-1 (CONTINUED)
FORT CALHOUN STATION ENVIRONMENTAL REPORT
DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
11. Discharge of other metals in waste water	1	4.1	4.2.1.2.4/4-10
12. Water use conflicts (plants with once-through cooling systems)	1	4.1	4.2.1.3/4-13
13. Water-use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	2	NA[f]	
14. Refurbishment impacts to aquatic resources	1	NA[c]	
15. Accumulation of contaminants in sediments or biota	1	4.1	4.2.1.2.4/4-10
16. Entrainment of phytoplankton and zooplankton	1	4.1	4.2.2.1.1/4-15
17. Cold shock	1	4.1	4.2.2.1.5/4-18
18. Thermal plume barrier to migrating fish	1	4.1	4.2.2.1.4/4-17
19. Distribution of aquatic organisms	1	4.1	4.2.2.1.6/4-19
20. Premature emergence of aquatic insects	1	4.1	4.2.2.1.7/4-20
21. Gas supersaturation (gas bubble disease)	1	4.1	4.2.2.1.8/4-21
22. Low dissolved oxygen in the discharge	1	4.1	4.2.2.1.9/4-23
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.1	4.2.2.1.10/4-24
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4.1	4.2.2.1.11/4-25

TABLE 1.0-1 (CONTINUED)
FORT CALHOUN STATION ENVIRONMENTAL REPORT
DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	4.2	4.2.2.1.2/4-16
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	4.3	4.2.2.1.3/4-16
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	4.4	4.2.2.1.4/4-17
28. Entrainment of fish and shellfish in early life stages for plants with cooling tower-based heat dissipation systems	1	NA[f]	
29. Impingement of fish and shellfish for plants with cooling tower-based heat dissipation systems	1	NA[f]	
30. Heat shock for plants with cooling tower-based heat dissipation systems	1	NA[f]	
31. Impacts of refurbishment on groundwater use and quality	1	NA[c]	
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	4.1	4.8.1.1/4-116, 4.8.1.2/4-117
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	NA[g]	
34. Groundwater use conflicts (plants using cooling towers withdrawing makeup water from a small river)	2	NA[f]	
35. Groundwater use conflicts (Ranney wells)	2	NA[h]	

TABLE 1.0-1 (CONTINUED)
FORT CALHOUN STATION ENVIRONMENTAL REPORT
DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
36. Groundwater quality degradation (Ranney wells)	1	NA[h]	
37. Groundwater quality degradation (saltwater intrusion)	1	NA[d]	
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	NA[f]	
39. Groundwater quality degradation (cooling ponds at inland sites)	2	NA[f]	
40. Refurbishment impacts to terrestrial resources	2	4.5	3.6/3-6
41. Cooling tower impacts on crops and ornamental vegetation	1	NA[f]	
42. Cooling tower impacts on native plants	1	NA[f]	
43. Bird collisions with cooling towers	1	NA[f]	
44. Cooling pond impacts on terrestrial resources	1	NA[f]	
45. Power line right-of-way management (cutting and herbicide application)	1	4.1	4.5.6.1/4-71
46. Bird collisions with power lines	1	4.1	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.1	4.5.6.3/4-77
48. Floodplains and wetlands on power line right-of-way	1	4.1	4.5.7/4-81
49. Threatened or endangered species	2	4.6	3.9/3-48 4.1/4-1

TABLE 1.0-1 (CONTINUED)
FORT CALHOUN STATION ENVIRONMENTAL REPORT
DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
50. Air quality during refurbishment (nonattainment and maintenance areas)	2	4.7	3.3/3-2
51. Air quality effects of transmission lines	1	4.1	4.5.2/4-62
52. Onsite land use	1	4.1	3.2/3-1
53. Power line right-of-way land-use impacts	1	4.1	4.5.3/4-62
54. Radiation exposures to the public during refurbishment	1	NA[c]	
55. Occupational radiation exposures during refurbishment	1	NA[c]	
56. Microbiological organisms (occupational health)	1	4.1	4.3.6/4-48
57. Microbiological organisms (public health) (Plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	4.8	4.3.6/4-48
58. Noise	1	4.1	4.3.7/4-49
59. Electromagnetic fields, acute effects (electric shock)	2	4.9	4.5.4.1/4-66
60. Electromagnetic fields, chronic effects	NA[i]	4.1	4.5.4.2/4-67
61. Radiation exposures to public (license renewal term)	1	4.1	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	1	4.1	4.6.3/4-95
63. Housing impacts	2	4.10	3.7.2/3-10, 4.7.1/4-101

TABLE 1.0-1 (CONTINUED)
FORT CALHOUN STATION ENVIRONMENTAL REPORT
DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
64. Public services: public safety, social services, and tourism and recreation	1	4.1	3.7.4/3-14, 3.7.4.3/3-18, 3.7.4.4/3-19, 3.7.4.6/3-20, 4.7.3/4-104, 4.7.3.3/4-106, 4.7.3.4/4-107, 4.7.3.6/4-107
65. Public services: public utilities	2	4.11	3.7.4.5/3-19, 4.7.3.5/4-107
66. Public services: education (refurbishment)	2	4.12	3.7.4.1/3-15
67. Public services: education (license renewal term)	1	4.1	4.7.3.1/4-106
68. Offsite land use (refurbishment)	2	4.13.1	3.7.5/3-20
69. Offsite land use (license renewal term)	2	4.13.2	4.7.4/4-107
70. Public services: transportation	2	4.14	3.7.4.2/3-17, 4.7.3.2/4-106
71. Historic and archaeological resources	2	4.15	3.7.7/3-23, 4.7.7/4-114
72. Aesthetic impacts (refurbishment)	1	NA[c]	
73. Aesthetic impacts (license renewal term)	1	4.1	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	1	4.1	4.5.8/4-83
75. Design basis accidents	1	4.1	5.3.2/5-11, 5.5.1/5-114
76. Severe accidents	2	4.16	5.3.3/5-12, 5.5.2/5-114
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level radioactive waste)	1	4.1	6.2.4/6-27, 6.6/6-87
78. Offsite radiological impacts (collective effects)	1	4.1	6.2.4/6-27, 6.6/6-88

TABLE 1.0-1 (CONTINUED)
FORT CALHOUN STATION ENVIRONMENTAL REPORT
DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
79. Offsite radiological impacts (spent fuel and high-level radioactive waste disposal)	1	4.1	6.2.4/6-28, 6.6/6-88
80. Nonradiological impacts of the uranium fuel cycle	1	4.1	6.2.2.6/6-20, 6.2.2.7/6-20, 6.2.2.8/6-21, 6.2.2.9/6-21, 6.6/ 6-90
81. Low-level radioactive waste storage and disposal	1	4.1	6.4.2/6-36, 6.4.3/6-37, 6.4.4/6-48, 6.6/6-90
82. Mixed waste storage and disposal	1	4.1	6.4.5/6-63, 6.6/6-91
83. Onsite spent fuel	1	4.1	6.4.6/6-70, 6.6/6-91
84. Nonradiological waste	1	4.1	6.5/6-86, 6.6/6-92
85. Transportation	1	4.1	Addendum 1 (Ref. 1.0-2)
86. Radiation doses (decommissioning)	1	4.1	7.3.1/7-15, 7.4/7-25
87. Waste management (decommissioning)	1	4.1	7.3.2/7-19, 7.4/7-25
88. Air quality (decommissioning)	1	4.1	7.3.3/7-21, 7.4/7-25
89. Water quality (decommissioning)	1	4.1	7.3.4/7-21, 7.4/7-25
90. Ecological resources (decommissioning)	1	4.1	7.3.5/7-21, 7.4/7-25
91. Socioeconomic impacts (decommissioning)	1	4.1	7.3.7/7-24, 7.4/7-25
92. Environmental justice	NA [i]	4.17	Not addressed in GEIS

FCS = Fort Calhoun Station Unit 1
GEIS = Generic Environmental Impact Statement for License Renewal of Nuclear Plants
gpm = gallons per minute
NA = Not Applicable
NEPA = National Environmental Policy Act
OPPD = Omaha Public Power District

TABLE 1.0-1 (CONTINUED)
FORT CALHOUN STATION ENVIRONMENTAL REPORT
DISCUSSION OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category[a]	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)

a. Source: 10 CFR 51, Subpart A, Appendix B, Table B-1 (Issue numbers added by OPPD to facilitate discussion).
b. Source: Reference 1.0-1.
c. NRC findings are not applicable because OPPD has no plans for major refurbishment.
d. Not applicable because FCS is not in a coastal area.
e. Not applicable because FCS does not withdraw cooling water from a lake.
f. Not applicable because FCS is not equipped with cooling ponds or cooling towers.
g. Not applicable because FCS uses less than 100 gallons of groundwater per minute (no dewatering; potable and service water are from municipal supply. Groundwater use limited to occasional withdrawals for maintaining water level in sanitary lagoons and flushing of center pivot irrigation system).
h. Not applicable because FCS does not use Ranney wells.
i. Not applicable. Regulation does not categorize this issue.

APPENDIX 2.0 CLEAN WATER ACT DOCUMENTATION

STATE OF NEBRASKA

DEPARTMENT OF ENVIRONMENTAL QUALITY
Suite 400, The Atrium
1200 'N' Street
P.O. Box 98922
Lincoln, Nebraska 68509-8922
Phone (402) 471-2186

Mike Johanns
Governor

MAR 2 6 2001

RETURN RECEIPT REQUESTED

Mr. Ken Fielding, Vice President
OPPD Fort Calhoun Station
444 South 16th Street Mall
Omaha, NE 68102

RE: NPDES Number NE0000418

Dear Mr. Fielding:

Enclosed is the National Pollutant Discharge Elimination System (NPDES) Permit for OPPD Fort Calhoun Nuclear Station. Monitoring reports prescribed in Appendix A are required to be submitted to NDEQ. Also enclosed is a Signatory Authorization Form to be completed and returned to Sharon Brunke in the NPDES Permits Unit, ***only if*** there has been change(s) to the most recently submitted form, of which a copy is enclosed.

Questions regarding this permit or monitoring reports should be directed to Brett Anderson of the NPDES Permits Unit of NDEQ at (402) 595-1766. Your cooperation in helping to improve and maintain the quality of Nebraska's waters is appreciated.

Sincerely,

Rudy Fiedler, Acting Unit Supervisor
NPDES Permits Unit
Water Quality Division

Enclosure(s)
sb

STATE OF NEBRASKA

DEPARTMENT OF ENVIRONMENTAL QUALITY
Suite 400, The Atrium
1200 'N' Street
P.O. Box 98922
Lincoln, Nebraska 68509-8922
Phone (402) 471-2186

Mike Johanns
Governor

WQD-P/C

APR 05 2001

RETURN RECEIPT REQUESTED

Mr. Ken Fielding, Vice President
OPPD Fort Calhoun Station
444 South 16th Street Mall
Omaha, Nebraska 68102

RECEIVED
APR 06 2001

RE: NPDES Permit Number NE0000418

Dear Mr. Fielding:

During a review of your National Pollutant Discharge Elimination System Permit NE0000418, it was noted some errors and omissions were made. Errors were made on Page 6 of 29 and Page 12 of 29. Omissions were made Page 4 of 29, Page 5 of 29, and Page 10 of 29. As a result, we are enclosing the corrected copies. Please remove the existing Page 4 of 29 and Page 5 of 29, Page 6 of 29, Page 10 of 29, and Page 12 of 29 and insert these enclosed corrected pages.

If you have any questions, feel free to contact **Ron Asch at (402) 471-2188.**

Sincerely,

Rudy Fiedler, Unit Supervisor
NPDES Permits Unit
Municipal and Industrial Section
Water Quality Division

Enclosure

pc: Gretchen Johnson, Data Processing w/enc
Brett Anderson, NDEQ w/enc

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STATE OF NEBRASKA

DEPARTMENT OF ENVIRONMENTAL QUALITY
Suite 400, The Atrium
1200 'N' Street
P.O. Box 98922
Lincoln, Nebraska 68509-8922
Phone (402) 471-2186

Mike Johanns
Governor

AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the Federal Water Pollution Control Act, (33 U.S.C. §1251 et. seq., as amended to date), the Nebraska Environmental Protection Act (Neb. Rev. Stat. §81-1501 et. seq., as amended to date) and the Rules and Regulations promulgated pursuant to these Acts, **Omaha Public Power District (OPPD) Fort Calhoun Nuclear Station, Fort Calhoun, Nebraska** is authorized to discharge noncontact cooling water and treated wastewater to **Missouri River** in accordance with the effluent limitations, monitoring requirements, and other conditions set forth herein. This authorization to discharge is limited to the noncontact cooling water and wastewater treated by the facility described and this noncontact cooling water and treated wastewater must be discharged via the outfalls described herein. Issuance of an NPDES permit by the Nebraska Department of Environmental Quality does not relieve the permittee of other duties and responsibilities under the Nebraska Environmental Protection Act, as amended, or any rules and regulations promulgated pursuant to this Act. Requirements pertaining to sludge generated at this facility are also set forth in this permit.

NPDES Permit No.:	NE0000418
Facility Name:	Omaha Public Power District (OPPD) Fort Calhoun Nuclear Station
Facility Location:	NW¼, NW¼, Section 21, Township 18 North, Range 12, East, Washington County, Nebraska.

This authorization to discharge shall become effective on April 1, 2001. This authorization to discharge shall expire at midnight, on March 31, 2006.

Pursuant to a Delegation Memorandum dated July 26, 1999, and signed by the Director, the undersigned hereby executes this document on behalf of the Director.

Signed this 23rd day of March, 2001

Jay D. Ringenberg
Deputy Director, Programs

Page 1 of 29

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TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

OPPD Fort Calhoun Nuclear Station
NPDES Permit Number NE0000418
Effective: April 1, 2001
Page 4 of 29

PART I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. **Requirements for Outfall 001:** The flow authorized for discharge through Outfall 001 is once through condenser cooling water and low volume wastewater [(a)]. To comply with these monitoring requirements, samples shall be taken prior to discharge to the drainage to the Missouri River (receiving waters). This discharge shall be monitored and limited as specified in the following table.

		LIMITATION			
PARAMETER	UNITS	DAILY MINIMUM	DAILY MAXIMUM	MONITORING FREQUENCY	SAMPLE TYPE
pH (00400)	S.U.	6.5	9.0	Monthly	Grab
		LIMITATIONS			
PARAMETERS	UNITS	30 DAY AVERAGE	DAILY MAXIMUM	MONITORING FREQUENCY	SAMPLE TYPE
Flow (50050)	MGD	Report	Report	Continuous	Metered
Oil and Grease (00552)	mg/L	Report [(d)]	10 [(d)]	Monthly	Grab
Temperature (00011)	°F	Report	110 [(b)]	Continuous	Recorder
Total Residual Chlorine [(c)] (50060)	mg/l	Report	0.20	Monthly	Grab
Total Suspended Solids (00530)	mg/l	30	100	Monthly	Grab

Footnotes:

[(a)] This permit specifically authorizes the discharge described in the permit application and the supplemental information provided during the permit review process. These discharges were identified as once through condenser cooling water and low volume wastewater during the application process. Department approval is required prior to adding any additional discharge sources or modification of the existing system that may increase the pollutant loadings or significantly increase flows.

[(b)] Case No. 2206 Consent Order allows a daily maximum temperature limitation of 112°F from this point of discharge until NDEQ makes a final determination to issue or deny the permit modification to allow a temperature increase from this outfall or the NDEQ determines that OPPD has not complied satisfactorily with the terms of the Consent Order.

[(c)] If chlorine is **not used** for macro-invertebrate control, the total residual chlorine monitoring and daily maximum limitation shall not apply.

[(d)] This parameter limitation shall be calculated and reported on a net basis, if the oil and grease and total suspended solids samples of the intake water and effluent discharge are sampled during the same time frame.

PART I. INTAKE WATER MONITORING REQUIREMENTS

B. **Requirements for Intake Water for Outfall 001:** The permittee is authorized to monitor the intake water for Outfall 001 designated as once through condenser cooling water and low volume wastewater discharge [(a)]. To comply with these monitoring requirements, samples shall be taken at the intake. This discharge shall be monitored and limited as specified in the following table.

		LIMITATIONS		
PARAMETERS	UNITS	DAILY MAXIMUM	MONITORING FREQUENCY	SAMPLE TYPE
Flow (50050)	MGD	Report	Continuous	Calculated or Metered
Oil and Grease (00552)	mg/L	Report	Monthly	Grab
Total Suspended Solids (00530)	mg/l	Report	Monthly	Grab

Footnotes:

[(a)] This permit specifically authorizes the monitoring of intake water described in the permit application and the supplemental information provided during the permit review process.

PART I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

C. **Requirements for Outfall 002:** The flow authorized for discharge through Outfall 002 is low volume wastewater discharge (water treatment plant discharge) [(a)]. To comply with these monitoring requirements, samples shall be taken prior to discharge to the Missouri River (receiving waters). This discharge shall be monitored and limited as specified in the following table.

PARAMETER	UNITS	LIMITATIONS DAILY MINIMUM	LIMITATIONS DAILY MAXIMUM	MONITORING FREQUENCY	SAMPLE TYPE
pH (00400)	S.U.	6.5	9.0	Monthly	Grab
PARAMETERS	**UNITS**	**LIMITATIONS 30 DAY AVERAGE**	**LIMITATIONS DAILY MAXIMUM**	**MONITORING FREQUENCY**	**SAMPLE TYPE**
Flow (50050)	MGD	Report	Report	Daily	Calculated or Metered
Conductivity (00094)	µmho/cm	Report	Report	Monthly	Grab
Oil and Grease (00552)	mg/L	Report	10	Monthly	Grab
Total Suspended Solids (00530)	mg/l	30	100	Monthly	Grab

Footnotes:

[(a)] This permit specifically authorizes the discharge described in the permit application and the supplemental information provided during the permit review process. The discharge identified during the application as a low volume wastewater discharge (water treatment plant discharge). Department approval is required prior to adding any additional discharge sources or modification of the existing system that may increase the pollutant loadings or significantly increase flows.

PART I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

D. **Requirements for Outfalls 003 and 004:** The flows authorized for discharge through Outfall 003 and Outfall 004 are the traveling screen backwash plant discharge and the surface spray discharge [(a)]. To comply with these monitoring requirements, samples shall be taken prior to discharge to the Missouri River (receiving waters). This discharge shall be monitored and limited as specified in the following table.

		LIMITATIONS			
ARAMETERS	UNITS	30 DAY AVERAGE	DAILY MAXIMUM	MONITORING FREQUENCY	SAMPLE TYPE
No Monitoring Parameters					

Footnotes:

(a) This permit specifically authorizes the discharges described in the permit application and the supplemental information provided during the permit review process. The discharges identified during the application as the traveling screen backwash plant discharge and the surface spray discharge. Department approval is required prior to adding any additional discharge sources or modification of the existing system that may increase the pollutant loadings or significantly increase flows.

PART I.

E. **Requirements for Outfall 005:** The flow authorized for discharge through Outfall 005 is the warmwater recirculation for deicing [(a)]. To comply with these monitoring requirements, samples shall be taken prior to discharge to the Missouri River (receiving waters). This discharge shall be monitored and limited as specified in the following table.

		LIMITATIONS			
PARAMETER	UNITS	DAILY MINIMUM	DAILY MAXIMUM	MONITORING FREQUENCY	SAMPLE TYPE
Temperature (00011)	°F	Report	110 [(b)]	Continuous	Recorder

Footnotes:

[(a)] This permit specifically authorizes the discharge described in the permit application and the supplemental information provided during the permit review process. The discharge was identified as the warmwater recirculation for deicing during the application process. Department approval is required prior to adding any additional discharge sources or modification of the existing system that may increase the pollutant loadings or significantly increase flows.

[(b)] Case No. 2206 Consent Order allows a daily maximum temperature limitation of 112°F from this point of discharge until NDEQ makes a final determination to issue or deny the permit modification to allow a temperature increase from this outfall or the NDEQ determines that OPPD has not complied satisfactorily with the terms of the Consent Order.

PART I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

F. **Requirements for Outfall 006:** The flow authorized for discharge through Outfall 006 is condensation tank discharge [(a)]. To comply with these monitoring requirements, samples shall be taken prior to discharge to the Missouri River (receiving waters). This discharge shall be monitored and limited as specified in the following table.

		LIMITATIONS			
PARAMETERS	UNITS	30 DAY AVERAGE	DAILY MAXIMUM	MONITORING FREQUENCY	SAMPLE TYPE
No Monitoring Parameters					

Footnotes:

(a) This permit specifically authorizes the discharges described in the permit application and the supplemental information provided during the permit review process. The discharges identified during the application as the condensation tank discharge. Department approval is required prior to adding any additional discharge sources or modification of the existing system that may increase the pollutant loadings or significantly increase flows.

OPPD Fort Calhoun Nuclear Station
NPDES Permit Number NE0000418
Effective: April 1, 2001
Page 10 of 29

PART I.

G. **Requirements for Outfall 007:** The flow authorized for discharge through Outfall 007 is the controlled sanitary lagoon discharge [a]. To comply with these monitoring requirements, samples shall be taken prior to discharge e to the Missouri River (receiving waters). This discharge shall be monitored and limited as specified in the following table.

		LIMITATION			
PARAMETER	UNITS	DAILY MINIMUM	DAILY MAXIMUM	MONITORING FREQUENCY	SAMPLE TYPE
pH (00400)	S.U.	6.5	9.0	During each Drawdown Event[b]	Grab
		LIMITATIONS			
PARAMETER	UNITS	30 Day Average	DAILY MAXIMUM	MONITORING FREQUENCY	SAMPLE TYPE
Flow (50050)	MGD	Report	Report	Daily During Drawdown Event	Calculated or Metered
Ammonia as Nitrogen (00610)	mg/L	Report	Report	During each Drawdown Event[b]	Grab
Carbonaceous Biochemical Oxygen Demand (5-Day) (80082)	mg/L	25	40	During each Drawdown Event[b]	Grab
Duration of Discharge (81381)	Days	Report	Report	During each Drawdown Event[b]	Calculated
Total Suspended Solids (00530)	mg/L	80	120	During each Drawdown Event[b]	Grab

May 1 through September 30

PARAMETER	UNITS	LIMITATIONS		MONITORING FREQUENCY	SAMPLE TYPE
		30 DAY AVERAGE	DAILY MAXIMUM		
Fecal Coliform Colonies (74055)	#/100ml	200	400	During each Drawdown Event[b]	Grab

Footnotes:

[a] This permit specifically authorizes the discharges described in the permit application and the supplemental information provided during the permit review process. The discharge identified during the application as the controlled sanitary lagoon discharge. Department approval is required prior to adding any additional discharge sources or modification of the existing system that may increase the pollutant loadings or significantly increase flows.

[b] Two grab samples must be collected during each discharge event. One prior to the drawdown event and a second sample shall be collected prior to stopping the drawdown event.

PART I.

H. CONTROLLED DISCHARGE LAGOON REQUIREMENTS

1. Discharges, if necessary, are required to occur within the following two calendar periods:

   a. Between April 1 and June 30

   b Between October 1 and December 31, but prior to ice formation on the lagoon cell.

   c. The drawdown flow rate shall be measured or calculated at least once per day during each drawdown period.

   d. The duration of the drawdown (number of days) and the daily average of flow (in MGD) shall be reported.

   e. No cell shall be drawn down below the depth of two feet.

   * When a lagoon cell is discharging through an overflow structure, the permittee shall sample the effluent and contact NDEQ immediately.

2. Prior to drawing down any lagoon cell:

   a. The cell(s) to be drawn down shall be isolated from the lagoon cell(s) that is receiving raw wastewater for a minimum of seven days.

   b. Compliance with permit limits must be verified.

3. Drawdowns, if necessary, must last a minimum of five days.

4. If the drawdown lasts under twenty days, the effluent must be sampled on the first and last days of the drawdown.

5. If the drawdown lasts longer than twenty days, an effluent sample shall be taken once every seven days.

PART I.

I. LAND APPLICATION MONITORING REQUIREMENTS

Requirements for Outfall 008: The flow authorized for discharge through Outfall 008 is the discharger into the land application system [(a)]. To comply with these monitoring requirements, samples shall be taken prior to discharge to the land application system. This discharge shall be monitored and limited as specified in the following table.

		LIMITATION			
PARAMETERS	**UNITS**	**DAILY MINIMUM**	**DAILY MAXIMUM**	**MONITORING FREQUENCY**	**SAMPLE TYPE**
pH (00400)	S.U.	Report	Report	Twice per Season [(b)]	Grab
		LIMITATIONS			
PARAMETERS	**UNITS**	**30 DAY AVERAGE**	**DAILY MAXIMUM**	**MONITORING FREQUENCY**	**SAMPLE TYPE**
Flow (50050)	MGD	Report	Report	Daily	Calculated or Metered
Ammonia as Nitrogen (00610)	mg/L	Report	Report	Twice per Season [(b)]	Grab
Conductivity (000094)	μmho/cm	Report	Report	Twice per Season [(b)]	Grab
Total Chlorides (00940)	mg/L	Report	Report	Twice per Season [(b)]	Grab
Total Kjeldahl Nitrogen (00625)	mg/L	Report	Report	Twice per Season [(b)]	Grab
Nitrate as Nitrogen (00620)	mg/L	Report	Report	Twice per Season [(b)]	Grab

Footnotes:

[(a)] This permit specifically authorizes the discharges described in the permit application and the supplemental information provided during the permit review process. The discharges identified during the application as the condensation tank discharge. Department approval is required prior to adding any additional discharge sources or modification of the existing system that may increase the pollutant loadings or significantly increase flows.

[(b)] Land application compliance samples shall be collected twice during each season. One sample shall be collected at the start of land application season. The second sample shall be collected prior to the end of the land application season. The land application season is from April 1 through October 31 each year.

PART I. STORM WATER MONITORING REQUIREMENTS

J. **Requirements for the Storm Water Outfalls:** The flows authorized for discharge through these Outfalls is storm water from the switching yard and two other storm water outfalls [(a)]. To comply with these monitoring requirements, samples shall be taken prior to discharge to the Missouri River (receiving waters). This discharge shall be monitored as specified in the following table. The Department may request sampling of the two other storm water outfalls identified in the Pollution Prevention Plan (Fort Calhoun Station Unit No. 1, Standing Order: **SO-G-108**).

PARAMETER	UNITS	REPORTING REQUIREMENT	MONITORING FREQUENCY	SAMPLE TYPE
Flow (50050)	MGD	Report	(b)	Calculated or Metered
Total Ammonia as Nitrogen (00610)	mg/L	Report	(b)	(c)
Biochemical Oxygen Demand (5-Day) (00310)	mg/L	Report	(b)	(c)
Chemical Oxygen Demand (81017)	mg/L	Report	(b)	(c)
Fecal Coliform (74055)	mg/L	Report	(b)	(c)
Fecal Streptococcus (74054)	mg/L	Report	(b)	(c)
Total Nitrate as Nitrogen (00620)	mg/L	Report	(b)	(c)
Total Kjeldahl Nitrogen (00625)	mg/L	Report	(b)	(c)
Oil and Grease (00552)	mg/L	Report	(b)	(c)
pH (00400)	mg/L	Report	(b)	(c)
Dissolved Phosphorus (00666)	mg/L	Report	(b)	(c)
Total Phosphorus (00665)	mg/L	Report	(b)	(c)
Total Dissolved Solids (70295)	mg/L	Report	(b)	(c)
Total Suspended Solids (00530)	mg/L	Report	(b)	(c)

Footnotes:

(a) This permit specifically authorizes the discharges described in the permit application and the supplemental information provided during the permit review process. These discharges were identified as storm water discharges in the Pollution Prevention Plan (Fort Calhoun Station Unit No. 1, Standing Order: **SO-G-108**). Department approval is required prior to adding any additional discharge sources or modification of the existing system that may increase the pollutant loadings or significantly increase flows.

(b) and (c) See Part II. A. Other Requirements, Paragraphs 10 and 11.

PART II

A. OTHER REQUIREMENTS

1. The wastewater shall not cause: noxious odors, floating, suspended, colloidal or settleable materials that produce objectionable films, colors, turbidity or deposits; and the occurrence of undesirable or nuisance aquatic life.

2. Sludge shall be disposed of or utilized in a manner approved by the Department of Environmental Quality.

3. This permit may be reopened and modified after the public notice and opportunity for a public hearing for reasons specified in NDEQ Title 119 - Rules and Regulations Pertaining to the Issuance of Permits Under the National Pollutant Discharge Elimination System, Chapter 14. These reasons include but are not limited to: the effluent has been monitored for two years and a written request by the permittee provides justification for reducing the frequency of monitoring of any parameter(s) in this permit or if new information becomes available that justifies an increase or decrease of any effluent limitation(s) in this permit. The results of a water quality study may be considered new information.

4. The permittee shall analyze wastewater parameters using the approved methods listed in 40 CFR, Part 136, as adopted in NDEQ Title 121 - Effluent Guidelines and Standards, Chapter 8.

5. This facility is to be operated and maintained by operators certified in accordance with NDEQ Title 197 - Rules and Regulations for the Certification of Wastewater Treatment Facility Operators in Nebraska.

6. The Minimum Limit (ML) is defined as the level at which the entire analytical system gives acceptable calibration points. If the analytical results are below the ML, the results should be reported as "**as a numerical value less than the detection limit (i.e. <0.005)**".

7. The permittee shall notify the NDEQ Permits and Compliance Section prior to adding any compound (i.e., biocides or conditioners) to the noncontact cooling water. The notification shall include: the quantity to be added, Material Safety Data Sheets (MSDS), and any information regarding the compound's toxicity to aquatic life.

8. There shall be no discharge of polychlorinated biphenyl compounds (**PCBs**) from any outfall at any time.

9. Chlorine may not be injected into any single generating unit for more than two (2) hours per day unless the permittee demonstrates to the Department that injection for more than two (2) hours is required for macro invertebrate control. Both simultaneous multi-unit and sequential chlorination for are allowed for power plants rated at greater than 25 megawatts. Simultaneous multi-unit chlorination for power plants at rated at less than 25 megawatts is allowed.

10. The switching yard storm water outfall shall be sampled and the results reported as an addendum to the regular discharge monitoring report once during the first year and the fifth year of this permit term during discharge event. The storm water sample points and sampling techniques to be used were identified in the Pollution Prevention Plan (Fort Calhoun Station Unit No. 1, Standing Order **SO-G-108**).

11. The Department may request the sampling of the other storm water outfalls identified in the Pollution Prevention Plan - Fort Calhoun Station Unit No. 1, Standing Order **SO-G-108.**

12. Best management practices shall be employed to prevent and minimize pollutant releases into the storm water discharges.

APPENDIX A - Standard Conditions for NPDES and NPP Permits.

These general conditions are applicable to all NPDES and NPP permits. These conditions shall not preempt any more stringent requirements found elsewhere in this permit.

A. General Conditions

1. Information Available

All permit applications, fact sheets, permits, discharge data, monitoring reports, and any public comments concerning such shall be available to the public for inspection and copying, unless such information about methods or processes is entitled to protection as trade secrets of the owner or operator under Neb. Rev. Stat. §81-1527, (Cum. Supp. 1992) and Title 115, Chapter 9.

2. Duty to Comply

All authorized discharges shall be consistent with the terms and conditions of this permit. The discharge of any pollutant identified in this permit more frequently than or at a level in excess of that authorized shall constitute a violation of the permit.

The permittee shall comply with all conditions of this permit. Failure to comply with these conditions may be grounds for administrative action or enforcement proceedings including injunctive relief and civil or criminal penalties.

The filing of a request by the permittee for a permit modification, revocation and reissuance, termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

3. Duty to Mitigate

The permittee shall take all reasonable steps to minimize, prevent or correct any adverse impact to the environment resulting from noncompliance with this permit, including such accelerated or additional monitoring as required by the NDEQ to determine the nature and impact of the noncompliant discharge.

4. Permit Actions

This permit may be modified, suspended, revoked or reissued, in part or in whole, in accordance with the regulations set forth in NDEQ Titles 119 and/or 127. In addition, this permit may be modified, revoked and reissued to incorporate standards or limitations issued pursuant to Sections 301(b)(2)(c), 301(b)(2)(d), 304(b)(2), 307(a)(2), or 405(d) of the Clean Water Act, Public Law 100-4 (i.e., industrial categorical standards and municipal sludge regulations) and Title 121.

5. Toxic Pollutants

The permittee shall not discharge pollutants to waters of the State that cause a violation of the standards established in NDEQ Titles 117, 118 or 121. All discharges to surface waters of the State shall be free of toxic (acute or chronic) substances which alone or in combination with other substances, create conditions unsuitable for aquatic life outside the appropriate mixing zone.

Appendix A (continued)

6. **Oil and Hazardous Substances/Spill Notification**

   Nothing in this permit shall preclude the initiation of any legal action or relieve the permittee from any responsibilities, liabilities or penalties under Section 311 of the Clean Water Act. The permittee shall conform to the provisions set forth in NDEQ Title 126 in the event of a release of a reportable quantity of oil or hazardous substances. If the permittee knows, or has reason to believe, that oil or hazardous substances were released at the facility and could enter waters of the State or any of the outfall discharges authorized in this permit, the permittee shall immediately notify the Department of a release of oil or hazardous substances. During Department office hours (i.e., 8:00 a.m. to 5:00 p.m., Monday through Friday, except holidays), notification shall be made to the LUST/ER Section (telephone number 402/471-4230). When the LUST/ER Section cannot be contacted, the permittee shall report to the Nebraska State Patrol for referral to the NDEQ Emergency Response Team (telephone number 402/471-4545). It shall be the permittee's responsibility to maintain current telephone numbers necessary to carry out the notification requirements set forth above.

7. **Property Rights**

   The issuance of this permit does not convey any property rights of any sort or any exclusive privileges nor does it authorize any damage to private property or any invasion of personal rights nor any infringement of federal, state or local laws or regulations.

8. **Severability**

   If any provision of this permit is held invalid, the remainder of this permit shall not be affected.

9. **Other Rules and Regulations Liability**

   The issuance of this permit in no way relieves the obligation of the permittee to comply with other rules and regulations of the Department.

10. **Inspection and Entry**

    The permittee shall allow the Director or his authorized representative, upon the presentation of his identification and at a reasonable time:

    a. to enter upon the permittee's premises where a regulated facility or activity is located or conducted, or records are required to be kept under the terms and conditions of the permit,

    b. to have access to and copy any records required to be kept under the terms and conditions of the permit,

    c. to inspect any facilities, equipment (including monitoring and control), practices or operations regulated or required in the permit, and

    d. to sample or monitor any substances or parameters at any location.

Appendix A (continued)

11. **Penalties**

Violations of the terms and conditions of this permit may result in the initiation of criminal and/or civil actions. Civil penalties can result in fines of up to $10,000.00 per day [Neb. Rev. Stat. §81-1508, as amended to date. Criminal penalties for willful or negligent violations of this permit may result in penalties of $10,000.00 per day or by imprisonment. Violations may also result in federal prosecution.

B. **Management Requirements**

1. **Duty to Provide Information**

The permittee shall furnish to the Department within a reasonable time, any information which the Department 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 to the Department upon request, copies of records retained as a requirement of this permit.

2. **Duty to Reapply**

The permittee shall apply for a reissuance of this permit, if an activity regulated by this permit is to be continued after the expiration date of this permit. The application shall be submitted at least 180 days before the expiration of this permit on an application form supplied by the Department, as set forth in NDEQ Titles 119 and/or 127.

3. **Signatory Requirements**

All reports and applications required by this permit or submitted to maintain compliance with this permit, shall be signed and certified as set forth in this section.

a. Permit applications shall be signed by a **cognizant official** who meets the following criteria:

(1) for a corporation: by a principal executive officer of at least the level of vice-president,

(2) for a partnership or sole proprietorship: by a general partner or the proprietor, respectively, or

(3) for a municipality, state, federal or other public facility: by either a principal executive officer or highest ranking elected official.

b. Discharge monitoring reports and other information shall be signed by the cognizant official or by an **authorized representative**.

c. An authorized representative is designated by the cognizant official. The authorized representative is responsible for the overall operation of the facility (i.e., a plant manager, a well field operator or a wastewater treatment plant superintendent).

d. Any change in the signatories shall be submitted to the Department, in writing, within 30 days after the change.

Appendix A (continued)

e. Certification. All applications, reports and information submitted as a requirement of this permit, shall contain the following certification statement:

"I certify, under penalty of law, that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment for knowing violations."

C. Monitoring and Records

1. Representative Sampling

Samples and measurements taken as required within this permit shall be representative of the discharge. All samples shall be taken at the monitoring points specified in this permit and, unless otherwise specified, before the effluent joins or is diluted by any other waste stream, body of water or substance. Monitoring points shall not be changed without notification to the Department and with the written approval of the Director.

a. Composite sampling shall be conducted in one of the following manners:

(1) continuous discharge - a minimum of one discrete aliquot collected every three hours,

(2) less than 24 hours - a minimum of hourly discrete aliquots or a continuously drawn sample shall be collected during the discharge, or

(3) batch discharge - a minimum of three discrete aliquots shall be collected during each discharge.

b. Composite samples shall be collected in one of the following manners:

(1) the volume of each aliquot must be proportional to either the waste stream flow at the time of sampling or the total waste stream flow since collection of the previous aliquot,

(2) a number of equal volume aliquots taken at varying time intervals in proportion to flow,

(3) a sample continuously collected in proportion to flow, and

(4) where flow proportional sampling is infeasible or nonrepresentative of the pollutant loadings the Department may approve the use of time composite samples.

c. Grab samples shall consist of a single aliquot collected over a time period not exceeding 15 minutes.

d. All sample preservation techniques shall conform to the methods adopted in NDEQ Title 121, Chapter 8, unless:

(1) in the case of sludge samples, alternative techniques are specified in the 40 CFR, Part 503, or

Appendix A (continued)

(2) other procedures are specified in this permit.

2. Flow Measurements

Appropriate flow measurement devices and methods consistent with accepted scientific practices shall be used to insure the accuracy and reliability of measurements. The devices shall be installed, calibrated and maintained to insure that the accuracy of the measurements are consistent with the accepted capability of that type of device. Devices selected shall be capable of measuring flows with a maximum deviation of +/- 10% from the true discharge rates throughout the range of expected discharge volumes. Guidance in selection, installation, calibration and operation of acceptable flow measurement devices can be obtained from the following references:

a. "Water Management Manual," U. S. Department of Interior, Bureau of Reclamation, Second Edition, Revised Reprint, 1974, 327 pp. Available from the U. S. Government Printing Office, Washington, DC 20402. Order by Catalog Number 127.19/2:W29/2, Stock Number S/N 24003-0027.

b. "Flow Measurement in Open Channels and Closed Conduits," U. S. Department of Commerce, National Bureau of Standards, NBS Special Publication 484, October, 1977, 982 pp. Available in paper copy or microfiche from National Technical Information Service (NTIS), Springfield, VA 22151. Order by NTIS Number PB-273 535/5ST.

c. "NPDES Compliance Sampling Manual," U. S. Environmental Protection Agency, Office of Water Enforcement, Publication MCD-51, May, 1988, 140 pp. Available from the General Services Administration (8FFS), Centralized Mailing Lists Services, Building 41, Denver Federal Center, Denver, CO 80225.

3. Test Procedures

Test procedures used for monitoring required by this permit, shall conform to the methods adopted in NDEQ Title 121, Chapter 8 unless:

a. in the case of sludge samples, alternative techniques are specified in the 40 CFR, Part 503, or

b. other procedures are specified in this permit.

4. Averaging of Measurements

Averages shall be calculated as an arithmetic mean except:

a. bacterial counts which shall be calculated as a geometric mean, or

b. where otherwise specified by the Department.

5. Retention of Records

The permittee shall retain records of all monitoring activities for a period of at least three years (five years for sludge; see below) as set forth in NDEQ Titles 119 and/or 127. The types of records that must be retained include, but are not limited to:

Appendix A (continued)

a. calibration and maintenance records,

b. original strip chart recordings,

c. copies of all reports required by this permit,

d. monitoring records and information, and

e. electronically readable data.

The permittee shall retain records of monitoring required by this permit that are related to sludge use and disposal for a period of five years or longer, as required in 40 CFR, Part 503.

6. Record Contents

Records of sampling or monitoring information shall include:

a. the date(s), exact place, time and methods of sampling or measurements,

b. the name(s) of the individual(s) who performed the sampling or measurements,

c. the date(s) the analyses were performed,

d. the individual(s) who performed the analyses,

e. the analytical techniques or methods used,

f. the results of such analyses, and

g. laboratory data, bench sheets and other required information.

D. Reporting Requirements

1. Immediate Notification

a. NPP permittees shall report immediately to the publicly owned treatment works (POTW), any discharge to the POTW that may result in a violation of NDEQ Title 127, Chapter 3.

b. All permittees shall report immediately to the NDEQ:

(1) discharges of oil or hazardous substances which threaten waters of the State or public health and welfare, and

(2) discharges causing in-stream toxicity (i.e., a fish kill) or an immediate threat to human health.

Initial notification may be verbal. A written noncompliance notification shall be submitted as set forth in Section D. 3. of this Appendix.

Appendix A (continued)

2. 24-Hour Reporting

The permittee shall report to the NDEQ, within 24 hours of becoming aware of:

a. any noncompliance which may endanger the environment or human health or welfare,

b. any unanticipated bypass as set forth in NDEQ Titles 119 and/or 127,

c. all upsets as set forth in NDEQ Titles 119 and/or 127,

d. any discharge to a POTW that causes a violation of the prohibited discharge standards set forth in NDEQ Title 127, Chapter 3, or

e. any noncompliance of an effluent limitation in this permit.

Initial notification may be verbal. A written noncompliance notification shall be submitted as set forth in Section D. 3. of this permit.

If sampling performed by an industrial user (NPP permittee) indicates a permit effluent violation, the permittee shall notify the Department and the city within 24 hours of becoming aware of the violation. The permittee shall resample and have it analyzed. The results of the resampling analysis shall be submitted to the Department and the city within 30 days after becoming aware of the violation.

3. Written Noncompliance Notification

a. The permittee shall submit a written noncompliance report to the NDEQ:

(1) within five days of becoming aware of any noncompliance with the:

(a) NPP effluent limitations or requirements set forth in this permit, or

(b) NPDES toxic pollutant effluent limitations or requirements set forth in this permit.

(2) within seven days of becoming aware of any other noncompliance with the NPDES requirements and/or effluent limitations set forth in this permit.

b. the written notification shall be submitted on a noncompliance form supplied by the Department and shall include:

(1) a description of the discharge and cause of noncompliance,

(2) the period of noncompliance, including exact dates and times, or if not corrected, the anticipated time the noncompliance is expected to continue, and

(3) the steps taken to reduce, eliminate and prevent the reoccurrence of the noncompliance.

The submittal of a written noncompliance report does not relieve the permittee of any liability from enforcement proceedings that may result from the violation of permit or regulatory requirements.

Appendix A (continued)

4. **Quarterly Discharge Monitoring Reports (DMRs)**

The permittee shall report the monitoring results required by this permit on a DMR form supplied or approved by the Department. Monitoring results shall be submitted on a quarterly basis using the reporting schedule set forth below, unless otherwise specified in this permit or by the Department.

Monitoring Quarters	DMR Reporting Deadlines
January - March	April 28
April - June	July 28
July - September	October 28
October - December	January 28

If the permittee monitors any pollutant more frequently than required by this permit, using procedures specified in this permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted on the DMR. The frequency of the analysis shall also be reported on the DMR.

5. **Changes in Discharge**

Any facility expansion, production increases or process modifications which will result in new or substantially increased discharges of pollutants or a change in the nature of the discharge of pollutants must be reported by the permittee 180 days prior to the expansion, increases or modifications, either by amending his original application or by submitting a new application. This permit may be modified or revoked and reissued as a result of this notification to maintain compliance with applicable state or federal regulations.

6. **Changes in Toxic Discharges from Manufacturing, Commercial, Mining and Silvicultural Facilities**

Permittees discharging from manufacturing, commercial, mining and silvicultural facilities shall report to the Department:

a. if any toxic pollutant not limited in this permit is discharged from any NPDES outfall as a result of any activity that will or has occurred and results in its routine or frequent discharge. The Department shall be informed if that discharge exceeds the following notification levels:

(1) 100 micrograms per liter (0.1 mg/l) for any toxic pollutant,

(2) 200 micrograms per liter for acrolein and acrylonitrile (0.2 mg/l),

(3) 500 micrograms per liter for 2,4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol (0.5 mg/l),

(4) 1000 micrograms per liter for antimony (1 mg/l),

(5) five times the maximum concentration value reported for that pollutant in the permit application or

(6) an alternative level established by the Director, and

Appendix A (continued)

b. if any toxic pollutant not limited in this permit is discharged from an NPDES outfall as a result of any activity that will or has occurred and results in its nonroutine discharge. The Department shall be informed if that discharge exceeds the following notification levels:

(1) 500 micrograms per liter (0.5 mg/l) for any toxic pollutant,

(2) 1000 micrograms for antimony (1 mg/l),

(3) ten times the maximum concentration value reported for that pollutant in the permit application, or

(4) an alternative level established by the Director.

7. **Changes in Sludge Quality**

The permittee shall provide written notice to the Department of any alteration or addition that results in a significant change in the permittee's sludge use or disposal practices. This permit may be modified or revoked and reissued as a result of this notification to maintain compliance with applicable state or federal regulations.

8. **Changes of Loadings to Publicly Owned Treatment Work (POTW)**

POTW's shall notify the Department of the following:

a. any new introduction of pollutants from dischargers subject to the categorical pretreatment discharge limitations set forth in NDEQ Title 121, Chapter 2, and

b. any substantial change in the volume or character of pollutants being introduced into the POTW.

Notification shall be made 180 days in advance whenever possible. Information on the quantity and quality of new discharges and their anticipated impact on the POTW shall be included.

9. **Transfers**

The permittee shall notify the Department at least 30 days prior to the proposed transfer of ownership of this permit or the permitted facility to another party as set forth in NDEQ Title 119, Chapter 12 and/or NDEQ Title 127, Chapter 14. The Department may modify or revoke and reissue this permit according to the regulations set forth in NDEQ Titles 119 and/or 127.

10. **Compliance Schedules**

The permittee shall submit a written report of compliance or noncompliance with any compliance schedule established in this permit. The written report shall be submitted within 14 days following all deadlines established in the compliance schedule. If compliance has not been achieved, the report shall include an alternative completion date, an explanation of the cause of the noncompliance and an explanation of the steps being taken to ensure future compliance. The submission of this report does not ensure the Department's acceptance of alternative compliance dates nor does it preclude the Department from initiating enforcement proceedings based upon the reported noncompliances.

Appendix A (continued)

E. Operation and Maintenance

1. **Proper Operation and Maintenance**

   The permittee shall, at all times, maintain in good working order and operate as efficiently as possible, any facilities or systems of control installed by the permittee in order to achieve compliance with the terms and conditions of this permit. This would include, but not be limited to, effective performance based on designed facility removals, effective management, adequate operator staffing and training, adequate laboratory and process controls, and adequate funding which reflects proper user fee schedules.

2. **Treatment System Failure and Upset**

   An upset is an affirmative defense to an enforcement action brought for noncompliance with technology-based permit effluent limitations if the permittee can demonstrate, through properly signed, operating logs or other relevant evidence, that:

   a. an upset occurred and the specific cause was identified,

   b. that the facility was properly operated and maintained at such time,

   c. the Department was notified within 24 hours of the permittee becoming aware of the upset, and

   d. the permittee took action to reduce, eliminate and prevent a reoccurrence of upset, including minimizing adverse impact to waters of the State.

3. **Bypassing**

   Any diversion from or bypass of the treatment facilities is prohibited, unless:

   a. it is unavoidable to prevent loss of life, personal injury or severe property damage,

   b. no feasible alternative exists, i.e., auxiliary treatment facilities, retention of untreated wastes or maintenance during normal periods of equipment downtime,

   c. the permittee submits notice to the Department within 24 hours of becoming aware of the bypass or if the bypass is anticipated or should have been anticipated, the Department is notified at least ten days prior to the bypass, and

   d. the bypass is conducted under conditions determined to be necessary by the Director to minimize any adverse effects.

   If the bypass is needed for regular preventative maintenance for which back-up equipment should be provided, the bypass will not be allowed. When a bypass occurs, the burden is on the permittee to demonstrate compliance with items "a" through "d" above.

   Additionally, NPP permittees shall report any bypasses to the POTW. Unanticipated bypasses shall be reported immediately and anticipated bypasses shall be reported at least ten days in advance.

Appendix A (continued)

All NPDES permittees shall notify the general public that a bypass of the treatment system is occurring. The public notification shall include:

a. location of the bypass,

b. the date the bypass started,

c. anticipated length of time the bypass will occur, and

d. an estimate of the total volume of wastewater bypassed.

4. Removed Substances

Solids, sludge, filter backwash or other pollutants removed in the course of treatment or control of wastewater shall be disposed of at a site and in a manner approved by the Nebraska Department of Environmental Quality. The disposal of nonhazardous industrial sludges shall conform to the standards established in or to the regulations established pursuant to 40 CFR, Part 257. The disposal of sludge shall conform to the standards established in or to the regulations established pursuant to 40 CFR, Part 503. If solids are disposed of in a licensed sanitary landfill, the disposal of solids shall conform to the standards established in Title 132. Publicly owned treatment works shall dispose of sewage sludge in a manner that protects public health and the environment from any adverse effects which may occur from toxic pollutants as defined in Section 307 of the Clean Water Act. This permit may be modified or revoked and reissued to incorporate regulatory limitations established pursuant to 40 CFR, Part 503.

F. Definitions

Administrator: The Administrator of the USEPA.

Aliquot: An individual sample having a minimum volume of 100 milliliters (unless the test method calls for a smaller sized sample) that is collected either manually or in an automatic sampling device.

Biweekly: Once every other week.

Bimonthly: Once every other month.

Bypass: The intentional diversion of wastes from any portion of a treatment facility.

Daily Average: An effluent limitation that cannot be exceeded and is calculated by averaging the monitoring results for any given pollutant parameter obtained during a 24-hour day.

Department: Nebraska Department of Environmental Quality.

Director: The Director of the Nebraska Department of Environmental Quality.

Industrial User: A source of indirect discharge (a pretreatment facility).

Monthly Average: An effluent limitation that cannot be exceeded, calculated by averaging the monitoring results for any given pollutant parameter obtained during a calendar month.

Appendix A (continued)

Publicly Owned Treatment Works (POTW): A treatment works as defined by Section 212 of the Clean Water Act (Public Law 100-4) which is owned by the state or municipality, excluding any sewers or other conveyances not leading to a facility providing treatment.

Sludge: Any solid, semisolid, or liquid waste generated from a municipal, commercial, or industrial wastewater treatment plant, water supply treatment plant, or air pollution control facility or any other such waste having similar characteristics and effect.

30-Day Average: An effluent limitation that cannot be exceeded, calculated by averaging the monitoring results for any given pollutant parameter obtained during a calendar month.

Total Toxic Organics (TTO): The summation of all quantifiable values greater than 0.01 milligrams per liter (mg/l) for toxic organic compounds that may be identified elsewhere in this permit. (If this term has application in this permit, the list of toxic organic compounds will be identified; typically in the Limitations and Monitoring Section(s) or in an additional Appendix to this permit.)

Toxic Pollutant: Those pollutants or combination of pollutants, including disease causing agents, after discharge and upon exposure, ingestion, inhalation or assimilation into an organism, either directly from the environment or indirectly by ingestion through food chains will, on the basis of information available to the administrator, cause death, disease, behavioral abnormalities, cancer, genetic mutations, physiological malfunction (including malfunctions in reproduction) or physical deformations, in such organisms or their offspring.

Upset: An exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee, excluding such factors as operational error, improperly designed or inadequate treatment facilities or improper operation and maintenance or lack thereof.

Volatile Organic Compounds (VOC): The summation of all quantifiable values greater than 0.01 milligrams per liter (mg/l) for volatile, toxic organic compounds that may be identified elsewhere in this permit. (See the definition for Total Toxic Organics above. In many instances, VOCs are defined as the volatile fraction of the TTO parameter. If the term "VOC" has application in this permit, the list of toxic organic compounds will be identified; typically in the Limitations and Monitoring Section(s) or in an additional Appendix to this permit.)

Weekly Average: An effluent limitation that cannot be exceeded, calculated by averaging the monitoring results for any given pollutant parameter obtained during a fixed calendar week. The permittee may start their week on any weekday but the weekday must remain fixed unless a change is approved by the Department.

"X" Day Average: An effluent limitation defined as the maximum allowable "X" day average of consecutive monitoring results during any monitoring period where "X" is a number in the range of one to seven days.

G. Abbreviations

CFR: Code of Federal Regulations

kg/Day: Kilograms per Day

MGD: Million Gallons per Day

Appendix A (continued)

mg/L: Milligrams per Liter

NDEQ: Nebraska Department of Environmental Quality

NDEQ Title 115: Rules of Practice and Procedure

NDEQ Title 117: Nebraska Surface Water Quality Standards

NDEQ Title 118: Ground Water Quality Standards and Use Classification

NDEQ Title 119: Rules and Regulations Pertaining to the Issuance of Permits Under the National Pollutant Discharge Elimination System

NDEQ Title 121: Effluent Guidelines and Standards

NDEQ Title 126: Rules and Regulations Pertaining to the Management of Wastes

NDEQ Title 127: Rules and Regulations Governing the Nebraska Pretreatment Program

NDEQ Title 132: Rules and Regulations Pertaining to Solid Waste Management

NPDES: National Pollutant Discharge Elimination System

NPP: Nebraska Pretreatment Program

POTW: Publicly Owned Treatment Works

ug/L: Micrograms per Liter

WWTF: Wastewater Treatment Facility

APPENDIX B. Total Toxic Organic (TTO) and Volatile Organic Compounds

If required in Part I of this permit, the permittee shall monitor for the following compounds to demonstrate compliance with the TTO effluent limitations.

1. **Volatile Fraction**. To be analyzed using EPA Method 624 or 1624 as set forth in NDEQ Title 121, Chapter 8.

Acrolein	1,4-Dichlorobenzene
Acrylonitrile	1,2-Dichloropropane
Benzene	1,3-Dichloropropylene
Bromoform	Ethylbenzene
Carbon tetrachloride	Methyl bromide
Chlorobenzene	Methyl chloride
Chlorodibromomethane	Methylene chloride
Chloroethane	1,1,2,2-Tetrachloroethane
2-Chloroethylvinyl ether	Tetrachloroethylene
Chloroform	Toluene
Dichlorobromomethane	1,2-Trans-dichloroethylene
1,1-Dichloroethane	1,1,1-Trichloroethane
1,2-Dichloroethane	1,1,2-Trichloroethane
1,1-Dichloroethylene	Trichloroethylene
1,2-Dichlorobenzene	Vinyl chloride
1,3-Dichlorobenzene	

2. **Acid Fraction**. To be analyzed using EPA Method 625 or 1625 as set forth in NDEQ Title 121, Chapter 8.

2-Chlorophenol	N-nitrosodimethylamine
2,4-Dichlorophenol	N-nitrosodi-n-propylamine
2,4-Dimethylphenol	N-nitrosodiphenylamine
4,6-Dinitro-o-cresol	Parachlorometa cresol
2,4-Dinitrophenol	Pentachlorophenol
2-Nitrophenol	Phenol
4-Nitrophenol	2,4,6-Trichlorophenol

3. **Base/Neutral Fraction**. To be analyzed using EPA Method 625 or 1625 as set forth in NDEQ Title 121, Chapter 8.

Acenaphthene	Diethyl phthalate
Acenaphthylene	Dimethyl phthalate
Anthracene	Di-N-Butyl phthalate
Benzidine	2,4-Dinitrotoluene
Benzo(a)anthracene	2,6-Dinitrotoluene
Benzo(a)pyrene	Di-n-octyl phthalate
3,4-Benzofluoranthene	1,2-Diphenylhydrazine (as Azobenzene)
Benzo(ghi)perylene	Fluoranthene
Benzo(k)fluoranthene	Fluorene
Bis(2-chloroethoxy)methane	Hexachlorobenzene
Bis(2-chloroethyl)ether	Hexachlorobutadiene
Bis(2-chloroisopropyl)ether	Hexachloroethane

Appendix B - (Continued)

3. **Base/Neutral Fraction**. To be analyzed using EPA Method 625 or 1625 as set forth in NDEQ Title 121, Chapter 8 (Continued).

Bis(2-ethylhexyl)phthalate	Hexachlorocyclopentadiene
4-Bromophenyl phenyl ether	Indeno(1,2,3-cd) pyrene
Butylbenzyl phthalate	Isophorone
2-Chloronaphthalene	Naphthalene
4-Chlorophenyl phenyl ether	Nitrobenzene
Chrysene	Phenanthrene
Dibenzo(a,h)anthracene	Pyrene
3,3-Dichlorobenzidine	1,2,4-Trichlorobenzene

4. **Pesticide Fraction**. To be analyzed using EPA Method 608 as set forth in NDEQ Title 121, Chapter 8.

Aldrin	Endrin
Alpha-BHC	Endrin aldehyde
Beta-BHC	Heptachlor
Gamma-BHC	Heptachlor epoxide
Delta-BHC	PCB-1242
Chlordane	PCB-1254
4,4'-DDT	PCB-1221
4,4'-DDE	PCB-1232
4,4'-DDD	PCB-1248
Dieldrin	PCB-1260
Alpha-endosulfan	PCB-1016
Beta-endosulfan	Toxaphene
Endosulfan sulfate	

5. **Dioxin (2,3,7,8-tetrachlorodibenzo-p-dioxin)**. To be analyzed for using Environmental Protection Agency (EPA) Method 613 as set forth in NDEQ Title 121, Chapter 8.

Nebraska Department of Environmental Quality

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES) PERMIT for OMAHA PUBLIC POWER DISTRICT FORT CALHOUN NUCLEAR STATION
26 August 2000 Draft

Fact Sheet Contents Summary

A. Applicant Information

Permittee Name: **Omaha Public Power District - Fort Calhoun Station**
U.S. Highway 75
Fort Calhoun, Nebraska 68023

B. **Facility Description**

Omaha Public Power District Fort Calhoun Station is a nuclear powered steam electric generating plant (SIC Number 4911). The effluents from the OPPD Fort Calhoun Station are discharged into the Missouri River.

C. Receiving Waters

1. The general and numerical criteria that make up the water quality standards are provided in NDEQ Title 117 - Nebraska Surface Water Quality Standards.

2. The various wastewaters are discharged into the Missouri River. This segment is designated as MT1-10000 of the Missouri Tributaries River Basin. The following beneficial uses of this surface water are as follows:

   Recreation: Full Body Contact
   Aquatic Life: Warm Water Class A
   Industrial Water Supply
   Public Drinking Water Supply
   Aesthetics
   Endangered Species: Pallid Sturgeon.
   Threatened Species: Lake Sturgeon.
   Key Species: Blue Catfish, Channel Catfish and Flathead Catfish, Paddlefish

D. Description of Discharges

The process water from OPPD Fort Calhoun Nuclear Station is discharged from eight different outfalls. The primary process water discharged from Outfall 001 is noncontact cooling water. The primary process water discharged from Outfalls 002 is the water treatment plant discharge. The primary process water discharged from Outfall 003 is recirculated back wash water to the cooling water traveling inlet screen. The primary process water discharged from Outfall 004 is recirculated water to reduce the foam by surface spray at the cooling water inlet. The primary process water discharged from Outfall 005 is recirculated water to de-ice the cooling water inlet during the freezing weather. The primary process water discharged from Outfall 006 is water from the condensation tank. The primary process water discharged from Outfall 007 is treated sanitary wastewater from a lagoon system. The treated sanitary wastewater the lagoon system discharged from Outfall 008 is land applied to agricultural cropland.

The primary pollutants of concern are ammonia as nitrogen, carbonaceous biochemical oxygen demand, conductivity, oil and grease, pH, total suspended solids, and water temperature.

E. Proposed Permit Changes

1. All the seasonal hydrazine parameters and limitations have been deleted from Outfall 001 in the draft permit.

2 The existing permit footnotes page has been deleted from the permit.

3. A storm water parameters and monitoring requirements have been added to the permit

F. Supporting Documentation

The following is a brief explanation of the regulatory provisions on which permit requirements are based. Including appropriate supporting references in accordance with NDEQ Titles 119 and 121. The following items were used to develop the basis of the draft permit:

1. The NPDES permit application for reissuance was received 4 April 1999.

2. A letter dated 11 September 2000, Hutchens (OPPD) to Asch (NDEQ) stating that no modifications had been made and current application were correct.

3. Letter dated 22 September 1999, Rice (NDEQ) to Fielding (OPPD) administratively extending the existing NPDES permit beyond its normal expiration date.

4. Letter dated 17 July 1999, Kovar (NDEQ) to Neal (OPPD) containing a copy of a consent order addressing the temperature limitations in the NPDES permit NE0000418.

5. Memorandum dated 20 May 1999 with attached OPPD letter, Walker (NDEQ.) to Rice (NDEQ) requesting a variance from hydrazine during period of high sediment loading causing inference in the analysis process.

6. Letter dated February 16, 1994, (NDEQ) to Ambrose (Lindsay Mfg Co.) responding to comments concerning the draft permit placed on public notice May 10, 1993. The letter was.

7. NDEQ Title 117 - Nebraska Surface Water Quality Standards, February 7, 2000.

8. NDEQ Title 119 - Rules and Regulations Pertaining to the Issuance of Permits Under the National Pollutant Discharge Elimination System, January 5, 1992.

9. NDEQ Title 121 - Effluent Guidelines and Standards, January 5, 1992, Chapters 2 - Steam Electric Power Generating Point Source Category.

10. 40 CFR (Code of Federal Regulations), Part 122.44 - Establishing limitations standards, and other permit conditions (applicable to State NPDES programs), (d) Water quality standards and State requirements (1) (v).

11. 40 CFR Part 125, Criteria and Standards for National Pollutant Discharge Elimination System, Subpart H.

12. 40 CFR Part 423, Steam Electric Power Generating Point Source Category.

13. NDEQ "NPDES Permitting Procedure" document, August, 1996.

14. Federal Clean Water Act (33 U.S.C. §§ 1251 et seq.);

15. Nebraska Nongame and Endangered Species Conservation Act (Neb. Rev. Stat. §§ 37-430 through 37-438).

16. Technical Support Document for Water Quality-based Toxic Control (EPA 505/2-90-001 PB91-127415, March, 1991

G. Rational for Effluent Limitations and Requirements

1. **Permit Term**

This permit is being issued for a five-year term. This term is in accordance with NDEQ Title 119, Chapter 30 and the "Basin Management Approach to the NPDES Permitting Reissuance Schedule".

2. **Wasteload Allocations**

No Wasteload allocations (WLA) were calculated for the discharge from Outfall 001. The reasonable potentials for ammonia as nitrogen, hydrazine, and nitrite/nitrate as nitrogen were calculated. No water quality impacts were indicated for ammonia as nitrogen, hydrazine, or nitrite/nitrate as nitrogen.

3. **Outfall 001 - Effluent Parameters, Limitations, and Requirements**

a. Sampling Requirements

Sampling point for Outfalls 001 was established prior to the effluent being discharged back into the Missouri River. The sampling frequency was established in accordance with NDEQ Title 119, Chapter 41. The compliance samples shall be collected using grab sampling techniques, except the permitttee chooses to continuously monitor the flow and water temperature using recording devices.

b. pH Range

The draft permit establishes a pH range effluent limitation of 6.5 to 9.0. This provision is based on regulations promulgated in NDEQ Title 117, Chapter 4. The sampling frequency is monthly.

c. Flow

The draft permit establishes a flow monitoring requirement. The permittee choose to monitor the flow requirement by continuous monitoring by either calculation or metering.

d. Oil and Grease

The draft permit establishes 30-day average monitoring requirement and a daily maximum limitation of 10 mg/L for oil and grease. This categorical parameter was added because low volume waste is discharge into this outfall. The limitation is based on the water quality criteria for oil and grease established in accordance with NDEQ Title 117, Chapter 4. The sampling frequency is monthly.

e. Temperature

The draft permit establishes 30-day average monitoring requirement and a daily maximum limitation of 110 °F for temperature. This daily maximum limitation was established according to Section 316a of the Federal Clean Water Act (33 U.S.C. §§ 1251 et seq.). The sampling frequency is continuous by recorder. Consent Order No. 2206 allows a daily maximum temperature limitation of 112°F from this point of discharge until NDEQ makes a final determination to issue or deny the permit modification of the existing system that may increase the pollutant loadings or significantly increase flows.

f. Total Residual Chlorine

The draft permit establishes 30-day average monitoring requirement and a daily maximum limitation of 0.20 mg/L for total residual chlorine. This categorical parameter was added because total residual chlorine may be used to control macro-invertebrates in this outfall. The categorical limitation is based on the total residual chlorine limitation established in accordance with NDEQ Title 121, Chapter 2 and 40 CFR Part 423. If the permittee chooses not to use chlorine for macro-invertebrate control, this parameter and limitation shall not apply. The sampling frequency is monthly.

g. Total Suspended Solids

The draft permit establishes 30-day average limitation of 30 mg/L and a daily maximum limitation of 100 mg/L for total suspended solids. This categorical parameter and limitations were added because low volume waste is discharge into this outfall. The sampling frequency is monthly.

4. **Outfall 002 - Effluent Parameters, Limitations, and Requirements**

a. Sampling Requirements

This is the water treatment plant discharge. The sampling point for effluent Outfall 002 has been established prior to discharge to the Missouri River. The monitoring frequency shall be monthly. Compliance samples shall be collected using grab sampling techniques.

b. pH Range

The draft permit establishes a pH range effluent limitation of 6.5 to 9.0. This provision is based on regulations promulgated in NDEQ Title 117, Chapter 4. The sampling frequency is monthly.

c. Flow

The draft permit establishes a daily flow monitoring requirement. The permittee shall monitor the flow by either calculation or metering.

d. Conductivity

The draft permit established conductivity monitoring requirements. This provision is based on regulations promulgated in NDEQ Title 117, Chapter 4. The sampling frequency is monthly.

e. Oil and Grease

The draft permit establishes 30-day average monitoring requirement and a daily maximum limitation of 10 mg/L for oil and grease. This categorical parameter was added because low volume waste is discharge into this outfall. The limitation is based on the water quality criteria for oil and grease established in accordance with NDEQ Title 117, Chapter 4. The sampling frequency is monthly.

f. Total Suspended Solids

The draft permit establishes a 30-day average limitation of 30 mg/L and a daily maximum limitation of 100 mg/L for total suspended solids. These categorical limitations are based on the total suspended solids limitations established in accordance with NDEQ Title 121, Chapter 2 and 40 CFR Part 423. The sampling frequency is monthly.

5. **Outfalls 003 and 004 - Effluent Parameters, Limitations, and Requirements**

Outfall 003 is the discharge used to backwash the intake screens for outfall 001. The draft permit establishes no monitoring parameters or requirement for this outfall. The discharge from this outfall is recirculated intake water from once through noncontact cooling water through Outfall 001

Outfall 004 is the discharge used to reduce the foam build-up upstream of the intake screen for outfall 001. The draft permit establishes no monitoring parameters or requirement for this outfall. The discharge from this outfall is recirculated intake water from once through noncontact cooling water through Outfall 001.

6. **Outfall 005 - Effluent Parameters, Limitations, and Requirements**

a. Sampling Requirements

Outfall 005 is the discharge used to de-ice the intake screen for outfall 001. The sampling point for effluent Outfall 005 has been established prior to discharge into the Missouri River. The monitoring frequency shall be quarterly. The permittee shall monitor the flow during each discharge event by either calculation or metering.

b. Flow

The draft permit establishes a flow monitoring requirement. The permittee shall monitor the flow during each discharge event by either calculation or metering.

c. Temperature

The draft permit establishes 30-day average monitoring requirement and a daily maximum limitation of 110 °F for temperature. This daily maximum limitation was established according to Section 316a of the Federal Clean Water Act (33 U.S.C. §§ 1251 et seq.). The sampling frequency is continuous by recorder. Consent Order No. 2206 allows a daily maximum temperature limitation of 112°F from this point of discharge until NDEQ makes a final determination to issue or deny the permit modification of the existing system that may increase the pollutant loadings or significantly increase flows.

7. **Outfall 006 - Effluent Parameters, Limitations, and Requirements**

Outfall 006 is the discharge condensation water. The draft permit establishes no monitoring parameters or requirement for this outfall. The discharge from this outfall is condensation water accumulated in a storage tank.

8. **Outfall 007 - Effluent Parameters, Limitations, and Requirements**

a. Sampling Requirements

This is a discharge from the sanitary lagoon system. The sampling point for effluent Outfall 007 has been established at the sanitary lagoon and prior to discharge to the Missouri River. The monitoring frequency shall be in accordance with the controlled lagoon discharge requirements. Compliance samples shall be collected using grab sampling techniques.

b. pH Range

The draft permit establishes a pH range effluent limitation of 6.5 to 9.0. This provision is based on regulations promulgated in NDEQ Title 117, Chapter 4.

c. Flow

The draft permit establishes a flow monitoring requirement. The permittee shall monitor the flow during each discharge event by either calculation or metering.

d. Duration of Each Flow Event

The draft permit requires measurement of the duration of each flow event. The length of each discharge event in days shall be reported. This requirement may be met by calculation in accordance with NDEQ Title 119, Chapter 41.

e. Carbonaceous Biochemical Oxygen Demand

The draft permit establishes 30 day average limitation of 25 mg/L and a daily maximum limitation of 40 mg /L for carbonaceous biochemical oxygen demand. This parameter and limitations are based on regulations promulgated in NDEQ Title 121, Chapter 3.

f. Total Suspended Solids

The draft permit establishes a 30-day average limitation of 80 mg/L and a daily maximum limitation of 120 mg/L for total suspended solids. This parameter and limitations are based on regulations promulgated in NDEQ Title 121, Chapter 3.

g. Ammonia as Nitrogen

The draft permit establishes 30-day average and daily maximum monitoring requirements for ammonia as nitrogen. This parameter and monitoring requirements were established according to regulations promulgated in NDEQ Title 119, Chapter 19.

h. Fecal Coliforms

The draft permit establishes 30-day average of 200 colonies per 100 ml of effluent and daily maximum of 400 colonies per 100 ml of effluent for fecal coliform bacteria. These limitations apply during May 1 though September 30 each year. These limitations are established according to NDEQ Title 117, Chapter 4.

9. **Outfall 008 - Effluent Parameters, Limitations, and Requirements**

a. Sampling Requirements

Sampling point for Outfall 008 was established prior to the effluent being discharged to the irrigation system. The sampling frequency was established in accordance with NDEQ Title 119, Chapter 41. The compliance samples shall be collected using grab sampling techniques. Irrigation compliance samples shall be collected two times during the irrigation season. One sample shall be collected at the beginning of the irrigation season. The second sample shall be collected prior to the end of the irrigation season.

b. pH Range

The draft permit establishes a pH effluent limitation range of 6.0 to 9.0 standard units. This pH effluent range limitations has been place in other similar land application permits.

c. Flow

The draft permit established monthly flow monitoring. The flow monitoring requirement may be met by calculation or metering.

d. Ammonia as Nitrogen

The draft permit established 30-day average concentration and daily maximum concentration reporting requirements for ammonia as nitrogen. This ammonia as nitrogen monitoring requirements has been place in other similar land application permits.

e. Chloride

The draft permit established 30-day average concentration and daily maximum concentration reporting requirements for chloride. The chloride monitoring requirement has been place in other similar land application permits.

f. Conductivity

The draft permit established 30-day average concentration and daily maximum concentration reporting requirements for conductivity. These conductivity monitoring requirements have been place in other similar land application permits.

g. Nitrate as Nitrogen

The draft permit established 30 day average concentration monitoring and daily maximum concentration requirements for nitrate as nitrogen. These nitrate as nitrogen monitoring requirements have been place in other similar land application permits. The monitoring frequency shall be monthly by grab sample in accordance with regulations promulgated in NDEQ Title 119, Chapter 41.

h. Total Kjeldahl Nitrogen

The draft permit established 30 day average concentration monitoring and daily maximum concentration requirements for total Kjeldahl nitrogen. These total Kjeldahl nitrogen monitoring requirements have been place in other similar land application permits. The monitoring frequency shall be monthly by grab sample in accordance with regulations promulgated in NDEQ Title 119, Chapter 41.

10. **Storm Water Outfalls - Effluent Parameters and Monitoring Requirements**

a. Sampling Requirements

Sampling points for these Outfalls were established and identified in the Pollution Prevention Plan (Fort Calhoun Station Unit No. 1, Standing Order: **SO-G-108**. The storm water discharge from the switching yard shall be sample once during the first year and during the fifth year of this permit term. The sampling frequency for the other two outfalls will at the request of the NDEQ as needed. These sampling frequencies were established according to NDEQ Title 119, Chapter 41. The compliance samples shall be collected using sampling techniques and sampling points identified in Standing Order: **SO-G-108**.

b. Flow

The draft permit established flow requirement that may be met by calculation or metering.

c. Ammonia as Nitrogen

The draft permit established a reporting requirement for ammonia as nitrogen according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

d. Biochemical Oxygen Demand

The draft permit established a reporting requirement for biochemical oxygen demand according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

e. Chemical Oxygen Demand

The draft permit established a reporting requirement for chemical oxygen demand according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

f. Fecal Coliform

The draft permit established a reporting requirement for fecal coliform according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119

g. Fecal Streptococcus

The draft permit established a reporting requirement for fecal streptococcus according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

h. Nitrate as Nitrogen

The draft permit established a reporting requirement for nitrate as nitrogen according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

i. Total Kjeldahl Nitrogen

The draft permit established a reporting requirement for total Kjeldahl nitrogen according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

j. Oil and Grease

The draft permit establishes a reporting requirement for oil and grease according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

k. pH Range

The draft permit establishes a pH effluent reporting requirement according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

l. Dissolved Phosphorus

The draft permit establishes a reporting requirement for dissolved phosphorus according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

m. Total Phosphorus

The draft permit establishes a reporting requirement for total phosphorus according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

n. Total Dissolved Solids

The draft permit establishes a reporting requirement for total dissolved solids according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119.

o. Total Suspended Solids

The draft permit establishes a reporting requirement for total suspended solids according to 40 CFR, Part 122.26 as adopted in NDEQ Title 119

11. **Other Requirements**

a. Chemical Analyses Methods

Analyses of the proposed technology-based and water quality-based NPDES permit parameters shall be in accordance with the methods set forth in 40 CFR Part 136 as adopted in NDEQ Title 121.

b. Prohibited Pollutant Discharges

There shall be no discharge of polychlorinated biphenyl compounds (PCBs) or 126 toxic pollutants in detectable amounts from any outfall at any time.

c. The Minimum Detection Level

For the purpose of this permit, the Minimum Limit (ML) shall be the permit limit found in Part I. of this permit. Compliance with these limits will be based upon applicable and appropriate detection limits. If the result of analysis is above a detection limit, it shall be reported. If an analysis result is stated as "not detectable", the results shall be reported as "less than the detection limit".

d. Discharge Monitoring Reports

According to Appendix A. D. 4 the permit requires that monitoring results gathered during the previous 3 months be summarized for each month and reported on the Discharge Monitoring Report Form on a quarterly basis.

H. Submission of Written Comments

A copy of the fact sheet, draft permit, attachments, comments and other public information are available for review and copying at the Department's office between 8:00 a.m. and 5:00 p.m., weekdays.

Nebraska Department of Environmental Quality
Suite 400, The Atrium, 1200 N Street
Lincoln, Nebraska
Telephone (402) 471-4220
FAX (402) 471-2909

The public may make written comment upon or object to the draft permit or may make a written request for a public hearing during the public comment period specified in the attached public notice. All comments, objections and/or petitions for a hearing shall be considered prior to making a final decision regarding this application. These comments, objections and/or petitions for a hearing must state the nature of the issues to be raised, and all arguments and factual grounds supporting such positions. All comments, objections and/or petitions for a hearing should be sent to:

Rudy Fiedler, Acting Unit Supervisor
NPDES Permits Unit
Municipal and Industrial Section
Nebraska Department of Environmental Quality
P.O. Box 98922
Lincoln, Nebraska 68509-8922

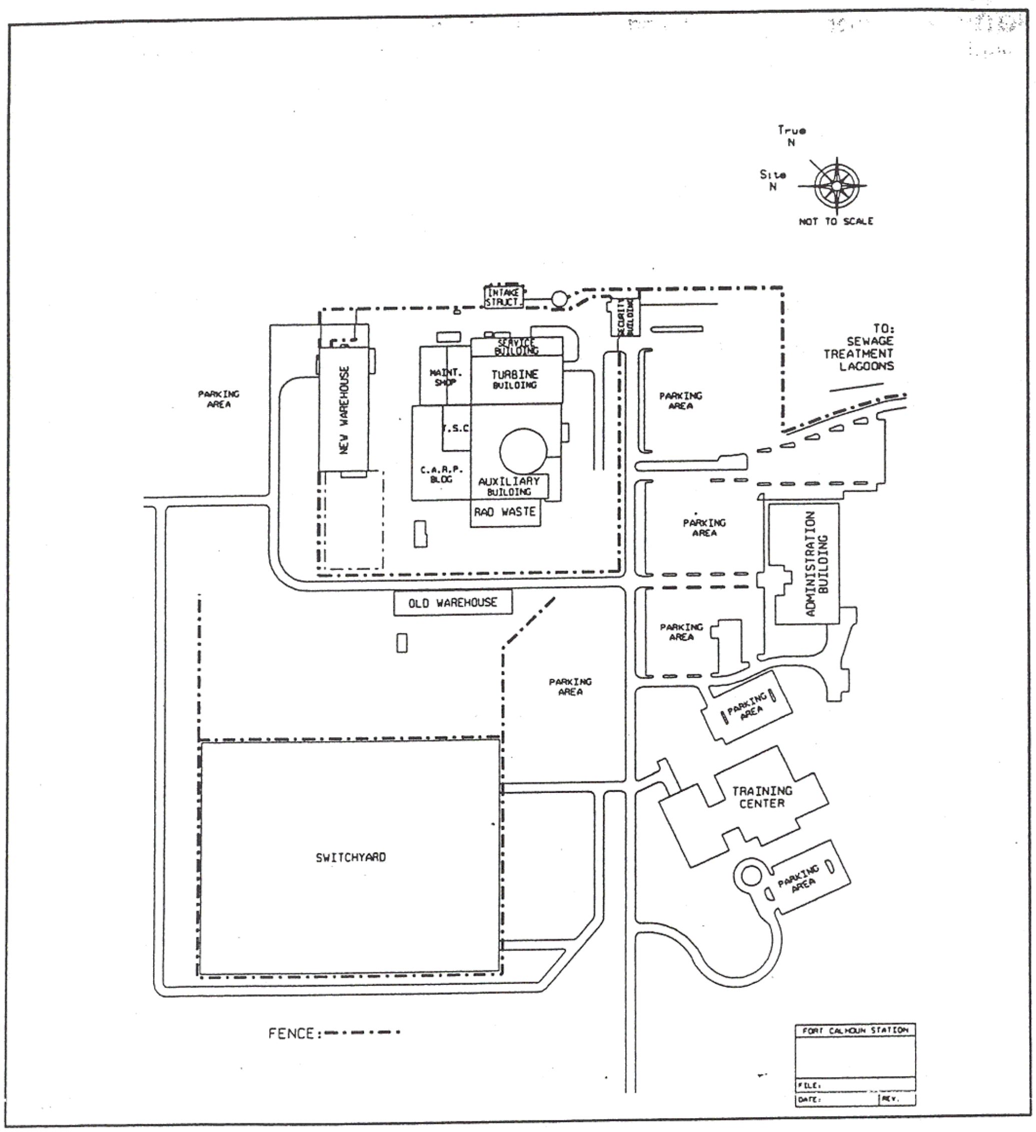
J. Fact Sheet Attachments

1. Maps of the site.
2. NPDES permit NE0000418

FORT CALHOUN STATION
STANDING ORDER

SO-G-108
PAGE 21 OF 32

Attachment 10.1

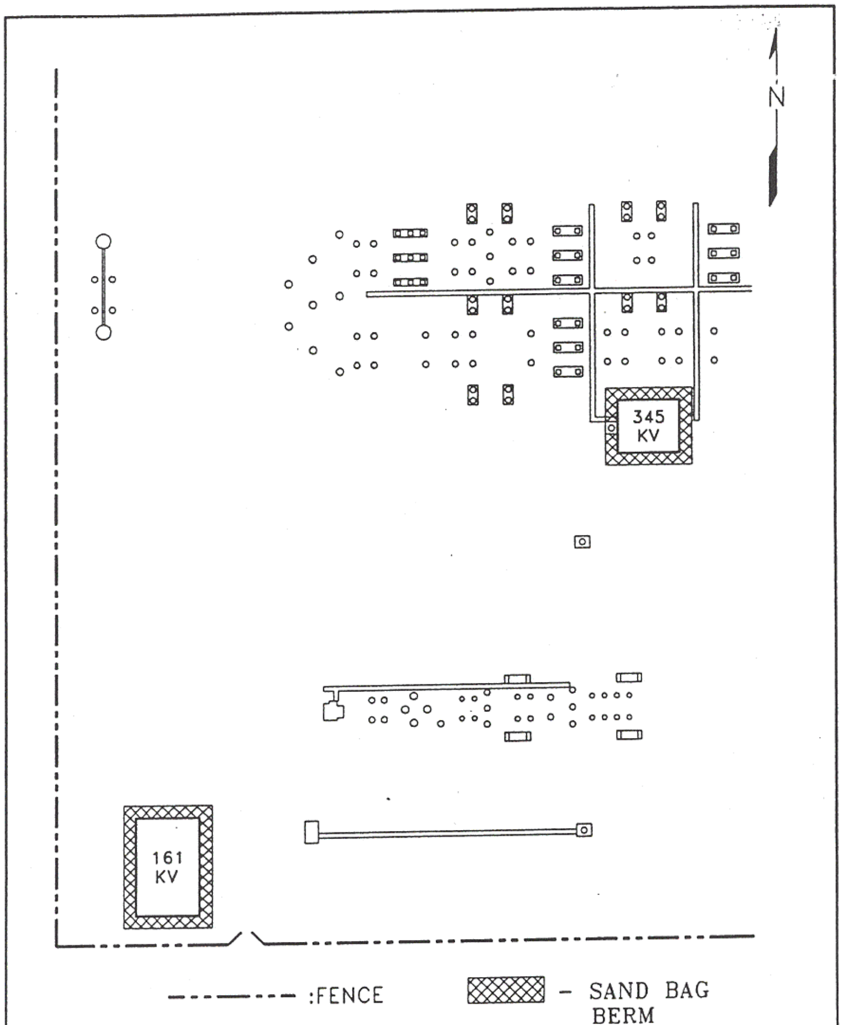


R3

FORT CALHOUN STATION
STANDING ORDER

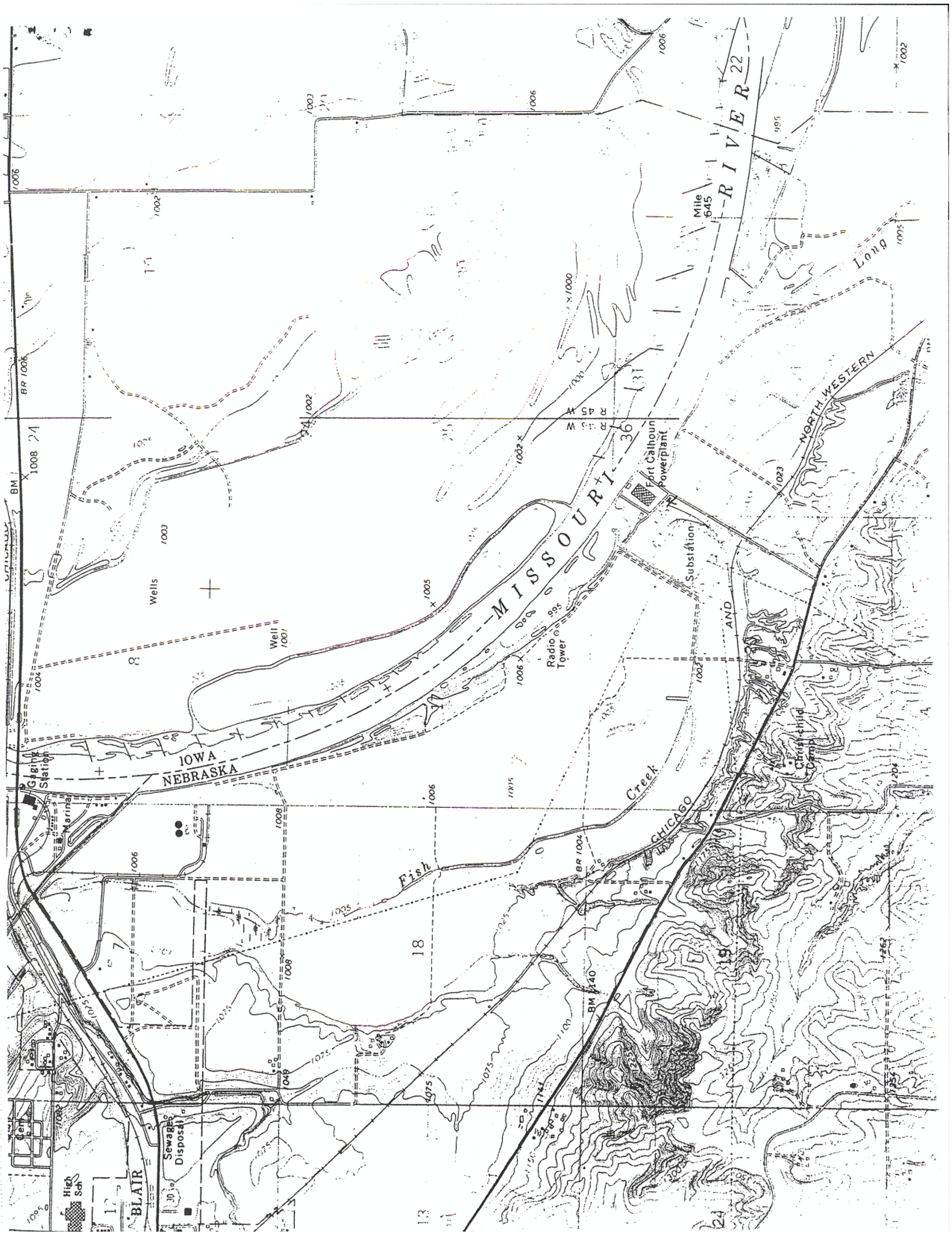
SO-G-108
PAGE 22 OF 32

Attachment 10.1



SUBSTATION

R3


MISSOURI
RIVER
IOWA
NEBRASKA
Fort Calhoun Powerplant
Substation
Radio Tower
Wells
Well
Gaging Station
Marina
Fish Creek
Long
CHICAGO AND NORTH WESTERN
Sewage Disposal
BLAIR
High Sch
Mile 645

BEFORE THE NEBRASKA DEPARTMENT OF ENVIRONMENTAL QUALITY

IN THE MATTER OF	)	
OMAHA PUBLIC POWER	)	CASE NO. 2206
DISTRICT - FORT CALHOUN	)	
NUCLEAR STATION,	)	CONSENT ORDER
Respondent.	)	

The Omaha Public Power District (OPPD), Respondent, and the Nebraska Department of Environmental Quality (NDEQ) stipulate and agree as follows:

1. The Respondent's Fort Calhoun Nuclear Station is a nuclear-fired steam electric generating station and the permittee under a National Pollutant Discharge Elimination System (NPDES) Permit #NE0000418 issued pursuant to the Nebraska Environmental Protection Act (Act) and Title 119 - Rules and Regulations Governing the Issuance of Permits under the National Pollutant Discharge Elimination System on November 20, 1997.

2. Respondent's NPDES permit authorizes the discharge of identified pollutants from designated outfalls in accordance with specific permit conditions. The permit contains effluent limitations and monitoring requirements for temperature applicable to outfalls 001 and 005. Outfall 001 discharges once through condenser cooling water during normal operation and outfall 005 discharges warmwater recirculation for deicing.

3. The effluent limitation for temperature for both these outfalls is 110 degrees Fahrenheit (°F) as a daily maximum, measured continuously and reported quarterly. This

1

effluent limitation is based on protecting the water quality of the receiving stream, the Missouri River.

4. On or about May 10, 1999, the Respondent requested a variance from the permit effluent limitation for temperature to allow a 2°F increase in the temperature discharge from outfalls 001 and 005 in anticipation of potential low stream flows in the Missouri river and high ambient water temperatures. As justification for the increase in temperature, the Respondent presented discharge temperature modeling data to the NDEQ on June 21, 1999. In further support of the request, the Respondent stated that significant social and economic hardship could result if power output would have to be curtailed in order to comply with the temperature limit.

5. Neb. Rev. Stat. §81-1513 authorizes the Director of the NDEQ to grant a variance from rules and regulations. The parties have agreed that the Respondent's request may be pursued as an application for a permit modification.

6. In order to completely evaluate the effect of a 2°F increase in the temperature discharge from outfalls 001 and 005, the NDEQ requires additional information to verify that the instream water quality criteria for temperature of 90°F as a maximum with a maximum temperature change of 5°F from natural conditions are not and will not be exceeded outside the applicable mixing zone identified for these discharges to the Missouri River.

7. Pending NDEQ consideration of the Respondent's application for a permit modification to increase the temperature of its discharges from outfalls 001 and 005 from a maximum of 110°F to a maximum of 112°F, the parties agree as follows:

A. The following effluent limitation shall be met at the point of discharge from outfalls 001 and 005:

Parameter	Monthly Average	Daily Maximum	Measurement Frequency
Temperature	**Report**	**112°F**	**Continuous**

B. The Respondent shall not be required to submit non-compliance reports for exceedances of the temperature effluent limitation for outfalls 001 and 005 during the term of this Consent Order provided that the Respondent complies with the limitation set forth in paragraph A.

C. The Respondent shall submit water quality information to evaluate the impact of a 2°F increase in the temperature discharge from outfalls 001 and 005 to verify that the instream water quality criteria for temperature of 90°F as a maximum with a maximum temperature change of 5°F from natural conditions are not, and will not, be exceeded outside the mixing zone identified for these discharges to the Missouri River. The Respondent shall submit any additional information required by the NDEQ to evaluate the application for a permit modification in accordance with any schedule established by the NDEQ.

8. This Consent Order shall remain in effect until the NDEQ makes a final determination to issue or deny the permit modification to allow a temperature increase in the discharges from outfalls 001 and 005 or the NDEQ determines that the Respondent has not complied satisfactorily with the terms of this Consent Order. Failure to submit any information deemed necessary by the NDEQ to evaluate the application for a permit modification may result in denial of the application.

9. Nothing in this Consent Order shall be deemed to modify or suspend or relieve the Respondent of the obligation to comply with any of the conditions of the Respondent's NPDES permit except as modified by this Consent Order. Nothing in this Consent Order precludes the Respondent from requesting any other permit modification of its NPDES permit.

10. This Consent Order may be modified by a specific written amendment agreed to and signed by the parties as identified below. The NDEQ reserves the right to revoke or modify the conditions of this Consent Order and seek enforcement for any violation of the Act or this Consent Order.

11. Signatures:

A. For the Respondent: The undersigned representative of the Respondent certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Order and to bind the Respondent.

Agreed this 27th day of July, 1999.

By: W. L. Neal

Title: Division Manager - Environmental and Governmental Affairs

B. For the NDEQ:

IT IS SO ORDERED and agreed this 27th day of July, 1999.

By:
Michael J. Linder
Director

4

Omaha Public Power District

1623 HARNEY ▪ OMAHA, NEBRASKA 68102 ▪ TELEPHONE 536-4000 AREA CODE 402

July 1, 1976

Department of Environmental Control
Mailbox 94653, State House Station
1424 "P" Street
Lincoln, Nebraska 68509

Attn: Mr. D. T. Drain

Gentlemen:

<u>Fort Calhoun Station</u>
<u>Intake Monitoring Report</u>

In compliance with NPDES Permit No. 0000418 for [redacted] four (attached) copies of "Intake Monitoring Report Fort Calhoun Station Unit No. 1 NPDES Permit No. 0000418" are submitted. This report discusses the findings of Omaha Public Power District's intake monitoring program at Fort Calhoun Station Unit No. 1. Additional copies are available at your request.

Sincerely,

W. C. Jones

W. C. Jones
Section Manager - Operations

WCJ/LGH:jmm

Attach.

cc: Mr. T. E. Short
Mr. G. G. Bachman
Mr. T. P. Harding
Mr. W. D. Dermyer
Mr. B. E. Dose, Jr.
Mr. L. G. Harrow
Mr. Chester Culley
F. C. File

DRW#: 399 REEL#
☐ QA CONST. REC.
☐ DB REF.
☒ N/A
INITIAL:

State of Nebraska
Department of
Environmental Control

J. James Exon
Governor
Dan T. Drain
Director

Mail, Box 94653 State House Station Office, 1424 'P' Street Lincoln, Nebraska 68509 (402) 471-2186

January 19, 1977

WPC-SS

Mr. Gerald Bachman
Assistant to the General Manager
Omaha Public Power District
1623 Harney Street
Omaha, Nebraska 68102

RE: Intake Monitoring Report Fort Calhoun Station
Unit II, No. 1 NPDES No. NE 0000418

Dear Mr. Bachman:

The review of the above-referenced document has been completed. Our staff agrees with the general discussion and data presentations in this report, however, we would offer the following comments.

The staff feels that although it is true that the majority of fish impinged at this power station are young-of-the year fish which under normal conditions do have high mortality rates, they do not generally agree that the loss would result in a minimal effect on fish populations in the vicinity of the power station or the river as a whole. We feel that fish which have reached the size of those impinged have a much better chance for survival than do smaller larval fish and therefore may be of more importance to the fisheries as a whole.

Entrainment losses at this facility were evaluated using the conservative approach by assuming 100% mortality of entrained organisms. We have used this approach based on the lack of adequate information to support a lesser percentage of mortality. However, we do agree that there is a potential for organisms to pass through the cooling system unharmed and we have tempered our final conclusions based on this assumption.

Based on the information available at this time, we have concluded that the losses due to entrainment and impingement at the facility are within the acceptable range. However, should future information refute this conclusion it may be necessary to consider additional fish protective devices should an economically and biologically acceptable method be developed.

Mr. Gerald Bachman Page 2 January 19, 1977

In an effort to reduce the monitoring burden and to confine submittal of information to that which would best define the environmental losses due to operation of the intake structure, we will no longer require information on zooplankton, phytoplankton and macroinvertebrates. We feel due to the regeneration capacity of these populations the effort necessary to define the effects of this facility is unwarranted at this time.

We would be very interested in seeing any information that OPPD may develop concerning condenser passage of larval fish, compensatory mechanisms and fishes recruitment potentials in the Missouri River whereever such information is available.

If you have any questions or comments, please contact Mr. Robert Todd of this office.

Very truly yours,

Robert B. Wall, Chief
Water Pollution Control Division

RDT/th

cc: Ralph Langemeier, EPA

State of Nebraska
Department of
Environmental Control

J. James Exon
Governor
Dan T. Drain
Director

Mail, Box 94653 State House Station Office, 1424 'P' Street Lincoln, Nebraska 68509 (402) 471-2186

February 2, 1977

WPC-SS

Mr. Gerald Bachman
Assistant to the General Manager
Omaha Public Power District
1623 Harney
Omaha, Nebraska 68102

Dear Mr. Bachman:

This is to correct a typographical error in our letter dated January 19, 1977 which discussed the intake monitoring report for the Fort Calhoun Unit II. This should be changed as the review was conducted on the Fort Calhoun Unit I intake monitoring report.

This letter serves to verify that all comments and approvals stated in the above-referenced letter were addressed to Fort Calhoun Unit I only and should in no way be interpreted as approval of the proposed intake system for Fort Calhoun Unit II.

If you have any questions, please contact our office.

Very truly yours,

Robert B. Wall

Robert B. Wall, Chief
Water Pollution Control Division

RDT/th

cc: Ralph Langemeier, EPA

APPENDIX 3.0 THREATENED AND ENDANGERED SPECIES CORRESPONDENCE

DNR = Department of Natural Resources
FWS = U.S. Fish and Wildlife Service
NGPC = Nebraska Game and Parks Commission
OPPD = Omaha Public Power District

OPPD
Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

August 7, 2001
01-EA-239

Mr. John Cochnar
Regional Coordinator, Endangered Species Program
U.S. Fish and Wildlife Service
Lakewood, Colorado 80225

Subject: Fort Calhoun Station Unit 1
License Renewal Project
NRC Informal Consultation Preparation

Dear Mr. Cochnar:

Omaha Public Power District (OPPD) is preparing an application to renew the operating licenses for Fort Calhoun Station Unit 1, and we intend the application be consistent with your agency's interests and the priorities of our community. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or refurbishment activities associated with the license renewal. OPPD believes that operation of the plant has no adverse impact on any protected species. In addition, there are no planned operational or refurbishment activities for the period of extended operations that would invalidate this conclusion. The NRC may request an informal consultation from your agency on this matter.

To assist you in making your determination, a figure is enclosed which depicts the Fort Calhoun site and the associated transmission line corridors.

It is our intent that, by contacting you at this point in the process, we can identify any deficiencies, concerns, or data needed so that those areas identified can be addressed to ensure that the consultation process proceeds smoothly and efficiently.

We would appreciate it if you would provide your comments and any additional information or actions that might be required from OPPD to expedite the upcoming consultation process.

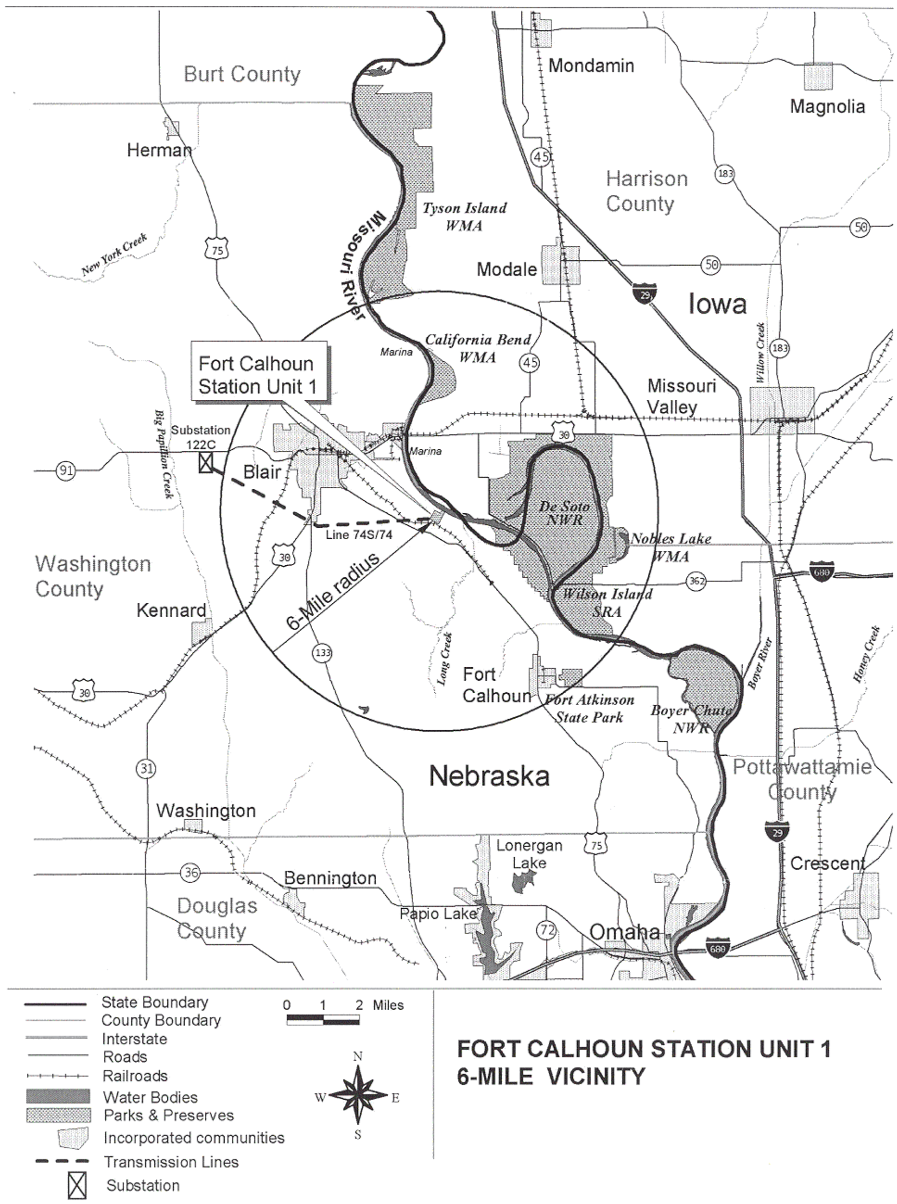
If you have any comments or questions, please contact me at (402) 636-2313.

Sincerely yours,

Donovan C. Hutchens
Manager – Environmental and Regulatory Affairs

Attachment

45-5124 Employment with Equal Opportunity


Burt County
Mondamin
Magnolia
Herman
Harrison County
Tyson Island WMA
Missouri River
New York Creek
Modale
Iowa
California Bend WMA
Marina
Fort Calhoun Station Unit 1
Missouri Valley
Willow Creek
Big Papillion Creek
Substation 122C
Blair
Marina
De Soto NWR
Nobles Lake WMA
Line 74S/74
Washington County
Kennard
6-Mile radius
Wilson Island SRA
Long Creek
Fort Calhoun
Fort Atkinson State Park
Boyer Chute NWR
Boyer River
Honey Creek
Nebraska
Pottawattamie County
Washington
Lonergan Lake
Crescent
Bennington
Douglas County
Papio Lake
Omaha
State Boundary
County Boundary
Interstate
Roads
Railroads
Water Bodies
Parks & Preserves
Incorporated communities
Transmission Lines
Substation
0 1 2 Miles
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W
E
S
FORT CALHOUN STATION UNIT 1
6-MILE VICINITY

OPPD
Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

August 7, 2001
01-EA-242

Mr. Rex Amack
Director
Nebraska Game and Parks Commission
2200 North 33rd Street
P. O. Box 30370
Lincoln, Nebraska 68503-0370

Subject: Fort Calhoun Station Unit 1
License Renewal Project
NRC Informal Consultation Preparation

Dear Mr. Amack:

Omaha Public Power District (OPPD) is preparing an application to renew the operating licenses for Fort Calhoun Station Unit 1, and we intend the application be consistent with your agency's interests and the priorities of our community. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or refurbishment activities associated with the license renewal. OPPD believes that operation of the plant has no adverse impact on any protected species. In addition, there are no planned operational or refurbishment activities for the period of extended operations that would invalidate this conclusion. The NRC may request an informal consultation from your agency on this matter.

To assist you in making your determination, a figure is enclosed which depicts the Fort Calhoun site and the associated transmission line corridors.

It is our intent that, by contacting you at this point in the process, we can identify any deficiencies, concerns, or data needed so that those areas identified can be addressed to ensure that the consultation process proceeds smoothly and efficiently.

We would appreciate it if you would provide your comments and any additional information or actions that might be required from OPPD to expedite the upcoming consultation process.

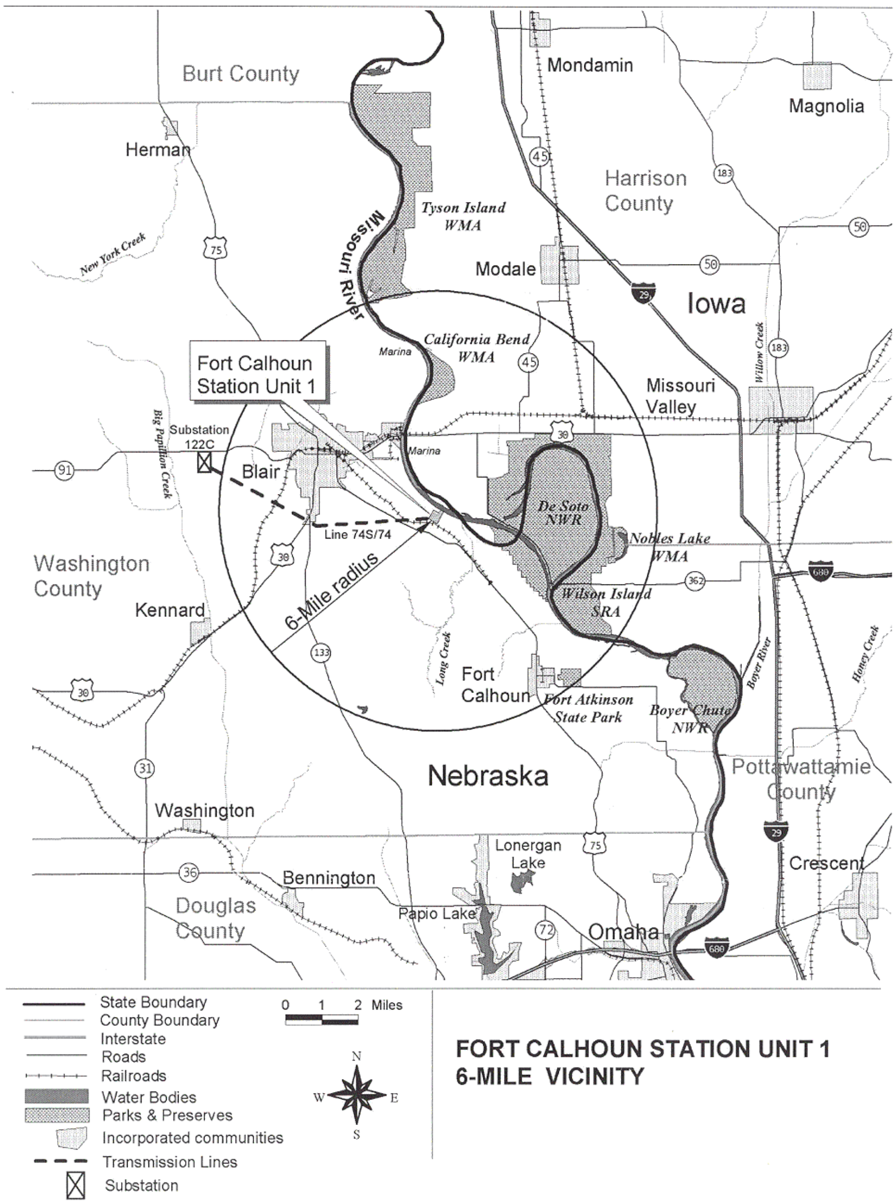
If you have any comments or questions, please contact me at (402) 636-2313.

Sincerely yours,

Donovan C. Hutchens
Donovan C. Hutchens
Manager – Environmental and Regulatory Affairs

Attachment

45-5124 Employment with Equal Opportunity



FORT CALHOUN STATION UNIT 1
6-MILE VICINITY

OPPD
Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

August 7, 2001
01-EA-241

Ms. Angela Chen
Iowa Department of Natural Resources
Henry A. Wallace Building
502 East 9th
Des Moines, Iowa 50319

Subject: Fort Calhoun Station Unit 1
License Renewal Project
NRC Informal Consultation Preparation

Dear Ms. Chen:

Omaha Public Power District (OPPD) is preparing an application to renew the operating licenses for Fort Calhoun Station Unit 1, and we intend the application be consistent with your agency's interests and the priorities of our community. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or refurbishment activities associated with the license renewal. OPPD believes that operation of the plant has no adverse impact on any protected species. In addition, there are no planned operational or refurbishment activities for the period of extended operations that would invalidate this conclusion. The NRC may request an informal consultation from your agency on this matter.

To assist you in making your determination, a figure is enclosed which depicts the Fort Calhoun site and the associated transmission line corridors.

It is our intent that, by contacting you at this point in the process, we can identify any deficiencies, concerns, or data needed so that those areas identified can be addressed to ensure that the consultation process proceeds smoothly and efficiently.

We would appreciate it if you would provide your comments and any additional information or actions that might be required from OPPD to expedite the upcoming consultation process.

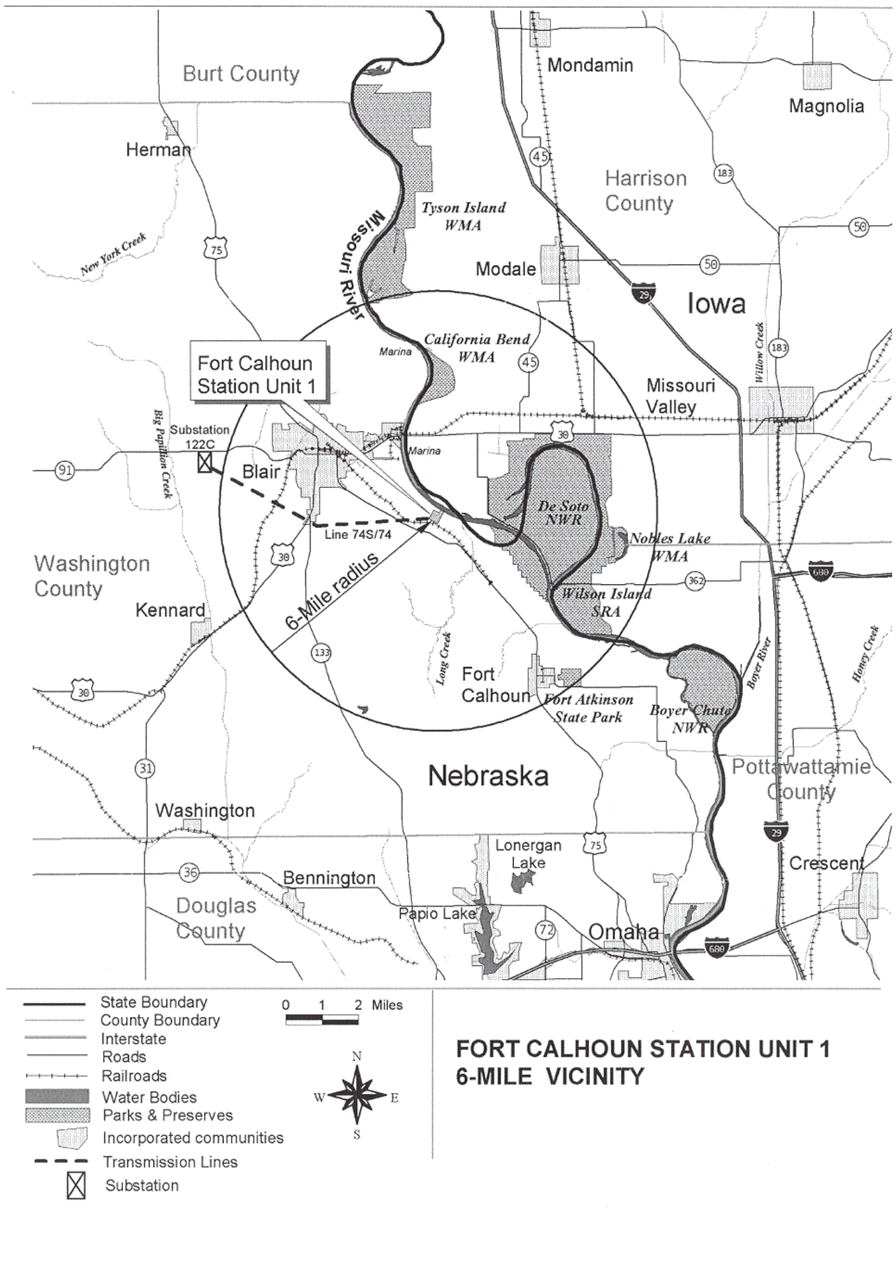
If you have any comments or questions, please contact me at (402) 636-2313.

Sincerely yours,

Donovan C. Hutchens
Manager – Environmental and Regulatory Affairs

Attachment

45-5124 Employment with Equal Opportunity



FORT CALHOUN STATION UNIT 1
6-MILE VICINITY

Iowa
Fields of Opportunities

STATE OF IOWA

THOMAS J. VILSACK, GOVERNOR
SALLY J. PEDERSON, LT. GOVERNOR

DEPARTMENT OF NATURAL RESOURCES
JEFFREY R. VONK, DIRECTOR

September 4, 2001

Mr. Donovan C. Hutchens
Omaha Public Power District
444 South 16th Street Mall
Omaha, NE 68102-2247

RE: Ooperating Permit Licensing Renewal for the Fort Calhoun Nuclear Power Generating Facility

Dear Mr. Hutchens:

Thank you for inviting our comments on the impact of the above referenced project on protected species and rare natural communities.

Within the 6-mile radius of Fort Calhoun Station Unit 1, the Department has records for the piping plover (Charadrius melodus, Iowa listed endangered) and the least tern (Sterna antillarum, Iowa listed endangered) 1 ½ miles east in the Desoto Bend National Wildlife Area. Nearby Desoto Bend are the Nobles Lake Wildlife Management Area and the Wilson Island State Recreation Area. About 2 miles NNW of Unit 1 is Rand Bar, and 4 miles north is California Bend and the California Cut-off Revetment.

This letter is a record of review for protected species and rare natural communities in the project area. It does not constitute a permit and before proceeding with the project, you may need to obtain permits from the DNR or other state and federal agencies.

If you have any questions about this letter or if you require further information, please contact Keith Dohrmann at (515) 281-8967.

Sincerely,

Allen L. Farris

ALLEN L. FARRIS
IOWA DEPARTMENT OF NATURAL RESOURCES

AF:kd

01-491L.doc

WALLACE STATE OFFICE BUILDING / DES MOINES, IOWA 50319
515-281-5918 TDD 515-242-5967 FAX 515-281-6794 WWW.STATE.IA.US/DNR

APPENDIX 4.0 CULTURAL RESOURCES CORRESPONDENCE

NSHS = Nebraska State Historical Society
OPPD = Omaha Public Power District

OPPD
Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

August 7, 2001
01-EA-240

Mr. L. Robert Puschendorf
State Historic Preservation Officer
Nebraska State Historical Society
P. O. Box 82554
Lincoln, NE 68501-2554

Subject: Fort Calhoun Station Unit 1
License Renewal Project
NRC Informal Consultation Preparation

Dear Mr. Puschendorf:

Omaha Public Power District (OPPD) is preparing an application to renew the operating licenses for Fort Calhoun Station Unit 1, and we intend the application to be consistent with your agency's interests and the priorities of our community. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify impacts to cultural resources resulting from the renewal of the license. The NRC will request an informal consultation with your agency. There are no land disturbing operational or refurbishment activities planned for operations during the license renewal term. OPPD, therefore, believes there will be no cultural impacts from license renewal activities.

To assist you in your determination, please find enclosed a figure that depicts the Fort Calhoun Site and the associated transmission line corridors.

It is our intent that, by contacting you at this point in the process, we can identify any deficiencies, concerns, or data needed so that those areas identified can be addressed to ensure that the consultation process proceeds smoothly and efficiently.

After your review, we would greatly appreciate a letter confirming OPPD's conclusion that impacts to cultural resources will be minimal or no impact and that there is no need for mitigation.

If you have any comments or questions, please contact me at (402) 636-2313.

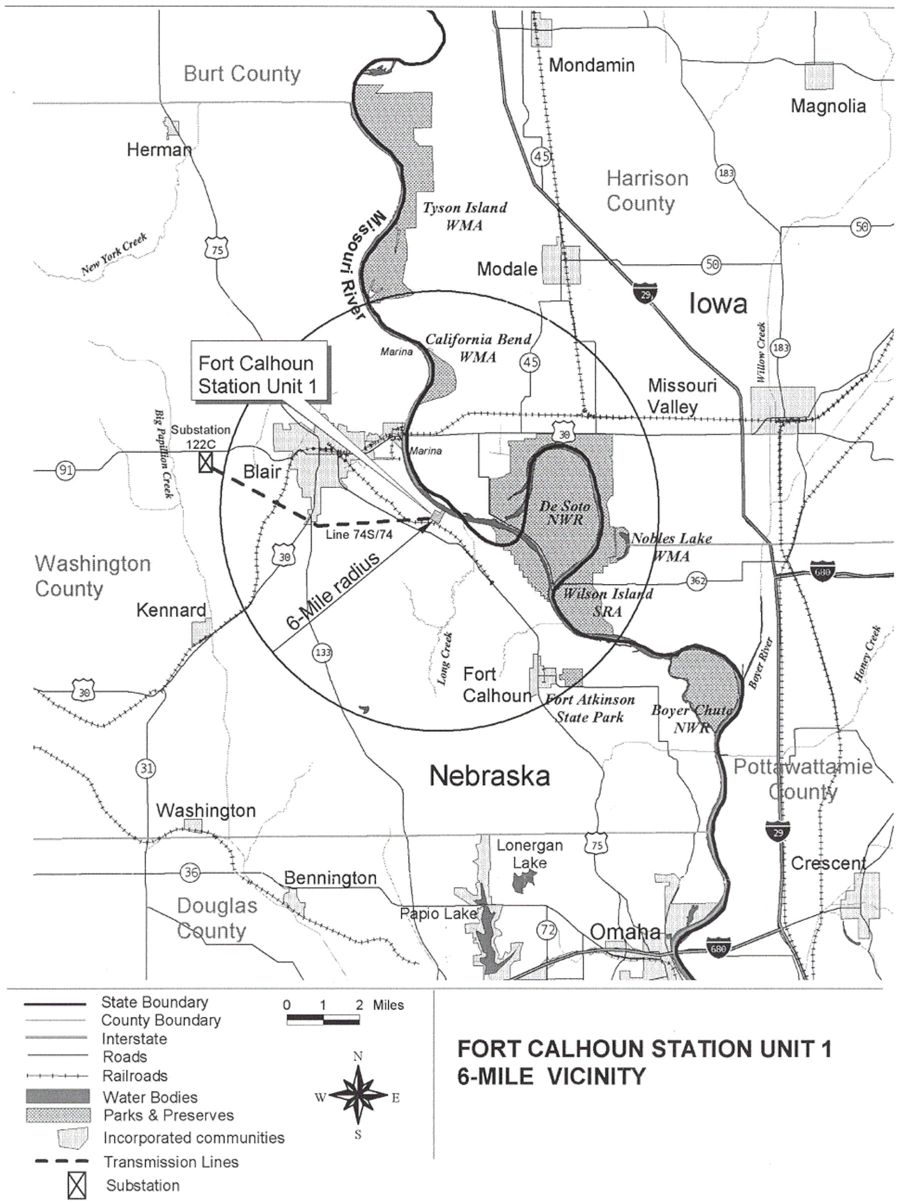
Sincerely yours,

Donovan C. Hutchens
Manager – Environmental and Regulatory Affairs

Attachment

DCH/ses

45-5124 Employment with Equal Opportunity


Burt County
Mondamin
Magnolia
Herman
Harrison County
Tyson Island WMA
Missouri River
New York Creek
Modale
Iowa
California Bend WMA
Marina
Fort Calhoun Station Unit 1
Missouri Valley
Willow Creek
Substation 122C
Big Papillion Creek
Blair
Marina
De Soto NWR
Nobles Lake WMA
Line 74S/74
Washington County
Wilson Island SRA
Kennard
6-Mile radius
Long Creek
Fort Calhoun
Fort Atkinson State Park
Boyer Chute NWR
Boyer River
Honey Creek
Nebraska
Pottawattamie County
Washington
Lonergan Lake
Crescent
Bennington
Douglas County
Papio Lake
Omaha
State Boundary
County Boundary
Interstate
Roads
Railroads
Water Bodies
Parks & Preserves
Incorporated communities
Transmission Lines
Substation
0 1 2 Miles
N
W
E
S
FORT CALHOUN STATION UNIT 1
6-MILE VICINITY

NEBRASKA STATE HISTORICAL SOCIETY
1500 R STREET, P.O.BOX 82554, LINCOLN, NE 68501-2554
(402) 471-3270 Fax: (402) 471-3100 1-800-833-6747 www.nebraskahistory.org

21 August 2001

Donovan C. Hutchens
OPPD
444 South 16th Street Mall
Omaha, NE 68102-2247

Re: Fort Calhoun Station Unit 1
License Renewal
Washington Co.
H.P. #0108-051-01

Dear Mr. Hutchens:

A review of our files indicates that the referenced project does not contain recorded historic resources. It is our opinion that no survey for unrecorded cultural resources will be required. Your undertaking, in our opinion, will have no effect on an historic property.

There is, however, always the possibility that previously unsuspected archaeological remains may be uncovered during the process of project construction. We therefore request that this office be notified immediately under such circumstances so that an evaluation of the remains may be made, along with recommendations for future action.

Sincerely,

Terry Steinacher
H.P. Archaeologist

Concurrence:

L. Robert Puschendorf
Deputy NeSHPO

APPENDIX 5.0 SEVERE ACCIDENT MITIGATION ALTERNATIVES ANALYSIS

Appendix 5 contains the following sections:

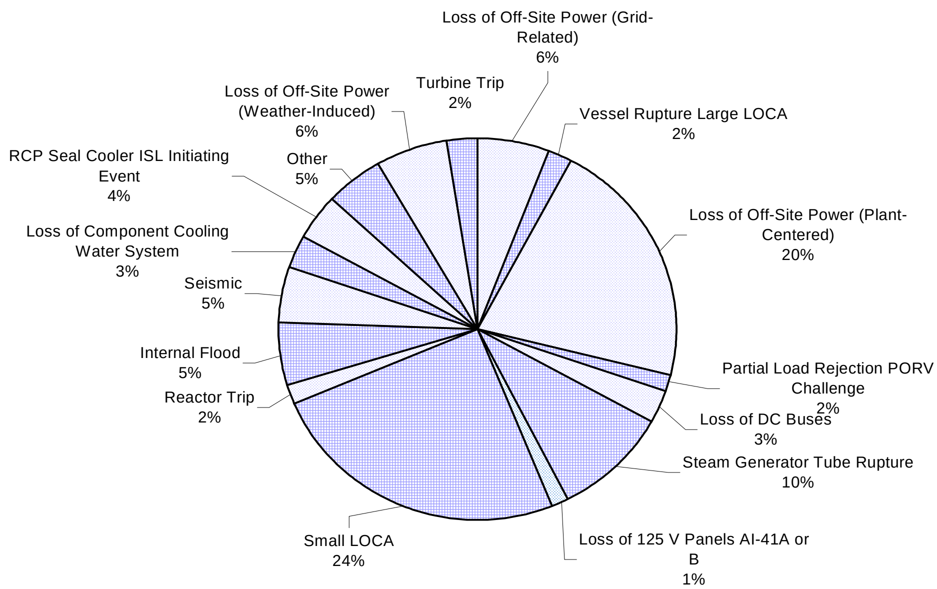
5.1 FCS PRA MODEL AND RISK PROFILE

5.1.1 BACKGROUND

In response to Generic Letter 88-20, “Individual Plant Examination of Severe Accident Vulnerabilities,” and its supplements, Omaha Public Power District (OPPD) performed a Level 1, full-scale Level 2, and Level 3 probabilistic risk assessment (PRA) for Fort Calhoun Station Unit 1 (FCS). OPPD submitted its Individual Plant Examination (IPE) to the U.S. Nuclear Regulatory Commission (NRC) in December 1993. The IPE addressed internal initiating events and internal flooding events and indicated an estimated core damage frequency (CDF) of 1.36E-05 per reactor year (including internal flooding). OPPD submitted a complete assessment for external events for FCS in June 1995. The Individual Plant Examination for External Events (IPEEE) submittal covered seismic, fire, tornado, external flooding, transportation, and nearby facility accidents, as well as “other” external events. The submittal indicated that external events have a total CDF per reactor year of 3.13E-05, and that apart from seismic, 88 percent of the IPEEE CDF is dominated by fires. The Seismic Margins Analysis method was used and, thus, results were not quantified in terms of CDF.

Improvements identified through these analyses have been implemented. A peer review, conducted in 1999, confirmed the strengths of the FCS PRA model and identified some additional improvements that have either been implemented or were accounted for in the severe accident mitigation alternatives (SAMA) analysis.

OPPD maintains a “living” plant risk model, and the current total core damage frequency is 2.48E-05. The initiating events leading to core damage and their respective contributions to risk are depicted in Figure 5.3-3.



Note: Acronyms are defined in Appendix 5.6.

Figure 5.3-3: Contributors to FCS Core Damage Frequency

Several features incorporated into the FCS design have contributed to the low core damage frequency. Attention to the proper operation and maintenance of these features provides assurance that the risk of severe accidents at FCS remains low. FCS plant features that contribute to risk reduction are summarized below:

- **Large Pressurizer Capacity** – The capacity of the pressurizer is larger than required. This feature provides extra inventory for mitigating loss-of-coolant accidents (LOCAs).

- **Diesel Generators** – The emergency diesel generators are air cooled (radiator type) and do not rely on cooling water to perform their function. The non-reliance on cooling water enhances the reliability of the emergency diesel generators.

- **Heating, Ventilation, and Air Conditioning –** The openness of the Auxiliary Building and various rooms within the plant reduces the reliance on the Heating, Ventilation, and Air Conditioning (HVAC) System for equipment heat removal. It is unlikely that HVAC will be required to cool equipment.

- **Power-Operated Valves** – FCS is equipped with two large-capacity power-operated relief valves (PORVs). Either valve in conjunction with one of the high-pressure safety injection (HPSI) pumps is capable of supporting once-through cooling in the unlikely event that steam generator cooling is lost.

- **Auxiliary Feedwater System Diversity**- FCS is equipped with three auxiliary feedwater pumps: one motor-driven, one turbine-driven, and one diesel-driven. The diesel-driven pump is equipped with its own sources of cooling and electric power. There are multiple paths available for supplying feedwater to the steam generators, thus making the auxiliary feedwater system diverse and reliable.

- **Emergency Core Cooling System (ECCS) Pump Cooling** – The seals/ bearings for the HPSI, low-pressure safety injection (LPSI), and containment spray pumps do not require cooling water to protect their integrity during the injection mode of operation. Cooling for the seals/bearings is required during the recirculation mode of operation.

- **Fire Water Backup** – A diesel-driven fire pump, independent of plant support systems, is available for long-term makeup to the Emergency Feedwater Storage Tank. This pump can also serve as backup to the Raw Water System, which provides cooling for the Component Cooling Water System.

- **Raw Water Backup** – In the unlikely event that the Component Cooling Water System becomes unavailable, the Raw Water System can be manually aligned to provide cooling to essential safety-related equipment including shutdown cooling heat exchangers, containment cooling units, coolers for the ECCS pump seals/bearings, and Control Room air conditioners.

- **Vital AC Power Backup** – If a vital inverter fails and 480 volts alternating current (VAC) power is available, the 120 VAC control power normally supplied by the affected inverter is automatically switched to an alternate bypass source. No operator actions are required and the switching from the preferred to the alternate source takes place while maintaining the function of the powered equipment.

5.1.2 FCS PRA MODEL PEER REVIEW

In March 1999, the FCS PRA model was peer reviewed by a team of PRA engineers from Westinghouse, four other utilities, and a PRA consultant. This peer review was conducted in accordance with the Combustion Engineering (CE) Owners Group version of the nuclear power industry peer review process documented in NEI-00-02 (Reference 5.1-1). The peer review team found the FCS PRA model to be effective for assessing planned plant maintenance and operations configurations and evaluating future plant design changes. The FCS PRA model was also found to be adequate for other applications where supported by deterministic insights and plant expert panel input.

5.1.3 PRA CONFIGURATION CONTROL

A key element of the PRA Configuration Control Program (PED-SEI-037) is the tracking of plant design, procedure, and operating changes that could potentially impact the FCS PRA. The PRA Configuration Control Form (CCF) is the primary vehicle for tracking plant changes that could potentially impact the FCS PRA and ensuring that such changes are incorporated as required. The CCFs are also used to track any errors detected in the PRA or associated documentation and to ensure that such errors are corrected as part of each update. The CCFs were used to track all of the peer review comments. A CCF is closed out once the requisite changes to the FCS PRA model or associated documentation have been completed.

In preparing this environmental report, the CCF database was reviewed to identify the outstanding FCS PRA issues and to evaluate their potential impacts on the SAMA analysis. Based upon the review of the FCS PRA issue database, OPPD concludes that the FCS PRA model is complete and correctly represents the as-built, as-operated plant.

5.1.4 CDF UNCERTAINTY

The SAMA analysis is based on bounding assessments of the benefits of each SAMA using mean values for CDF and cutset frequencies. Detailed uncertainty analyses for the latest version of the FCS PRA model indicate that the 95th percentile value of the CDF is 4.68E-05 per year. This is a factor of about 1.85 greater than the mean CDF value of about 2.5E-05 per year. External events are partially included in the baseline plant PRA through the inclusion of the dominant seismic sequences. The mean external event contribution resulting from weather-related factors (excluding external floods) is an order of magnitude lower than the plant baseline CDF and, therefore, will not impact SAMA assessments. Furthermore, these events do not introduce any new dominant sequences. External floods were explicitly considered as they impact core damage. While risk significant, the dominant sequences are focused on specific events and do not contribute to SAMA uncertainty. OPPD has not performed a fire PRA for FCS, but the plant fire risks were conservatively evaluated using a fire-induced vulnerability evaluation (FIVE) assessment. The results of this assessment were expressed in terms of CDF. However, it is expected that the FIVE CDF represents a fire-induced core damage frequency much greater than that of the actual plant fire CDF. The FIVE CDF for FCS is 2.78E-05 per year. This is approximately equal to the mean FCS internal events CDF. As with the external events assessment, no new risk-dominant sequences were noted. One can approximate an upper bound uncertainty factor by combining the 95th percentile baseline CDF and FIVE CDF and dividing by the mean baseline CDF. Performing the above operations, the estimated uncertainty factor for application to SAMA assessments should be approximately 3.

5.2 MELCOR ACCIDENT CONSEQUENCE CODE SYSTEM MODELING

This section of Appendix 5 describes the assumptions made and the results of modeling performed to assess the risks and consequences of severe accidents (U.S. Nuclear Regulatory Commission Class 9).

The Level 3 analysis was performed using the Melcor Accident Consequence Code System (MACCS) 2 code (Reference 5.2-1). MACCS2 simulates the impacts of severe accidents at nuclear power plants upon the surrounding environment. The principal phenomena considered in MACCS2 are atmospheric transport, mitigative actions based on dose projections, dose accumulation by a number of pathways including food and water ingestion, early and latent health effects, and economic costs. Input for the Level 3 analysis includes the reactor core radionuclide inventory, source terms from the IPE (as applied to the FCS PRA model), site meteorological data, projected population distribution (within a 50-mile radius) for the year 2030, emergency response evacuation modeling, and economic data. These inputs are described in the following section.

5.2.1 INPUT DATA

The input data required by MACCS2 are outlined below.

5.2.1.1 CORE INVENTORY

The initial core inventory of radioisotopes was obtained from the OPPD alternative source term (AST) application submitted to the NRC in February 2001 (Reference 5.2-2). The core inventory was calculated using the ORIGEN-S computer code and provided in Table 4.1 of the AST application. To perform the analysis associated with this environmental report, the inventory was reduced to the isotopes with dose conversion factors, resulting in the 131 radioisotopes presented in Table 5.2-1. Previous versions of the MACCS model used a standard set of 60 radioisotopes, the computer code's limit. MACCS2, however, has the capability of using up to 150 isotopes.

TABLE 5.2-1
FCS CORE INVENTORY

Nuclide	Fraction	Nuclide	Fraction	Nuclide	Fraction
H-3	2.12E+04	Ag-110	6.00E+06	Cs-135m	1.41E+06
Ga-72	6.69E+02	Ag-110m	1.43E+05	Cs-136	1.97E+06
As-76	7.58E+02	Ag-111	2.39E+06	Cs-137	4.80E+06
Ge-77	2.92E+04	Ag-112	1.10E+06	Cs-138	7.93E+07
Se-83	2.51E+06	In-115m	3.30E+05	Ba-137m	4.57E+06
Br-82	1.16E+05	Cd-115	3.30E+05	Ba-139	7.59E+07
Br-83	5.40E+06	Cd-115m	1.15E+04	Ba-140	7.59E+07
Kr-83m	5.43E+06	Sn-121	3.28E+05	Ba-142	6.62E+07
Kr-85	4.35E+05	Sn-123	2.58E+04	La-140	7.78E+07
Kr-85m	1.15E+07	Sn-125	2.02E+05	La-141	6.94E+07
Kr-87	2.32E+07	Sn-127	1.41E+06	La-142	6.84E+07
Kr-88	3.25E+07	Sb-122	3.58E+04	La-143	6.58E+07
Rb-86	6.31E+04	Sb-124	2.75E+04	Ce-141	7.00E+07
Rb-88	3.33E+07	Sb-125	3.30E+05	Ce-143	6.63E+07
Rb-89	4.37E+07	Sb-127	3.50E+06	Ce-144	5.24E+07
Sr-89	4.54E+07	Sb-129	1.31E+07	Pr-142	2.25E+06
Sr-90	3.82E+06	Sb-130	4.35E+06	Pr-143	6.48E+07
Sr-91	5.59E+07	Sb-131	3.25E+07	Pr-144	5.27E+07
Sr-92	5.84E+07	Te-127	3.44E+06	Nd-147	2.78E+07
Y-90	3.92E+06	Te-127m	5.66E+05	Pm-147	8.38E+06
Y-91	5.76E+07	Te-129	1.24E+07	Pm-148	6.73E+06
Y-91m	3.25E+07	Te-129m	2.51E+06	Pm-148m	1.31E+06
Y-92	5.88E+07	Te-131	3.44E+07	Pm-149	2.31E+07
Y-93	4.39E+07	Te-131m	8.06E+06	Pm-151	8.08E+06
Y-94	6.88E+07	Te-132	5.86E+07	Sm-153	1.71E+07
Y-95	7.08E+07	Te-133	4.65E+07	Eu-154	2.62E+05
Zr-95	7.32E+07	Te-133m	3.83E+07	Eu-155	1.16E+05

TABLE 5.2-1 (CONTINUED)
FCS CORE INVENTORY

Nuclide	Fraction	Nuclide	Fraction	Nuclide	Fraction
Zr-97	6.78E+07	Te-134	7.75E+07	Eu-156	8.45E+06
Nb-95	7.34E+07	I-129	1.39E+00	Eu-157	9.40E+05
Nb-95m	8.38E+05	I-130	8.34E+05	Eu-158	3.40E+05
Nb-97	6.81E+07	I-131	4.08E+07	Gd-159	2.24E+05
Nb-97m	6.43E+07	I-132	5.97E+07	Tb-160	3.42E+04
Mo-99	7.70E+07	I-133	8.47E+07	Ho-166	2.61E+03
Mo-101	6.94E+07	I-134	9.47E+07	Th-228	1.19E-01
Tc-99m	6.81E+07	I-135	8.04E+07	Np-239	8.42E+08
Tc-101	6.94E+07	Xe-131m	5.35E+05	Pu-238	1.14E+05
Tc-104	5.23E+07	Xe-133	8.48E+07	Pu-239	1.67E+04
Ru-103	6.41E+07	Xe-133m	2.64E+06	Pu-240	2.14E+04
Ru-105	4.37E+07	Xe-135	3.08E+07	Pu-241	5.40E+06
Ru-106	2.15E+07	Xe-135m	1.75E+07	Pu-242	8.25E+01
Rh-103m	6.39E+07	Xe-138	7.38E+07	Am-241	5.86E+03
Rh-105	4.05E+07	Cs-132	1.39E+03	Cm-242	1.74E+06
Rh-106	2.37E+07	Cs-134	6.06E+06	Cm-244	1.37E+05
Pd-109	1.47E+07	Cs-134m	1.46E+06		

As described in the AST application, the equilibrium core inventory is calculated based on plant operation at 102 percent of the power level [1530 megawatts (thermal)], assuming an 18-month fuel cycle. The equilibrium core at the end of a fuel cycle is assumed to consist of fuel assemblies with three different burnups, i.e., approximately 1/3 of the core is subjected to one fuel cycle, 1/3 of the core to two fuel cycles, and 1/3 of the core to three fuel cycles. Minor variations in fuel irradiation times and duration of refueling outages will have a slight impact on the estimated inventory of long-lived isotopes in the core. However, these changes will have an insignificant impact on the radiological consequences of postulated accidents.

5.2.1.2 SOURCE TERMS

The atmospheric source terms used in the MACCS2 model were obtained from the latest Level 2 FCS PRA model analysis.

5.2.1.3 METEOROLOGICAL DATA

Site-specific meteorological data were used in the analysis. A full year (1988) of consecutive hourly meteorological data (wind speed, wind direction, stability class, and precipitation) were placed in MACCS2 format. Meteorological data for years 1994-1998 were used to demonstrate that the 1998 data set is representative.

5.2.1.4 POPULATION DISTRIBUTION

FCS is located on the west bank of the Missouri River approximately 20 miles from the Omaha Metropolitan Area. The 50-mile region includes the Omaha Metropolitan Area and 12 counties in Nebraska and 10 counties in Iowa that are completely, or partially within the 50-mile radius.

Population estimates within the 50-mile radius were performed using block-group resolution. The “block group” is one of several arial units used by the U.S. Bureau of the Census to aggregate data resulting from the decennial census. During the census conducted in 1990, the Census Bureau partitioned the U.S. into approximately 229,000 block groups nominally containing between 250 and 500 housing units per block group. Although the Census Bureau’s block-group structure may have changed for the census performed in 2000, data at the block-group level of resolution are not scheduled for release until 2002. Thus, block-group boundaries from the 1990 census were used throughout this analysis.

A circle comprising a 50-mile radius centered at FCS defines the subject population distribution region. A total of 778 block groups are totally enclosed by the 50-mile circle centered at FCS (636 block groups in Nebraska and 142 block groups in Iowa). All residents in those block groups are included in the population estimate. However, 61 block groups are partially included within the circle (31 partially included block groups in Nebraska and 30 in Iowa). The precise location of residents within individual block groups is unknown. Estimates of the population for partially included block groups were obtained under the assumption that residents are uniformly distributed throughout each block group. Under this assumption, the fraction of the total block group population residing within 50 miles of FCS equals the fraction of the block group area that is enclosed by the 50-mile circle.

The 1990 census data were used to prepare population estimates for the region surrounding the plant. As described above, the 1990 population distribution by sector for the 50-mile region was prepared using population data extracted from the STF3A files released by the Census Bureau in 1992 (Reference 5.2-3). A commercially available Geographic Information System (GIS), Maptitude, developed by Caliper Corporation, was used to estimate the population within each of the 16 sectors. The total 1990 population residing in the 50-mile radius region was estimated to be 770,065 persons.

County-level data extracted from the year 2000 census data were used to estimate the year 2000 population distribution. Changes in population between 1990 and 2000 were calculated under the assumption that increase or decrease in the population for each census block group within a given county were the same as those for the county as a whole. A comparison of projected populations for potentially affected counties in Nebraska for the year 2000 to Census 2000 data for the same counties shows that the projected populations are approximately 2.4 percent less than the enumerated populations. This difference was determined not to be significant. The county population change factors were applied to the respective block groups to generate a population distribution for year 2000. The total year 2000 50-mile radius population estimate is 853,459 persons.

County-specific population estimates were used to extrapolate the year 2000 population estimate to year 2030. Projections of county populations for Iowa counties for the years 2010, 2020, and 2025 were obtained from Dr. Willis Gaudy, Census Services, Iowa State University (Reference 5.2-4). Projections of county populations for Nebraska counties for the years 2000, 2005, 2010, 2015, and 2020 were obtained from the Nebraska Databook and Economic Trends (Reference 5.2-5).

County population projections for the year 2030 were not available for the States of Iowa and Nebraska; therefore, straight-line projections to the year 2030 were made using available population projections for 2020 and 2025 (Iowa), or 2015 and 2020 (Nebraska). The county population change factors were then applied to the respective block groups. The year 2030 50-mile radius population total for the FCS region was estimated to be 1,055,770 persons.

5.2.1.5 EMERGENCY RESPONSE

The emergency response assumptions were obtained from the FCS MACCS analysis submitted with the IPE (Reference 5.2-6). That analysis used a 45-minute evacuation delay time and a 2.0 meters per second evacuation speed. The analysis assumed that 95 percent of the population surrounding the plant would evacuate in an emergency.

5.2.1.6 LAND FRACTIONS

Land fractions for a given sector refer to the fractions of the area of that sector within each potentially affected county. For example, sector R21N lies partly in Monona County, Iowa, and partly in Woodbury County, Iowa. The land fractions for R21N were identified from an overlay of the area of R21N with the area of each county. Sixty-one percent of R21N is in Monona County and the remaining 39 percent is in Woodbury. Areas with water features enclosed or partially enclosed by a sector do not contribute to a land fraction for that sector. Sectors for which the sum of land fractions over all counties is less than one are those that enclose or partially enclose water features.

5.2.1.7 DOSE CONVERSION FACTORS

Dose conversion factors (DCFs) issued by the U.S. Environmental Protection Agency in Federal Guidance Report (FGR) 11 and FGR 12 were used to determine the dose calculations and latent cancer effects in the FCS Level 3 analysis (Reference 5.2-7; Reference 5.2-8). These reports provide inhalation and ingestion DCFs for over 600 radionuclides, and cloudshine and groundshine DCFs for 825 radionuclides. The FGRs, however, do not provide the DCFs required for acute dose calculations. In order to determine early fatalities and injuries, DCFs were obtained from DOE/EH-0070, a 1988 DOE database (Reference 5.2-9). This database is limited to the original MACCS set of 60 radionuclides.

5.2.1.8 AGRICULTURAL DATA

Agricultural data required for MACCS2 include:

- the fraction of land devoted to farming;
- the farmland property values;
- the total annual farm sales; and
- the fraction of farm sales resulting from dairy production.

The land area for each county was taken from the 1997 Census of Agriculture (Reference 5.2-10) and the land area within each county from the 2000 U.S. Census (Reference 5.2-11). Farmland property values, on a county-by-county basis, used in the FCS analysis are the estimated market value for land and buildings ($ per acre) from the 1997 Census of Agriculture.

The total annual farm sales data for Iowa and Nebraska used in the FCS analysis were derived from the total annual farm sales values reported for each county in the 1997 Census of Agriculture. The fraction of farm sales resulting from dairy production in Iowa was derived from the following 1997 Census of Agriculture data :

- data for the total annual farm sales,
- the total value of all dairy products produced in Iowa, and
- the number of dairy cows for the State of Iowa and each county within 50 miles of FCS.

For each county in Nebraska, data as reported in the Nebraska Databook and Economic Trends was used to develop the value of the farm sales from dairy production in each county used for the FCS analysis. The available data include:

- the number of dairy cows in each county and agricultural district,
- the total milk production in each district, and
- the average milk price paid to Nebraska farmers.

The agricultural data are presented in Table 5.2-2.

TABLE 5.2-2
MACCS2 AGRICULTURAL DATA

County	Fraction of Land Devoted to Farming	Fraction of Farm Sales Resulting from Dairy Production	Total Annual Farm Sales ($/ hectare)	Farmland Property Values ($/hectare)
Nebraska				
Burt	0.928	0.0068	950.70	554.84
Butler	0.946	0.0129	716.19	476.74
Cass	0.840	0.0230	552.09	637.81
Colfax	0.871	0.0061	1915.75	573.46
Cuming	0.982	0.0047	3483.47	635.78
Dodge	0.945	0.0110	1079.14	669.37
Douglas	0.533	0.0188	967.31	915.03
Lancaster	0.784	0.0355	483.44	570.63
Sarpy	0.066	0.0096	1390.23	953.88
Saunders	0.903	0.0136	814.46	629.71
Thurston	0.750	0.0281	778.72	414.01
Washington	0.877	0.0356	1043.39	842.99
Iowa				
Cass	0.917	0.0071	701.70	533.39
Crawford	0.944	0.0086	818.52	607.05
Fremont	0.973	0.0000	684.46	523.28
Harrison	0.881	0.0014	710.89	610.29
Monona	0.829	0.0040	675.82	532.99
Montgomery	0.894	0.0055	841.16	496.57
Pottawattamie	0.879	0.0030	874.76	787.55
Shelby	0.905	0.0045	958.77	658.45
Woodbury	0.890	0.0013	751.98	539.06
Mills	0.830	0.0026	630.07	642.66

5.2.1.9 REGIONAL ECONOMIC DATA

Regional economic data (excluding the economic data associated with the farming industry, which are presented in the previous section) factored into the FCS risk analysis are limited to non-farm property values. As an estimate for the per capita property values one of two data sets was referenced. The median home value as reported in the 2000 US Census was used for each county in Iowa (Reference 5.2-11). The average single-family-home selling price as reported in the Nebraska Databook and Economic Trends was used for each county in Nebraska (Reference 5.2-15). The non-farm property values are presented in Table 5.2-3.

TABLE 5.2-3
NON-FARM PER CAPITA PROPERTY VALUES

County	Non-Farm Property Value ($/person)	County	Non-Farm Property Value ($/person)
Nebraska		***Iowa***	
Burt	42873	Cass	34700
Butler	40474	Crawford	33900
Cass	78143	Fremont	32000
Colfax	41424	Harrison	33600
Cuming	55857	Monona	27400
Dodge	68770	Montgomery	35200
Douglas	113154	Pottawattamie	46900
Lancaster	201780	Shelby	36400
Sarpy	117426	Woodbury	41000
Saunders	70839	Mills	47000
Thurston	46101		
Washington	109702		

5.2.1.10 FOOD PATHWAY ASSUMPTIONS

The MACCS2 ingestion model preprocessor, COMIDA2, was used to model the food pathway. COMIDA2 is a dynamic food-chain model that models the transfer of radionuclides into the edible portion of plants as a function of plant growth. COMIDA2 models transport through the human food chain and calculates the respective nuclide concentration in nine foodstuffs (grains, leafy vegetables, roots, fruits, legumes, milk, beef, poultry, and eggs), based on initial deposition.

After screening the radionuclide inventory it was found that 16 radionuclides sufficiently represented the ingestion effects for the FCS analysis. These radionuclides are Strontium-89, Strontium-90, Molybdenum-99, Ruthenium-103, Ruthenium-105, Tellurium-127m, Tellurium-129m, Tellurium-132, Iodine-129, Iodine-131, Iodine-133, Cesium-134, Cesium-137, Barium-140, Lanthanum-140, and Cerium-144.

5.2.1.11 DEPOSITION VELOCITIES

A deposition velocity value of 0.03 meters per second was used for the FCS analysis.

5.2.2 RESULTS

The result of the Level 3 model is a matrix of offsite exposure and offsite property costs associated with a postulated severe accident in each release category. This matrix was combined with the results of the Level 2 model to yield the probabilistic offsite dose and probabilistic offsite property damage resulting from the analyzed plant configuration. The base case offsite exposure risk for FCS is 10.15 person-rem per year. Table 5.2-4 provides the baseline exposures associated with each release category. The offsite exposure risk was calculated by multiplying the frequency of the release by the dose.

The base case offsite economic risk is $15,427 per year. Table 5.2-4 also provides the base case offsite economic costs associated with each release category. The economic risk for each release category was calculated by multiplying the frequency by the offsite dollar factor.

The final result of a Level 3 evaluation of a SAMA is a value of the cumulative dose expected to be received by offsite individuals and a value of the expected offsite property losses due to severe accidents given the plant configuration under evaluation.

TABLE 5.2-4
SUMMARY OF OFFSITE CONSEQUENCES

Release Category	Frequency	Offsite Dose (person-rem)	Offsite Dose Risk	Offsite Economic Costs ($)	Offsite Economic Risk ($)
1. Intact Containment (with / without Spray Scrubbing of Releases)	1.31E-05	1.52E+04	0.20	4.10E+05	5
3. Late Containment Failure (with / without Spray Scrubbing of Releases)	8.79E-06	1.59E+05	1.40	8.80E+07	774
4. Early Containment Failure (with / without Spray Scrubbing of Releases)	4.75E-07	3.16E+06	1.50	4.81E+09	2,285
5. Alpha Mode Containment Failure	1.65E-09	1.07E+06	0.00	1.52E+09	3
6. Isolation Failure (with / without Containment Cooling) / SGTR (with Open / Cycling SRV)	1.43E-06	2.34E+06	3.35	4.65E+09	6,650
7. Containment Bypass (Small / Large V-Sequence)	1.00E-06	3.70E+06	3.70	5.71E+09	5,710
Total	2.48E-05		10.15		15,427

SGTR = steam generator tube rupture
SRV = safety relief valve

5.2.3 SENSITIVITY ANALYSIS

Sensitivity analyses were performed for reduced evacuation speed, fission product release, and weather. Each sensitivity case is discussed below and results are presented in terms of impacts to latent cancer fatality (LCF) risk.

5.2.3.1 REDUCED EVACUATION SPEED

The analysis assumed that 95 percent of the population surrounding the plant would evacuate in an emergency. Analyses were performed for both 100 percent (full) and no evacuation of the surrounding population. The difference in LCF risk between full evacuation and no evacuation is approximately 6.1E-4 per year.

5.2.3.2 FISSION PRODUCT RELEASE

A sensitivity analysis was performed for a 10 percent increase in fission product release. The core inventory was increased by 10 percent while maintaining the release fractions. While short-term dose effects are proportional to the releases, the impact of long-term dose effects associated with groundshine, resuspension, and ingestion is limited by the use of MACCS2 interdiction triggers, which are based on U.S. Environmental Protection Agency Protective Action Guide dose limits. These triggers impact population relocation, ingestion, and long term land uses. As shown in the table below, a 10 percent increase in source term results in a 5.7 percent increase in population dose risk increase and a 6.2 percent increase in LCF.

Parameter	Nominal Release	10% Increase in Releases	Percent Change
Population Dose Risk (millirem/year)	4.32	4.56	5.7
LCF Risk (LCF/year)	2.41E-03	2.57E-03	6.2

5.2.3.3 WEATHER

Data from the years 1994 to 1998 were compared with the base 1988 meteorological year data used in the plant model for the FCS IPE. For the year studied, the mean LCF risk was 1.93E-03 per year. The 1988 meteorological data used in the base assessment conservatively bounded the results of the other five years given the impact was 25 percent greater than the sample mean.

5.3 SAMA IDENTIFICATION AND SCREENING

This section describes the generation of the initial list of potential severe accident mitigation alternatives (SAMAs) for Fort Calhoun Station Unit 1 (FCS), screening methods, and results.

5.3.1 SAMA LIST COMPILATION

Omaha Public Power District generated a list of candidate SAMAs by reviewing industry documents and considering plant-specific enhancements not considered in published industry documents. Industry documents reviewed include the following:

- The Watts Bar Nuclear Plant Unit 1 Individual Plant Examination (IPE) submittal (Reference 5.3-1);
- The Limerick Severe Accident Mitigation Design Alternative (SAMDA) cost estimate report (Reference 5.3-2);
- NUREG-1437 description of Limerick SAMDA (Reference 5.3-3);
- NUREG-1437 description of Comanche Peak SAMDA (Reference 5.3-4);
- Watts Bar Nuclear Plant SAMDA submittal (Reference 5.3-5);
- Tennessee Valley Authority (TVA) response to the U.S. Nuclear Regulatory Commission's (NRC's) Request for Additional Information on the Watts Bar Nuclear Plant SAMDA submittal (Reference 5.3-6);
- Westinghouse AP600 SAMDA (Reference 5.3-7);
- Safety Assessment Consulting presentation by Wolfgang Werner at the NUREG-1560 conference (Reference 5.3-8);
- NRC IPE Workshop – NUREG-1560 presentation (Reference 5.3-9);
- NUREG-0498, Supplement 1, Section 7 (Reference 5.3-10);
- NUREG/CR-5567, PWR Dry Containment Issue Characterization (Reference 5.3-11);
- NUREG-1560, Volume 2, NRC prospective on the IPE program (Reference 5.3-12);
- NUREG/CR-5630, PWR Dry Containment Parametric Studies (Reference 5.3-13);
- NUREG/CR-5575, Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment (Reference 5.3-14);
- Combustion Engineering (CE) System 80+ SAMDA submittal (Reference 5.3-15;
- NUREG-1462, NRC Review of the Asea Brown Boveri, Inc./CE System 80+ Submittal (Reference 5.3-16);
- An ICONE paper by C. W. Forsberg, et al., on a core melt source-reduction system (Reference 5.3-17);

- TVA's SAMDA evaluation for Watts Bar Nuclear Plant based on the updated IPE (Reference 5.3-18);

- Arkansas Nuclear One Unit 1 Probabilistic Risk Assessment Summary Report (Reference 5.3-19);

- The Arkansas Nuclear One, Unit 1 Individual Plant Examination of External Events (IPEEE) (Reference 5.3-20);

- Turkey Point, Applicant's Environmental Report, Operating License Renewal Stage, Attachment F (Reference 5.3-21);

- Oconee Nuclear Station, Applicant's Environmental Report, Operating License Renewal Stage, Attachment K (Reference 5.3-22);

- Edwin I. Hatch Nuclear Plant Application for Renewed Operating License (Reference 5.3-23);

- FCS IPE submittal (Reference 5.3-24); and

- Calvert Cliffs Nuclear Power Plant, Applicant's Environmental Report, Operating License Renewal Stage, Attachment 3 (Reference 5.3-25).

Although FCS has a CE-designed nuclear steam supply system, each of the above documents was reviewed for potential SAMAs even if they were not necessarily applicable to a CE plant. Those items not applicable to FCS were subsequently screened from this list. The containment performance improvement programs for boiling water reactors and for plants with ice condensers were not reviewed (and the NUREG-1560 portion of the containment performance improvements for these were not reviewed). Omaha Public Power District assumed that any issues from these documents have been included in the large, dry containment performance improvement program (NUREG/CR-5567). Conceptual enhancements for which no specific details were available (e.g., "improve diesel reliability" or "improve procedures for loss of support systems") were not included on the list unless they were considered as vulnerabilities in the FCS IPE.

5.3.2 QUALITATIVE SCREENING OF SAMAS

The resulting initial list of potential SAMAs is presented in Table 5.3-1. Table 5.3-1 also presents a qualitative screening of the initial list. Items were eliminated from further evaluation based on one of the following criteria:

- SAMA improvements that modify features not applicable to FCS;

- SAMA improvements that have already been implemented at FCS;

- SAMA improvements that could be consolidated with one or more other SAMA improvement(s);
- SAMA improvements that have previously been identified as costing greater than the maximum attainable benefit; or
- SAMA improvements that would provide minimal risk reduction.

Based on preliminary screening, 170 improvements were eliminated. Of these, 57 candidate SAMAs were not applicable, 8 were duplicates and combined into other SAMAs, 31 SAMAs were prohibitively expensive, 24 resulted in minimal risk reduction, and 50 were already implemented. The remaining 20 SAMAs were subject to further evaluation and final screening. The final screening and cost-benefit evaluation are presented in Section 4.16 of the main report.

TABLE 5.3-1

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
	Improvements related to reactor coolant pump seal loss-of-coolant accidents (loss of component cooling or service water)			
1	Cap piping downstream of normally closed component cooling drain and vent valves.	D	1, 13	Actions would not significantly impact loss-of-CCW events.
2	Improve saltwater, service water, and component cooling pump recovery (post-trip only).	D	2, 10, 13	Recoverable loss of these pumps would not significantly impact CDF or LERF.
3	Improve saltwater, service water, and component cooling pump recovery (pre-trip and post-trip).	D	2, 10, 13	Recoverable loss of these pumps would not significantly impact CDF or LERF.
4	Implement procedure and operator training enhancements for support-system failure sequences, with emphasis on anticipating problems and coping with events that could lead to loss of cooling to the RCP seals.	F	2, 13	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
5	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	B	2, 6, 11, 13	Cooling water does not cool charging pump seals.
6	Implement procedure changes to allow cross-connection of motor cooling for RHRSW pumps.	B	24	Motors are air cooled.
7	Perform enhancements to charging pump, such as increasing lube oil capacity, preventing flow diversion from relief valves, or adding a centrifugal pump.	D	2, 13, 22	Existing system is adequate and charging system poses minimal contribution to plant risk.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
8	Eliminate reactor coolant pump thermal barrier dependence on component cooling, such that loss of component cooling does not result directly in core damage.	C	2, 13	Without eliminating the impact for SBO events, the modifications would not provide a significant risk reduction. However, to address SBO a fix such as SAMA No. 11 would be required, which is cost prohibitive.
9	Install an additional service water pump.	F	5	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
10	Install the improved N 9000 reactor coolant pump seals.	F	11, 13	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
11	Create an independent reactor coolant pump seal injection system with or without a dedicated diesel.	C,D	6, 11, 13	Without a dedicated diesel, the impact of the modification on CDF and LERF would be negligible. With a dedicated diesel, the change would be cost prohibitive.
12	Use existing hydro test pump for reactor coolant pump seal injection.	B	7	Not applicable to FCS.
13	Eliminate Emergency Core Cooling System dependency on Component Cooling Water System by replacing ECCS pump motors with air-cooled motors or by providing self-cooled ECCS seals.	B	10, 13, 22	Motors are air cooled. FCS can function in injection and recirculation without seal cooling.
14	Install an additional CCW pump.	A	13	FCS already has three CCW pumps.
15	Change procedures to isolate reactor coolant pump seal letdown flow on loss of component cooling, and provide guidance on loss of injection during seal loss-of-coolant accident.	E	13	This SAMA is a subset/duplicate of SAMA No. 4 and will be evaluated as part of SAMA No. 4.

TABLE 5.3-1 (CONTINUED)

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
16	Implement procedures to stagger high-pressure safety injection pump use after a loss-of-service water.	B	13	Not applicable to FCS.
17	Use Fire Protection System pumps as a backup for seal injection and high-pressure makeup.	B	13	Fire Protection System capabilities do not support makeup to RCS. Guidance to use fire pumps for SG cooling is included in the FCS SAMG.
18	Improve ability to cool residual heat removal heat exchangers.	A	12, 13	RW backs up CCW. Additional redundancy is not required.
	Improvements related to Heating, Ventilation, and Air Conditioning			
19	Stage backup fans in switchgear rooms.	A	1, 13	Equivalent procedures in place.
20	Provide a redundant train of ventilation to 480V switchboard rooms.	A	2, 13, 18	Air conditioners in rooms with fresh air backup.
21	Implement procedures for temporary heating, ventilation, and air conditioning.	A	11, 13	EOP-13 addresses this issue.
22	Add a switchgear room high-temperature alarm.	B	13	Some high-temperature alarms are available in the room. In addition, the long heatup times coupled with individual equipment alarms make this issue not applicable at FCS.
23	Create ability to switch fan power supply to direct current in a station blackout event.	D	13	FCS has electrical equipment located in large rooms; therefore, contribution from HVAC would be small.
	Improvements related to ex-vessel accident mitigation/containment phenomena			
24	Delay Containment Spray System actuation after large loss-of-coolant accident.	D	2, 6	Risk impact negligible.

TABLE 5.3-1 (CONTINUED)

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
25	Install containment spray pump header automatic throttle valves.	E	11, 12, 13	The issues associated with this SAMA are related to SAMA No. 172. FCS is monitoring industry research and will address this issue as it relates to compliance with design criteria on an as-needed basis.
26	Install an independent method of suppression pool cooling.	B	3, 4	Not applicable to PWRs.
27	Develop an enhanced drywell spray system.	B	3, 4, 16, 17	Not applicable to PWRs.
28	Provide a dedicated existing drywell spray system.	B	3, 4	Not applicable to PWRs.
29	Install a containment vent large enough to remove anticipated transients without scram decay heat.	B	3, 4	Not applicable to PWRs.
30	Install a filtered containment vent to remove decay heat.	C	3, 4	CCNPP (Reference 5.3-25) estimated the cost of this enhancement as $5.7M, which exceeds the maximum attainable benefit.
31	Install an unfiltered, hardened containment vent.	A	3, 4, 9, 14	FCS can vent containment via a hydrogen purge line.
32	Install hydrogen recombiners.	D	24	Hydrogen recombiners have been determined to have limited value for mitigating large, dry PWR severe accident consequences.
33	Create/enhance hydrogen igniters with independent power supply or passive ignition system.	D	3, 5, 6, 7, 9, 11, 12, 13, 14, 15, 16, 17	Analyses of post-accident containment hydrogen threats were evaluated in the FCS PRA model and found to be a negligible contributor to containment failure.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
34	Create a molten core debris containment system with heat removal capabilities under the basemat or other enhancements to prevent melt-through, such as thicker basemat.	B	3, 4, 6, 8, 11, 16, 17, 19	FCS is designed with a passively flooded cavity. Any severe accident event that does not bypass the containment and fails the RV lower head will result in the quenching of debris. When the SIRWT contents are injected into the Containment, the RV can be flooded to the vessel beltline.
35	Provide modification for flooding of the drywell head.	B	4, 9	Not applicable to PWRs.
36	Enhance Fire Protection System and/or Standby Gas Treatment System hardware and procedures.	B	4	The Standby Gas Treatment System is not applicable to FCS. The Fire Protection System portion of this SAMA will be evaluated as part of SAMA No. 41.
37	Create a reactor cavity flooding system.	A	5, 6, 9, 11, 12, 13, 15, 16, 17	See response to SAMA No. 34.
38	Create other options for reactor cavity flooding.	A	7, 9, 13	See response to SAMA No. 34.
39	Enhance air return fans (ice condenser containment).	B	6, 11	SAMA is not applicable to FCS.
40	Provide containment inerting capability.	B	6, 9, 11, 14	SAMA is not applicable to FCS.
41	Use the Fire Protection System as a backup source for the Containment Spray System.	F	7, 9, 10, 12	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
42	Install a passive Containment Spray System.	C	8	FCS has redundant containment heat removal systems consisting of 2 CS and 2 CARC trains with multiple coolers per train. Benefit of passive containment heat removal is minimal and ability to perform such a backfit is unlikely.
43	Install secondary containment filtered ventilation.	B	8	SAMA is not applicable to FCS.
44	Increase containment design pressure.	C	8	Extensive reconstruction of the Containment Building would be needed for an existing plant.
45	Provide a reactor vessel exterior cooling system.	A	16, 17	See response to SAMA No. 34.
46	Construct a building, maintained at a vacuum, to be connected to the Containment.	C	17	Engineering judgement indicates that the implementation costs of this SAMA would greatly exceed the maximum attainable benefit. In addition, CE System 80+ judged this would not help to mitigate containment bypass.
47	Add ribbing to the containment shell.	B	17	SAMA is not applicable to FCS.
48	Install a Reactor Building liner protective barrier.	C	20	Engineering judgement indicates that the implementation costs of this SAMA would greatly exceed the maximum attainable benefit.
	Improvements related to improvement of alternating current/direct current power reliability/availability			
49	Train operations crew for response to inadvertent actuation signals.	B	1, 13	In general, procedures of this type are already in place. Specific procedure under consideration not applicable to FCS design.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
50	Proceduralize alignment of spare diesel to shutdown board after loss-of-offsite power and failure of the diesel normally supplying it.	B	2	SAMA is not applicable to FCS.
51	Provide an additional diesel generator.	C	5, 6, 10, 13, 16, 17	The cost of this enhancement exceeds the maximum attainable benefit . CCNPP (Reference 5.3-25) estimated the cost of this enhancement as greater than $20M.
52	Provide additional DC battery capacity.	F	5, 6, 13, 16, 17	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
53	Improve bus cross-tie ability.	A	10, 13	FCS has evaluated the applicability of this SAMA and significant issues associated with spurious actuation have been resolved previously. OI-EE-2B addresses the issue of bus cross tie.
54	Incorporate an alternate battery charging capability.	F	10, 11, 12, 13	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
55	Modify direct current bus A reliability.	D	24	Reliability is already high. No benefit expected.
56	Increase/improve direct current busload shedding.	F	10, 11, 12, 13	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
57	Replace batteries with a more reliable model.	A	10	Batteries are of acceptably high reliability.
58	Create alternating current power cross-tie capability across units at a multi-unit site.	B	11, 12, 13	FCS is a single-unit site.
59	Create a cross-unit tie for diesel fuel oil.	B	13	FCS is a single-unit site.

TABLE 5.3-1 (CONTINUED)

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
60	Develop procedures to repair or replace failed 4- kV breakers.	F	13	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
61	Emphasize steps in recovery of offsite power after a station blackout.	A	13	FCS Station Blackout EOP has been recently upgraded and has adequate detail.
62	Develop a severe weather conditions procedure.	A	13	Severe weather procedures are already in place.
63	Develop procedures for replenishing diesel fuel oil.	A	13	FCS has a seven-day diesel fuel oil supply and refill procedures are included in EPIPs.
64	Install gas turbine generators.	C	13	CCNPP (Reference 5.3-25) estimated the cost of this enhancement at $3.3M, which exceeds the maximum attainable benefit.
65	Install gas turbine generators with tornado protection.	C	16, 17	See response to SAMA No. 64.
66	Create a backup source for diesel cooling.	B	13	FCS diesels are air cooled.
67	Provide a connection to an alternate offsite power source.	C	13	CCNPP (Reference 5.3-25) estimated the cost of this enhancement as greater than $25M. The FCS supply grid has been recently upgraded.
68	Implement underground offsite power lines.	C	13	CCNPP (Reference 5.3-25) estimated the cost of this enhancement as greater than $25M, which exceeds the maximum attainable benefit.
69	Replace anchor bolts on diesel generator oil cooler.	A	13	Walkdown done as part of SQUG Program has been completed. Any seismic enhancements addressed through SQUG .

TABLE 5.3-1 (CONTINUED)

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
70	Change undervoltage, auxiliary feedwater actuation signal block, and high pressurizer pressure actuation signals to 3-out-of-4 logic, instead of 2-out-of-4.	B	18	FCS trip signals utilize 2-out-of-4 logic.
71	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.	B	18	Feature not available at FCS.
72	Add disconnects at the junction box on the roof of the Auxiliary Building where 4 kV power from the 0C diesel generator branches to all four switchgears. The disconnects would allow the recovery of the 0C diesel generator following the loss of any switchgear.	B	18	SAMA refers to third EDG. Equivalent equipment not available at FCS.
	Improvements in identifying/coping with containment bypass			
73	Create/enhance Reactor Coolant System depressurization ability.	E	1, 5, 6, 7, 9, 11, 12, 13, 14, 15, 16, 17	Feed-and-bleed can be successfully accomplished with one PORV. See SAMA No. 183 for evaluation.
74	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture.	D	16, 17	Sufficient means of plant cooldown exist. Action has minimal benefit.
75	Improve/add additional steam generator tube rupture coping abilities.	D	7, 8, 9, 10, 13, 14, 16, 17	Thermal-hydraulic analyses suggest SIRWT inventory is sufficient to accommodate a SGTR event for more than 24 hours. Additional coping capabilities not necessary.

TABLE 5.3-1 (CONTINUED)

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
76	Increase secondary-side pressure capacity such that a steam generator tube rupture would not cause the relief valves to lift.	C	8, 17	For an existing plant, increasing the secondary-side pressure capacity is not feasible, as it would require an entirely new secondary system.
77	Replace steam generators with new design.	C	13	CCNPP (Reference 5.3-25) estimated the cost of this enhancement at more than $100M.
78	Revise emergency operating procedures to direct that a faulted steam generator be isolated	A	13	Guidance already addressed in FCS EOPs.
79	Direct steam generator flooding after a steam generator tube rupture, prior to core damange.	A	14, 15	The action described in this SAMA is already recommended in the FCS SAMG.
80	Implement a maintenance practice that inspects 100 percent of the tubes in a steam generator.	C	16, 17	CCNPP (Reference 5.3-25) estimated the cost of this enhancement at $8M per year.
81	Locate residual heat removal inside of the Containment.	C	8	For an existing plant, relocating the RHR System inside the Containment is not feasible, as it would require an entirely new RHR system.
82	Install self-actuating containment isolation valves.	B	8	Vast majority of penetrations are AOVs that fail closed on loss of power or loss of IA.
83	Install additional instrumentation for inter-system loss-of-coolant accidents.	A	5, 6, 11, 13	Maintenance and testing procedures already cover this. Power is removed from SDC MOVs.
84	Increase frequency of valve leak testing.	D	12	Impact negligible based on CIV RRW.
85	Improve operator training on inter-system loss-of-coolant accident coping.	A	12, 13	ISLOCAs identified in the FCS PRA model are included in the biennial operator requalification training cycle.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
86	Install relief valves in the Component Cooling Water System.	A	13	Issue addressed by adjusting positioning of associated CIV.
87	Revise emergency operating procedures to improve inter-system loss-of-coolant accident identification.	E	13	This SAMA duplicates SAMA No. 85.
88	Ensure all interfacing system loss-of-coolant accident releases are scrubbed.	F	14, 15	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
89	Add redundant and diverse limit switch to each containment isolation valve.	D	16, 17	This involves a hardware change with minimal risk reduction.
90	Keep low-pressure injection/decay heat removal and reactor building spray pump drains closed.	B	20	Each room has its own sump.
91	Verify valve position.	A	20	Procedures for checking valve position are in place.
92	Conserve/makeup Borated Water Storage Tank inventory post accident.	F	20	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
93	Remove and flange the hydrogen purge valves.	B	20	FCS credits use of hydrogen purge in SAMG actions.
	Improvements in reducing internal flooding frequency			
94	Modify swing direction of doors separating Turbine Building basement from areas containing safeguards equipment.	B	13	FCS has different design. Basement does not communicate with any safeguards compartments.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
95	Improve inspection of rubber expansion joints on main condenser.	A	13	FCS has rubber expansion joints that are replaced on a preventive maintenance schedule. In addition, a flood like this is not a credible serious risk for FCS.
96	Implement internal flood prevention and mitigation enhancements.	A	13	Enhancements already included following plant internal flooding study.
	Improvements related to feedwater/feed-and-bleed reliability/availability			
97	Install a digital feedwater upgrade.	D	1, 13	Performance of main FW regulation valves is not risk-significant and FCS has motor-driven MFW pumps.
98	Perform surveillance on manual valves used for backup auxiliary feedwater pump suction.	A	1, 13	SO-0-37 requires periodic verification of AFW alignment.
99	Install manual isolation valves around auxiliary feedwater turbine-driven steam admission valves.	D	1, 13	Risk reduction worth of existing TAV is small. No benefit expected.
100	Install accumulators for turbine-driven auxiliary feedwater pump flow control valves (control valves).	B	11	Accumulators good for 3 cycles. Valves may then be hand jacked. No action required.
101	Install separate accumulators for the auxiliary feedwater cross-connect and block valves.	A	18	Cross-tied MOV and AOV have separate accumulators.
102	Install a new Condensate Storage Tank.	C	13, 16, 17	CCNPP (Reference 5.3-25) estimated the cost of this enhancement at $1M. Costs at FCS would be similar and the benefit would be small.
103	Provide cooling of steam-driven auxiliary feedwater pump in a station blackout event.	B	13	Pump is self-cooled.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
104	Proceduralize local manual operation of auxiliary feedwater when control power is lost.	A	13	OI-AFW-4 addresses manual operation.
105	Provide portable generators, to be hooked into the turbine-driven auxiliary feedwater pump after battery depletion.	B	16, 17	TD pump does not need electrical power once it starts.
106	Add a motor train of auxiliary feedwater to the steam trains.	A	13	FW-6 is in place.
107	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate.	A	12, 18	Installed cross-tie between Fire Water and FW systems. (See FCS EOP-20.)
108	Use Fire Protection System as a backup for steam generator inventory.	A	13	FCS EOP-20 provides for FP System backup source for steam generator inventory.
109	Procure a portable diesel pump for isolation condenser makeup.	B	13	Not an FCS component.
110	Install an independent diesel generator for the Condensate Storage Tank makeup pumps.	D	13	There are four ways to refill the CST; two with power and two without power. Existing CST can accommodate 24 hrs + of post-accident operation.
111	Change failure position of condenser makeup valve.	A	13	LCV-1190 was modified by adding an accumulator and a manual isolation valve.
112	Create passive secondary-side coolers.	C	17	For an existing plant, design and installation of this SAMA is not considered feasible, as it would involve major changes in plant structures.
113	Reduce the support system requirements for low-pressure feed.	B	18	Equivalent systems not available at FCS.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
114	Replace current power-operated relief valves with larger ones such that only one is required for successful feed-and-bleed.	A	18	Only one PORV is required for feed-and-bleed.
115	Install an emergency feedwater pump common discharge valve.	B	20	No common discharge at FCS.
	Improvements in core cooling systems			
116	Provide capability for diesel-driven, low-pressure vessel makeup.	C	4, 13, 15	Engineering judgment indicates that the implementation costs of this SAMA would greatly exceed the maximum attainable benefit because a complete new system would be required.
117	Provide an additional high-pressure safety injection pump with independent diesel.	C	6, 16, 17	CCNPP (Reference 5.3-25) estimated the cost of this enhancement at between $5M and $10M, which exceeds the maximum attainable benefit.
118	Install independent alternating current High-Pressure Safety Injection System.	C	11	CCNPP (Reference 5.3-25) estimated the cost of this enhancement at between $5M and $10M, which exceeds the maximum attainable benefit.
119	Create the ability to manually align Emergency Core Cooling System recirculation.	A	12	Capability exists via remote operation.
120	Implement a Refueling Water Tank makeup procedure.	E	12, 13	See SAMA No. 92.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
121	Stop low-pressure safety injection pumps earlier in medium or large loss-of-coolant accidents/ emphasize timely recirculation swapover in operator training.	D	13	The benefits for this SAMA are minimal, as estimated by CCNPP (Reference 5.3-25). FCS has automatic recirculation actuation. The costs associated with revising calculations, accident analyses, and procedures would exceed the minimal benefits.
122	Upgrade Chemical and Volume Control System to mitigate small loss-of-coolant accidents.	C	8	Larger charging pumps could reduce ISLOCA CDF; however, cost would be very expensive.
123	Install an active High-Pressure Safety Injection System.	B	8	SAMA intended for passive plant assessment. FCS has active HPSI System.
124	Change “in-containment” Refueling Water Tank suction from 4 check valves to 2 check and 2 air-operated valves.	B	8	SAMA intended for passive plant assessment. FCS has active HPSI System.
125	Replace two of the four safety injection pumps with diesel-powered pumps.	C	16, 17	Engineering judgment indicates that the implementation costs of this SAMA would greatly exceed the maximum attainable benefit.
126	Align low-pressure core injection or core spray to Condensate Storage Tank on loss of suppression pool cooling.	B	10, 13	BWR issue.
127	Raise high-pressure core injection/reactor core isolation cooling backpressure trip setpoints.	B	13	BWR issue.
128	Improve the reliability of the automatic depressurization system.	B	4	BWR issue.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
129	Disallow automatic vessel depressurization in non-anticipated transients without scram scenarios.	B	13	BWR issue.
130	Create automatic swapover to recirculation on Refueling Water Tank depletion.	A	5, 6, 11	Included in original plant design.
		Instrument air/gas improvements		
131	Modify emergency operating procedures for ability to align diesel power automatically to air compressors.	A	13	EOP Attachments 12 and 13 provide procedures for charging the EDG air start banks with the diesel-driven compressors.
		Improvements in anticipated transient without scram coping		
132	Replace old air compressors with more reliable ones.	D	13	The compressors installed at FCS are highly reliable.
133	Install nitrogen bottles as backup gas supply for safety relief valves.	E	13	Duplicate of SAMA No. 186.
134	Install motor-generator set trip breakers in Control Room.	B	11	FCS does not have motor-generator sets.
135	Add capability to remove power from the bus powering the control rods.	A	13	This is part of the original FCS plant design.
136	Create cross-connect ability for standby liquid control trains.	A	13	FCS has capability to cross-tie boric acid pumps or boric acid gravity feed.
137	Create an alternate boron injection capability (backup to standby liquid control).	A	13	FCS has capability to cross-tie boric acid pumps or boric acid gravity feed.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
138	Remove or allow override of low-pressure core injection during anticipated transients without scram.	B	13	LPSI provides no benefit during ATWS scenarios.
139	Install a system of relief valves that prevents any equipment damage from a pressure spike during anticipated transients without scram event.	D	16, 17	Minimal benefit since ATWS is a small contributor to CDF and LERF.
140	Create a boron injection system to back up the mechanical control rods.	A	16, 17	Boron injection system is available at FCS.
141	Provide an additional instrument system for anticipated transients without scram mitigation (e.g., anticipated transients without scram mitigation scram actuation circuitry).	A	16, 17	Plants trips on “Hi-Hi” pressurizer pressure.
		Other improvements		
142	Provide capability for remote operation of secondary-side relief valves in station blackout.	E	2	Duplicates SAMA No. 186.
143	Defeat 100 percent load rejection capability.	B	13	FCS does not have the ability to reject load; therefore, there is no way to defeat this ability.
144	Change control rod drive flow control valve failure position.	B	13	Not applicable to PWR plants.
145	Install secondary-side guard pipes up to the main steam isolation valves.	C	16, 17	Engineering judgment indicates that the implementation costs of this SAMA would greatly exceed the maximum attainable benefit.

TABLE 5.3-1 (CONTINUED)

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
146	Install digital large break loss-of-coolant accident protection.	C	17	Engineering judgment indicates that the implementation costs of this SAMA would greatly exceed the maximum attainable benefit.
147	Increase seismic capacity of the plant to a high confidence, low-pressure failure of twice the safe shutdown earthquake.	A	17	Seismic analysis done in response to GL 88-20 included identification of cost-beneficial seismic. These are being addressed within the SQUG.
148	Enhance the reliability of the demineralized water makeup system through the addition of diesel-backed power to one or both of the demineralized water makeup pumps.	A	18	FCS already has four sources of makeup water for long-term decay heat removal.
149	Proceduralize intermittent operation of high-pressure coolant injection.	A	24	This is part of the HPSI stop and throttle strategy included in the FCS EOPs.
150	Increase the reliability of safety relief valves (adding electrical signal to open automatically).	B	24	Does not apply to PWRs.
151	Install motor-driven feedwater pump.	A	24	FCS has three motor-driven FW pumps.
152	Implement procedure to instruct operators to trip unneeded residual heat removal/CS pumps on loss of room ventilation.	B	24	FCS does not have an HVAC dependency for RHR/CS pumps.
153	Increase available NPSH for the injection pumps.	A	24	Analyses have verified existence of adequate NPSH.
154	Increase the safety relief valve reseat reliability.	D	24	Stuck open SRV is not a significant contributor to CDF and LERF.

TABLE 5.3-1 (CONTINUED)

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
155	Reduce direct current dependency between high-pressure injection system and automatic depressurization system.	B	24	Item refers to BWR systems.
156	Modify RWCU for use as a decay heat removal system and proceduralize use.	B	24	Item refers to BWR systems.
157	Use control rod device for alternate boron injection.	B	24	Item refers to BWR systems.
158	Allow cross-connection of uninterruptible compressed air supply to opposite unit.	B	24	Not applicable to a single-unit site.
159	Ensure that motor control centers are adequately secured per seismic or other requirements.	A	21	Seismic analysis done in response to GL 88-20 included identification of cost-beneficial seismic modifications. These are being addressed within the SQUG.
160	Ensure that control cabinets are adequately secured per seismic or other requirements.	A	21	Seismic analysis done in response to GL 88-20 included identification of cost-beneficial seismic modifications. These are being addressed within the SQUG.
161	Ensure that compressed gas, gas, propane, or tanks containing other flammable/ combustible fluids are adequately secured per seismic or other requirements.	A	21	Seismic analysis done in response to GL 88-20 included identification of cost-beneficial seismic modifications. These are being addressed within the SQUG.
162	The angle frame around the cover plate for valves CV-2233, CV-2234, CV-2214 must be widened to accommodate more movement.	B	21	Specific to ANO-1; therefore, not applicable to FCS.
163	Adequate clearance for motor-operated valve CV-3851 must be verified.	B	21	Specific to ANO-1; therefore, not applicable to FCS.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
164	Additional flexibility in the power cable for CV-3850 must be provided.	B	21	Specific to ANO-1; therefore, not applicable to FCS.
165	Further investigate the calculated value for high confidence of low probability of failure (<0.3f) for the Emergency Diesel Fuel Tanks (T-57A and T-57B).	A	21	Seismic analysis done in response to GL 88-20 included identification of cost-beneficial seismic modifications. These are being addressed within the SQUG.
166	Add scuppers to the parapet walls of the roof structures to limit the amount of water that can build up.	A	21	Compliance with the design basis of the plant provides sufficiently low risk.
167	Separate non-vital buses from vital buses.	C	22	Negligible risk reduction and large anticipated cost.
168	Make component cooling water trains separate.	C	22	Negligible risk reduction and large anticipated cost.
169	Make intermediate cooling water trains separate.	C	22	Negligible risk reduction and large anticipated cost.
170	Provide a motor-operated auxiliary feedwater pump.	E	22	See SAMA No. 151.
171	Provide containment isolation design per General Design Criteria and Standard Review Plan.	C	22	Addressed through design basis; further improvements determined to be cost prohibitive.
172	Improve residual heat removal sump reliability.	D	22	Minimal risk reduction.
173	Provide Auxiliary Building Vent/Seal structure.	C	22	Iodine retention in AB considered in plant-specific FCS fixes. Sealing AB at FCS considered not cost beneficial.

TABLE 5.3-1 (CONTINUED)
INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
174	Add charcoal filters on Auxiliary Building exhaust.	B	22	FCS does not have a secondary containment.
175	Add penetration valve leakage control system.	D	22	Penetration leakage is not a significant contributor to LERF.
176	Enhance screen wash.	D	22	Wash does not significantly reduce CDF or LERF.
177	Enhance training for important operator actions.	D	22	Operator actions have been highlighted in FCS PRA model-associated training; therefore, operator actions are not likely to measurably reduce the probabilities of failure.
178	Enhance tornado protection for tanks, pumps, switchgear, or other equipment/rooms that may not have protection or that may be susceptible to tornadoes in category F2.	A	23	Most equipment important to severe accident risk is located inside buildings. The CST and HVAC units have been evaluated for severe weather vulnerability.
179	Man safe shutdown valve continuously to align Coolant Makeup System for reactor coolant pump seal cooling.	B	23	Equivalent component not available at FCS.
180	Replace reactor vessel with stronger vessel.	C	23	RV failure probability is low (less than 10E-07 per year). RV replacement would be very costly.
	Ft. Calhoun Station Unit 1-specific SAMAs			
181	Add accumulators or implement training on SIRWT bubblers and recirculation valves.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
182	Add capability for steam generator level indication during an SBO.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.

TABLE 5.3-1 (CONTINUED)

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition
183	Add 480 VAC power supply to open the PORV.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
184	Add capability to flash the field on the EDG to enhance SBO recovery.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
185	Remove SI-2C from auto-start.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
186	Add manual steam relief capability and associated procedures.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
187	Enhance operation of FW-54.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
188	Enhance external flood procedures.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
189	Add TSP into Auxiliary Building.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.
190	Enhance EOPs to provide guidance to operators to better avert TI-SGTR.	F	FCS	Considered in cost-benefit evaluation. See Section 4.16 of the main report and Appendix Section 5.4.

TABLE 5.3-1 (CONTINUED)

INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE FCS SAMA ANALYSIS[a]

SAMA No.	Potential Enhancement	Screening Criterion[b]	Reference Source	Disposition

a. Acronyms used in Table 5.3-1 are defined in Section 5.6. Numbers provided as reference sources correspond to references listed for Section 5.3 in the reference list presented in Section 5.5.

b. Screening Criteria:
A – Already Implemented
B – Does Not Apply
C – Excess Cost
D – Minimal Risk Reduction
E – Duplicate
F – Further Evaluation

5.4 SAMA EVALUATION SUMMARIES

This section includes an evaluation summary for each of the 20 Severe Accident Mitigation Alternatives (SAMAs) Omaha Public Power District (OPPD) evaluated in the cost-benefit analysis. Each summary includes a Fort Calhoun Station Unit 1-(FCS-) specific description of the candidate SAMA, a discussion of the potential benefits, a summary of the evaluation and resulting benefits, and discussion of the associated costs.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 4
CATEGORY: Improvements Related to the Mitigation of RCP Seal LOCA
TITLE: Implement procedure and operator training enhancements for support-system failure sequences, with emphasis on anticipating problems and coping with events that could lead to loss of cooling to the RCP seals

Description:
This SAMA would provide procedural changes and associated operator training for coping with events that could lead to loss of cooling to reactor coolant pump (RCP) seals. Operator actions to be added potentially include: (1) directions for operators to control reactor coolant system (RCS) cooling on the reactor cold leg to >50 deg F; and (2) directions for operators to fully isolate controlled bleed off (CBO) (including potential excess flow relief valves) following events that could lead to loss of RCP seal cooling.

SAMA Benefits:
This SAMA potentially improves the ability of the operator to minimize the probability of incurring a loss of seal cooling. Byron Jackson (BJ) pump seals have a greater probability of failure when subcooling in the seal stages is decreased. The ability to control subcooling will minimize seal stage heatup, increase pressure, and subsequently increase subcooling of downstream seal stages.

Evaluation:
The impact of this SAMA was evaluated by assuming that all core damage events associated with loss of component cooling water (LOCCW) initiators and those associated with station blackouts (SBOs) with induced RCP seal failures will be eliminated from the plant core damage frequency (CDF). Using the Rev. 3 CDF as a basis, the CDF would decrease by 1.10E-06 per year. The population dose would decrease by 0.24 person-rem per year.

Cost of Implementation:
Analysis would need to be performed to provide the bases for the procedure changes. Procedure changes to the Emergency Operating Procedures (EOPs) would need to be made and training for the operators would be required. After initial training on the procedures, the operators would be trained in the existing training regime. The cost of this alternative is expected to be less than $30K. OPPD will continue to monitor industry developments.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 9
CATEGORY: Improvements Related to the Mitigation of RCP Seal LOCA
TITLE: Install an additional service water pump

Description:
The Raw Water (RW) System and Component Cooling Water (CCW) System are subsystems within the FCS Service Water System. This SAMA assumes that a swing pump will be installed in the FCS RW System. To increase the pump's capabilities and reliability, the pump will be procured such that no common-cause failure link exits between the new and existing RW pumps. The RW pump will be designed such that the swing pump will automatically align to the service water header without an operating pump.

SAMA Benefits:
The addition of an independent RW pump will increase the reliability of RW System backup in the event of an LOCCW event. Consequently, availability of the RW System will limit the potential impact of LOCCW events.

Evaluation:
The impact of this SAMA change was optimistically evaluated by assuming that all core damage events associated with an LOCCW can be eliminated. Elimination of LOCCW events would decrease the plant CDF by 7.0E-07 per year. This would result in a reduction in population dose exposure of 0.145 person-rem per year.

Cost of Implementation:
Addition of a swing pump to the RW System is a major project. The cost of a safety-related (SR) RW pump, volute, and 400 horsepower (hp) Westinghouse motor at Calvert Cliffs Nuclear Power Plant (CCNPP) is about $460K. In addition, each header would have to be modified to accept the swing pump piping, system piping, valves, supports, SR power supply to the motor with diesel back-up capability, and pump and valve control logic and circuitry. The estimated costs are expected to exceed $460K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 10
CATEGORY: Improvements Related to the Mitigation of RCP Seal LOCA
TITLE: Install the improved N 9000 reactor coolant pump seals

Description:
This SAMA will replace the current BJ RCP seal with a newer version ("N") seal. The replacement seal is an enhanced RCP seal design that is more resistant to temperature-induced RCP seal failures. This improved performance is a result of the replacement of the Nitril "U" cup with an ethylene propylene rubber seal of an improved hydrodynamic design.

SAMA Benefits:
The "N" seal will improve seal performance during normal operation, as well as, during plant upsets. The "N" seal has been specially tested under plant SBO conditions (including effects of shaft motion) for a period of 8 hours.

Evaluation:
The risk benefits are bounded by the risk benefits of SAMA No. 4. That is, the "N" seal is assumed to reduce CDF (due to decreased probability of induced RCP seal failures) by 1.10E-06 per year and decrease population dose by 0.24 person-rem per year.

Cost of Implementation:
One replacement BJ N 9000 RCP seal costs $400K. Material costs alone exceed $2M.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 41
CATEGORY: Improvements Related to the Mitigation of RCP Seal LOCA
TITLE: Use FP System as back-up source for the CS System

Description:
This SAMA involves upgrading the Fire Protection (FP) System and constructing a hard-pipe connection to the Containment Spray (CS) System. The FP System utilizes a diesel-powered pump and will, therefore, be available during SBO events. Procedures for implementation would be included in the FCS Severe Accident Mitigation Guidelines (SAMG).

SAMA Benefits:
This upgrade would add additional redundancy for achieving Containment Heat Removal (CHR) during a severe accident. Currently, CHR is supported by containment sprays or containment air recirculation coolers.

Evaluation:
Availability of the FP System for CHR is assumed to reduce all late containment failures to zero. There is no associated impact on the CDF, and the population dose would decrease by 0.86 person-rem per year.

Cost of Implementation:
This alternative would require a piping modification and design evaluation, including analysis of the pipe layout and seismic supports. System operating characteristics would also be closely reviewed. Procedure changes would be needed, as well as training. Assuming a minimum cost of $70K for a hardware modification, implementation costs would greatly exceed the benefit.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 52
CATEGORY: Improvements in Identifying/Coping with Containment Bypass
TITLE: Provide additional DC battery capacity

Description:
Install additional batteries to extend 125 volts direct current (VDC) battery life to 24 hours.

SAMA Benefits:
This upgrade would increase the capability of the plant to cope with SBO events. By extending the battery life to 24 hours, the opportunity for power recovery is increased and alternative coping strategies can be established.

Evaluation:
The evaluation of longer battery life calculates the post-SAMA CDFs by eliminating core damage due to long-term battery depletion. This assumes all late SBOs are fully recoverable (full recovery). This results in a 20 percent reduction in CDF (change in CDF of 4.2E-06 per year). Assuming the release classes would be divided into containment bypass and late containment failures (10 percent bypass and 90 percent late), bypass events are assumed to result from a thermally induced steam generator tube rupture (TI-SGTR). The resulting population dose reduction would be 1.22 person-rem per year.

Cost of Implementation:
The scope of this modification includes the purchase of new battery strings at a cost of approximately $100K for a string of 12 yielding 120 amps. Modifications to the storage racks and potential modification to the battery room would cost an additional $60K per string. Design analysis costs for installation of an additional string would be minor, on the order of $50K. To triple the life of the battery by expansion would require a new structure to house the additional batteries, driving the cost to the $8M level. The batteries alone would cost over $2M. CCNPP estimated $3.5M to double the batteries, changing the configuration from a 4-hour to an 8-hour design. The estimated cost well exceeds the benefit.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 54
CATEGORY: Improvements in Identifying/Coping with Containment Bypass
TITLE: Incorporate an alternate battery charging capability

Description:
Add independent power supply (20-kilowatt DC source) to charge batteries.

SAMA Benefits:
This upgrade would increase the capability of the plant to cope with SBO events. By extending the battery life to 24 hours the opportunity for power recovery is increased and alternative coping strategies can be established.

Evaluation:
The evaluation of longer battery life calculates the post-SAMA CDFs by eliminating core damage due to long-term battery depletion. This assumes all late SBOs are fully recoverable (full recovery). This results in a 20 percent reduction in CDF (change in CDF of 4.2E-06 per year). Assuming the release classes will be divided into containment bypass and late containment failures (10 percent bypass and 90 percent late), bypass events are assumed to result from a TI-SGTR. The resulting population dose reduction would be 1.22 person-rem per year.

Cost of Implementation:
The scope of this modification includes the purchase of a dedicated 20-kilowatt diesel power supply. Associated housing, fuel supply, and monitoring equipment would also have to be acquired. Implementation would require revisions to existing plant operating and maintenance procedures and operator training. OPPD estimates the cost of implementation to exceed $150K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 56
CATEGORY: Improvements in Identifying/Coping with Containment Bypass
TITLE: Increase/improve DC busload shedding

Description:
Improve 125 VDC busload management to allow the 125 VDC batteries to last for 24 hours.

SAMA Benefits:
This upgrade would increase the capability of the plant to cope with SBO events. By extending the battery life to 24 hours the opportunity for power recovery is increased and alternative coping strategies can be established.

Evaluation:
The evaluation of longer battery life calculates the post-SAMA CDFs by eliminating core damage due to long-term battery depletion. This assumes all late SBOs are fully recoverable (full recovery). This results in a 20 percent reduction in CDF (change in CDF of 4.2E-06 per year). Assuming the release classes will be divided into containment bypass and late containment failures (10 percent bypass and 90 percent late), bypass events are assumed to result from a TI-SGTR. The resulting population dose reduction would be 1.22 person-rem per year.

Cost of Implementation:
FCS is an 8-hour plant for battery life during an SBO. It is estimated to take 1,500 to 2,000 man-hours of design work to review the DC loads and the SBO calculations and load requirements, perform battery sizing calculation reviews, and determine the impact of shedding loads to extend the battery life to 24 hours (approximately $160,000). Revisions to the EOPs and associated operator training would have to be performed to allow the operator to manually shed loads during an SBO. The likelihood of being able to manage the battery load for 24 hours is very small. When the probability of success is applied to the estimated benefit, the implementation costs are expected to well exceed the benefit.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 60
CATEGORY: Improvements in Identifying/Coping with Containment Bypass
TITLE: Develop procedures to repair or replace failed 4 kV breakers

Description:
This SAMA includes the enhancement of procedures for recovery of a failed 4 kiloVolt (kV) transfer breaker and associated operator training. The enhancement can improve the reliability of offsite power to equipment or the associated bus.

SAMA Benefits:
This SAMA would offer a recovery path from a failure of breakers that perform transfer of 4.16 kV non-emergency buses from unit station service transformers to system station service transformers, leading to loss of emergency alternating current (AC) power (i.e., in conjunction with failures of the diesel generators).

Evaluation:
The evaluation assumed setting Basic Events ECBD1A11, ECBD1A31, ECBD1A22, and ECBD1A42 at zero. No changes in CDF or population dose were noted.

Cost of Implementation:
No benefit is associated with implementation; therefore, associated cost was not evaluated.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 88
CATEGORY: Improvements in Identifying/Coping with Containment Bypass
TITLE: Ensure all ISLOCA releases are scrubbed

Description:
Develop procedures and install systems such that every possible interfacing system loss-of-coolant accident (ISLOCA) path would undergo scrubbing.

SAMA Benefits:
ISLOCA events can potentially release large quantities of fission products directly to the environment. This SAMA would provide systems and/or procedures to ensure that all bypass releases due to ISLOCAs would be reduced.

Evaluation:
The evaluation assumed all ISLOCA sequences are scrubbed, reducing the associated releases by a factor of 5. As the progression of the ISLOCA event is unaltered, no change in CDF would result. The evaluation indicates that a reduction in the population dose of 1.30 person-rem per year could be obtained.

Cost of Implementation:
To ensure every leak path is scrubbed, multiple systems would have to be custom designed for the individual location of each vent. It is estimated that to determine the best design for each individual situation and to modify the system would cost $500K for each potential vent path. Significant effort would have to be expended to scope these modifications.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 92
CATEGORY: Improvements in Identifying/Coping with Containment Bypass
TITLE: Conserve/makeup Borated Water Storage Tank inventory post accident

Description:
Modify procedures to conserve or prolong the inventory in the Borated Water Storage Tank (Safety Injection Refueling Water Storage Tank, or SIRWT) during SGTRs. At FCS this SAMA would be implemented by providing procedures to refill the SIRWT with borated water and ensuring that the necessary boration and water sources are available.

SAMA Benefits:
An increased supply of borated water would reduce the potential for a SGTR to result in core damage. Revision 3 of the FCS probabilistic risk assessment (PRA) model conservatively assumes that once the initial SIRWT inventory is depleted the event will progress to core damage.

Evaluation:
The evaluation assumed procedures and additional sources of borated water would eliminate failures associated with depletion of the SIRWT inventory during ISLOCAs and SGTRs. The resulting improvement in plant CDF would be a reduction of approximately 5.8E-06 per year, and the resulting population dose reduction would be 1.66 person-rem per year.

Cost of Implementation:
With the assumption that no hardware modifications would be required, enhancing the guidance to replenish the tank and providing the associated training is expected to cost less than $30K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 181 (page 1 of 2)
CATEGORY: FCS-Specific SAMAs
TITLE: Add accumulators or implement training on SIRWT bubblers and recirculation valves

Description:
This SAMA would involve adding the capability to prevent an early Recirculation Actuation Signal (RAS) following the loss of instrument air. Depletion of the SIRWT bubblers will result in a low-level indication in the SIRWT and cause a premature RAS. This may cause the Emergency Core Cooling System (ECCS) and spray pumps to take suction from a sump with inadequate net positive suction head (NPSH). Pump damage and failure are possible.

The options considered by this SAMA are: (1) procurement and installation of additional accumulators to extend the instrument measurement time; (2) replacement of the existing accumulators with larger ones; or (3) implementation of procedural guidance (and the associated engineering analyses and training) to support operator actions to avert and/or recover from the premature RAS.

SAMA Benefits:
This SAMA would significantly reduce the potential for a premature RAS resulting from the depletion of the SIRWT level indication air bubblers. Currently the bubblers will last 13 hours. Several events, such as SGTRs and smaller LOCAs, may require extended feeding from the SIRWT. Extending the capability of the bubblers and/or increasing the guidance documents (EOPs /AOPs) to alert the operator to the potential inadvertent RAS will reduce the potential for or mitigate the consequences of premature RAS.

Evaluation:
The impact of this SAMA was modeled by assuming that the air supply to the bubblers will always be available. This resulted in a CDF reduction of 4.2E-06 per year. Assuming that these events will all result in late containment failures, the estimated reduction in the population dose would be 0.36 person-rem per year.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 181 (page 2 of 2)
CATEGORY: FCS-Specific SAMAs
TITLE: Add accumulators or implement training on SIRWT bubblers and recirculation valves

Cost of Implementation:
SR Instrument Air (IA) System consumption and capacity calculations would be performed as part of the modification package. A design modification to install a larger accumulator would be required, assuming the larger accumulator and regulator would fit in the same footprint as the original. If custom equipment is necessary, procurement of a larger SR accumulator and regulator to fit the location may be an added expense. Changing operator actions and the supporting design analysis to avert and recover from a premature RAS would cost about $40K and should be analyzed separate from the larger accumulator changeout option. The accumulator modification would cost about $120K. Economies in the design and analysis costs could be realized between the procedure changes and the modification. Estimated costs are expected to exceed $150K.

As an alternative, enhancing the guidance to alert operators on available time before onset of a premature RAS would involve minimal costs. OPPD estimates these costs to be less than $30K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 182
CATEGORY: FCS-Specific SAMAs
TITLE: Add capability for SG level indication during an SBO

Description:
This SAMA is intended to increase the capability of a plant to cope with an SBO event by extending the steam generator (SG) level indication. Inadequate level indication may cause SG overfeed, which can potentially drive liquid into FW-10 [the turbine-driven auxiliary feedwater (AFW) pump]. Other plants have used portable 120-volt AC (VAC) generators with manual clamps to provide the power supply to the level instrumentation.

SAMA Benefits:
Reliable feeding of the SG following an SBO will enable the plant to keep inventory in the SG, increase the reliability of the turbine-driven AFW pump, and, consequently reduce the likelihood of SG dryout.

Evaluation:
This SAMA was evaluated by assuming all SBOs that were not predicted to have induced RCP seal failure would be eliminated. This results in a CDF reduction of approximately 4.1E-06 per year. The resulting reduction in population dose was calculated to be 0.37 person-rem per year.

Cost of Implementation:
A power supply could be provided on a “crash cart” that could be used in various applications beyond that described above. A design modification package would need to be prepared. The equipment required would include a 120 VAC generator, inverters, and cables. Equipment modification may also be required to facilitate quick installation. EOPs would have to be changed and operators trained to respond to this contingency. Estimated hardware and procedure changes are expected to cost less than $30K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 183
CATEGORY: FCS-Specific SAMAs
TITLE: Add 480 VAC power supply to open the PORV

Description:
This SAMA would provide a portable power source, inverter, associated implementing cables, and necessary operating and implementation instructions for use as a backup power supply for opening the power-operated relief valve(s) [PORV(s)]. Guidance for use of this backup supply will be provided in the FCS SAMG.

SAMA Benefits:
This SAMA is primarily directed at mitigating severe accident releases following a core damage event with RCS release paths (or potential release paths) to the environment. These events include ISLOCAs and some SGTRs. Opening a PORV during a core damage event would reduce the potential for a TI-SGTR, lower RCS pressure while potentially averting a high-pressure melt ejection challenge to the Containment, and retain RCS fission products within the Containment.

Evaluation:
As this is intended for post-core damage implementation, no credit was taken for the use of the PORV in averting core damage. The post-core damage impact was assessed by assuming that all SGTRs that resulted in direct releases to the environment (due to loss of secondary-side isolation) were assumed to go to zero. This results in no change to the CDF, and a population dose reduction of 0.79 person-rem per year.

Cost of Implementation:
The equipment associated with this SAMA would not be SR. Procedure changes and training to implement this modification would also have to be developed. The estimated costs for both the hardware and procedure changes are expected to be less than $25K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 184
CATEGORY: FCS-Specific SAMAs
TITLE: Add capability to flash the field on the EDG to enhance SBO recovery

Description:
This SAMA is intended to increase the capability of FCS to cope with an SBO event when one or more emergency diesel generator (EDG) fails to start or an EDG failure occurs and restart is required after battery depletion. This SAMA would require hardware modification and operational changes. The hardware modification includes the addition of a power supply to flash the field. Operational changes include the development of procedures for restoring the affected EDGs to operability and the associated operator training.

SAMA Benefits:
This SAMA enhances EDG recovery for SBO accident sequences involving the unavailability of one or more EDG following a loss of offsite power event. This SAMA will enhance safety by reducing the probability of core damage due to certain SBO events.

Evaluation:
This SAMA was assessed by assuming that (1) 20 percent of the mechanical failures of the EDGs would be recoverable, and (2) 15 percent of the battery-related failures (which prevented the EDG startup) would be recoverable. The resulting CDF reduction was estimated to be approximately 6.4E-06 per year. The population dose reduction was 0.544 person-rem per year.

Cost of Implementation:
Similar to SAMA No. 182, a power supply could be provided on a “crash cart” that could be used in various applications beyond that described above. A design modification package would need to be prepared. The equipment required would include a power supply and cables. Equipment modification may also be required to facilitate quick installation. EOPs would have to be changed and operators trained to respond to this contingency. Estimated hardware and procedure changes are expected to cost less than $30K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 185
CATEGORY: FCS-Specific SAMAs
TITLE: Remove SI-2C from auto-start

Description:
This SAMA involves making the necessary electrical changes (including appropriate documentation) to remove the auto-start capability for SI-2C. This modification will probably require alarm changes to prevent a control board alarm with the pump in "pull-to-lock." It will also require EOP changes and associated operator training.

SAMA Benefits:
SI-2C is the designation for the station's spare high pressure safety injection (HPSI) pump. Currently SI-2C will initiate pumping action upon receipt of a safety injection actuation signal (SIAS). In the event of RAS failures, all safety injection (SI) pumps may fail simultaneously. Removing SI-2C from auto-start enhances safety by reducing the probability of an accident that could cause radiation exposure to the public. This is accomplished by removing the common-cause coupling between the pumps that occurs due to challenges like inadvertent RAS failures.

Evaluation:
This SAMA was assessed by removing the RAS dependency on SI-2C. The CDF was reduced by 2.4E-06 per year. The population dose reduction was calculated to be 0.20 person-rem per year.

The risk reduction is dominated by preventing accidents that could fail all HPSI pumps (e.g., RAS occurring at the wrong time; heating, ventilation, and air-conditioning (HVAC) problems, flooding issues). Operation of fewer HPSI pumps also improves pressurized thermal shock (PTS) concerns and reduces the severity of overcooling transients.

Cost of Implementation:
This modification will require design input to identify the wiring changes and control panel modifications. The hardware modifications are estimated to cost less than $50K. In addition to modification cost, licensing activities would also be associated with this modification. Implementation of this SAMA would require a Technical Specification change, given all three pumps are required to be operable. EOP changes and associated operator training would also need to be performed. OPPD estimates the cost of this project is to be approximately $90K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 186
CATEGORY: FCS-Specific SAMAs
TITLE: Add manual steam relief capability and associated procedures

Description:
This SAMA involves performing specific procedural and/or hardware changes to give the plant the alternate capability to increase heat removal from the RCS and accelerate RCS cooldown. Introducing an alternate cooldown pathway will increase the capability of the plant to cope with ISLOCAs, SGTRs, and long-term SBOs.

This modification is designed to facilitate reducing RCS temperature and pressure to mitigate ISLOCAs and RCS SGTRs. ISLOCAs are often complicated by equipment failures due to flooding in the AB, which preclude normal cool down methods such as HCV-1040 or steam dump and bypass. This modification may involve nitrogen backup to open the Main Steam (MS) valves, MS-291 and -292 (and leave them open) while continuing to feed both steam generators. This would also facilitate rapid RCS temperature reduction to preclude RCP seal LOCAs during prolonged SBO.

SAMA Benefits:
These changes would both avert core damage and reduce potentially high releases of radioactivity by extending the time until core uncovery following an SBO-induced RCP seal LOCA. Efficient depressurization of the RCS to below 200 pounds per square inch atmospheric (psia) may terminate the small ISLOCA. RCS heatups that result from SGTRs may also be cooled down more quickly, allowing the potential for reaching safe shutdown cooling (SDC).

Evaluation:
The evaluation assumed a 20 percent reduction in SGTR core damage frequency and elimination of the small ISLOCA sequences. The net reduction in CDF was 6.0E-07 with a population dose reduction of 1.28 person-rem per year.

Cost of Implementation:
A number of low-cost modifications could be implemented to achieve the stated benefit. For the purposes of this analysis, implementation would involve minor hardware costs associated with nitrogen backup. Procedure changes and training would also have to be performed. OPPD estimates the implementation costs to be less than $40K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 187
CATEGORY: FCS-Specific SAMAs
TITLE: Enhance operation of FW-54

Description:
This SAMA is intended to enhance the operability of the diesel-driven AFW, FW-54. There are two low-cost opportunities for improving the operation of FW-54. The first is to increase the Day Tank low-level alarm setpoint to increase the time between receipt of the low-level alarm and emptying of the tank. The second is to devise the optimum strategy for use of the diesel protection bypass switch. A determination should be made whether it is better to leave the protective trips bypassed during normal operation or enabled during normal operation. Procedural changes are also included for enhancing the operability of FW-54. These changes involve the development of provisions and procedures for refilling the Day Tank and restarting FW-54 when the Day Tank is replenished.

SAMA Benefits:
This SAMA enhances the reliability of FW-54. Consequently, the probability of accidents involving the loss of secondary heat removal, which could cause releases to the public, is reduced. The reduction in risk is shown below.

Evaluation:
The evaluation assumes FW-54 will never fail. The core damage sequences averted typically result in late containment failures. The CDF reduction is 6.0E-07 per year with a reduction in population dose of 0.05 person-rem per year.

Cost of Implementation:
The first part of the modification is to change the setpoint on the Day Tank low-level alarm. It will cost about $10K to provide the engineering justification, paper work changes, and implementation tasks associated with this change. Determining a strategy for the use of the diesel protection bypass switch and implementing the associated procedure changes will exceed the $30K minimum cost of procedure changes. With these considerations, the implementation cost is expected to exceed $40K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 188
CATEGORY: FCS-Specific SAMAs
TITLE: Enhance external flood procedures

Description:
This SAMA includes hardware or procedural changes to enhance the plant response to external flooding. The hardware enhancements involve: (1) provisions for adding a redundant portable pump to feed the SGs; and (2) upgrading the existing portable pumps to account for equipment diversity and increased pumping capacity, with supporting analysis. The consideration of strategies to utilize the pumps for long-term mitigation is included. A strategy for filling the Containment basement with water to assist in the scrubbing of fission products is also included in this SAMA. The associated procedure revisions and operator training for utilizing the portable pumps to feed the SGs on a long-term basis are also included as part of the enhancement.

SAMA Benefits:
By making the hardware addition and/or enhancing the external flooding procedures, the CDF due to external flooding is expected to be reduced by a factor of two or more.

Evaluation:
The CDF for external floods could be reduced by 50 percent, from the current value of 1.3E-06 per year to 6.5E-07 per year. The population dose reduction would be less than 0.01 person-rem per year.

Cost of Implementation:
Assuming the minimum cost is $70K for a hardware modification, implementation costs are expected to well exceed the benefit.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 189
CATEGORY: FCS-Specific SAMAs
TITLE: Add TSP into Auxiliary Building

Description:
Trisodium Phosphate (TSP) is utilized in containment sumps to maintain the sump water pH above 7. pH control will provide for long-term retention of dissolved iodine in the sump water. The intent of this SAMA is to procure and store extra TSP for use in the Auxiliary Building (AB) in the event of an ISLOCA. The TSP will be placed in the vicinity of the ISLOCA locations so that evolution of iodines from the AB sump water will be reduced.

SAMA Benefits:
By retaining a greater portion of iodines in the sump water post-accident, airborne releases would be reduced.

Evaluation:
Placement of TSP has no impact on CDF. It was assumed that ISLOCA releases from the small ISLOCA events would be reduced by a factor of 5. This results in a reduction in population dose of 0.65 person-rem per year.

Cost of Implementation:
In the mid-1990s, three baskets of TSP were installed in the Containment at CCNPP utilizing a modification to an existing design and at a cost of $150K. In this case, new design work would have to be performed; therefore, estimated costs are expected to exceed $200K.

SEVERE ACCIDENT ALTERNATIVE ASSESSMENT SHEET

SAMA No. 190
CATEGORY: FCS-Specific SAMAs
TITLE: Enhance EOPs to provide guidance to operators to better avert TI-SGTR

Description:
Combustion Engineering, Inc. (CE), designed pressurized water reactors (PWRs) have an increased susceptibility to TI-SGTRs. This SAMA would provide additional guidance to the plant operator on averting a TI-SGTR . Changes are to be included in the EOPs. These changes include guidance to not allow complete dryout of the SG and procedures to depressurize the RCS. Such procedures have been implemented by operators at other CE PWRs. Owner's group implementation of changes into CEN-152 is possible.

SAMA Benefits:
Guidance will minimize the likelihood of TI-SGTR. Reduction of these events is significant since they progress to potential core damage events with loss of isolation capability.

Evaluation:
This was evaluated by assuming all SGTR event loss of isolation releases go to zero. No change in CDF is expected. The reduction in population dose is estimated to be 0.24 person-rem per year.

Cost of Implementation:
Estimated costs associated with this SAMA are expected to be at least $30K.

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5.6 LIST OF ACRONYMS USED IN APPENDIX 5

AB	Auxiliary Building
AC	Alternating Current
AFW	Auxiliary Feedwater
ANO-1	Arkansas Nuclear One, Unit 1
AOP	Abnormal Operating Procedure
AOV	Air-Operated Valve
AST	Alternative Source Term
ATWS	Anticipated Transients Without Scram
BJ	Byron Jackson
BWR	Boiling Water Reactor
CARC	Containment Air Recirculation Cooler
CBO	Controlled Bleed Off
CCF	[PRA] Configuration Control Form
CCNPP	Calvert Cliffs Nuclear Power Plant
CCW	Component Cooling Water
CDF	Core Damage Frequency
CE	Combustion Engineering, Inc.
CHR	Containment Heat Removal
CIV	Containment Isolation Valve
COE	Cost of Enhancement
CS	Containment Spray
CST	Condensate Storage Tank
DC	Direct Current
DCF	Dose Conversion Factor
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EP	Emergency Plan
EPIP	Emergency Plan Implementing Procedure

5.6 LIST OF ACRONYMS USED IN APPENDIX 5 (Continued)

FCS	Fort Calhoun Station Unit 1
FGR	Federal Guidance Report
FIVE	Fire-Induced Vulnerability Evaluation
FP	Fire Protection
FW	Feedwater
GIS	Geographic Information System
GL	Generic Letter (NRC)
HP	Horsepower
HPSI	High-Pressure Safety Injection
HVAC	Heating, Ventilation, and Air Conditioning
IA	Instrument Air
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events
ISLOCA	Interfacing System Loss-Of-Coolant Accident
K	Thousand
KV	Kilovolt
LCF	Latent Cancer Fatality
LERF	Large Early Release Frequency
LOCA	Loss-Of-Coolant Accident
LOCCW	Loss of Component Cooling Water
LPSI	Low-Pressure Safety Injection
M	Million
MACCS	Melcor Accident Consequence Code System
MFW	Main Feedwater
MOV	Motor-Operated Valve
MS	Main Steam
MSSV	Main Steam Safety Valve
MW(t)	Megawatts (thermal)
NPSH	Net Positive Suction Head

5.6 LIST OF ACRONYMS USED IN APPENDIX 5 (Continued)

NRC	U.S. Nuclear Regulatory Commission
OI	Operating Instruction
OPPD	Omaha Public Power District
PORV	Power-Operated Relief Valve
PRA	Probabilistic Risk Assessment
PSIA	Pounds per square inch atmospheric
PTS	Pressurized Thermal Shock
PWR	Pressurized-Water Reactor
RAS	Recirculation Actuation Signal
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RRW	Risk Reduction Worth
RV	Reactor Vessel
RW	Raw Water
RWCU	Raw Water Cooling Unit
SAMA	Severe Accident Mitigation Alternative
SAMDA	Severe Accident Mitigation Design Alternative
SAMG	Severe Accident Mitigation Guidelines
SBO	Station Blackout
SDC	(Safe) Shutdown Cooling
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIAS	Safety Injection Actuation Signal
SIRWT	Safety Injection Refueling Water Tank
SO	Standing Order
SQUG	Seismic Qualification Users Group

5.6 LIST OF ACRONYMS USED IN APPENDIX 5 (Continued)

SR	Safety Related
SRV	Safety Relief Valve
TAV	Turbine-Steam Admission Valve
TD	Turbine Driven
TI-SGTR	Thermally Induced Steam Generator Tube Rupture
TSP	Trisodium Phosphate
TVA	Tennessee Valley Authority
V	Volt
VAC	Volt AC
VDC	Volt DC

APPENDIX 6.0 OTHER AGENCY CORRESPONDENCE

DPH = Department of Public Health
NDHHS = Nebraska Department of Health and Human Services
OPPD = Omaha Public Power District

OPPD
Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

August 7, 2001
01-EA-244

Mr. Richard P. Nelson
Director
Nebraska Department of Health and Human Services
P.O. Box 95007
301 Centennial Mall South
Lincoln, NE 68509-5007

SUBJECT: Fort Calhoun Station Unit 1
License Renewal Project

Dear Mr. Nelson:

Omaha Public Power District (OPPD) is preparing an application to renew the operating license for its Fort Calhoun Station Unit 1 (FCS) and we intend the application to be consistent with your agency's interests and the priorities of our community. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify adverse impacts that might be associated with the continued operation of, or refurbishment to, a facility. If discharges are to a small river with an average annual flow rate of less than 3.15×10^{12} cubic feet per year, impact of the proposed action on public health from thermophilic organisms in the affected water is required. FSC discharges cooling water into the Missouri River, which has an average flow of 9.1×10^{11} cubic feet per year in the vicinity of FCS. NRC considers it a small river and so this issue is applicable.

Omaha Public Power District has reviewed this matter and concluded that the Missouri River near Fort Calhoun Station Unit 1 provides poor conditions for supporting populations of pathogenic organisms. Ambient water temperatures vary from 30°F in the winter to 85°F in the summer. Though discharge temperatures at the outfall are at their highest in the summer, averaging 101°F in July and 103°F in August, the rapid mixing characteristics of the Missouri River would result in organisms being exposed to these temperatures in an area limited to within 500 feet of the plant. Any organisms entrained in the condenser cooling water would be subjected to a rapid temperature rise through the condenser followed by cooling as the thermal plume rapidly mixes with the ambient river water. With river flow averaging approximately 5 feet per second, residence time in areas of the plume with temperatures of 95°F or greater would be short and so create an adverse environment for thermal bacteria. In addition, no pathway for significant human exposure exists, considering there is no mechanism for inhalation exposure from aerosol production (such as spray nozzles or cooling towers), and the likelihood of swimming and fishing occurring in the immediate vicinity of the discharge stream preclude both direct contact and ingestion routes.

45-5124 Employment with Equal Opportunity

August 7, 2001
01-EA-244
Page 2

After your review, we would greatly appreciate a letter concurring with OPPD's conclusions. You are welcome to visit the site. A copy of your response will be submitted to the NRC as part of the license renewal application.

If you have any comments or questions, please contact me at (402) 636-2313.

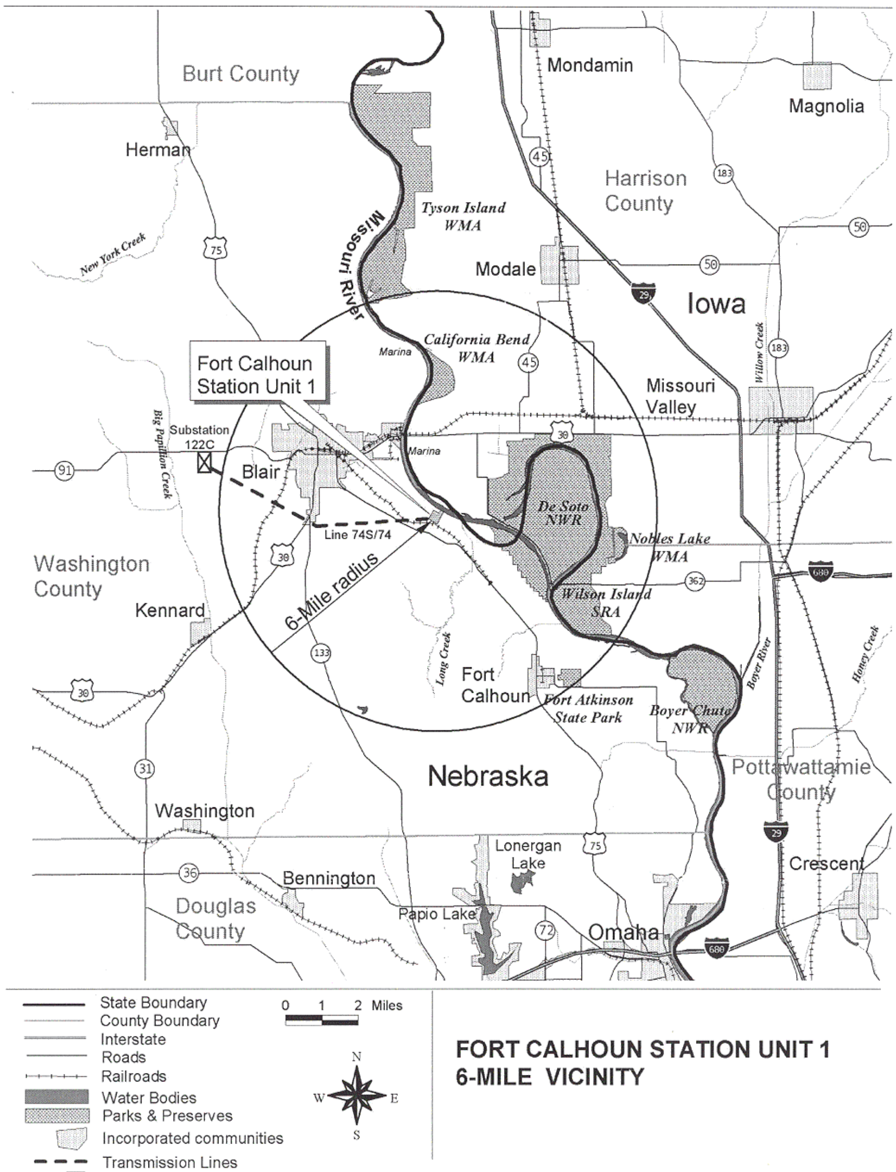
Sincerely yours,

Donovan C. Hutchens

Donovan C. Hutchens
Manager – Environmental and Regulatory Affairs

Attachment

DCH/ses


Burt County
Mondamin
Magnolia
Herman
Harrison County
Tyson Island WMA
Missouri River
New York Creek
Modale
Iowa
California Bend WMA
Marina
Fort Calhoun Station Unit 1
Missouri Valley
Willow Creek
Big Papillion Creek
Substation 122C
Blair
De Soto NWR
Nobles Lake WMA
Line 74S/74
Washington County
6-Mile radius
Wilson Island SRA
Kennard
Long Creek
Boyer River
Honey Creek
Fort Calhoun
Fort Atkinson State Park
Boyer Chute NWR
Nebraska
Pottawattamie County
Washington
Lonergan Lake
Crescent
Bennington
Douglas County
Papio Lake
Omaha
State Boundary
County Boundary
Interstate
Roads
Railroads
Water Bodies
Parks & Preserves
Incorporated communities
Transmission Lines
Substation
0 1 2 Miles
N
W
E
S
FORT CALHOUN STATION UNIT 1
6-MILE VICINITY

OPPD
Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

August 7, 2001
01-EA-243

Mr. Steve Quirk
Division Director Environmental Health
Iowa Department of Public Health
321 East 12 Street
Des Moines, IA 50319

SUBJECT: Fort Calhoun Station Unit 1
License Renewal Project

Dear Mr. Quirk:

Omaha Public Power District (OPPD) is preparing an application to renew the operating license for its Fort Calhoun Station Unit 1 (FCS) and we intend the application to be consistent with your agency's interests and the priorities of our community. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify adverse impacts that might be associated with the continued operation of, or refurbishment to, a facility. If discharges are to a small river with an average annual flow rate of less than 3.15×10^{12} cubic feet per year, impact of the proposed action on public health from thermophilic organisms in the affected water is required. FSC discharges cooling water into the Missouri River, which has an average flow of 9.1×10^{11} cubic feet per year in the vicinity of FCS. NRC considers it a small river and so this issue is applicable.

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Sincerely yours,

Donovan C. Hutchens

Donovan C. Hutchens
Manager – Environmental and Regulatory Affairs

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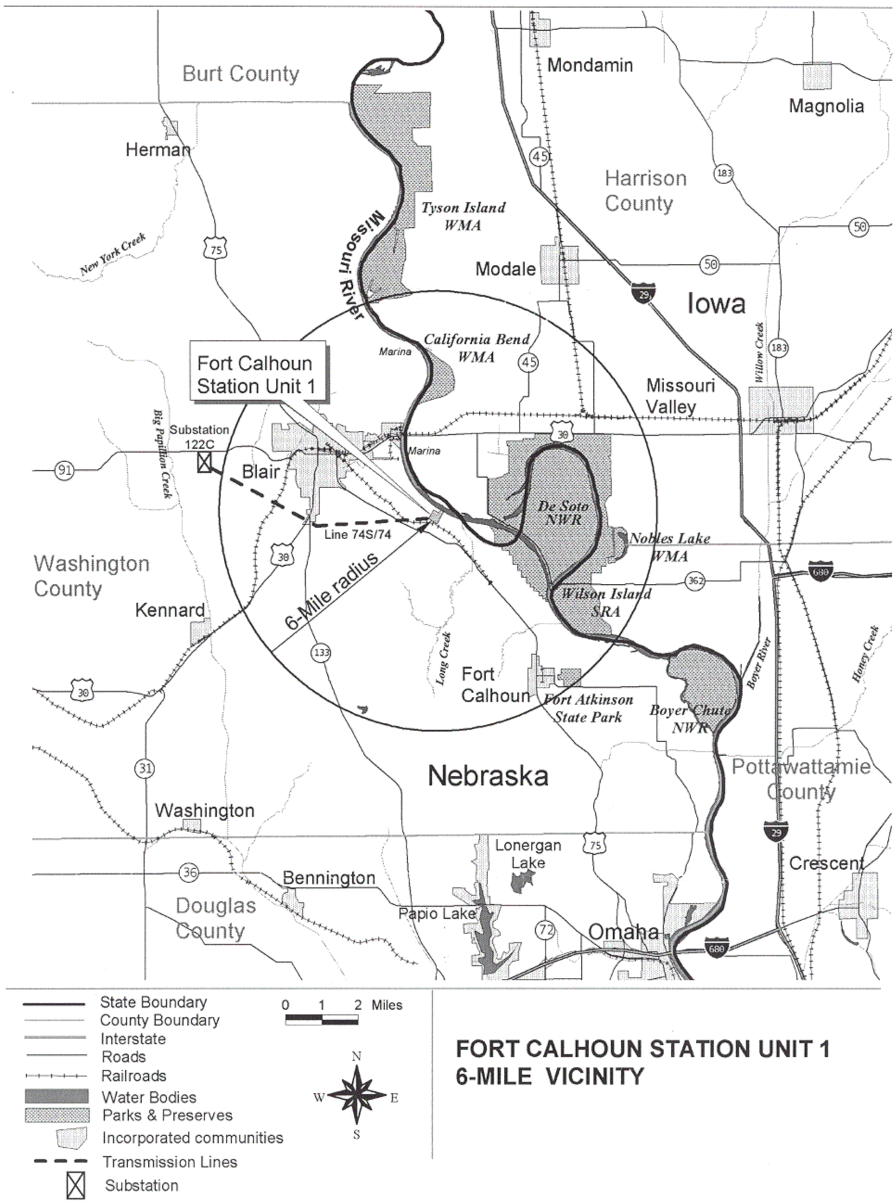

FORT CALHOUN STATION UNIT 1
6-MILE VICINITY