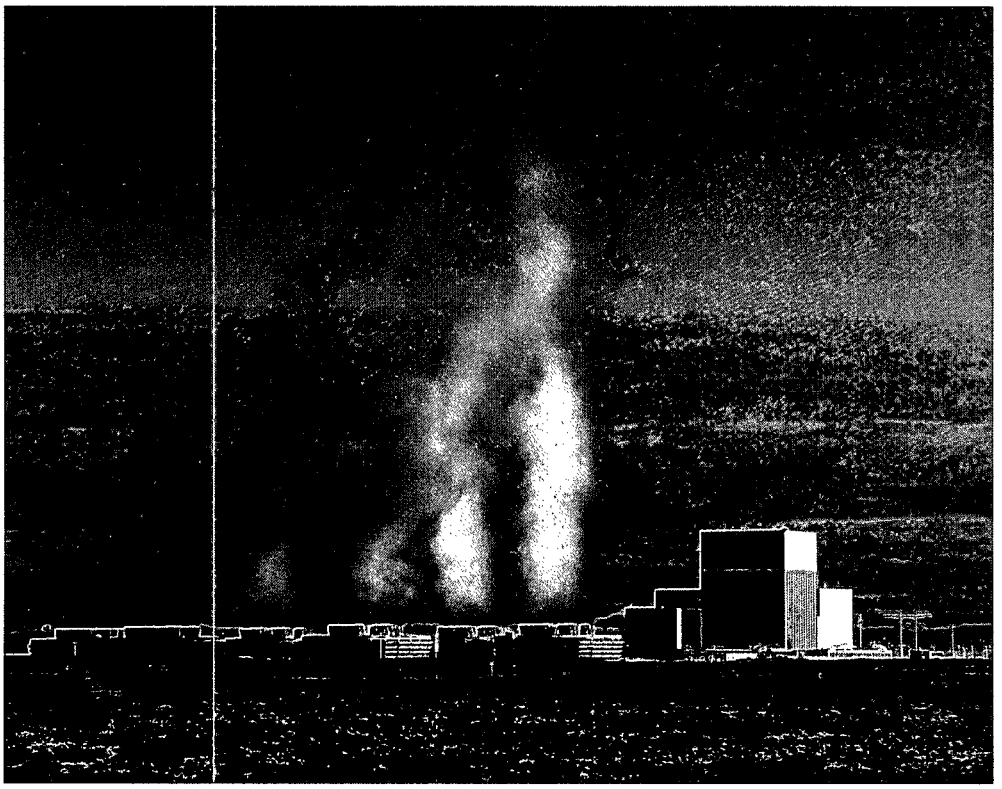
Appendix E

Applicant's Environmental Report
Operating License Renewal Stage

Columbia Generating Station
Energy Northwest

Docket No. 50-397
License No. NPF-21



January 2010

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Acronyms and Abbreviations

AADT	annual average daily traffic
ACOE	Army Corps of Engineers
ARR	Advanced Recycling Reactor
AEC	Atomic Energy Commission
aMW	average megawatt
BP	before present
BLM	Bureau of Land Management
BOR	Bureau of Reclamation
BPA	Bonneville Power Administration
Btu	British thermal unit
BWR	Boiling Water Reactor
°C	degrees Celsius
CDF	core damage frequency
CEQ	Council on Environmental Quality
CET	containment event tree
CFR	Code of Federal Regulations
cfs	cubic feet per second
CGS	Columbia Generating Station
CO	carbon monoxide
CO_2	carbon dioxide
CWA	Clean Water Act
DSM	demand-side management
EFSEC	Energy Facility Site Evaluation Council
EIA	Energy Information Administration
EN	Energy Northwest
EPRI	Electric Power Research Institute
ER	environmental report
ESA	Endangered Species Act
°F	degrees Fahrenheit
FBC	fluidized bed combustor
FERC	Federal Energy Regulatory Commission

Acronyms and Abbreviations
(continued)

FES	Final Environmental Statement
FFTF	Fast Flux Test Facility
fps	feet per second
FSAR	Final Safety Analysis Report
GEIS	Generic Environmental Impact Statement
GNEP	Global Nuclear Energy Partnership
gpd	gallons per day
gpm	gallons per minute
HEPA	high efficiency particulate air
IDC	Industrial Development Complex
IGCC	integrated gasification combined cycle
IPA	Integrated Plant Assessment
ISFSI	independent spent fuel storage installation
kWh	kilowatt-hour
kV	kilovolt
lb	pound
LIGO	Laser Interferometer Gravitational-Wave Observatory
LOS	level of service
mA	milliampere
mgd	million gallons per day
MM	million
MSA	metropolitan statistical area
MSL	(above) mean sea level
MSW	municipal solid waste
MW	megawatt
MWd/MTU	megawatt-days per metric ton uranium
MWe	megawatts-electric
MWh	megawatt-hour
MWt	megawatts-thermal
NAAQS	National Ambient Air Quality Standards
NASS	National Agricultural Statistics Service

Acronyms and Abbreviations
(continued)

NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NESC	National Electrical Safety Code
NMFS	National Marine Fisheries Service
NO_x	nitrogen oxides
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NRFC	Nuclear Fuel Recycling Center
NRC	Nuclear Regulatory Commission
pCi/L	picoCuries per liter
PDS	plant damage state
PEIS	programmatic environment impact statement
PNNL	Pacific Northwest National Laboratory
PM	particulate matter
PM_{10}	particulates with diameters less than 10 microns
$PM_{2.5}$	particulates with diameters less than 2.5 microns
ppt	parts per thousand
PSA	probabilistic safety assessment
PV	photovoltaic
RM	river mile
rms	root mean square
RC	release category
RCW	Revised Code of Washington
SAMA	Severe Accident Mitigation Alternative(s)
SCR	selective catalytic reduction
SHPO	State Historic Preservation Officer
SIP	State Implementation Plan
SMITTR	Surveillance, Monitoring, Inspections, Testing, Trending, and Recordkeeping
SO_2	sulfur dioxide
SO_x	sulfur oxides
TRIDEC	Tri-City Industrial Development Council

Acronyms and Abbreviations
(continued)

TSP	total suspended particulates
USCB	U.S. Census Bureau
USDOE	U.S. Department of Energy
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
WCTED	Washington Department of Community, Trade and Economic Development
WDAHP	Washington Department of Archaeology and Historic Preservation
WDFW	Washington Department of Fish and Wildlife
WDNR	Washington Department of Natural Resources
WDOE	Washington Department of Ecology
WDOR	Washington Department of Revenue
WDOT	Washington Department of Transportation
WESD	Washington State Employment Security Department
WHR	Washington State Historic Register
WNHP	Washington Natural Heritage Program
WNP-1/4	WPPSS Nuclear Projects Nos. 1 & 4
WPPSS	Washington Public Power Supply System
WRCC	Western Regional Climate Center
WSAO	Washington State Auditors Office
WSPI	Washington Office of Superintendent of Public Instruction
WSU	Washington State University

1.0 INTRODUCTION

1.1 PURPOSE OF AND NEED FOR ACTION

The Columbia Generating Station (CGS) Operating License, NPF-21, was granted on December 20, 1983, and will expire on December 20, 2023. Per 10 CFR 50.51, the license allows the plant to operate up to 40 years, and may be renewed for a period of up to an additional 20 years (10 CFR 54.31).

For license renewal, the U.S. Nuclear Regulatory Commission (NRC) has defined the purpose and need for the proposed action as follows:

> *The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by State, utility, and, where authorized, Federal (other than NRC) decision makers.* (**NRC 1996a**, Page 28472)

The proposed action is to renew the CGS license for an additional 20 years of plant operation beyond the current licensed operating period. License renewal would extend the facility operating license to December 20, 2043.

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1.2 ENVIRONMENTAL REPORT SCOPE AND METHODOLOGY

NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled Applicant's Environmental Report - Operating License Renewal Stage. This report fulfills that requirement and is an appendix to the CGS license renewal application.

The requirements regarding information to be included in the environmental report (ER) are codified at 10 CFR 51.45 and 51.53(c). Table 1.2-1 lists the regulatory requirements and identifies the ER sections that respond to the requirements. In addition, affected ER sections are prefaced by a boxed quote of the relevant regulatory language.

The ER has been developed to meet the format and content of Supplement 1 to Regulatory Guide 4.2 (**NRC 2000**). Additional insight regarding content was garnered from the NRC's generic environmental statement for license renewal (**NRC 1996b**).

Table 1.2-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements

Regulatory Requirement	Description	ER Section(s)
10 CFR 51.53(c)(1)	Submit an operating license renewal stage ER.	Entire Document
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)	ER contains descriptions of the environment, the proposed action, and plans to modify the facility or its administrative control procedures as described in accordance with 10 CFR 54.21. ER must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment.	1.1, 2.0, 3.0
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	ER discusses impacts of alternatives.	7.0, 7.2.2, 8.0
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	ER discusses impacts of other matters in 10 CFR 51.45. ER discusses the impact of the proposed action on the environment.	4.0
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	ER discusses any adverse environmental effects which cannot be avoided should the proposal be implemented.	6.3
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	Environmental report discusses the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity.	6.5
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	Environmental report discusses any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.	6.4
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	ER includes analysis that considers and balances environmental effects of the proposed action,	4.0, 6.2
	environmental impacts of alternatives to the proposed action, and	7.2.2
	alternatives available for reducing or avoiding adverse environmental effects.	8.0
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	ER includes a discussion of the status of compliance with applicable environmental standards and requirements imposed by Federal, State, regional, and local agencies.	9.0
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2) and (e)	The information submitted pursuant to 10 CFR 51.45(b) through (e) should not be confined to information supporting the proposed action but should also include adverse information.	4.0, 6.3

Table 1.2-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements
(continued)

Regulatory Requirement	Description	ER Section(s)
10 CFR 51.53(c)(3)(ii)(A)	ER contains an assessment of the impact of proposed action on flow of the river and related impacts on in-stream and riparian ecological communities.	4.1
	ER also contains an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow.	4.6
10 CFR 51.53(c)(3)(ii)(B)	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 are provided, or	4.2, 4.3, 4.4
	an assessment of the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.	4.2, 4.3, 4.4
10 CFR 51.53(c)(3)(ii)(C)	ER contains assessment of the impact on groundwater use.	4.5, 4.7
10 CFR 51.53(c)(3)(ii)(D)	ER contains assessment of the impact on groundwater quality.	4.8
10 CFR 51.53(c)(3)(ii)(E)	ER contains assessment of the impact of refurbishment and other license renewal-related construction activities on important plant and animal habitats, and	4.9
	threatened or endangered species in accordance with the Endangered Species Act.	4.10
10 CFR 51.53(c)(3)(ii)(F)	ER contains assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce.	4.11
10 CFR 51.53(c)(3)(ii)(G)	ER contains assessment of the impact on public health from thermophilic organisms in the affected water.	4.12
10 CFR 51.53(c)(3)(ii)(H)	ER contains assessment of the impact on the potential shock hazard from the transmission lines.	4.13
10 CFR 51.53(c)(3)(ii)(I)	ER contains an assessment of the impact (from refurbishment activities only) on housing,	4.14
	population increases attributable to the proposed project on the public water supply,	4.15
	public schools, and	4.16
	land use.	4.17
10 CFR 51.53(c)(3)(ii)(J)	ER contains assessment of the impact on local transportation during periods of license renewal refurbishment activities and during the term of the renewed license.	4.18

Table 1.2-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements
(continued)

Regulatory Requirement	Description	ER Section(s)
10 CFR 51.53(c)(3)(ii)(K)	ER contains assessment as to whether any historic or archaeological properties will be affected.	4.19
10 CFR 51.53(c)(3)(ii)(L)	ER considers alternatives to mitigate severe accidents.	4.20
10 CFR 51.53(c)(3)(iii)	ER considers alternatives for reducing adverse impacts for all Category 2 license renewal issues.	4.0, 6.2
10 CFR 51.53(c)(3)(iv)	ER contains any new and significant information regarding the environmental impacts of license renewal.	5.0
10 CFR 51, Appendix B, Table B-1, Footnote 6	Environmental justice	4.21

1.3 COLUMBIA GENERATING STATION LICENSEE AND OWNERSHIP

Energy Northwest (EN) is the owner and licensee of the CGS, which was formerly known as Washington Public Power Supply System Nuclear Project No. 2 (WNP-2).

Energy Northwest is a municipal corporation and joint operating agency of the State of Washington. It is comprised of 27 public member utilities from across the state. It is governed by two boards: the Board of Directors, which includes representatives from member utilities, and the Executive Board, which includes representatives from member utilities, gubernatorial appointees, and public representatives selected by the Board of Directors.

In addition to CGS, Energy Northwest owns and operates three other generating stations: Packwood Lake Hydroelectric Project, Nine Canyon Wind Project, and White Bluffs Solar Station. All electrical energy produced by Energy Northwest at CGS is delivered to electrical distribution facilities owned and operated by Bonneville Power Administration (BPA) as part of the Federal Columbia River Power System.

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1.4 REFERENCES

NRC 1996a. Environmental Review for Renewal of Nuclear Power Plant Operating Licenses, Federal Register, Vol. 61, No. 109, June 5, 1996.

NRC 1996b. Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants (GEIS), NUREG-1437, Volumes 1 and 2, Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, May 1996.

NRC 2000. Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses; Supplement 1 to Regulatory Guide 4.2, Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, September 2000.

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2.0 SITE AND ENVIRONMENTAL INTERFACES

This chapter describes the overall character of the Columbia Generating Station (CGS) site and local environment. Its purpose is to portray the plant's setting and the environment affected, with particular attention to information required to address the environmental issues designated by the Generic Environmental Impact Statement (GEIS) (**NRC 1996**) as Category 2. Also included is information related to environmental justice.

2.1 LOCATION AND FEATURES

CGS is located in Benton County, Washington, in Section 5 of Township 11 north, Range 28 east, Willamette Meridian. The CGS site is in the southeastern area of the U.S. Department of Energy (USDOE) Hanford Site, a 586 square mile reservation established in 1943 by the federal government for the production of defense nuclear materials. The CGS site comprises 1,089 acres that are leased by Energy Northwest from the USDOE. The lease describes the site in two parcels – a nearly square section containing the plant power block and associated structures and an elongated area running to the river east of the plant. The lease grants Energy Northwest authority to control activities in an exclusion area (per 10 CFR 100.3) outside the lease boundary.

Nearby communities include Richland approximately 10 miles south, Pasco 18 miles southeast, and Kennewick 21 miles southeast. The nearest residence is 4¼ miles from CGS in an east-southeasterly direction across the Columbia River. Prominent features of the surrounding area out to 50 miles are shown in Figure 2.1-1. The area within six miles is shown on Figure 2.1-2.

The reactor is located at 46° 28' 18" north Latitude and 119° 19' 58" west Longitude. The approximate Universal Transverse Mercator coordinates are 5,148,840 meters north and 320,930 meters east (**EN 2007**, Section 2.1). Figure 2.1-3 shows the site boundaries and exclusion area. Section 3.1 describes key features of CGS, including reactor and containment systems, cooling water system, and transmission system.

The site is situated on a relatively flat plain with slight topographic relief of approximately 20 feet across the plant site. Dominant topographic features in the area include the Rattlesnake Hills, 13 to 15 miles west-southwest, which rise 3,200 feet above the plant site, and the steep river-cut bluffs that form the east bank of the Columbia River, approximately four miles east of CGS.

The site area is a shrub steppe with sagebrush interspersed with perennial native and introduced annual grasses. Notable manmade features within a three-mile radius of CGS include two abandoned power plant construction projects (WNP-1 and WNP-4) located about one mile east-southeast and east-northeast, the Bonneville Power

Administration's H.J. Ashe Substation one-half mile north, and two USDOE facilities – the Fast Flux Test Facility (FFTF) located within the Hanford 400 Area 2¾ miles south-southwest and the 618-11 radioactive waste burial ground immediately west of the plant. Located between three and six miles from CGS are the USDOE 618-10 waste burial ground 3½ miles south of CGS and the Laser Interferometer Gravitational-Wave Observatory (LIGO) 3¼ miles west-southwest. LIGO is a collaborative effort of the California Institute of Technology and Massachusetts Institute of Technology for the study of gravitational waves of cosmic origin (**LIGO 2009**).

Construction of nuclear projects WNP-1 and WNP-4 was started by Energy Northwest in the mid-1970s. Construction was suspended in the early-1980s and the projects were later abandoned. The location of the projects is shown on Figure 2.1-3. The WNP-1/4 site abuts the CGS site and consists of 2,061 acres in two parcels that are leased to Energy Northwest by the USDOE. The site is now referred to as the Industrial Development Complex (IDC). Several IDC facilities (e.g., shops, warehouses, office space) are under lease to USDOE contractors and other commercial entities.

Motor vehicle access to the CGS site is by a three-lane road off the USDOE-owned Route 4S, a four-lane artery located west of the station. State Highway 240, about seven miles southwest of the site, traverses the Hanford Site from the southeast to the northwest (Figure 2.1-1). The USDOE railroad track runs through the CGS site and passes within about 500 feet of the plant on the east side. The track is used infrequently by USDOE and has security barriers north and south of the plant. The nearest scheduled passenger air service is located 17 miles southeast, in Pasco. Section 2.9.4.2 describes local and regional transportation in more detail.

As shown on Figure 2.1-2, a narrow portion of the CGS site is within the Hanford Reach National Monument. The monument is an approximately 195,000-acre reserve carved out of the USDOE Hanford Site by Presidential proclamation in June 2000 (**Clinton 2000**). The arc-shaped area is shown on Figure 2.1-1. In the vicinity of CGS the boundary of the monument is one-quarter mile upland from the Columbia River shoreline. The proclamation provides for the continuing operation and maintenance of existing facilities within the monument area. The U.S. Fish & Wildlife Service (USFWS) is assigned lead responsibility for managing the monument resources.

Figure 2.1-1. Project Area Map, 50-Mile Radius

Figure 2.1-2. Project Area Map, 6-Mile Radius

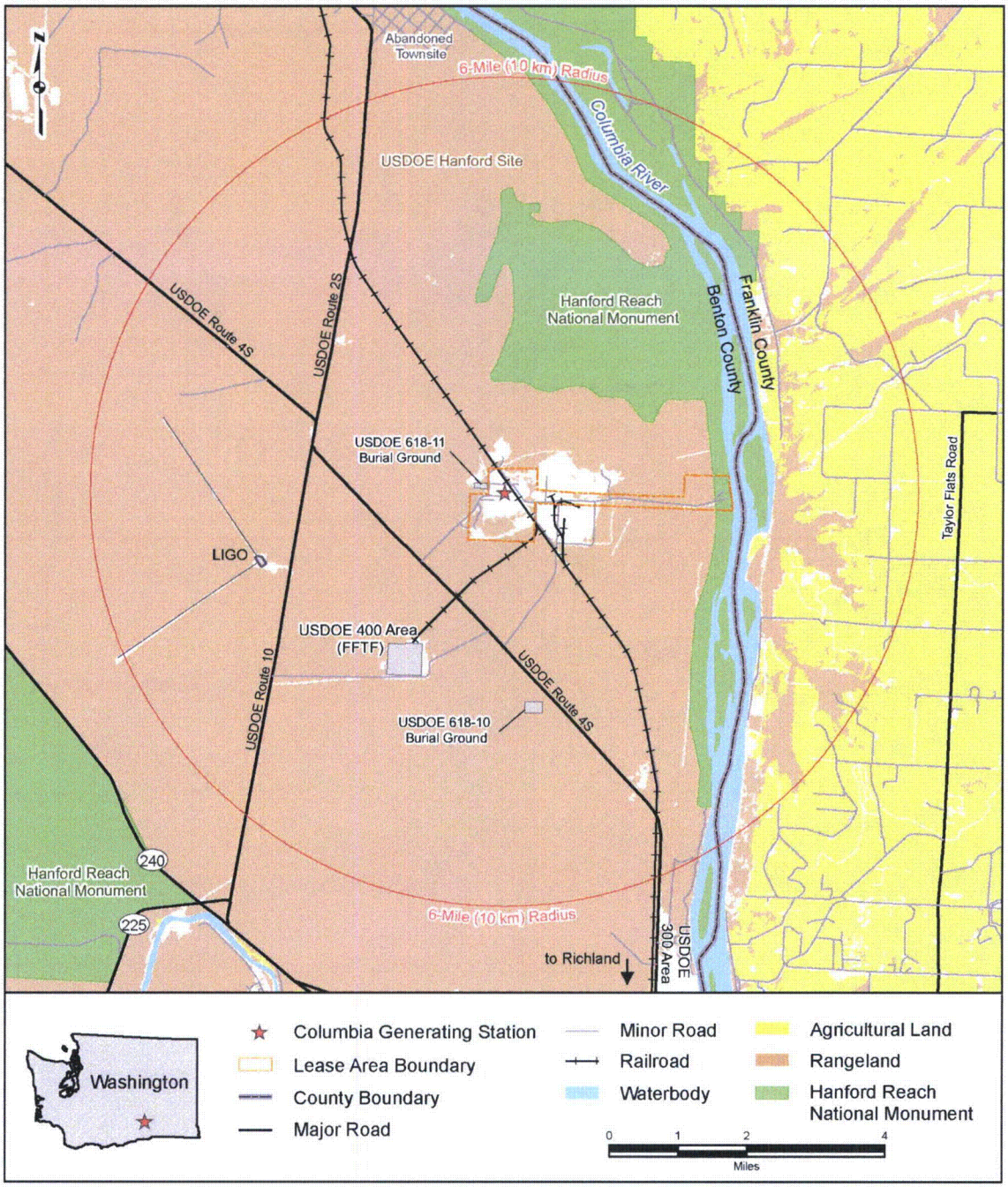
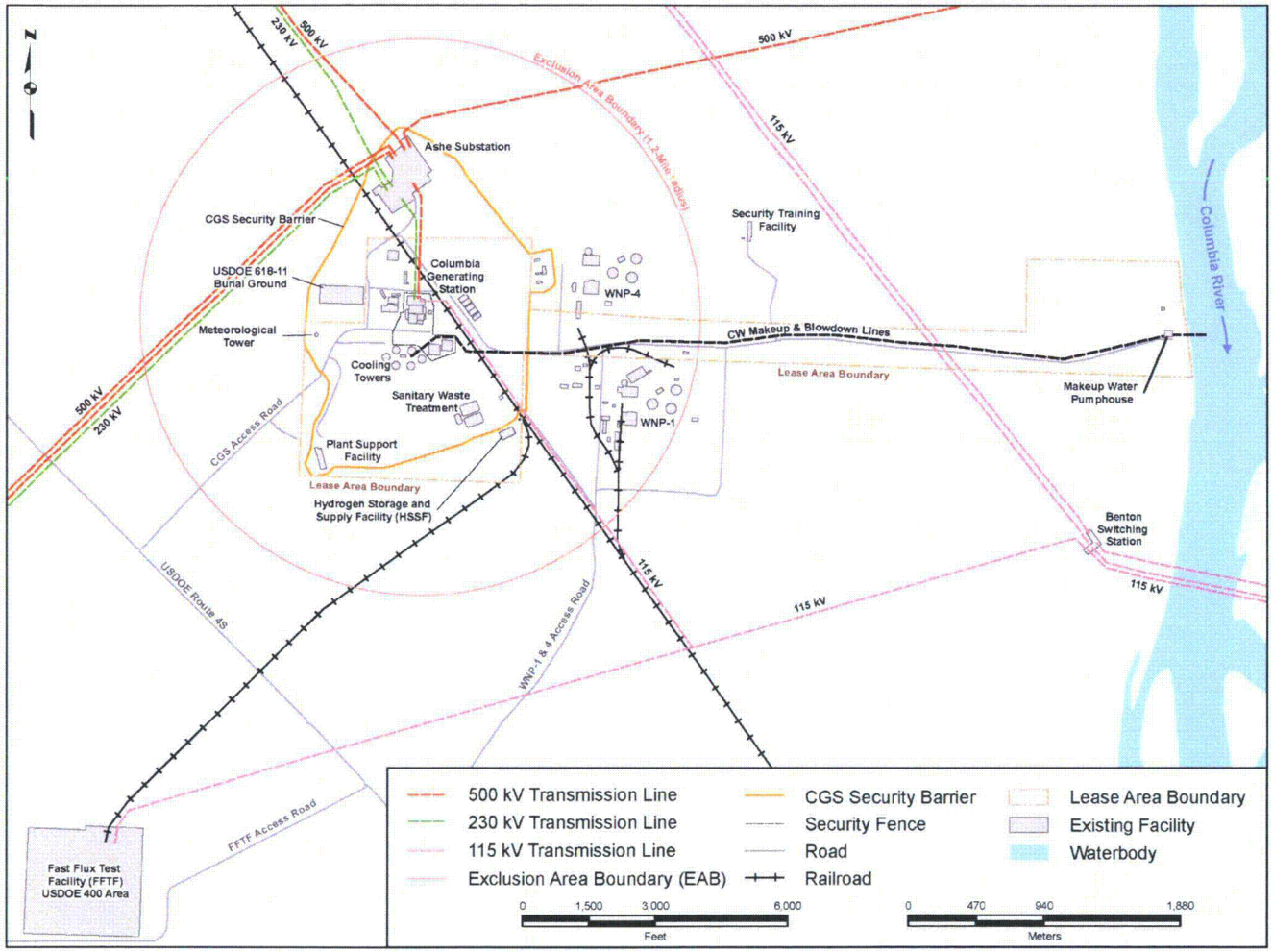


Figure 2.1-3. Site Area Map



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2.2 AQUATIC AND RIPARIAN ECOLOGICAL COMMUNITIES

The Columbia River is the dominant hydrologic feature in the site area. The Columbia Generating Station (CGS) is located about three miles west of the river at river mile 352 near the downstream end of the Hanford Reach. Hydrology and ecology in this reach of the river are influenced by operation of upstream hydroelectric dams, the semi-arid climate, and seasonal flows related to snowmelt (**USDOE 1999,** Section 4.3). The Columbia River is used for transportation, irrigation, potable water supply, industrial processes, and recreation, and provides critical habitat for key migratory fish species. Because the river represents an important natural resource, state and federal agencies are jointly developing conservation plans for the entire basin to provide long-term hydrologic and ecological sustainability (**WDOE 2007**, Chapter 1; **USFWS 2008a**, Section 1.1; **ACOE 1995a**, Section 1.1). This environmental report section summarizes aquatic resources near CGS within the Hanford Reach.

2.2.1 Hydrology and Water Quality

2.2.1.1 Hydrology

The Columbia River is the largest North American river by annual volume of discharge flowing into the Pacific Ocean and is the fourth largest in North America. The main stem is considered to be a high-volume, high-gradient river fed by snowmelt from large mountain ranges to the north (**Benke and Cushing 2005**, Section 13). The river originates at Columbia Lake in the Canadian Rockies of British Columbia at elevation 2,650 feet, and travels over 1,200 miles, occupying a drainage area of approximately 262,000 mi^2 (**USFWS 2008a**, Section 3.3.1.1). The river is roughly divided into three physiographic regions: the coastal rain forest, the central semi-arid basin, and the headwaters segment in the Canadian Rocky Mountains. CGS is located in the central semi-arid region.

Flow is regulated by 10 mainstream dams above the CGS site (including seven in the U.S.) and four below. The nearest upstream dam is Priest Rapids at river mile (RM) 397 and the nearest downstream dam is McNary at RM 292. The impoundment created by the McNary Dam extends to about six miles below CGS. The 51-mile river reach extending from the Priest Rapids Dam to the McNary Dam pool (RM 346) is free flowing but flow release is regulated. The elevation drop between the Priest Rapids Dam tailrace and McNary Dam impoundment is approximately 70 feet.

Flow varies seasonally and typically peaks from April through July during spring runoff and is lowest from September through October. The means of monthly flows recorded by the U.S. Geological Survey (USGS) below Priest Rapids Dam during water years[1]

[1] The water year is October 1 through September 30. The USGS has recorded data for this location back to October 1917. The data to October 1959 have some gaps. Also, the pre-1941 data do not reflect the peak flow attenuation and shifting attributable to the completion of Grand Coulee Dam.

1960 through 2008 range from 79,300 cubic feet/second (cfs) in September to 202,000 cfs in June. Mean annual flows for the same period ranged from 80,650 cfs to 165,600 cfs and averaged 118,263 cfs. For water years 1984 through 2008, coincident with the period of CGS operation, measured flows averaged 114,410 cfs (**USGS 2009**).

The impact of upstream impoundments has been to dampen flows during spring freshets and to limit flooding. Flows vary daily and hourly as water is released from upstream impoundments to meet electrical demands. Flow is also regulated seasonally to limit the impact on spawning salmon. Due to fluctuating river flows in this reach, river stage can vary in excess of 10 feet on a daily basis. River widths in the Hanford Reach can vary between approximately 1,000 and 3,300 feet (**USFWS 2008a**, Section 3.3.1.1; **PNNL 2008a**, Section 10.4.1).

The only other significant hydrological feature in the site area is the Yakima River, which flows generally west to east and enters the Columbia River at RM 335. At its closest approach, the Yakima is about eight miles southwest of CGS.

2.2.1.2 Water Quality

Before being revised in 2003, the State of Washington's water quality standards classified the Columbia River in the reach occupied by CGS as Class A or excellent (**PNNL 2008a**, Appendix D). The revised standards classify the state's waterbodies by designated and potential uses based on water quality criteria. The Columbia River in the stretch that includes the CGS site has the following uses designated for protection: salmonid spawning, rearing, and migration; primary contact recreation; domestic, industrial and agricultural water supply; stock watering; wildlife habitat; fish harvesting; commerce and navigation; boating; and aesthetic values (**WDOE 2006**, Page 55).

Water quality parameters measured by the USGS at Vernita Bridge (RM 388) below Priest Rapids Dam include water temperature, dissolved oxygen, pH, nutrients, ions, and metals (**USGS 2006**). Statistics for selected parameters are listed in Table 2.2-1. During the period 1996 through 2003, water temperature ranged between 3.0° and 20.5°C with a median of 12.0°C (53.6°F). Dissolved oxygen ranged between 9.2 and 14.0 mg/L with a median of 12.4 mg/L. The pH fluctuated between 7.4 and 8.2 standard units. Figure 2.2-1 compares key water quality parameters above and below the CGS site and shows that water quality is not altered through the Hanford Reach (**PNNL 2008a**, Section 10.4.1.3).

River water quality has also been extensively studied as part of ongoing Hanford Site environmental monitoring programs sponsored by USDOE to evaluate the effects of its Hanford facilities on the Columbia River. PNNL reported that concentrations of metals and ions in river water samples in the Hanford Reach during 2007 were similar to those observed in previous years and remained below Washington ambient surface water quality criteria for the protection of aquatic life (**PNNL 2008a**, Section 10.4.1.1). The most recent federally-required assessment of water quality by the State of Washington

found no quality impairments based on water samples in the river reach below Vernita Bridge. However, synthetic organics in fish tissue collected near RM 370 (18 miles upstream of CGS) were identified as a basis for water quality impairment. Irrigation return flows at upstream locations are also listed as impaired for pH and temperature (**WDOE 2008**).

As part of its operational monitoring programs, for several years Energy Northwest collected river water samples at four or more stations near the plant discharge at RM 352. Samples were collected approximately monthly and analyzed for temperature, dissolved oxygen, pH, conductivity, turbidity, alkalinity, hardness, phosphorus, inorganic phosphate, sulfate, copper, iron, zinc, nickel, lead, cadmium, and chromium (**WPPSS 1996**, Section 2.0). The water quality component of the environmental monitoring program was discontinued after 1995 when years of data showed no discernable changes in river water quality at monitoring locations 150 ft to 1900 ft downstream of the outfall.

Between December 2006 and March 2008 Energy Northwest collected water samples just upstream of the discharge location as part of a study of the outfall mixing zone (**EN 2008**). The data from that study are summarized in Table 2.2-2 and appear consistent with the USGS data discussed above. The metal concentrations in Table 2.2-2 are for unfiltered samples (i.e., total metals) while the USGS data in Table 2.2-1 are for filtered water (i.e., dissolved metals).

2.2.2 Aquatic Communities

Information describing the ecological characteristics of the Columbia River in the vicinity of CGS is available from pre-operational studies conducted by Energy Northwest (**Beak 1980**, **WPPSS 1980**) and from summaries of more recent studies conducted as part of the ongoing Hanford Site assessments (**PNNL 2007**, **PNNL 2008a**). Descriptions of the aquatic communities of the Hanford Reach are applicable to the CGS site area because the river gradient is fairly uniform throughout the reach and there are no substantial tributary inflows.

2.2.2.1 General

The abundance and diversity of aquatic organisms within the Hanford Reach of the Columbia River are influenced by the hydrologic conditions created by upstream dams and agricultural practices. Retention of waters within upstream reservoirs allows for the development of a diverse and abundant phytoplankton community that transits downstream through the Hanford Reach. Diatoms dominate the phytoplankton but golden and yellow-brown algae, blue-green algae, red algae, and dinoflagellates are also found. This community is consistent with forms found in lakes and likely originates in the upstream reservoirs, although some forms that likely originate as sessile algae are also found. Peak phytoplankton abundance in the Hanford Reach has been found

to occur in April and May and in late summer and early autumn. Green and blue-green algae have occurred during seasonally warmer waters (**PNNL 2007**, Section 4.5.2.1).

Production of periphyton (benthic microflora) peaks in spring and late summer. Dominant genera are diatoms including *Melosira* and *Gomphonema*. Filamentous mats of green algae, *Stigeoclonium* and *Ulothrix*, are also present in spring and summer (**USFWS 2008a**, Section 3.10.1.2.2; **PNNL 2007**, Section 4.5.2.1).

Zooplankton have been found to be generally sparse in the Hanford Reach with concentrations varying greatly from a summer peak to low winter levels. Summer peaks were dominated by the crustacean *Bosmina* and were found at concentrations as high as 4,500 organisms/ft^3. Winter densities were typically less than 50 organisms/ft^3 (**PNNL 2007**, Section 4.5.2.1). Fall, winter and spring microcrustacea were dominated by copepods (**WPPSS 1980**, Section 2.2.2.4).

Rooted aquatic plants (macrophytes) are relatively uncommon in the Hanford Reach due to strong river currents, rocky bottoms, and fluctuating water levels. Macrophyte species that do occur include duckweed, rooted pondweeds, and Canadian waterweed. The invasive Eurasian milfoil (*Myriophyllum spicatum*) also occurs (**USFWS 2008a**, Section 3.10.1.3; **PNNL 2007**, Section 4.5.2.1).

PNNL reported that benthic organisms in the Hanford Reach are represented by all the major freshwater benthic taxa (**PNNL 2007**, Section 4.5.2.1). A total of 151 taxa of benthic organisms were identified in studies conducted through 1999. Benthic organisms are generally attached or associated with substrate. Insect larvae associated with caddis flies (order *Trichoptera*), midge flies (family *Chironomidae*), and black flies (*Simuliidae*) were found to dominate this aquatic community in the Hanford Reach. Insect larvae occurred at concentrations as high as 2000/ft^3. Other benthic organisms observed included clams, limpets, snails, sponges, and crayfish. The microflora were generally the diatoms *Navicula*, *Nitzschia*, and *Synedra*. A study of fish stomach contents collected between 1973 and 1980 indicated that benthic invertebrates were an important food item for nearly all of the juvenile and adult fish sampled (**PNNL 2007**, Section 4.5.2.1).

Energy Northwest's operational phase studies included three years of monitoring of periphyton and benthic macrofauna in the vicinity of the CGS discharge at RM 352. Benthos was collected on smooth river rocks in wire baskets recovered quarterly at fixed stations upstream and downstream of the discharge. During the 1986 monitoring period caddisfly larvae (family *Hydropsychidae*) accounted for 57% of the number of organisms collected and 63% of the biomass. Midge fly larvae (family *Chironomidae*) were 15% of the collections, but less than 1% of the biomass. The collections showed considerable seasonal and spatial variation. Periphyton samples were collected on glass slide diatometers that were retrieved from the riverbed approximately quarterly. The slides were analyzed for total carbon as a measure of biomass. Periphyton biomass was found to be two to four times higher in winter as compared to spring and

summer. The results of these benthic monitoring programs showed no discernable impact related to CGS discharges (**WPPSS 1987**, Sections 2.3 and 3.3).

2.2.2.2 Fisheries

The Columbia River mainstream supports an estimated 118 fish species (**Benke and Cushing 2005**, Section 13). Of these, approximately 53 are nonnative introduced species and 65 are native. The Hanford Reach of the Columbia River supports resident and migrant fish species. PNNL listed a total of 45 species of fish observed in this reach. Sixteen of the 45 are introduced species (**PNNL 2007**, Section 4.5.2.1). Species in Hanford Reach that the USFWS have identified as culturally important are listed in Table 2.2-3. The USFWS does not consider the list to be static (**USFWS 2008a**, Section 3.12.9).

Migrating salmonids include the Chinook (*Oncorhynchus tshawytscha*), sockeye (*Oncorhynchus nerka*), coho (*Oncorhynchus kisutch*), and steelhead trout (*Oncorhynchus mykiss*). Another migrant includes the Pacific lamprey (*Lampetra tridentate*). Surveys of redds (spawning nests) performed since the 1950s indicate that Chinook and steelhead utilize the Hanford Reach for spawning during fall. It is estimated that up to 80 percent of the fall Columbia River Chinook run spawns in the Hanford Reach (**USFWS 2008a**, Section 3.10.1.5.1). A stretch of the eastern side of the river upstream of CGS between approximately RM 353 and RM 356 is considered major spawning habitat for the fall Chinook (**PNNL 2008a**, Section 10.12.1.1).

Fishes in the vicinity of the CGS site that are listed as threatened or endangered (see Section 2.5.2) are the steelhead trout (*O. mykiss*; threatened) and the upper Columbia run of Spring Chinook (*O. tshawytscha*; endangered). Steelhead spawn in the Hanford Reach and the Spring Chinook transit the area on the way to upriver spawning grounds. The mid-Columbia River, which includes the Hanford Reach, is designated as critical habitat for steelhead (**NMFS 2008**). Bull trout (*Salvelinus confluentus*), a species listed as threatened, are residents of the headwater streams and are less likely to be present in the reach (**USFWS 2008b**; **PNNL 2007**, Section 4.5.3).

Fisheries exist for steelhead and Chinook during their fall runs. In 2002, freshwater sport catch in the area between the McNary Dam and Priest Rapids totaled 6,190 salmon, excluding steelhead. The overwhelming majority (5,830) were Chinook, 95% of which were caught during September and October. A total of 6,510 steelhead were harvested in this reach from April 2002 through March 2003. Most were harvested during fall (**WDFW 2008a**, Pages 39 and 63).

The American shad (*Alosa sapidissima*), introduced from rivers in the eastern U.S., is also thought to spawn in the Hanford Reach and the numbers observed passing the McNary Dam has been steadily increasing since their introduction (**PNNL 2007**, Section 4.5.2.1).

Resident native fish species that provide an active fishery in the area include the whitefish (*Prosopium williamsoni*) and white sturgeon (*Acipenser transmontanus*). During April 2002 through March 2003, a total 372 white sturgeon were harvested between McNary Dam and Priest Rapids, mostly during summer (**WDFW 2008a**, Page 54). Introduced sport fish include the smallmouth bass, crappie, catfish, walleye, and yellow perch. Other fish species found in the Hanford Reach include carp, shiners, suckers, and northern pike minnow (**USFWS 2008a**, Section 3.10.1.5.4).

The preoperational monitoring program conducted by Energy Northwest included fish sampling by beach seine, hoop nets, gill net, and electroshocking. From September 1974 through March 1980 a total of 35,939 fish representing 37 species were collected at the CGS site. Chinook salmon (*O. tshawytscha*) comprised approximately 44% of all fish. Table 2.2-4 lists the species caught with a relative abundance greater than 0.1% (**WPPSS 1982**, Section 6.2).

In the early years of CGS operation the environmental monitoring programs included regular river intake fouling surveys and entrainment studies. (Features of the CGS river water intake system are described in Section 3.1.2.1.) Fish and debris were never observed impinged on the intake screens. No fish, fish eggs, or larvae were captured in special entrainment study baskets installed in the pump well. The entrainment studies were conducted during periods when juvenile fish were present in the vicinity (**WPPSS 1986**, Section 12.3).

Table 2.2-1. Water Quality Parameters Measured in the Columbia River at Vernita Bridge Below Priest Rapids Dam, Washington During 1996-2003

Parameter	Min	5th(*)	25th(*)	Median	75th(*)	95th(*)	Max
Temperature (°C)	3.0	4.0	7.5	12.0	15.4	19.2	20.5
Turbidity (NTU)	0.1	0.3	0.5	0.9	1.7	4.0	4.7
Conductivity (µS/cm)	111.0	114.0	124.0	135.0	145.0	153.0	157.0
Dissolved O_2 (mg/L)	9.2	9.5	10.8	12.4	13.2	13.8	14.0
pH (std. units)	7.4	7.7	7.9	8.0	8.1	8.2	8.2
HCO_3 (filtered) (mg/L)	55.0	56.0	61.0	67.0	72.0	76.0	77.0
Alk (filtered, as $CaCO_3$) (mg/L)	45.0	45.0	50.0	55.0	59.0	62.0	63.0
Suspended sediment (mg/L)	0.5	1.0	2.0	3.0	4.0	8.0	12.0
NO_2+NO_3-N (mg/L)	<0.050	<0.050	0.064	0.096	0.148	0.179	0.259
PO_4-P (mg/L)	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010
Calcium (mg/L)	13.94	14.26	15.55	17.27	18.32	19.74	20.00
Magnesium (mg/L)	3.28	3.34	3.72	4.12	4.56	4.98	5.16
Sodium (mg/L)	1.75	1.86	1.96	2.18	2.34	2.75	2.95
Chloride (mg/L)	0.57	0.70	0.80	0.98	1.14	1.52	1.95
Sulfate (mg/L)	4.97	5.80	6.96	8.14	8.95	10.09	11.00
Silica (mg/L)	4.30	4.44	5.11	5.72	7.22	8.43	9.14
Barium (mg/L)	22.1	23.0	26.4	27.2	29.6	33.0	33.6
Cadmium (µg/L)	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Chromium (µg/L)	<1.0	<1.0	<1.0	<1.0	1.0	1.6	1.6
Copper (µg/L)	<1.0	<1.0	<1.0	1.1	1.7	3.2	5.8
Iron (µg/L)	<3.0	4.0	5.0	5.0	8.5	20.2	65.7
Lead (µg/L)	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Manganese (µg/L)	<1.0	<1.0	<1.0	<1.0	1.2	2.2	6.6
Zinc (µg/L)	<1.0	<1.0	1.1	1.9	3.0	6.0	6.5

* Percentile data for 45 measurements, except Cd, Cr, Cu, & Pb which had 25 measurements. Metals filtered to 0.45 microns.

Source: **USGS 2006**

Table 2.2-2. Water Quality Parameters Measured in the Columbia River at Columbia Generating Station, December 2006 to March 2008

Parameter	Mean(*)	90th(*)	Max
Turbidity (NTU)	0.70	1.30	2.56
Conductivity (µS/cm)	126	140	150
pH (std. units)	7.9	8.1	8.2
Alk (filtered, as $CaCO_3$) (mg/L)	62	68	70
NO_3-N (mg/L)	0.104	0.158	0.180
NO_2-N (mg/L)			<0.03
Total P (mg/L)			<0.1
Calcium (mg/L)			25
Magnesium (mg/L)			5.8
Chloride (mg/L)	1.0	1.3	1.3
Fluoride (mg/L)	0.063	0.070	0.073
Sulfate (mg/L)	9.9	11.0	11.0
Chromium (µg/L)	0.3	1.4	5.6
Copper (µg/L)	0.3	0.9	1.0
Iron (µg/L)	53		180
Lead (µg/L)	0.1	0.1	1.4
Manganese (µg/L)	3.1	5.0	9.4
Zinc (µg/L)	0.9	2.3	4.2

* Mean is geometric mean; percentile data for 23 measurements. Metals unfiltered.

Source: **EN 2008**, Table 1

Table 2.2-3. Recreationally and Commercially Important Fish Species in or near the Hanford Reach

Name	Distribution
White Sturgeon (*Acipenser transmontanus*)	Abundant year-round
Channel Catfish (*Ictalurus punctatus*)	Common in spring and summer
Fall Chinook Salmon (*Oncorhynchus tshawytscha*)	Abundant
Coho Salmon (*Oncorhynchus kisutch*)	Uncommon
Rainbow Trout/Steelhead (*Oncorhynchus mykiss*)	Abundant spring through fall
Sockeye Salmon (*Oncorhynchus nerka*)	Juveniles common spring & adults common summer
Largemouth Bass (*Micropterus salmoides*)	Common
Smallmouth Bass (*Micropterus dolomieui*)	Abundant
Walleye (*Stizostedion vitreum*)	Common

Source: **USFWS 2008a**, Table 3.6

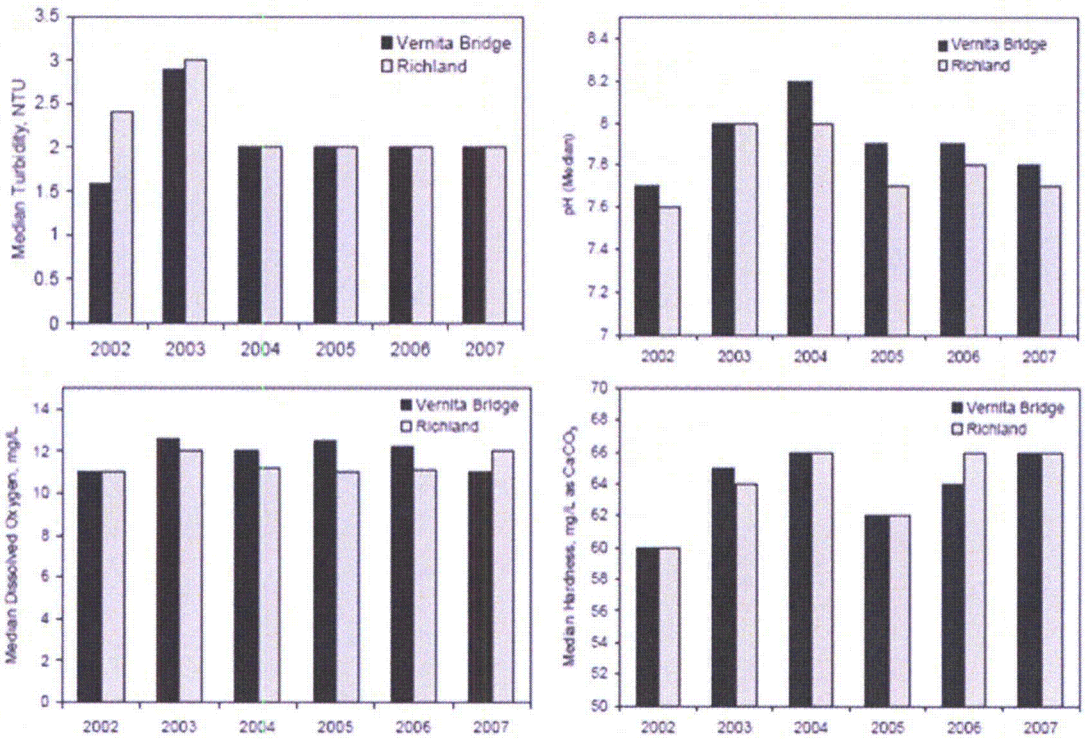
Table 2.2-4. Relative Abundance of Fish Species Collected Near CGS, September 1974 through March 1980

Common Name	Scientific Name	Relative Abundance(*) (%)
Chinook Salmon	*Oncorhynchus tshawytscha*	44.1
Redside shiner	*Richardsonius balteatus*	11.3
Largescale sucker	*Catostomus macrocheilus*	8.8
Northern pikeminnow	*Ptychocheilus oregonensis*	6.9
Peamouth chub	*Mylocheilus caurinus*	6.7
Mountain whitefish	*Prosopium williamsoni*	3.7
Chiselmouth	*Acrocheilus alutaceus*	3.5
Sucker (misc.)	*Catostomus spp.*	3.4
Bridgelip sucker	*Catostomus columbianus*	3.3
Sculpin (misc.)	*Cottus sp.*	0.9
Yellow perch	*Perca flavescens*	0.7
Rainbow trout/Steelhead	*Oncorhynchus mykiss*	0.6
Carp	*Cyprinus cario*	0.6
Prickly sculpin	*Cottus asper*	0.5
Longnose dace	*Rhinichthys cataractae*	0.3
White sturgeon	*Acipenser transmontanus*	0.2
Black crappie	*Pomoxis nigromaculatus*	0.2
Bluegill	*Lepomis macrochirus*	0.2
Smallmouth bass	*Micropterus dolomieui*	0.2
Carp, minnow, & sucker fry	*Cyprinid & Catostomid fry*	3.1

* Species with relative abundance greater than 0.1%.

Source: **WPPSS 1982**, Table 6.3

Figure 2.2-1. Water Quality Parameters Measured by the USGS Above and Below the Columbia Generating Station between 2002 and 2007



Note:

Verita Bridge is USGS Station No. 12472900 at RM 388 (36 miles above CGS).
Richland is USGS Station No. 12473520 at RM 340 (12 miles below CGS).

Source: **PNNL 2008a**, Figure 10.4.10

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2.3 GROUNDWATER RESOURCES

Columbia Generating Station (CGS) is situated within the east central part of the semi-arid Pasco Basin, one of several structural and topographical depressions within the Columbia Plateau in southeastern Washington (**EN 2007**, Section 2.5.1.1; **USDOE 2005,** Section 2.3.4). The plant is located on an approximate 50-foot thick layer of glaciofluvial sands and gravels underlain by the dense silt, sand, and gravel conglomerates of the Ringold Formation. Depth to the water table in the plant vicinity is about 60 feet beneath the surface and is below the top of the Ringold Formation, which is about 500 feet thick at the plant site. Bedrock in the site vicinity is volcanic rock (basalt). Water in sediments above bedrock typically occurs unconfined whereas groundwater in basalt occurs mainly under confined conditions. Beneath the CGS site, unconfined groundwater moves in an easterly direction towards the Columbia River, the primary discharge boundary for the aquifer. The river is approximately three miles east of CGS. Due to the distance from the river and the permeability characteristics and enormous volume of the Ringold Formation, the water table beneath the site fluctuates very little (**EN 2007**, Section 2.4.13.1).

Recharge of the unconfined aquifer comes from precipitation and runoff in the higher areas along the western margin of the Pasco Basin. Wastewater discharges and leakage from underlying basalt confined aquifers are other sources of recharge. The contribution from precipitation on the Hanford Site is relatively small because of the low precipitation rates (about 7 in/yr) and high evapotranspiration. This component of the recharge is highly variable both spatially and temporally and has been estimated to range from near zero to four inches per year (**HGI 2008**, Section 4.1.2).

The characteristics of the groundwater at the CGS site are largely influenced by historical and ongoing USDOE-sponsored activities on the Hanford Site.

2.3.1 Hanford Site Groundwater

In the past, significant artificial recharge of the unconfined aquifer occurred at the Hanford 200 East and 200 West Areas located, respectively, approximately 11 miles northwest and 15 miles west-northwest of CGS. For more than 40 years, large quantities of wastewater associated with plutonium production at the USDOE Hanford Site were discharged to the ground through cribs, ditches, injection wells, trenches, and ponds. Monitoring over several decades has shown many changes in groundwater characteristics caused by the USDOE's discharges of operational wastewaters. However, with discharges decreasing since 1984 and the subsequent elimination of all non-permitted liquid effluent discharges to the ground in 1996, groundwater levels have declined over most of the Hanford Site. Permitted discharges now contribute a volume of recharge in the same range as the estimated natural recharge from precipitation (**USDOE 2005**, Sections 2.2.1, 2.3.5.2.4, and 2.3.5.2.5).

As a result of the historical USDOE Hanford Site operations, groundwater beneath large areas of the Hanford Site has been contaminated by radiological and chemical constituents unrelated to CGS operation. The most extensive contaminant plumes emanating from the 200 Areas are those of tritium and nitrate, which move east and southeast, i.e., towards the river and CGS (**FH 2008**, Page xvi). The contaminants are associated with chemical processing of irradiated fuel rods. Other contaminants, with much smaller zones of contamination, include iodine-129, strontium-90, technetium-99, uranium, carbon tetrachloride, and chromium (**USDOE 2005**, Sections 2.3.5.2.2 and 2.3.5.2.8; **PNNL 2008a**, Section 10.7).

The USDOE has developed a groundwater cleanup plan that includes high-risk waste site remediation, contaminated area shrinkage, natural and artificial recharge reduction, and groundwater remediation and monitoring (**FH 2008**, Page xvi). Remedial actions include pump and treat and in-situ methods, soil-gas extraction, and tank farm surface water controls to minimize water infiltration in order to reduce contaminant movement into the vadose zone (**FH 2008**, Page iii; **USDOE 2005**, Sections 2.3.5.2.2 and 2.3.5.2.8).

The USDOE maintains an extensive network of monitoring wells to assess groundwater quality. In 2007, the area of groundwater with contaminants exceeding drinking water standards was about 71 mi^2 (**PNNL 2008a,** Section 10.7.3.1). As needed, new wells for monitoring, remediation, and characterization are installed and unneeded wells are decommissioned (**FH 2008**, Section 4.0).

Since implementation of cleanup activities circa 1996 (**PNNL 2008a**, Page v), the number of liquid effluent waste disposal sites requiring remediation has been reduced. The current focus of USDOE is on the remediation of waste burial grounds. Burial Ground 618-11 adjacent to the northwest corner of CGS (refer to Figure 2.1-3) covers 8.6 acres and was used between 1962 and 1967 for the disposal of fission products and plutonium (**FH 2003**, Section B2.2; **PNNL 2000**, Page 1.1). In 1999, the USDOE discovered that the burial ground was the source of a separate tritium plume beneath the CGS site. In response to this finding, additional monitoring wells were installed (**PNNL 2000**, Page 1.1).

The concentrations of tritium emanating from the 618-11 burial ground are much higher than in the surrounding site-wide plume from the 200 East Area (**FH 2008**, Sections 2.12.1). Concentrations as high as 8,000,000 picoCuries per liter (pCi/L) were found in 2000 in USDOE Well 699-13-3A next to the burial ground. Measured concentrations have been decreasing but still remain above the drinking water threshold of 20,000 pCi/L (**PNNL 2005a**, Table 3.1; **FH 2008,** Figure 2.12-19). In addition, elevated nitrate levels were detected in Well 699-13-3A above the drinking water standard of 45 milligrams per liter (as NO_3). Gross beta was also detected above the drinking water standard of 50 pCi/L. Other detectable radiological contaminants in the vicinity of Burial Ground 618-11 included technetium-99 and iodine-129 (**FH 2008**, Section 2.12.1).

USDOE continues to monitor the groundwater around 618-11 and, as noted above, is focused on the remediation of this burial ground and similar waste sites on the Hanford Site (see Section 2.12).

2.3.2 CGS Site Groundwater

Three water supply wells were constructed by Energy Northwest on the CGS site. Two of the wells, designated as Wells 699-13-1A and 699-13-1B, were constructed in the unconfined aquifer and are about 240 feet deep. These wells were installed during construction of the plant and usage was discontinued in 1979. The pumps have been removed. The third well, Well 699-13-1C, is approximately 695 feet deep and draws water from a confined aquifer in the basalt. This well was also installed for construction support, but is maintained as a backup source for plant operations (**EN 2007**, Sections 2.4.13.1 and 2.4.13.2; **PNNL 2000**, Table 2.1 and Figure 2.1). Typically, it is only pumped to support quarterly sample collections, with an estimated run time per year of two hours or less at an approximate rate of 200 gallons per minute (gpm). As noted in Section 3.1, normal water supply for CGS is from the Columbia River.

The only other point of groundwater withdrawal for water supply between CGS and the Columbia River is approximately one mile east on the IDC site. Two water supply wells were constructed in the mid-1970s to support construction of Nuclear Projects Nos. 1 & 4 (WNP-1/4). These wells are 372 and 465 feet deep and draw from the semi-confined aquifer in the lower Ringold Formation and upper basalt (**EN 2007**, Section 2.4.13.2; **PNNL 2000**, Page 1.4). The wells are maintained to support ongoing activities on the IDC site. The IDC water system is cross-tied to the CGS site potable water system and can be used to supply the CGS site during the infrequent maintenance and repair activities that make the CGS river water supply unavailable. Typically, the cross-tie is open less than 50 hours per year although in 2008 it was used for 1,655 hours to supply portions of the CGS site. The water is not metered but the estimated average annual usage rate for 2005 through 2008 was about 1 gpm.

As part of the CGS Radiological Environmental Monitoring Program (REMP), onsite Well 699-13-1C and the two wells at the IDC are sampled quarterly by Energy Northwest for gamma-emitting radionuclides and tritium. Results to date have been below the required levels of detection (**EN 2009a**, Sections 4.4.3 and 5.3, and Table 5-2).

Some recharge of the unconfined aquifer occurs onsite at an unlined pond located 1,500 feet northeast of the CGS reactor building. The outfall to the pond is designated as Outfall 002 in the CGS NPDES permit (see Attachment B). In addition to stormwater from plant roofs, the pond receives backwashes of the potable water treatment filter and a reject stream from a process water reverse osmosis unit. Infrequent batch-type discharges include flushes of emergency diesel engine cooling water and flushes of the fire protection system. Annually, about 15 million gallons of water is discharged. A

lesser point of recharge is the percolation beds at the site sanitary waste treatment facility 2,500 feet southeast of the reactor building. Once or twice per year 1-2 million gallons of treated effluent are released to the soil over a 3-5 day period. Additional information on these points of discharge to ground is included in Section 3.1.5.

A third onsite location for the discharge of water is an old soil borrow pit or swale located about 1500 feet south-southeast of the reactor building. The pit is designated as Outfall 003 in the NPDES permit. The location was used for the disposal of about 500,000 gallons per year of backwash water from a sidestream sand filter on the standby service water system from 1997 through 2003. Regular discharges at this location ceased in October 2003 when the filter was removed from service. The outfall is still available for discharge of water should the spray ponds need to be drawn down for cleaning or maintenance.

The CGS site has numerous drywells for the collection of rainwater. These wells also provide a groundwater recharge pathway. Drywells around the cooling towers catch the drift and spray of condenser cooling water from the towers during windy conditions.

Energy Northwest has installed 14 monitoring wells on the CGS site to support various groundwater monitoring programs. The well depths range from 28 to 73 feet below ground surface with screen lengths of 10 or 15 feet. The well locations are shown on Figure 2.3-1 with the "MW" designator. Also shown are monitoring wells with a "699" designator used by the USDOE to monitor plumes from the 618-11 burial ground and the Hanford 200 Areas.

The first five monitoring wells (MW-1 through MW-5) were installed in 1995 as part of an investigation of a construction debris landfill located just southwest of the cooling towers. The landfill was in a soil borrow pit created by the construction of CGS and was in use from 1976 to 1993. Sampling indicated low level concentrations of contaminants in the groundwater at the landfill (**Golder 1995**, Section 4.3). This led to the capping of the landfill with a synthetic membrane and soil cover in 1999. Sampling of the landfill wells for the purpose of tracking contaminants of landfill origin was continued until April 2002. The data indicated that the landfill contaminants were not causing degradation of the groundwater. Water drawn from wells in the vicinity of the cooling towers had higher conductivity and concentrations of chloride and sulfate than in the background well. This was attributed to the infiltration of circulating cooling water that entered the soil through drywells. The cooling water is treated with sulfuric acid and sodium hypochlorite and dissolved solids are concentrated through the evaporative cooling process (**EN 2002**). A small soil borrow pit abutting the closed landfill remains operable for the disposal of inert waste generated at CGS (see Section 3.1.5).

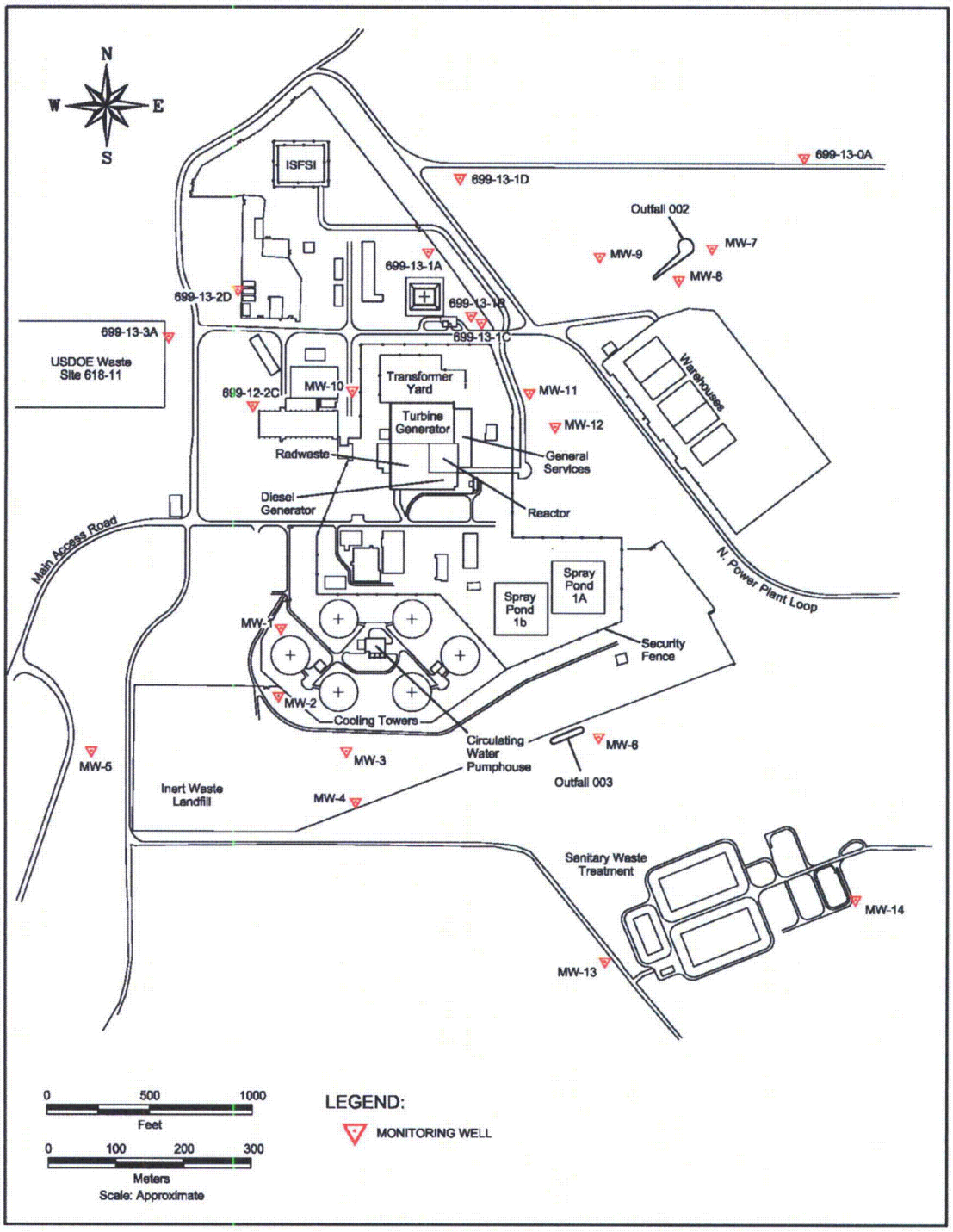
In 1997 four wells (MW-6 through MW-9) were installed to support groundwater monitoring requirements in the station NPDES permit. One well (MW-6) was installed downgradient of the pit (Outfall 003) receiving backwash from the service water filter. Well MW-3 downgradient of the landfill served as the background sampling point.

Three wells (MW-7, -8, & -9) were installed at the unlined stormwater pond (Outfall 002). One year (four quarters) of monitoring data showed no adverse effect on groundwater quality at the two points of discharge (**WPPSS 1999**, page 8). Samples collected at the two upgradient wells showed higher concentrations of some anions and metals. As noted above, later monitoring focused on the landfill wells suggested that the infiltration of cooling water was a plausible source of chloride and sulfate. Follow-on monitoring is being conducted under the terms of the current permit.

Five additional monitoring wells were installed onsite in late 2008 as part of the CGS response to an NEI initiative on groundwater protection (**NEI 2007**). Three wells were installed close to the CGS Turbine Building to help detect potential leakage from the condensate storage tanks and underground piping. One well (MW-10) is located upgradient on the west side of the plant and two wells (MW-11 and MW-12) are on the east side. Two wells (MW-13 and MW-14) were installed at the onsite Sanitary Waste Treatment Facility to help assess the effect of discharges to soil at the facility (described in Section 3.1.5).

Monitoring of the CGS wells in 2008 identified no gamma-emitting radionuclides of interest in groundwater samples. Tritium concentrations ranged from less than detection to 17,400 pCi/L. The highest concentration was in water drawn from well MW-5 upgradient of the plant (**EN 2009a**, Section 5.9.6) and is likely due to USDOE Hanford Site operations as described in Section 2.3.1.

Figure 2.3-1. Monitoring Well Locations



2.4 CRITICAL AND IMPORTANT TERRESTRIAL HABITAT

Various state and federal conservation agencies have adopted ecoregions for landscape-level planning. Ecoregions provide an ecological basis for partitioning the state into coherent units with common habitat types, wildlife species, and landforms. The Washington State Departments of Fish and Wildlife (WDFW) and Natural Resources (WDNR) have developed a comprehensive conservation plans for the state including a detailed accountings of plant and animal species of concern within the various ecoregions (**WDFW 2005**, **WDNR 2007**).

Columbia Generating Station (CGS) and the USDOE Hanford Site lie near the middle of the Columbia Plateau ecoregion (Figure 2.4-1). This area in eastern Washington and Oregon is bounded by the Cascade, Okanogan, Blue, and Rocky Mountains. It is largely characterized as shrub-steppe environment dominated by various species of drought-tolerant shrubs, forbs, and grasses. Approximately one-third of Washington is within this ecoregion and about half of the ecoregion has been converted to agriculture.

2.4.1 Hanford Site

The Hanford Site is typical of the Columbia Plateau ecoregion. Due largely to the protected status of the Site since 1943, it serves as an important refuge for the shrub-steppe ecosystem and contains some of the best remaining large-scale examples of the vegetation type in the Pacific Northwest. The area is relatively free of non-native species and retains characteristic populations of shrub-steppe plants and animals that are absent or scarce in areas of the region that were converted to agricultural uses. The diversity of physical features and examples of undeveloped, deep and sandy soil has led to a corresponding diversity of plant and animal communities (**USFWS 2008a,** Section 3.9; **TNC 2003**, Pages I-VI; **USDOE 2001**, Appendix C).

USFWS (**USFWS 2008a**, Section 3.9) and PNNL (**PNNL 2007**, Section 4.5.1) provide an extensive discussion of the Hanford terrestrial environment. The descriptions include a vegetative map of the area and listings of shrubland, grassland, and tree species found. Also included is a listing of wildlife within the shrub-steppe ecosystem as well as within the riparian zones along the Columbia River.

PNNL reported a total of 727 species representing 90 families of vascular plants on the Hanford Site. Of these, 179 were non-native. When data collected during inventories conducted from 1994 through 1999 are combined with earlier observations, 127 locations that include populations of 30 rare plant taxa have been identified on the Hanford Site.

Shrublands dominate the landscape in terms of area occupied and include seven of the nine major plant communities present. Sagebrush-dominated communities are the most widely dispersed of the shrublands. Grasses occur largely as understory. The

non-native cheatgrass (*Bromus tectorum*) is commonly found on disturbed areas. The microbiotic crust was found to include a total of 120 taxa of soil lichens and mosses, representing several different life forms or foliage expressions (**PNNL 2007**, Section 4.5.1.1).

Of the 23 tree species identified on the Hanford Site, most are found in the riparian zone along the Columbia River and at the old homestead sites near the river. Native species include the cottonwood (*Populus* spp.) and willows (*Salix* spp.). Non-native species include mulberry (*Morus alba*), Black locust (*Robinia pseudoacacia*), Russian olive (*Eleagnus angustifolia*), and Siberian elm (*Ulmus pumila*). Other vegetation that occurs along the river shoreline in the Hanford Reach includes water smartweed (*Polygonum amphibium*), sedges (*Carex* spp.), and various species of grass. Purple loosestrife (*Lythrum salicaria*), tamarisk (*Tamarix parviflora*), yellow nutsedge (*Cyperus esculentus*), knapweed (*Centaurea* spp.), and yellow star thistle (*Centaurea solstitialis*) are common noxious weeds that are becoming established in the riparian areas (**PNNL 2007**, Sections 4.5.1.1 and 4.5.1.2).

Range fires have significantly influenced the composition of plant communities and the distribution of wildlife on large areas of the Hanford Site. A fire in August 1984 burned about 310 mi^2 and another in June 2000 covered about 250 mi^2. The latter was considered to be of low severity in terms of damage to the soil structure and to the seed bank in the upper soil layer. The fires, however, create conditions favorable to invasive species such as Russian thistle (*Salsola tragus*) and tumble mustard (*Sisymbrium altissimum*) (**PNNL 2007**, Section 4.5.1).

Over 300 species of terrestrial vertebrates have been reported for the Hanford Site, including 145 bird species, 46 species of mammals, 5 species of amphibians, and 10 species of reptiles (**PNNL 2007**, Section 4.5).

Management plans for the Hanford Reach National Monument identify bluffs, river islands, and sand dunes as landforms providing unique habitats (**USFWS 2008a**, Section 3.10.4). The largest dune field lies between 2½ miles and 4½ miles from CGS in north to northeast sectors. The dunes are dominated by antelope bitterbrush (*Purshia tridentata*) and Indian ricegrass (*Oryzopsis hymenoides*) and provide habitat for mule deer, burrowing owls, and coyotes (**PNNL 2007**, Section 4.5.1.3).

Island habitat represents approximately two square miles and 40 miles of river shoreline within the Hanford Reach. Flow regulation upstream has allowed various tree species to become established creating additional habitat that supports wildlife species within the riparian zone (**PNNL 2007**, Section 4.5.1.3). One of 19 islands included within the national monument is the 1¼ mile long Homestead Island located opposite the CGS makeup water pumphouse. The USFWS noted that the island has been used as a roosting area by sandhill cranes (*Grus canadensis*) (**USFWS 2008a,** Section 3.21.5.4).

The Hanford Reach is located within the Pacific Flyway and serves as a resting area for numerous species of migrant birds, migratory waterfowl, and shorebirds.

The national monument has established a framework for identifying goals and management priorities to provide a link between the Monument Proclamation, legal requirements, and USFWS policies and procedures. The Monument's goals (**USFWS 2008a**, Section 2.2) are consistent with those developed by USDOE for the Hanford Site (**USDOE 2001**, Section 2.2) and together they provide a common strategy for preserving the natural resources of the site.

2.4.2 Columbia Generating Station Site

The terrain in the vicinity of the 1089-acre CGS site, located in the southeastern portion of the Hanford Site, is relatively flat with gentle hills. Surface soils in the site area are medium to coarse glaciofluvial sand. The elevation across the site ranges from about 350 ft above mean sea level (MSL) at the river to about 460 ft MSL on hills southwest of the plant. Plant grade is at 441 ft MSL.

Characterizations of the habitat of the Hanford Site are generally applicable to the area surrounding CGS. The undisturbed areas of the CGS site and transmission line corridor (see Section 3.1.7) support a mix of grasses, forbs, and shrubs. The August 1984 range fire approached the site from the west and burned much of the sagebrush and bitterbrush cover around the plant area. The June 2000 fire was stopped west of the site at USDOE Route 4S and did not affect habitat surrounding the CGS site.

Operational phase monitoring programs conducted by Energy Northwest at CGS focused on discerning effects of cooling tower drift at study plots surrounding the site out to about five miles. Between 1989, when the number of study plots was expanded from 9 to 15, and 2002 annual grasses comprised about 35% of the herbaceous cover and perennial grasses were about 17% of the cover. Cheatgrass (*Bromus tectorum*) was the dominant annual grass on the study plots and Sandberg's bluegrass (*Poa secunda*) was the dominant perennial grass. Herbaceous cover by all grasses and forbs was 66%. The monitoring program showed a strong relationship between herbaceous cover and precipitation and average temperature during the growing season (**EN 2003**, Section 2.2).

Measurements of the cover canopy attributable to shrubs were much more limited spatially and temporally because few of the study plots had shrubs and several of those were burned in the 1984 range fire. Mean cover at five study plots was about 15% in the years preceding the fire and about 2% during measurements made in 1985–1992 (**EN 2003**, Section 3.2). Dominant shrubs in the site area are bigtip sagebrush (*Artemisia tridentata*) and bitterbrush (*Purshia tridentata*).

Surveys of a narrow 2-km long stretch of the Columbia River riparian zone at CGS in 2008 identified 84 vascular plant species, of which 26 were non-native. Included in the recorded plants were tree species of cottonwood (*Populus balsamifera*), Narrowleaf willow (*Salix exigua*), Siberian elm (*Ulmus pumila*), and Rocky Mountain juniper (*Juniperus scopulorum*) (**Link 2008**). Separate surveys of upland areas of the Energy Northwest property in the spring of 2009 identified 66 vascular plant species, of which 18 were non-native. The most widely scattered and abundant species was cheatgrass. This occurs almost as a monoculture in areas that have been disturbed by construction. After cheatgrass, the next most common plant covers are associations of bluegrass/buckwheat (*Poa secunda / Eriogonum niveum*) and bluegrass/needle-and-thread grass (*Poa secunda / Hesperostipa comata*). Sagebrush (*Artemisia tridentata*), in association with grasses and rabbitbrush (*Ericameria nauseosa*), is found in relatively low abundance on the site (**Link 2009**).

Six species of noxious weeds were noted during the spring 2009 surveys. The most widely distributed weeds were diffuse knapweed (*Centaurea diffusa*), rush skeletonweed (*Chondrilla juncea*), and Dalmatian toadflax (*Linaria dalmatica*) (**Link 2009**). Strategies for preventing the spread of weeds are developed through a proceduralized noxious weed control program.

From 1981 through 1987 spring bird surveys were conducted on two 20-acre plots (one riparian and one upland shrub) off the CGS site to the southeast. The top ten most-sighted birds (of 281 sightings) in spring 1987 were: Western meadowlark (18.5%), Red-winged blackbird (13.9%), Bank swallow (9.6%), Brown-headed cowbird (9.3%), Eastern kingbird (8.2%), California gull (7.1%), Bullock's oriole (6.0%), Killdeer (5.3%), Western kingbird (4.3%), Barn swallow (4.3%). Twenty-five (25) species were sighted in 1987 and 72 during all surveys (**WPPSS 1988**, Section 3.3.1).

A list of birds sighted on or near the CGS site over the last decade or more is included as Table 2.4-1. Many of the shorebirds and waterfowl on the list have been sighted at the site sanitary waste treatment plant (described in Section 3.1.5) where the lagoons provide resting/feeding opportunities and limited breeding habitat for a few species. (**EN 2009b**)

The most visible mammals on or near the CGS site are mule deer (*Odocoileus hemionus*), coyote (*Canis latrans*), cottontail rabbit (*Sylvilagus nutalli*), and black-tailed jackrabbit (*Lepus californicus*). Less commonly seen are the American badger (*Taxidea taxus*) and porcupine (*Erithizon dorsatum*). The reptile most commonly seen on the site is the Pacific gopher snake (*Pituophis cetenifer*).

There is no designated critical habitat for threatened and endangered terrestrial species in the vicinity of the CGS site, including the transmission corridor described in Section 3.1.7. The State of Washington, however, has designated shrub-steppe environments of the Columbia Plateau ecoregion as priority habitats for preservation

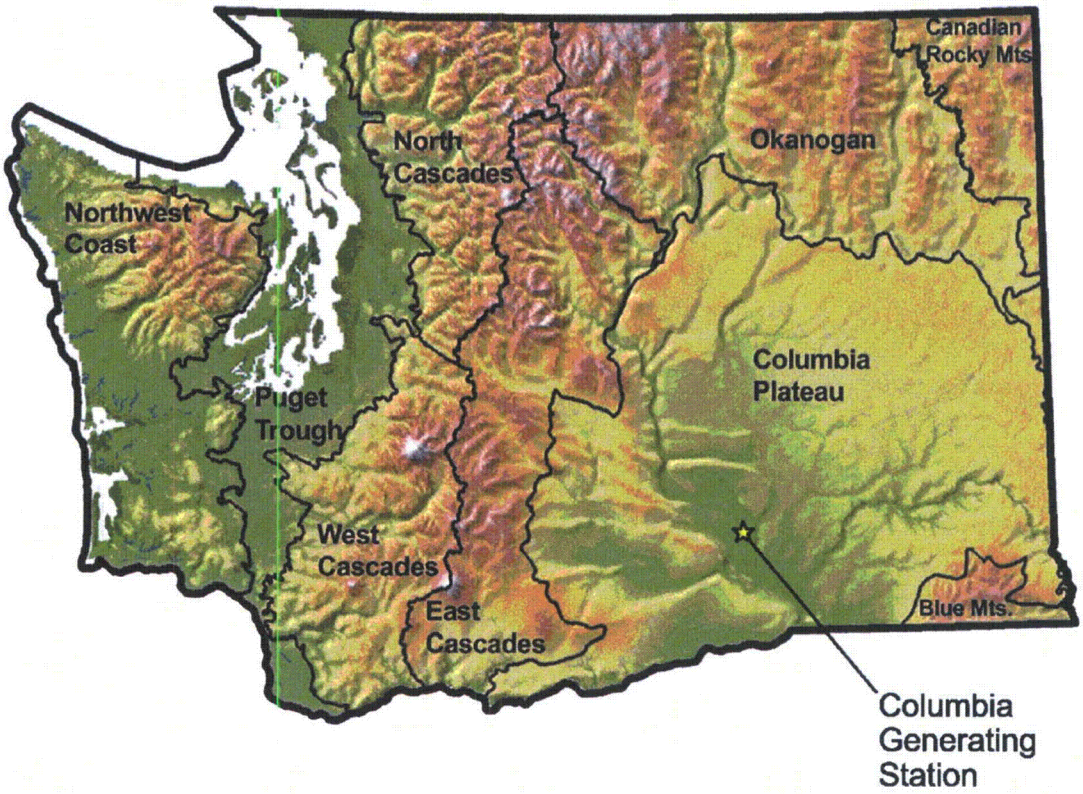
efforts (**WDFW 2005**, Page 533; **WDNR 2007**, Page 83). As noted above, the CGS site is characterized by shrub-steppe plant associations.

Table 2.4-1: Avian Species Sighted on the CGS Site

Common Name	Scientific Name
Passerines	
horned lark	*Eremophila alpestris*
western meadowlark	*Sturnella neglecta*
loggerhead shrike	*Lanius ludovicianus*
black-billed magpie	*Pica pica*
brewer's blackbird	*Euphagus cyanocephalus*
red-winged blackbird	*Agelaius phoeniceus*
yellow-headed blackbird	*X. xanthocephalus*
common raven	*Corvus corax*
barn swallow	*Hirundo rustica*
bank swallow	*Riparia riparia*
cliff swallow	*Hirundo pyrrhonota*
white-crowned sparrow	*Zonotrichia leucophrys*
lark sparrow	*Chondestes grammacus*
savannah sparrow	*Passerculus sandwichensis*
house sparrow	*Passer domesticus*
sage sparrow	*Amphispiza belli*
dark-eyed junco	*Junco hyemalis*
eastern kingbird	*Tyrannus tyrannus*
western kingbird	*Tyrannus verticalis*
say's phoebe	*Sayornis saya*
American robin	*Turdus migratorius*
house finch	*Carpodacus mexicanus*
Eurasian starling	*Sturnus vulgaris*
northern flicker	*Colaptes auratus*
common nighthawk	*Chordeiles minor*
Bullock's oriole	*Icterus bullockii*
golden-crowned kinglet	*Regulus satrapa*
brown-headed cowbird	*Molothrus ater*
western tanager	*Piranga ludoviciana*
American crow	*Corvus brachyrhynchos*
mountain chickadee	*Poecile gambeli*
house wren	*Troglodytes aedon*
Raptors	
sharp-shinned hawk	*Accipter striatus*
ferruginous hawk	*Buteo regalis*
Swainson's hawk	*Buteo swainsoni*
red-tailed hawk	*Buteo jamaicensis*
rough-legged hawk	*Buteo lagopus*
bald eagle	*Haliaeetus leucocephalus*
golden eagle	*Aquila chrysaetos*
American kestrel	*Falco sparverius*
northern harrier	*Circus cyaneus*
prairie falcon	*Falco mexicanus*
turkey vulture	*Cathartes aura*
barn owl	*Tyto alba*
great horned owl	*Bubo virginianus*
western screech-owl	*Megascops kennicottii*
burrowing owl	*Athene cunicularia*
Osprey	*Pandion haliaetus*
Waterbirds	
great blue heron	*Ardea herodias*
long-billed curlew	*Numenius americanus*
sandhill crane	*Grus canadensis*
common loon	*Gavia immer*
california gull	*Larus californicus*
killdeer	*Charadrius vociferus*
belted kingfisher	*Ceryle alcyon*
great egret	*Ardea alba*
pied-billed grebe	*Podilymbus podiceps*
eared grebe	*Podiceps nigricollis*
double-crested cormorant	*Phalacrocorax auritus*
green heron	*Butorides virescens*
black-crowned night heron	*Nycticorax nycticorax*
American coot	*Fulica americana*
black-necked stilt	*Himantopus mexicanus*
American avocet	*Recurvirostra americana*
spotted sandpiper	*Actitis macularia*
Wilson's phalarope	*Phalaropus tricolor*
Caspian tern	*Hydroprogne caspia*
Forster's tern	*Sterna forsteri*
lesser yellowlegs	*Tringa flavipes*
Waterfowl	
redhead	*Aythya americana*
mallard	*Anas platyrhynchos*
snow goose	*Chen caerulescens*
canada goose	*Branta canadensis*
tundra swan	*Cygnus columbianus*
American wigeon	*Anas americana*
blue-winged teal	*Anas discors*
cinnamon teal	*Anas cyanoptera*
northern shoveler	*Anas clypeata*
northern pintail	*Anas acuta*
green-winged teal	*Anas carolinensis*
canvasback	*Aythya valisineria*
gadwall	*Anas strepera*
ring-necked duck	*Aythya collaris*
lesser scaup	*Aythya affinis*
bufflehead	*Bucephala albeola*
common goldeneye	*Bucephala clangula*
Barrow's goldeneye	*Bucephala islandica*
ruddy duck	*Oxyura jamaicensis*
common merganser	*Mergus merganser*
Upland Game Birds	
california quail	*Callipepla californica*
ringnecked pheasant	*Phasianus colchicus*
chukar	*Alectoris chukar*
gray partridge	*Perdix perdix*
Doves	
morning dove	*Zenaida macroura*
rock dove	*Columba livia*

Source: EN 2009b

Figure 2.4-1. Washington State Ecoregions



Source: **WDFW 2005**, Figure 11

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2.5 THREATENED AND ENDANGERED SPECIES

The Washington Department of Natural Resources and Department of Fish and Wildlife maintain lists of federal and state threatened and endangered species. These state resource agencies also use several additional classifications to guide conservation and management of plant, fish, and wildlife resources (**WDNR 2008**, **WDFW 2008b**). Regional and county specific information on federally listed species possibly occurring near CGS and the associated transmission lines is also available through the U.S. Fish and Wildlife Service (**USFWS 2008b**) and the National Marine Fisheries Service (**NMFS 2008**).

2.5.1 Hanford Site

As discussed in Sections 2.2 and 2.4, the Hanford Site, including the Hanford Reach of the Columbia River, provides habitat for numerous wildlife and plant species. Federal and state listed species on the Hanford Site are described in reports prepared for USDOE by the Pacific Northwest National Laboratory (**PNNL 2007**, Section 4.5.3; **PNNL 2008a**, Section 10.11). These characterizations encompass the special status species that might be found in the vicinity of CGS and are compiled in Table 2.5-1.

There are no federal- or state-listed endangered or threatened mammals, reptiles, amphibians, or invertebrates on the Hanford Site.

The Columbia Basin population segment of the pygmy rabbit (*Brachylagus idahoesis*) is listed as endangered at the state and federal levels (**WDFW 2008b, USFWS 2008b**). Although the population area includes Benton, Franklin, and Grant Counties, the mammal has never been conclusively observed on the Hanford Site. It is suspected that it has been extirpated from the area (**USFWS 2008a**, Section 3.11.2). In early 2009 the USFWS shifted the focus of the species recovery efforts to building a population based on cross-breeds from an Idaho population. The Columbia Basin pygmy rabbit population was presumed extinct (**TCH 2009a**).

There are three species of fish, four species of birds, and 12 species of plants listed as threatened or endangered by either the state or federal governments potentially occurring on the Hanford Site (see Table 2.5-1).

Of the federally-listed fish species, only the steelhead trout (*Oncorhynchus mykiss*) spawns in the Hanford Reach. Spring Chinook (*O. tshawytscha*) migrate through the area on their way to spawning grounds upstream. Bull trout (*Salvelinus confluentus*) have been found in the reach but are not considered resident.

State-listed endangered bird species that migrate through the area include the American white pelican (*Pelecanus erythrorhynchos*) and the sandhill crane (*Grus canadensis*). Threatened species that might be resident on the Hanford Site include the

ferruginous hawk (*Buteo regalis*) and greater sage grouse (*Centrocercus urophasiamus*). Additional bird species listed as sensitive by Washington State are the common loon (*Gavia immer*), peregrine falcon (*Falco peregrinus*), and bald eagle (*Haliaeetus leucocephalus*).

No birds observed on the Hanford Site are federally listed as threatened or endangered. Federal bird species of concern include the Northern goshawk (*Accipiter gentilis*), burrowing owl (*Athene cunicularia*), ferruginous hawk, the Olive-sided flycatcher (*Contopus cooperi*), peregrine falcon and the loggerhead shrike (*Lanius ludovicianus*). The greater sage grouse is listed as a federal candidate species.

As of 2007, PNNL reported no federally listed endangered or threatened plants, although 12 were listed by Washington State. The one plant listed by USFWS as threatened (Utes ladies'-tresses, *Spiranthes diluvialis*) for Benton and Franklin Counties (**USFWS 2008b**) has not been reported by PNNL to date.

Additional Washington State monitored (watch list) plant species possibly occurring in the Hanford Site area are shown in Table 2.5-1 (**PNNL 2007**, Section 4.5.3; **PNNL 2008a**, Section 10.11).

2.5.2 Columbia Generating Station Site

No species federally listed as threatened or endangered have been observed on the CGS site or in the transmission line corridor between the plant and the Ashe Substation. Two federal species of concern that have been sighted on or near the CGS site are the loggerhead shrike and the burrowing owl. A location on the river shore about 1¼ miles south of the plant makeup water pumphouse (outside the CGS leased lands) has been identified in USDOE-sponsored surveys as a site occupied by bald eagles (**PNNL 2008a**, Section 10.12.1.3). Although not listed as threatened or endangered, the bald eagle is still protected under the Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act.

As noted in Section 2.4.1, sandhill cranes, state-listed as endangered, have been observed on the island across from the makeup water pumphouse. Other state-listed birds that have been observed on or near the CGS site are the American white pelican (state endangered), ferruginous hawk (state threatened), and common loon (state sensitive).

Vegetation surveys of the Columbia River shoreline near CGS in 2008 revealed the presence of the state-listed threatened species Lowland toothcup (*Rotala ramosior*) and watch list species Shining flatsedge (*Cyperus bipartitus*) at a location approximately one-half mile downstream of the Energy Northwest property. Also found near the water edge throughout the 2-km survey zone was the state watch list species Col. River

mugwort (*Artemisia lindleyana*). No federally-listed plant species were identified in the riparian area (**Link 2008**).

Vegetation surveys conducted in the spring of 2009 of the upland area leased by Energy Northwest identified a small population of Woodypod milkvetch (*Astragalus sclerocarpus*), a state watch list plant. Also found were two plants of Piper's daisy (*Erigeron piperianus*), a state sensitive species. No federally-listed plant species were found in the survey area (**Link 2009**).

Table 2.5-1. Federal and State Listed Species of Known Occurrences or Potentially Occurring on the Hanford Site

Scientific Name	Common Name	State Status	Federal Status
Plants			
Allium robinsonii	Robinson's onion	Watch List	
Allium scilloides	Scilla onion	Watch List	
Ammannia robusta	Grand redstem	Threatened	
Arenaria franklinii var. thompsonii	Thompson's sandwort	Review Group 2	
Artemisia lindleyana	Columbia River mugwort	Watch List	
Astragalus columbianus	Columbia milk-vetch	Sensitive	Species of Concern
Astragalus conjunctus var. rickardii	Basalt milk-vetch	Watch List	
Astragalus sclerocarpus	Stalked-pod milkvetch	Watch List	
Astragalus speirocarpus	Medic milkvetch	Watch List	
Astragalus succumbens	Crouching milkvetch	Watch List	
Astragalus geyeri	Geyer's milkvetch	Threatened	
Balsamorhiza rosea	Rosy balsamroot	Watch List	
Calyptridium roseum	Rosy pussypaws	Threatened	
Camissonia minor	Small-flower evening-primrose	Sensitive	
Camissonia minor	Dwarf evening-primrose	Sensitive	
Carex hystericiana	Porcupine sedge	Watch List	
Casrilleja exilis	Annual paintbursh	Watch List	
Centunculus minimus	Chaffweed	Review Group 1	
Crassula aquatica	Pigmy weed	Watch List	
Cyperus bipartitus	Shining flatsedge	Watch List	
Cryptantha leucophaea	Gray cryptantha	Sensitive	Species of Concern
Cryptantha scoparia	Miner's candle	Sensitive	
Cryptantha spiculifera	Snake River cryptantha	Sensitive	
Cuscuta denticulata	Desert dodder	Threatened	
Delphinium multiplex	Kittitas larkspur	Watch List	
Eatonella nivea	White eatonella	Threatened	
Eleocharis rostellata	Beaked spike-rush	Sensitive	
Epipactis gigantea	Giant hellborine	Watch List	
Erigeron piperianus	Piper's daisy	Sensitive	

Table 2.5-1. Federal and State Listed Species of Known Occurrences or Potentially Occurring on the Hanford Site
(continued)

Scientific Name	Common Name	State Status	Federal Status
Eriogonum codium	Umtanum desert buckwheat	Endangered	Candidate
Gilia leptomeria	Great basin gilia	Threatened	
Hierchloe odorata	Vanilla grass	Review Group 1	
Hypericum majus	Canadian St. John's-wort	Sensitive	
Lesquerella tuplashensis	White bluffs bladderpod	Threatened	Candidate
Limosella acaulis	Southern mudwort	Watch List	
Lindernia dubia var. anagallidea	False pimpernel	Watch List	
Lipocarpha aristulata	Awned halfchaff sedge	Threatened	
Loeflingia squarrosa var. squarrosa	Loeflingia	Threatened	
Lomatium tuberosum	Hoover's desert-parsley	Sensitive	Species of Concern
Mimulus suksdorfii	Suksdorf's monkey flower	Sensitive	
Minuartia pusilla var. pusilla	Annual sandwort	Review Group 1	
Myosurus clavicaulis	Mousetail	Sensitive	
Nama densum var. parviflorum	Small-flowered nama	Watch List	
Nicotiana attenuata	Coyote tobacco	Sensitive	
Oenothera caespitosa	Desert evening-primrose	Sensitive	
Opuntia fragilis	Brittle prickley pear	Review Group 1	
Pectocarya setosa	Bristly combseed	Watch List	
Pectocarya penicillata	Winged conbseed	Watch List	
Pediocactus simpsonii var. robustior	Hedge hog cactus	Review Group 1	
Pellaea glabella var. simplex	Smooth cliffbrake	Watch List	
Penstemon eriantherus var. whitedii	Fuzzytongue penstemon	Sensitive	
Rotala ramosior	Lowland toothcup	Threatened	
Rorippa columbiae	Persistentsepal yellowcress	Endangered	Species of Concern
Invertebrates			
Anodonta californiensis	California floater	Candidate	Species of Concern
Fisherola nuttali	Shortfaced lanx	Candidate	
Flumincola columbiana	Giant Columbia River spire snail	Candidate	Species of Concern

Table 2.5-1. Federal and State Listed Species of Known Occurrences or Potentially Occurring on the Hanford Site
(continued)

Scientific Name	Common Name	State Status	Federal Status
Cicindela columbica	Columbia River tiger beetle	Candidate	
Boloria selene atrocostalis	Silver-bordered fritillary	Candidate	
Fish			
Catostomus platyrhynchus	Mountain sucker	Candidate	
Lampetra ayresi	River lamprey	Candidate	Species of Concern
Lampetra tridentata	Pacific lamprey		Species of Concern
Oncorhynchus mykiss	Steelhead	Candidate	Threatened
Oncorhynchus tshawytscha	Spring-run Chinook	Candidate	Endangered
Rhinichthys falcatus	Leopard dace	Candidate	
Salvelinus confluentus	Bull trout	Candidate	Threatened
Amphibians and Reptile			
Bufo boreas	Western toad	Candidate	Species of Concern
Masticophis taeniatus	Striped whipsnake	Candidate	
Sceloporus graciosus	Sagebrush lizard	Candidate	Species of Concern
Birds			
Accipiter gentilis	Northern goshawk	Candidate	Species of Concern
Aechmophorus occidentalis	Western grebe	Candidate	
Amphispiza belli	Sage sparrow	Candidate	
Aquila chrysaetos	Golden eagle	Candidate	
Athene cunicularia	Burrowing owl	Candidate	Species of Concern
Buteo regalis	Ferruginous hawk	Threatened	Species of Concern
Centrocercus urophasianus	Greater sage grouse	Threatened	Candidate
Contopus cooperi	Olive-sided flycatcher		Species of Concern
Falco columbarius	Merlin	Candidate	
Falco peregrinus	Peregrine falcon	Sensitive	Species of Concern
Gavia immer	Common loon	Sensitive	
Grus canadensis	Sandhill crane	Endangered	
Haliaeetus leucocephalus	Bald eagle	Sensitive	Species of Concern
Lanius ludovicianus	Loggerhead shrike	Candidate	Species of Concern
Melanerpes lewis	Lewis's woodpecker	Candidate	
Oreoscoptes montanus	Sage thrasher	Candidate	
Otus flammeolus	Flamulated owl	Candidate	

Table 2.5-1. Federal and State Listed Species of Known Occurrences or Potentially Occurring on the Hanford Site
(continued)

Scientific Name	Common Name	State Status	Federal Status
Pelecanus erythrorhynchos	American white pelican	Endangered	
Mammals			
Brachyagus idahoesis	Pygmy rabbit	Endangered	Endangered
Lepus californicus	Black-tailed jack rabbit	Candidate	
Lepus townsendii	White-tailed jack rabbit	Candidate	
Sorex merriami	Merriam's shrew	Candidate	
Spermophilus townsendii	Townsend's ground squirrel	Candidate	Species of Concern
Spermophilus washingtoni	Washington ground squirrel	Candidate	Candidate

Sources: **PNNL 2007**, **PNNL 2008a**, **NMFS 2008**, and **USFWS 2008b**

Table Captions:

State Status

Candidate	=	Sufficient information exists to support listing as Endangered or Threatened.
Endangered	=	In danger of becoming extinct or extirpated.
Threatened	=	Likely to become Endangered.
Sensitive	=	Vulnerable or declining and could become Endangered or Threatened in the state.
Watch List	=	Taxa that are more abundant and/or less threatened than previously assumed, but still of interest.
Review Group	=	Taxa for which insufficient information is available for listing as threatened, endangered or sensitive.

Federal Status

Candidate	=	Sufficient information exists to support listing as Endangered or Threatened.
Endangered	=	In danger of extinction.
Species of Concern	=	An unofficial status, the species appears to be in jeopardy, but insufficient information to support listing.
Threatened	=	Likely to become endangered.

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2.6 DEMOGRAPHY

2.6.1 General Demographic Characteristics

The study area is defined by a 50-mile radius around the CGS site, and includes all or parts of eight counties in Washington and two counties in Oregon, and the three cities of Kennewick, Pasco, and Richland (the Tri-Cities) in Washington. The nearest major city to the CGS site is Richland, approximately 10 miles south-southeast of the site. Richland's estimated 2008 population was 46,080. Estimated populations in Kennewick and Pasco in 2008 totaled 65,860 and 52,290, respectively (**WOFM 2008**, Table 4). The study area is shown in Figure 2.6-1.

Table 2.6-1 and Table 2.6-2 present general demographic information for the jurisdictions potentially affected by renewal of the CGS operating license. These include the population of U.S. Census Bureau (USCB) block-groups within a 50-mile radius of the plant, the nearby Richland-Kennewick-Pasco Metropolitan Statistical Area (Tri-Cities MSA), and Franklin and Benton Counties. The latter three analysis areas were included because most of the CGS workforce resides within these areas. Background data presented includes the total population of the ten counties that fall entirely or partly within 50 miles of the plant, the entire state of Washington, and the entire state of Oregon. The data include the general population, institutional populations such as residents in correctional facilities, nursing homes and psychiatric hospitals, and noninstitutional populations such as residents in college dormitories and adult group homes. (**USCB 2000a**, **WOFM 2007**, **OOEA 2007**, **ESRI 2006**, **ESRI 2007**)

2.6.1.1 Current Demographic Characteristics

The population of persons residing within 20 and 50 miles of the CGS site was determined from the 2000 census block data. Census block population data were included if the block fell partly or entirely within an area. Most of the census blocks that fell partly within a zone were low density and, as a result, were not thought to significantly bias population size upward if included. Population density of the two zones was calculated using the total areas of the 20-mile and 50-mile radius circles. This calculation provides a conservatively higher estimate of density than using an area defined by census blocks including those that may fall partly outside the 20 or 50 mile distances.

Using the methodology described above, an estimated 387,512 people lived within 50 miles of the CGS site in 2000 with a population density of 49.4 people per square mile (Table 2.6-1). This density is lower than the average density for the state of Washington (88.6 people per square mile) and larger than Oregon (35.6 people per square mile) and the population density of the 10 counties surrounding the CGS site

(30.8 people per square mile). Within the 20-mile area there were an estimated 171,371 persons at a density of 136 persons per square mile.

Applying the GEIS population sparseness criterion, the CGS site is sparseness Category 4, "least sparse" (≥ 120 persons per square mile within 20 miles). Applying the GEIS proximity criterion, CGS falls into Category 1, "not in close proximity" (no city with 100,000 or more persons and <50 persons per square mile within 50 miles). Per the GEIS sparseness-proximity matrix, CGS is located in a medium population area (**NRC 1996**, Section C.1.4).

2.6.1.2 Population Projections

Based on the USCB data, an annual population increase of approximately 1.96% was estimated for the 50-mile radius study area between 2000 and 2005 (**USCB 2000a**). Much of the growth occurred in the cities of Richland, Kennewick, and Pasco, known collectively as the "Tri-Cities". The Tri-Cities MSA, comprising Benton and Franklin Counties, had a 2000 population of 191,822, and grew at a rate of 3.03% annually between the years of 2000 and 2005 (**USCB 2000a**). Tri-City Development Council estimated that the population of the Tri-Cities MSA had grown to 228,023 in 2007 and would grow to 251,025 by 2012 (**TRIDEC 2007a**).

The fastest growth during the 2000-2005 period occurred in Franklin County, which includes the city of Pasco, and was estimated to have grown at a rate of 4.52% annually between the years 2000 and 2005. Population growth in the Tri-Cities area and within 50 miles of CGS outpaced annual statewide growth for both Washington (1.23%) and Oregon (1.06%) during the same period (Table 2.6-1) (**USCB 2000a**).

The Washington Office of Financial Management (**WOFM 2007**) and Oregon Office of Economic Analysis (**OOEA 2007**) provided the population projections for each county presented in Table 2.6-2. State projections were developed using the Cohort-Survival Model:

$$\text{Population}_1 = \text{Population}_0 + \text{Births} - \text{Deaths} + \text{Net Migration}$$

Franklin, Benton, and Kittitas counties are all experiencing fast growth and are projected to sustain higher annual rates of population growth than the state of Washington.

2.6.2 Minority and Low-Income Populations

Minority and low-income populations in the 50-mile geographic area were analyzed based on 2000 decennial census block data. The results were compiled and maps were produced showing the geographic location of minority and low-income populations in relation to the site. Information for both groups was then reviewed with respect to NRC Office of Nuclear Reactor Regulation guidance (**NRC 2004**).

2.6.2.1 Minority Populations

Minority populations are defined as American Indian or Alaskan Native, Asian, Black, Native Hawaiian or Pacific Islander, Multi-Racial, and Hispanic ethnicity. Other races are analyzed as one group (Other). The relative sizes of minority populations in jurisdictions surrounding CGS are included in Table 2.6-4.

The NRC determined that a minority population exists in a specific census block if either of two criteria is met:

- The minority population percentage of the census block exceeds 50%.
- The minority population percentage of the census block is significantly greater (more than 20%) than the minority population percentage in the geographic region chosen for comparison.

The comparison area selected for this analysis consists of the 10 counties surrounding CGS that are entirely or partly within 50 miles of the station. This area contains 538 census block-groups. The study area is a subset of the comparison area and excludes the census blocks that are within the 10 counties but fall outside the 50-mile radius. The study area consists of 299 census block groups within 50 miles of CGS (Figure 2.6-1).

Table 2.6-3 depicts the general demography in the major jurisdictions near the CGS site. With few exceptions, the demographic composition of the two-county area (Benton and Franklin) around the site closely matches the larger areas listed in the table. The notable differences are in percentages of residents who describe their race as "other" and those who describe their ethnicity as Hispanic. Twenty-nine percent of Franklin County residents are identified by race as "other" and 47% are identified by ethnicity as Hispanic. These are considerably higher percentages than in Benton County, the eight other counties in the 50-mile area, or the state as a whole. When the Benton and Franklin County populations are combined (i.e., the Tri-Cities MSA), the percentages of the population counted racially as "other" or ethnically as Hispanic are closer to those in the surrounding counties but appreciably higher than in the state of Washington or in the state of Oregon.

Table 2.6-4 and Table 2.6-5 display the number of block-groups within the 50-mile radius study area that met the 50% and 20% race and ethnicity criteria, respectively, summarized by county. Figure 2.6-2 through Figure 2.6-5 locate the minority block groups with the 50-mile radius.

Forty-nine block-groups in the study area have other race proportions that exceed the comparison area average by 20% or more. No block-group met the 50% criterion without also meeting the 20% criterion.

Five block-groups in the study area have American Indian/Alaskan Native race proportions that exceed the comparison area average by 20% or more. No block-groups met the 50% criteria.

Fifty-four block-groups in the study area have aggregate minority proportions that exceed the comparison area average by 20% or more. No block-group met the 50% criterion without also meeting the 20% criterion.

Sixty-one block-groups in the study area have Hispanic ethnicity proportions that exceed the comparison area average by 20% or more. No block-group met the 50% criterion without also meeting the 20% criterion.

There are no census block-groups that meet the 20% or 50% criteria for Black, Asian, Native Hawaiian/Pacific Islander, or Multi-Racial minority populations.

2.6.2.2 Low Income Populations

Low-income populations are defined by assessing household income according to a poverty income threshold determined by the USCB. Within the comparison area, 14% of households are defined as low-income. The NRC determined that a low-income population exists in a specific census block if either of two criteria is met:

- The percentage of low-income households in the census block exceeds 50%.
- The percentage of low-income households in the census block is significantly greater (more than 20%) than the percentage of low-income households in the geographic region chosen for comparison.

The number of census block groups within a 50-mile radius of CGS meeting the above criteria for low-income households are included in Table 2.6-5 (50% criterion) and Table 2.6-6 (20% criterion). Thirteen block-groups in the study area had low-income household proportions that exceed the comparison area average by 20% or more. No block-group met the 50% criterion without also meeting the 20% criterion. The locations of the low income block groups are shown in Figure 2.6-6.

2.6.2.3 Migrant Populations

Data on migrant populations for the 10 counties that fall wholly or partially within 50 miles of CGS is available from the U.S. Department of Agriculture (**NASS 2007c**). Migrant laborers were defined as any worker whose employment required travel that prevented the migrant worker from returning to his/her permanent place of residence the same day. Approximately 15% of the farms in Franklin, Grant, and Yakima Counties employ migrant laborers for at least some portion of the year. These counties would be expected to have the highest populations of migrant workers during the peak

agricultural seasons, i.e., planting and harvest. Table 2.6-6 displays information on migrant farm labor for each of the 10 counties.

Table 2.6-1. Population Density and Recent Change in Major Jurisdictions near the CGS Site

(Population density is in people per square mile)

Location	2000 Population	2005 Population (estimated)	Percent Annual Change	2000 Density	2005 Density
Within 20 miles of CGS(1)	171,371	188,508	1.96%	136	149.6
Within 50 miles of CGS(1)	387,512	425,515	1.96%	49.4	54.2
Tri-Cities MSA(2)	191,822	220,892	3.03%	63.4	73.0
Benton County, WA(3)	142,475	158,100	2.19%	83.7	92.8
Franklin County, WA(3)	49,347	60,500	4.52%	39.7	48.7
Comparison Area*(3)	695,182	741,381	1.33%	30.8	32.9
Washington(3)	5,894,121	6,256,400	1.23%	88.6	93.9
Oregon(4)	3,436,750	3,618,200	1.06%	35.6	37.7

*Adams, Benton, Franklin, Grant, Kittitas, Klickitat, Walla Walla, Yakima, Morrow and Umatilla Counties.

Sources:
(1) **USCB 2000a, ESRI 2007**
(2) **USCB 2000a**
(3) **WOFM 2007**
(4) **OOEA 2007**

Table 2.6-2. Population Projections for Counties Surrounding the CGS Site

	Census 2000	Estimate 2005	Projections						
			2010	2015	2020	2025	2030	2035	2040
Washington	5,894,121	6,256,400	6,792,318	7,255,672	7,698,939	8,120,510	8,509,161	8,872,375	9,208,281
Adams	16,428	17,000	18,376	19,568	20,761	21,905	22,926	23,873	24,734
Benton	142,475	158,100	168,839	176,854	184,704	192,131	198,528	204,300	209,345
Franklin	49,347	60,500	70,038	80,348	90,654	100,666	109,861	118,588	126,759
Grant	74,698	79,100	88,389	92,719	95,623	98,303	100,449	102,268	103,708
Kittitas	33,362	36,600	39,783	42,426	44,748	46,970	48,942	50,764	52,411
Klickitat	19,161	19,500	21,640	23,049	24,470	25,831	27,049	28,179	29,208
Walla Walla	55,180	57,500	60,840	63,139	65,593	67,895	69,828	71,537	72,985
Yakima	222,581	229,300	241,446	257,867	272,992	287,468	300,362	312,296	323,115
Oregon	3,436,750	3,618,200	3,843,900	4,095,708	4,359,258	4,626,015	4,891,225	5,154,793	5,425,408
Morrow	11,100	12,286	13,581	15,011	16,520	18,101	19,703	21,358	23,122
Umatilla	70,850	71,495	75,271	79,701	85,242	90,660	95,844	101,001	106,149

Sources: **WOFM 2007, OOEA 2007**

Table 2.6-3. General Demography in the Major Jurisdictions Near the CGS Site in 2000

Location	Percent Female	Age				Racial / Ethnic Makeup*							
		Median Age	Under 5	18+	65+	White	Black	Alaskan /Native American	Asian	Hawaiian /Pacific Islander	Other	Multi-Racial	Hispanic
Within 50 miles of CGS	49%	30-39	9%	68%	10%	73%	1%	1%	1%	0%	20%	3%	30%
Tri-Cities MSA	50%	30-39	8%	69%	10%	80%	1%	1%	2%	0%	13%	3%	21%
Benton County, WA	50%	34.4	8%	70%	10%	86%	1%	1%	2%	0%	7%	3%	12%
Franklin County, WA	48%	28	10%	65%	9%	62%	2%	1%	2%	0%	29%	4%	47%
Surrounding Counties**	50%	30-39	8%	70%	11%	76%	1%	2%	1%	0%	16%	3%	25%
Washington	50%	35.3	7%	74%	11%	82%	3%	2%	5%	0%	4%	4%	7%
Oregon	50%	36.3	7%	75%	13%	87%	2%	1%	3%	0%	4%	3%	8%

* Multiple ethnic category reporting may occur.
** Surrounding counties are Adams, Grant, Kittitas, Klickitat, Walla Walla, Yakima, Morrow, and Umatilla.

Sources: **USCB 2000a**, **ESRI 2007**

Table 2.6-4. Minority and Low-Income Population Census Block Groups (50% Criterion) Within a 50-Mile Radius of the CGS Site, by County, in 2000

State	County	Total Block Groups Within 50 Miles	Minority								Low-Income Households
			Black	American Indian or Alaska Native	Asian	Native Hawaiian or Pacific Islander	Other	Multi-Racial	Aggregate	Hispanic	
Washington	Adams	14	0	0	0	0	2	0	2	6	0
Washington	Benton	120	0	0	0	0	0	0	0	3	1
Washington	Franklin	42	0	0	0	0	8	0	8	17	1
Washington	Grant	28	0	0	0	0	2	0	2	4	0
Washington	Kittitas	3	0	0	0	0	0	0	0	0	0
Washington	Klickitat	1	0	0	0	0	0	0	0	0	0
Washington	Walla Walla	7	0	0	0	0	0	0	0	1	0
Washington	Yakima	46	0	0	0	0	13	0	13	24	0
Oregon	Morrow	6	0	0	0	0	0	0	0	1	0
Oregon	Umatilla	32	0	0	0	0	0	0	0	0	0
Totals		**299**	**0**	**0**	**0**	**0**	**25**	**0**	**25**	**56**	**2**

Source: **USCB 2000a, ESRI 2007**

Table 2.6-5. Minority and Low-Income Population Census Block Groups (20% Criterion) Within a 50-Mile Radius of the CGS Site, by County, in 2000

State	County	Total Block Groups Within 50 Miles	Minority								Low-Income Households
			Black	American Indian or Alaska Native	Asian	Native Hawaiian or Pacific Islander	Other	Multi-Racial	Aggregate	Hispanic	
Washington	Adams	14	0	0	0	0	5	0	5	7	0
Washington	Benton	120	0	0	0	0	2	0	2	3	4
Washington	Franklin	42	0	0	0	0	14	0	14	19	5
Washington	Grant	28	0	0	0	0	3	0	3	4	1
Washington	Kittitas	3	0	0	0	0	0	0	0	0	0
Washington	Klickitat	1	0	0	0	0	0	0	0	0	0
Washington	Walla Walla	7	0	0	0	0	1	0	1	1	0
Washington	Yakima	46	0	5	0	0	23	0	28	26	3
Oregon	Morrow	6	0	0	0	0	1	0	1	1	0
Oregon	Umatilla	32	0	0	0	0	0	0	0	0	0
Totals		**299**	**0**	**5**	**0**	**0**	**49**	**0**	**54**	**61**	**13**

Source: **USCB 2000a, ESRI 2007**

Table 2.6-6. Farms Using Migrant Labor for the Counties within a 50-Mile Radius of CGS, by County in 2007

State	County	Number of Farms	Farms Using Migrant Labor	Percent of Total Farms
Washington	Adams	782	48	6.1%
Washington	Benton	1,630	139	8.5%
Washington	Franklin	891	155	17.4%
Washington	Grant	1,858	289	15.6%
Washington	Kittitas	1,038	25	2.4%
Washington	Klickitat	893	33	3.7%
Washington	Walla Walla	929	42	4.5%
Washington	Yakima	3,450	481	13.9%
Oregon	Morrow	421	11	2.6%
Oregon	Umatilla	1,658	81	4.9%

Source: **NASS 2007c**

Figure 2.6-1. Demographic Study Area and Surrounding Counties

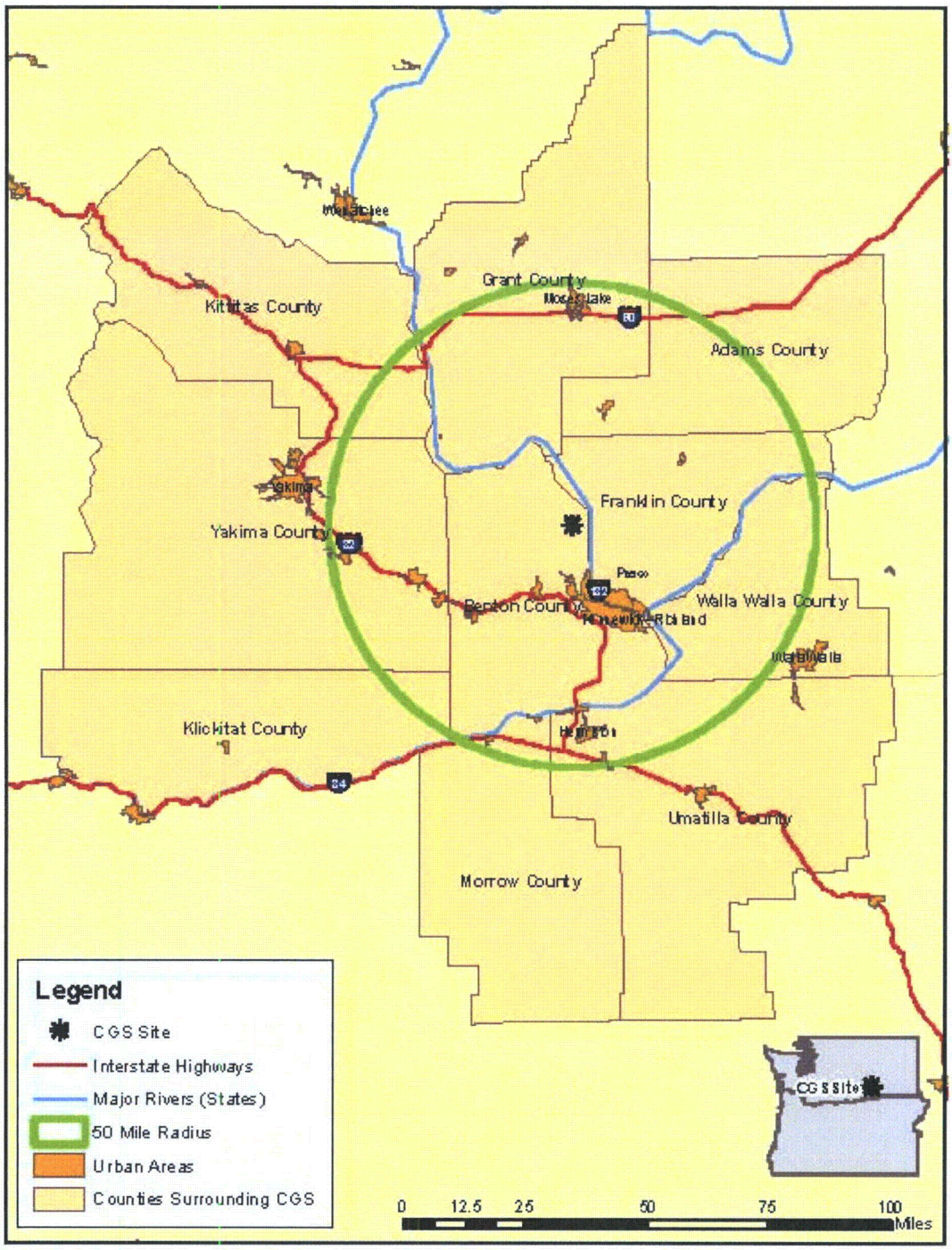


Figure 2.6-2. Other Minority Population Block Groups Within a 50-Mile Radius of the CGS Site

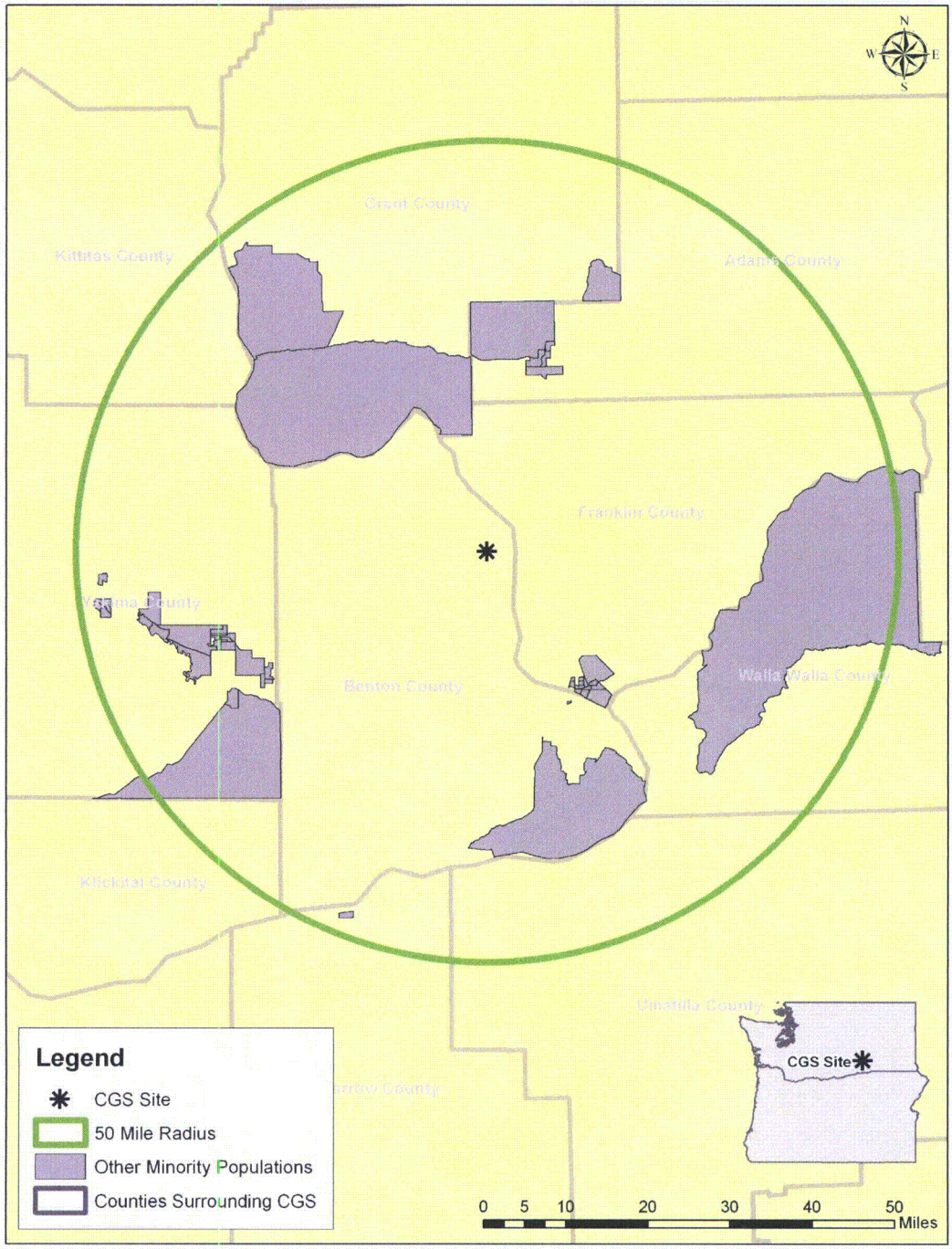


Figure 2.6-3. American Indian or Alaskan Native Minority Population Block Groups Within a 50-Mile Radius of the CGS Site

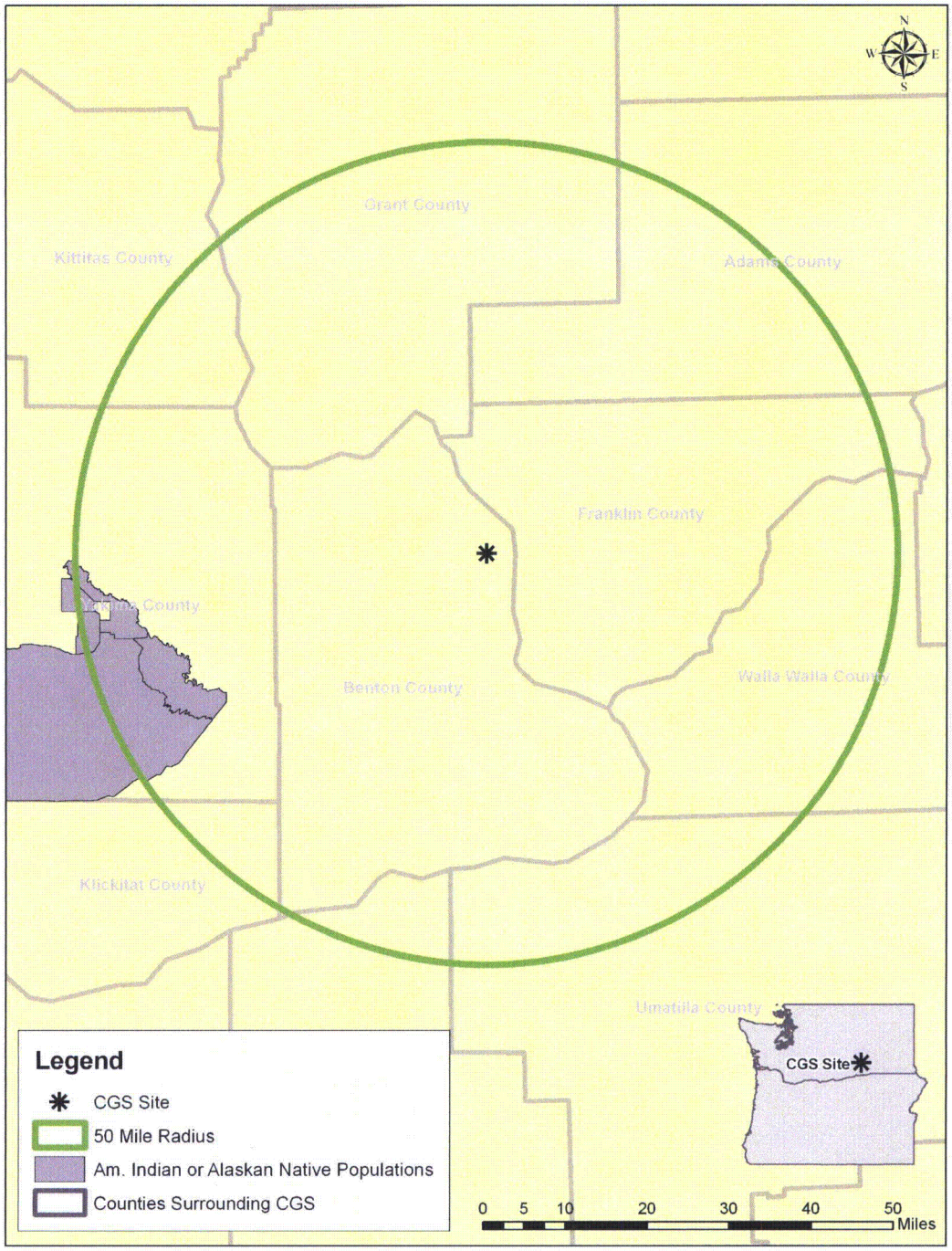


Figure 2.6-4. Aggregate Minority Population Block Groups Within a 50-Mile Radius of the CGS Site

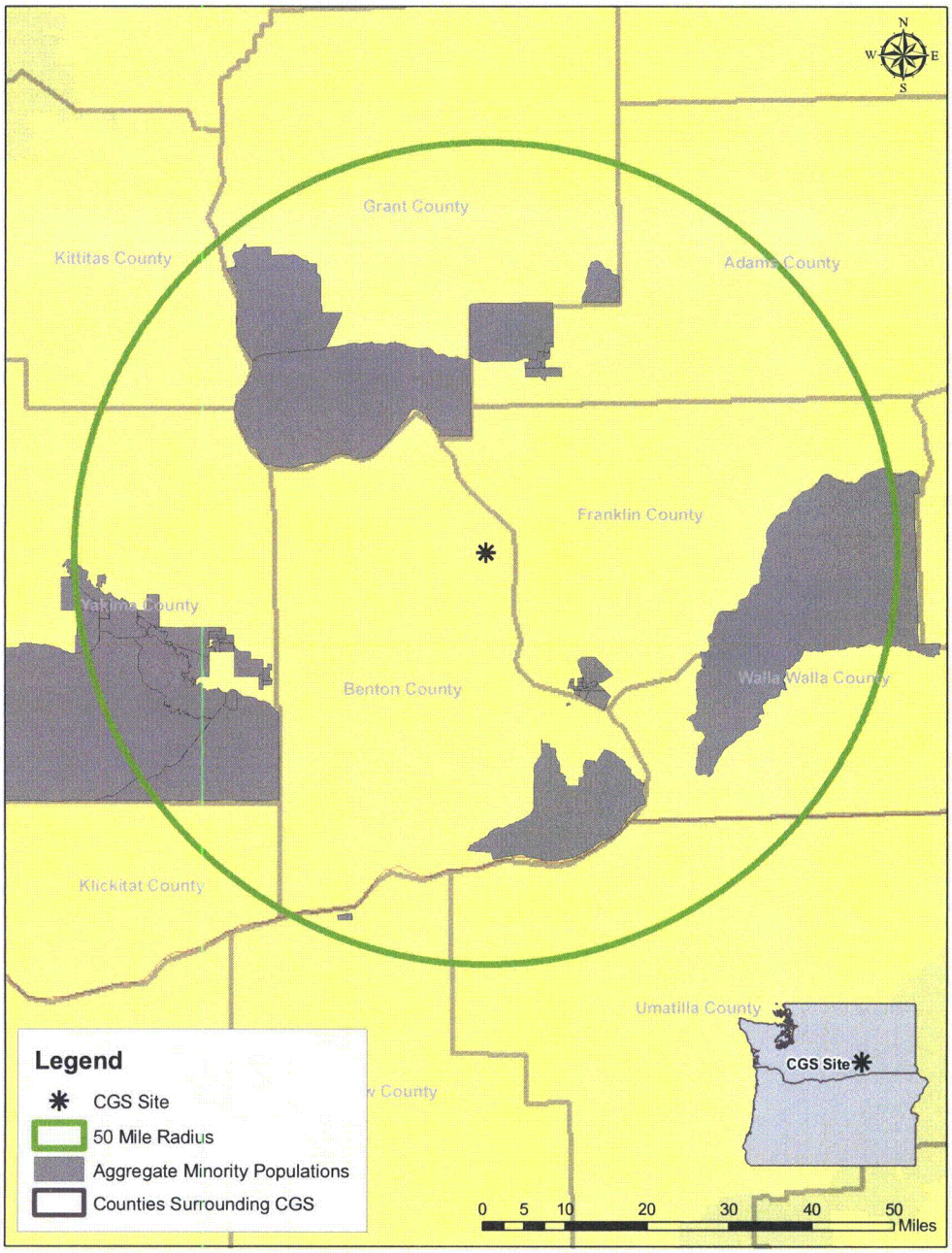


Figure 2.6-5. Hispanic Ethnicity Population Block Groups Within a 50-Mile Radius of the CGS Site

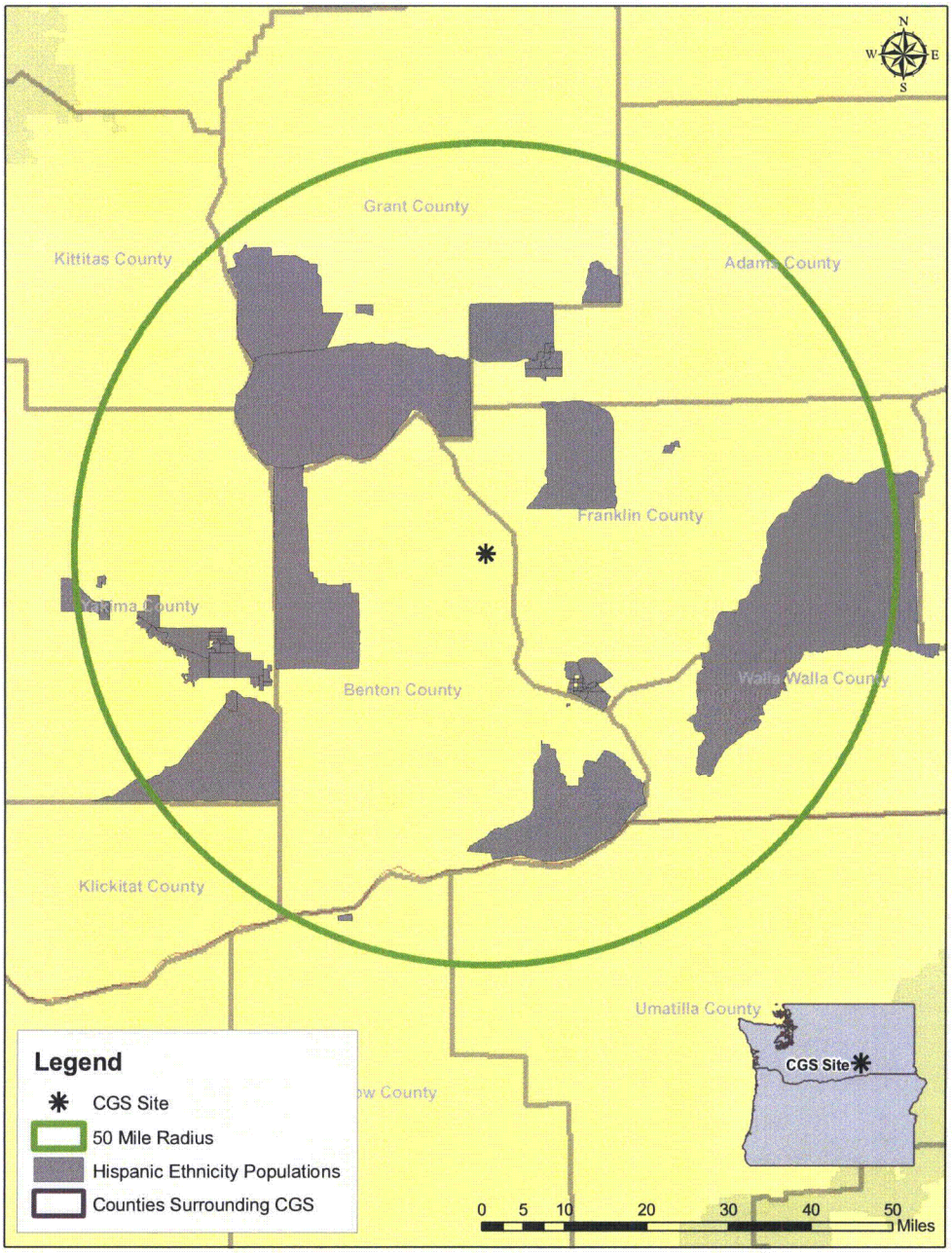
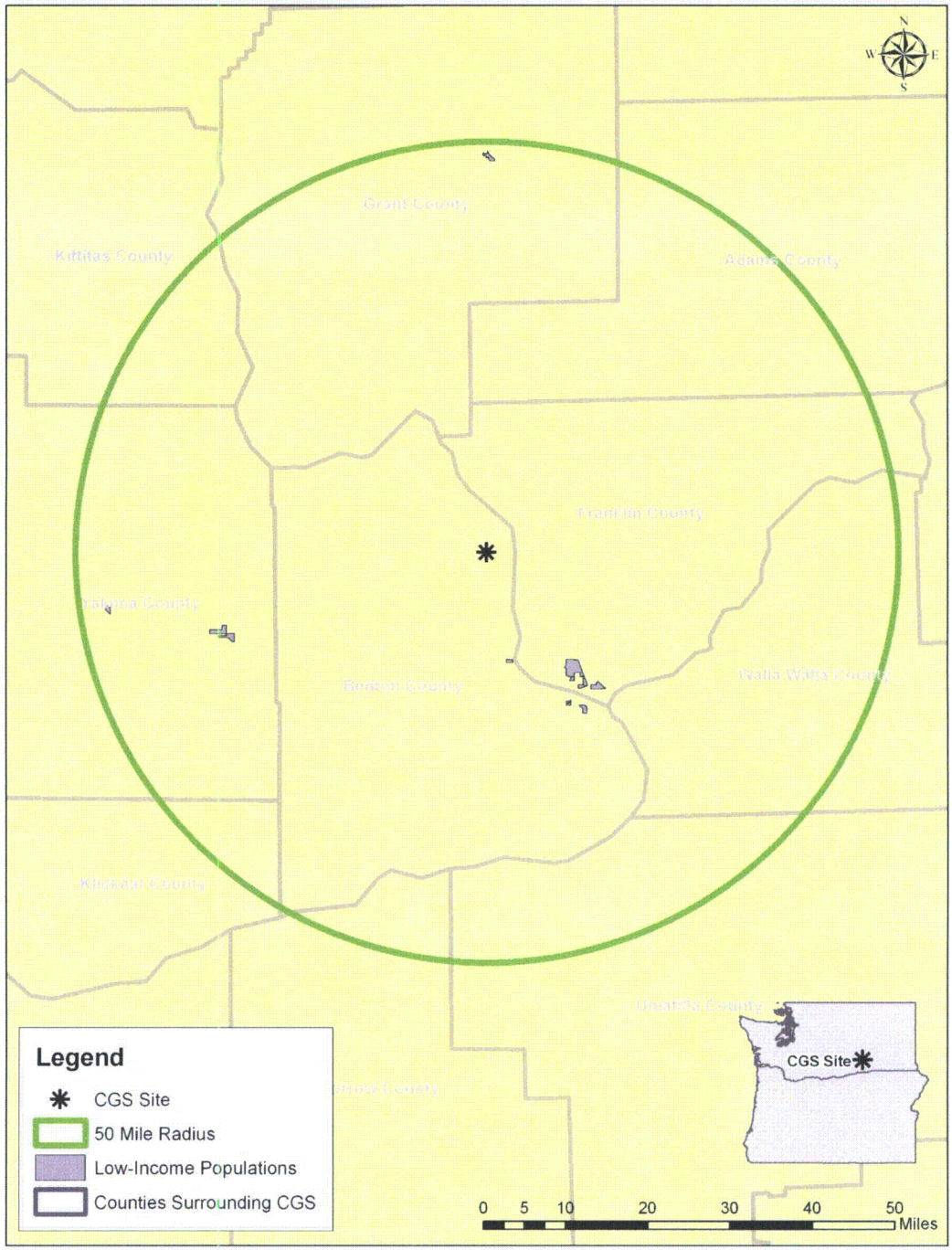


Figure 2.6-6. Low-Income Minority Population Block Groups Within a 50-Mile Radius of the CGS Site



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2.7 TAXES

Energy Northwest is a municipal corporation and joint operating agency of the State of Washington (see Section 1.3). As such, it is exempt from property taxes. Energy Northwest is, however, subject to state excise taxes.

The public utility privilege tax is a state excise tax that is levied on publicly-owned electric generating facilities in lieu of property tax assessments. The tax on thermal generating facilities is authorized by state law (Revised Code of Washington, Chapter 54.28) and is based on the net generation in a calendar year. The tax is distributed by the Washington Department of Revenue (WDOR) in accordance with specified formulas. About ten percent is deposited in the state general fund without earmark. The remaining approximately 90% is split evenly, with half going to the state general fund for the support of schools and half to jurisdictions within a defined impacted area. For CGS, the impact zone is defined by law as the area within 35 miles of the southern entrance to the USDOE Hanford Site (**WDOR 2007a,** Page 187).

Jurisdictions in the impacted area receiving payments include five counties (Benton, Franklin, Grant, Walla Walla, and Yakima), ten cities (Richland, Kennewick, Pasco, Benton City, Prosser, West Richland, Connell, Mesa, Grandview, Sunnyside), seventeen fire districts, and four library districts. The specified distribution of these payments is 22% to counties, 23% to cities, 3% to fire districts, and 2% to library districts. Distribution is based on the population in each jurisdictional area (**WDOR 2007a**, Page 187).

Privilege taxes paid by Energy Northwest for CGS energy generation over a five-year period are shown in Table 2.7-1.

The retail sales and use tax is a type of excise tax and is an important revenue source for state and local government in Washington State. The tax provides about 54% of state general fund revenue from in-state sources and 20% of local government tax receipts (**WDOR 2004**). The sales tax is levied on retail transactions. The state levy is 6.5% and the levies of local jurisdictions (e.g., cities, counties, public transit districts) can add another 0.5% to 2.4%. In the larger municipalities surrounding CGS the total tax rate is 8.3%, including 1% for city and county government. In the smaller cities and unincorporated areas the rate is as low as 7.7% (**WDOR 2007b**). The use tax applies to items and certain services that are not subject to the retail sales tax. These include purchases from out-of-state sellers and from sellers who are not required to collect the state sales tax. The tax rates are the same as the sales tax rates (**WDOR 2007a,** Page 32).

The leasehold excise tax is another tax in lieu of property tax that applies to leases of public property to private lessees. All receipts are deposited in the state general fund and about half is returned to the cities and counties in which the property is located

(**WDOR 2007a**, Page 189). Energy Northwest owns and leases office buildings in Benton County that are underwritten, in part, by bonds financing CGS. Accordingly, a leasehold tax is collected and paid to the state.

The sales/use and leasehold taxes attributable to CGS for fiscal years 2004 through 2008 are shown in Table 2.7-2. The sales/use tax fluctuates year-to-year largely because of the cyclical nature of the procurement activity related to the biennial refueling and maintenance outages at CGS. Nuclear fuel purchases comprise a significant component of the use tax.

Although Energy Northwest has paid substantial taxes related to the operation of CGS, the taxes do not represent significant fractions of the revenue of the local taxing jurisdictions. Estimating the relative amount of revenue these jurisdictions derive from CGS is somewhat difficult given the number of them and the fact that the distribution of sales/use tax revenue is indirect and varies based on the location of the merchant and point of delivery. To provide a sense of the relative support provided by CGS, estimates for several taxing districts are listed in Table 2.7-3 for 2007. The listed jurisdictions are representative of the many that could derive some revenue from sales taxes or privilege taxes paid by CGS. For most jurisdictions, the estimated revenue attributable to CGS is less than 1% of their general fund revenues.

Table 2.7-1. CGS Privilege Tax Distribution, 2004-2008

	Calendar Year(*)				
	2004	**2005**	**2006**	**2007**	**2008**
State General Fund	261,217	291,650	266,691	303,216	330,598
Public Schools	1,139,855	1,272,654	1,163,743	1,323,123	1,442,610
Counties (5)	501,536	559,968	512,047	582,174	634,748
Cities (10)	524,333	585,421	535,322	608,636	663,601
Fire Districts (17)	68,391	76,359	69,825	79,387	86,557
Library Districts (4)	45,594	50,906	46,550	52,925	57,704
Total Tax ($)	**2,540,927**	**2,836,959**	**2,594,178**	**2,949,461**	**3,215,818**

* Taxes, payable in June of each year, are based on the generation during the preceding calendar year.

Table 2.7-2. CGS Sales/Use and Leasehold Taxes, FY 2004-2008

	Fiscal Year (July 1- June 30)				
	2004	**2005**	**2006**	**2007**	**2008**
Sales/Use Tax ($)	2,799,321	7,767,808	2,570,866	11,489,074	4,602,412
Leasehold Tax ($)	41,587	43,032	39,499	45,654	59,818

Table 2.7-3. Estimated Relative Contribution of CGS to Revenue of Selected Jurisdictions, 2007

Jurisdiction	General Fund Revenue (1000 $)	Estimated Tax Revenue From CGS (1000 $)	Percent of General Fund Revenue from CGS Taxes
Benton County	51,493	393.9	0.77
Franklin County	20,760	146.2	0.70
Yakima County	51,055	74.9	0.15
City of Richland	37,920	276.5	0.73
City of Kennewick	34,122	306.4	0.90
City of Pasco	29,967	315.1	1.05
City of West Richland	4,943	45.6	0.92
City of Prosser	3,929	15.9	0.41
City of Connell	2,683	10.1	0.38
City of Grandview	4,400	27.9	0.63
Benton County Fire District No. 1	2,487	21.6	0.87
Benton County Fire District No. 4	1,343	14.9	1.11
Yakima County Fire District No. 5	3,626	8.6	0.24
Walla Walla Cnty Fire District No. 5	729	4.6	0.63
Mid-Columbia Library District	5,599	41.3	0.74
Yakima Valley Regional Library	5,946	6.8	0.11
Kennewick School District	84,830	39.0	0.05
Richland School District	126,905	59.3	0.05
Pasco School District	97,605	52.2	0.05
Ben Franklin Transit Authority	26,414	290.8	1.10

Notes:

(1) General fund revenue is normally for the operation and maintenance of the respective governmental function. Sources include taxes, license and permit fees, fines and forfeits, leases and rents, and charges for services. The Washington State Auditor's Office (**WSAO 2008**) is the source of the revenue numbers.

(2) The calendar year 2007 sale/use tax is assumed to be the average of the FY2007 and FY2008 tax in Table 2.7-2. Thus, CY2007 sales/use taxes from Table 2.7-2 are estimated to be $8,046K. Similarly, the CY2007 leasehold taxes are estimated to be $52.7K.
(3) For estimation it is assumed that 50% of the procurement subject to sales/use tax occurs locally with 30% in Benton County and 20% in Franklin County. Additional assumptions are made regarding the distribution of sales/use tax revenue among the cities. Benton County and the City of Richland are assumed to share half of the leasehold taxes that are paid.
(4) Estimated distribution of privilege taxes to school districts is based on fractional share of the total basic program support received by the district (from **WSPI 2008**). Distribution also assumes 33.4% of state general fund revenue supports K-12 education (**WDOR 2008**, Chart 3).
(5) Intergovernmental transfers of tax revenues are not considered.

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2.8 LAND USE PLANNING

This section focuses on Benton and Franklin Counties since over 95% of the permanent CGS workforce lives in these counties (see Section 3.4) and, as a result, would more likely influence present and future land use.

2.8.1 Existing Land Use Trends

Table 2.8-1 lists the types of land use and corresponding percentages of land area in Benton County and Franklin County. Following is a brief description of the land use in each county.

Benton County

Land-use in Benton County reflects a bimodal characteristic sustained by two large, independent components: commercial agricultural and the Hanford Site. Urban growth areas, principally the cities of Richland and Kennewick, account for only 6% of the total county area.

The principal agriculture land use outside of the Hanford Site is commercial dryland and irrigated crop produce and livestock products, with the market value of crops (mostly wheat for grain) being about nine times that of livestock, poultry, and their products. The number of farms in Benton County increased about 4% from 1997 to 2007. Farmland acreage in the county decreased less than 1% during the same period, and the average size of a farm decreased 4% to 388 acres (**NASS 2002a, NASS 2007a**).

The 586 square mile Hanford Site, most of which is in Benton County, contains large undisturbed areas of semiarid shrub and grassland and localized industrial areas that are principally supported by USDOE funding. Of note are the Fast Flux Test Facility (FFTF); eight decommissioned nuclear reactors; numerous hazardous waste storage, disposal and processing facilities; and newer structures such as the Environmental Molecular Sciences Laboratory (EMSL) and the Laser Interferometer Gravitational-Wave Observatory (LIGO). The Hanford Site also includes the Hanford Reach National Monument, the Fitzner/Eberhardt Arid Lands Ecology Reserve, and the Saddle Mountain National Wildlife Refuge (**PNNL 2004**, Section 2.1).

Franklin County

Franklin County is similar to Benton County in land use composition, with slightly less agricultural cropland and more livestock rangeland. Combined, agriculture and rangeland make up about 85% of the county land area. Urban growth areas, the largest being the city of Pasco, account for less than 5% of the total county area.

The principal crop is livestock forage (i.e., hay and grass silage), followed by wheat for grain, potatoes, vegetables, and sweet corn. Livestock (mostly cattle and calves) is about one-sixth the market value for all agriculture products. The number of farms in Franklin County decreased from 1997 to 2007 by 17%. The number of farmland acres and average size of a farm (in acres), however, increased during the same period by 5% and 26%, respectively (**NASS 2002b**, **NASS 2007b**).

A small portion of the Hanford Reach National Monument (approximately 40 square miles of the Wahluke Unit) extends into northwest Franklin County.

2.8.2 Future Land Use Trends

As required by the Washington State Growth Management Act of 1990 (Revised Code of Washington, Chapter 36.70A), both Benton County and Franklin County have developed comprehensive county-specific plans to accommodate and regulate growth and development. A key element of the planning process is the establishment of urban growth boundaries around existing incorporated areas for conversion to urban uses as growth occurs.

As noted in Section 2.6, both counties have experienced significant population growth in recent years. In fact, the Washington Department of Financial Management has reported that Benton and Franklin Counties are ranked fifth and first, respectively, in population growth between 2000 and 2008 among the 39 Washington counties (**WOFM 2008**, Table 3). This growth, and the associated land use changes, occurred at a time of stable employment at CGS. As shown in Table 2.6-3, the population growth is projected to continue. Nevertheless, the comprehensive plans of both counties conclude that there is ample urban and rural land to accommodate the anticipated growth over the 20-year planning horizon (**BCPD 2006**, Chapter 4; **FCPD 2008**, Page 38). Most of the growth will be in the designated urban growth areas that comprise less than 6% of the total area of the two counties (see Table 2.8-1). Agricultural will continue to be the major land use outside the urban growth areas.

Land-use planning at the Hanford Site is more complicated due to the multi-agency ownership of the various parcels on the site between the USDOE, Bureau of Land Management (BLM), and Bureau of Reclamation (BOR). When it is determined that the BLM or BOR lands are no longer necessary to support the USDOE mission, they are to revert to the respective agencies. After getting land back, the agencies would evaluate current land use, compatibility of uses, and suitability of the land for different uses (e.g., mining, grazing, recreation, and preservation) (**USDOE 1999**, Section 4.1.3). The Hanford Reach National Monument is likely to be an important factor in determining future uses of the river and the Hanford Site. As noted in Section 2.4, the U.S. Fish and Wildlife Service has developed, in cooperation with several local, state, and federal agencies, a plan for managing and conserving the monument resources (**USFWS 2008a**).

Table 2.8-1. Land Uses in Benton and Franklin Counties

Land Category	Acres	Square Miles	% Land
Benton County			
Urban Growth Areas	71,235	111	6.4
Hanford Site	266,220	416	23.9
Irrigated Cropland	251,406	393	22.5
Dryland Cropland	309,373	484	27.7
Rural Residential	22,342	35	2.0
Rangeland/Undeveloped	183,973	288	16.5
Other (*)	11,124	17	1.0
Total County Area	**1,115,673**	**1,744**	**100**
Franklin County			
Urban Growth Areas	35,508	58.5	4.4
Federal Lands/Waters	45,683	71.4	5.6
Irrigated Cropland	232,283	362.9	28.7
Dryland Cropland	222,992	348.4	27.6
Rural	13,243	20.7	1.6
Rangeland	259,776	405.9	32.1
Total County Area	**809,486**	**1,268**	**100**

* Commercial, Industrial, Public

Sources: **BCPD 2006**, Table 4.3; **FCPD 2008**, Table 25

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2.9 SOCIAL SERVICES AND PUBLIC FACILITIES

Table 3.4-1 presents the places of residence of the operational workforce of the Columbia Generating Station. The vast majority of the operational workforce resides in Benton County and Franklin County. As stated in Section 3.4, CGS anticipates that it can continue to operate the power plant for the 20-year license renewal period with the existing workforce. However, it is assumed that if any additional staff is required, that they will also reside primarily within the two-county area and in the same proportions as the existing workforce. Thus, the study area for the description of social services in the following sections is limited to the two-county area.

2.9.1 Economy, Employment and Income

2.9.1.1 Overall Economy

The Tri-Cities area within Benton and Franklin Counties historically has had one of the more volatile economies in Washington State even though, over the long run, its job growth rate has out-paced the state average. Until the 1990s, substantial volatility occurred as a result of changes in the agricultural sector and with federal funding for programs at the USDOE Hanford Site. The economic fluctuations have begun to dampen because of a growing diversification of the economy (**WESD 2007**).

The USDOE changed the role of the Hanford Site from the production of nuclear weapons material to the sealing and disposal of nuclear waste, and a significant amount of research is also conducted at the Pacific Northwest National Laboratory (PNNL) located onsite. Some economic growth has occurred from expansion of the traditional food processing industry (largely potato and fruit processing), but most of the agriculturally-related growth has resulted from expansion of the wine industry. Since 2000, several major companies also have moved to the Tri-Cities, including Ferguson Enterprises and Amazon.com, and the health care sector has grown. In addition, retirees from throughout the Pacific Northwest have been moving to the Tri-Cities because of the climate, lower cost of living, and healthcare facilities (**WESD 2007**).

Additional diversification of the economy and jobs base is expected with expansion of a minimum security prison at Connell in northern Franklin County by the Washington State Department of Corrections. In the future, the fastest growing industries in the Tri-Cities are projected to be information services, health care services, and public education (**WESD 2007**).

2.9.1.2 Employment

There were 70,520 people in the civilian labor force in Benton County in 2000 (Table 2.9-1). Of this total labor force, over 66,200 people were employed and just under 4,300 people (6.1%) were unemployed. The largest industrial sectors providing

employment included professionals, scientific, management, and administration (19.9%); educational, health, and social services (18.9%); and retail trade (11.6%). In comparison, Washington State had the same unemployment rate of 6.1% but the three largest industries providing employment were educational, health, and social services (19.4%); manufacturing (12.5%); and retail trade (12.1%) (**USCB 2000b**). As shown in Table 2.9-2, by 2006 it was estimated that the total civilian labor force had increased to almost 82,400 people, with over 75,400 people employed and almost 7,000 people (8.4%) unemployed. This sizable increase in the county's unemployment rate surpassed the state's slight rise to 6.4% (**USCB 2006**).

There were almost 21,900 people in the civilian labor force in Franklin County in 2000 (Table 2.9-1). Of this total labor force, over 19,500 people were employed and just under 2,400 people (10.8%) were unemployed, a significantly greater proportion than in Benton County. The largest industrial sectors providing employment included agriculture, forestry, fishing & hunting, and mining (17.0%); educational, health, and social services (15.6%); and manufacturing (11.6%) (**USCB 2000b**). By 2006 it was estimated that the total civilian labor force had increased to over 32,400 people, with over 29,000 people employed and almost 3,400 people (10.4%) unemployed (Table 2.9-2). Thus, the county's unemployment rate remained stable over the 7-year period but still significantly greater than the state rate (**USCB 2006**).

In 2006, it was estimated that the combined two-county study area had a total civilian labor force of over 114,800 people, with almost 104,500 people employed and over 10,300 people (9.0%) unemployed. The combined largest industrial sectors providing employment included educational, health, and social services (18.3%); professionals, scientific, management, and administration (17.0%); and retail trade (10.5%) (**USCB 2006**). The Hanford Site accounted for the three largest employers in the region, including Battelle/PNNL, Fluor, and Bechtel National, Inc (Table 2.9-3). Other major employers in the area include ConAgra/Lamb Weston (food processing), Kadlec Medical Center (hospital), Tyson Fresh Meats (meat packing), Energy Northwest (power generation, including CGS), and the CH2M Hill Hanford Group, Inc. (**TRIDEC 2007a**).

2.9.1.3 Income

Table 2.9-4 shows income and poverty levels for Benton and Franklin Counties and the state in 2000. Benton County's median household income in 2000 was $47,044, somewhat more than the $45,776 for the State of Washington. Per capita income was $21,301, which was less than the $22,973 for the state. The 7.8% of the families living below the poverty level was slightly greater than the 7.3% for the state, but the percentage of individuals was slightly less (**USCB 2000b**). The estimated 2006 median household income of $50,688 and per capita income of $24,852 were less than the income levels for the state (Table 2.9-5). Along with these lower income levels, the county also had a greater percentage of families and individuals (10.2% and 13.9%, respectively) living below the poverty level compared to the state (8.0% and 11.8%,

respectively). The percentage of families living below the poverty level grew by 2.4 percentage points from 2000 to 2006, and the percentage of individuals grew by 3.6 percentage points (**USCB 2006**).

Franklin County's median household income in 2000 was $38,991 and the per capita income was $15,459, both significantly less than for the State of Washington and Benton County. The 15.5% of the families and 19.2% of all individuals living below the poverty level also were significantly greater than the 7.3% and 10.6% (respectively) for the state (**USCB 2000b**). The estimated 2006 median household income of $42,417 and per capita income of $17,382 also were significantly less than the income levels for the state (Table 2.9-5). Along with these lower income levels, the county also had a significantly greater percentage of families and individuals (21.3% and 24.9%, respectively) living below the poverty level compared to the state (8.0% and 11.8%, respectively). From 2000 to 2006, the percentage of families and individuals living below the poverty level grew by almost 6 percentage points (**USCB 2006**).

2.9.2 Education

2.9.2.1 Primary Education

The Kennewick School District has 13 elementary, 4 middle, 3 high, 1 skills center, and 3 alternative schools. Enrollment was 14,820 during the 2006-07 school year. The district employed a total of 1,880 staff or about 1,465 full-time equivalents (FTEs), including 917 FTE certified and 547 FTE classified staff (**KSD 2007,** Page 3).

Pasco School District has 11 elementary, 3 middle, 2 high, and 1 alternative middle/high schools. The enrollment is over 11,500 students and they have 1,233 district employees, including 700 certified and 533 classified staff (**PSD 2007**).

The Richland School District serves the cities of Richland and West Richland. The district has 8 elementary, 3 middle, 2 high, 1 alternative middle, and 1 alternative high schools. Enrollment was 9,964 during the 2005-06 school year, but increased to 10,315 in the 2006-07 school year. The district has a total of 1,077 staff, including 577 certified and 500 classified staff (**RSD 2007**, Pages x, xi).

2.9.2.2 Secondary Education

Washington State University has a branch campus (WSU Tri-Cities) in northern Richland. The school formerly had a 2-year program; however, in 2005 the state approved converting the branch to a 4-year campus. The first undergraduates were admitted into the new 4-year program in Fall 2007. Student enrollment is about 1,300 at Richland and the affiliated satellite locations. The branch campus has over 50 full-time and 350 part-time faculty. The campus has bachelors and masters degree programs in a wide variety of majors (**WSU 2008**).

Columbia Basin College is a 2-year community college located in Pasco, with additional facilities in Richland. In Fall 2007, the college had an enrollment of over 7,600 students, and 117 full-time faculty, 194 part-time faculty, and a number of other staff. The college has associates degree programs in applied sciences and arts and sciences for a variety of majors, and also a number of 1-year certificate programs (**CBC 2008**).

2.9.3 Recreation

The Tri-Cities is at the confluence of the Columbia, Snake, and Yakima Rivers. Its location along these three major rivers and the typically warm and sunny climate of the region provides a wide variety of opportunities for water-based recreational activities. Typical water recreational activities include swimming, jet boat tours and river cruises, power and pleasure boating (e.g., canoeing and kayaking), water-skiing and wakeboarding, windsurfing, sailing, fishing and guided-fishing, and other activities. Other recreational activities include golfing, winery tours and tastings, hiking, camping, and hunting (**TCVCB 2008**).

A major regional recreational resource is the U.S. Fish and Wildlife Service's (USFWS) Hanford Reach National Monument, the Service's only national monument. The monument surrounds the northern, western, and southern borders of the Hanford Site and has been divided into six units:

- Wahluke Unit – managed by the USFWS, located north and northeast of the Hanford Site, with public access allowed;
- Saddle Mountain Unit - managed by the USFWS, located to the northwest, no public access is allowed;
- River Corridor Unit – comprising the Columbia River that flows along the eastern and northern border of the Hanford Site, with public access allowed;
- Vernita Bridge Unit – managed by the Washington Department of Fish and Wildlife, located to the northwest, with public access allowed;
- McGee Ranch/Riverlands Unit –managed by the USDOE, located to the northwest, no public access is allowed except along the Columbia River and where the Vernita Rest Area is located; and
- Fitzner/Eberhardt Arid Lands Ecology Reserve Unit - managed by the USFWS, located to the southwest and south, no public access is allowed.

As indicated above, public access is not allowed to large parts of the monument, but over 57,000 acres are publicly accessible. The Monument provides a variety of recreational opportunities, including fishing, hunting, boating, hiking, and wildlife observation. Several boat ramps are available for accessing the river (**USFWS 2009**).

The Tri-Cities area has a number of parks within each of its municipalities. Kennewick has 29 parks that include over 620 acres of facilities. The largest parks are Columbia Park (400 acres), Zintel Canyon (68 acres), Grange Park (26 acres), Lawrence Scott Park (26 acres), Hanson Park (23 acres), and Horse Heaven Hills (20 acres) (**CK 2007a**).

Pasco has 30 parks comprised of more than 343 acres, including Chiawana Park (125 acres), the Soccer Complex (45 acres), the Softball Fields (28 acres), and Wade Park (25 acres) (**CP 2007a**).

Richland has 49 parks totaling about 2,120 acres, including ORV Park (300 acres), Chamna Preserve (276 acres), W.E. Johnson Park (236 acres), South Columbia Point (230 acres), Columbia Point Golf Course (170 acres), Bateman Island (160 acres), Leslie Groves Park (149 acres), Badger Mountain (89 acres), and 7 additional parks that each comprise over 20 acres (**CR 2007a**).

2.9.4 Public Facilities

The following sections provide brief summaries of the municipal water supply systems and major modes of transportation and routes in the Tri-Cities area.

2.9.4.1 Water

Each of the municipalities comprising the Tri-Cities provides water service to its businesses and residences. Table 2.9-6 provides a summary of the capacities and peak and average daily rates of use of the municipal water systems.

The City of Kennewick draws its water from the Columbia River and two Ranney Collector wells, depending upon the time of the year. The water is treated at the Kennewick Water Treatment Plant before distribution in the water system. In 2007, about 37% of the annual water use was drawn from the Columbia River and 63% of the annual water use was drawn from the Ranney wells (**CK 2007b**). The Kennewick water system has excess capacity to meet its average daily water needs, with 44.8% use of its capacity, but during peak use periods it uses a significant portion of its capacity (78.6%) (**TRIDEC 2007a**).

The City of Pasco obtains all of its water from the Columbia River, which is then processed in its treatment plant before distribution (**CP 2007b**). The Pasco water system has excess capacity to meet its average daily use (30.4%) and peak use (52.2%) water needs (**TRIDEC 2007a**).

The City of Richland draws its water from the Columbia River and three groundwater wells. During 2007, about 56% of the water was drawn from the Columbia River and 44% was drawn from the wells. As with the City of Kennewick, withdrawals from each source vary depending upon the time of the year (**CR 2007b**). The Richland water

system has excess capacity to meet its average daily water needs, with 47.8% use of its capacity, but during peak periods it uses almost all of its capacity (95.1%) (**TRIDEC2007a**).

The City of West Richland obtains all of its water from eight groundwater wells, and has a water interconnect with the City of Richland's water system if additional water is needed (**CWR 2007**). The West Richland water system uses most of its capacity during average daily operations (87.7%) and during peak operations (93.0%) (**TRIDEC 2007a**).

The potable water system at CGS is not tied to any of the above municipal systems. As discussed in Section 3.1.2.4, Columbia River water is treated on site to supply the potable water needs at CGS.

2.9.4.2 Transportation

The Tri-Cities area is located at a hub of a number of major transportation networks, including highways, airports, rail, and water. The major facilities in the area are briefly described below.

Highways

The Tri-Cities area is located at the intersection of several major highways, including Interstate (I) 182/U.S. Highway (US) 12 and US-395. I-182/US-12 is a four-lane divided highway that lies to the south of the Hanford Site and runs east-west. As shown in Table 2.9-7, in 2006 I-182/US-12 had an annual average daily traffic (AADT) count of 44,671 vehicles in both directions at the Columbia River Bridge in Pasco (milepost [mp] 6.34). Weekday volumes were greater than weekend volumes, and westbound volumes were greater than eastbound volumes (**WDOT 2006**, Page 22).

Also included in Table 2.9-7 is the level of service (LOS) to evaluate the roadway traffic volume. LOS is a qualitative assessment of traffic flow and how much delay the average vehicle might encounter during peak hours (**NRC 1996**, Section 3.7.4.2). LOS is designated as A through F, where A is the best and F the worst. A designation of A, for instance, is a free flow of the traffic stream and users are unaffected by the presence of others. A designation of F, on the other hand, is forced or breakdown flow that causes delays characterized stop-and-go movement.

US-395 is a four-lane divided highway that lies 15 miles to the east of the Hanford Site, on the other side of the Columbia River, and runs north-south. In 2006 south of Vineyard Drive in Pasco (mp 27.20) US-395 had an AADT count of 13,512 vehicles in both directions. The weekday and weekend volumes and the northbound and southbound volumes are relatively similar. The average LOS for this stretch of US-395 is B. At the Columbia River Bridge (mp 18.58) it had an AADT count of 56,635 vehicles in both directions. Weekday volumes were greater than weekend volumes, and northbound volumes were greater than southbound volumes. The average LOS for

US-395 in the vicinity of the Columbia River Bridge is A (**WDOT 2006**, Page 22; **WDOT 2009**).

Another important highway route is State Route (SR) 240 that generally traverses southeast (from its junction with US-395) to the northwest. The northern part of SR-240 is a two-lane highway. The southern portion from Stevens Drive to Columbia Center Boulevard that serves as a commuter route to the Hanford Site was expanded from 4 to 6 lanes in a series of highway improvement projects between 2001 and June 2007 (**WDOT 2007**). Traffic volume information was not available for 2006. However, in 2005, the portion of SR-240 located west of the Columbia Park Trail interchange in Richland had an AADT of 54,460 vehicles in both directions. Eastbound and westbound volumes were relatively similar (**WDOT 2005**). The average LOS for SR-240 in this area is B (**WDOT 2009**). The other major north-south commuter arterial through Richland is George Washington Way. The street is four lanes except at the south end where it was widened to six lanes in 2006.

SR-24 also is a two-lane highway that lies on the northern part of the Hanford Site, and traverses east-west. In 2006, the Columbia River bridge at Vernita (mp 43.50) portion of SR-24 had an AADT of 3,519 vehicles. Although weekend volumes were slightly greater than weekday volumes, there was essentially no difference between eastbound and westbound volumes (**WDOT 2006**, Page 17). The average LOS in the vicinity of Vernita Bridge is B (**WDOT 2009**).

Airports

The Tri-Cities area is served by four public airports, the Tri-Cities Airport, the Richland Airport, the Prosser Airport, and Vista Field, as well as seven private airports and six heliports. The Tri-Cities Airport is a commercial airport located 17 miles southeast of CGS in Pasco. The airport is operated by the Port of Pasco. It is located near the junction of I-182 and US-395. The airport is served by Delta Connection, Horizon Air/Alaska, United Express, and Allegiant Air airlines with 28 daily flights and over 240,000 people boarding planes annually. The airport has three runways, a control tower, a 58,000-square foot terminal, and hangars. The two longest runways are 7,700 feet long and have lights and navigation aids (**PP 2007**, **TRIDEC 2007a**).

The Richland Airport is a general aviation facility located 11 miles south of CGS and is owned by the Port of Benton. The airport serves commuter aircraft and single and twin engine general aviation users, and has a commuter terminal and hangars. It has two 4,000-foot lighted runways (**TRIDEC 2007a**).

Prosser Airport is located about 25 miles southwest of CGS adjacent to US-12, and is owned by the Port of Benton. The airport serves general aviation users. The airport has one 3,450-foot lighted runway (**TRIDEC 2007a**).

Vista Field is also a general aviation facility located 18 miles south-southeast in Kennewick and is owned by the Port of Kennewick. The airport has a terminal, provides aircraft repair, charter service, and hangars. The airport serves commuter aircraft and single and twin engine propeller general aviation users weighing less than 8,000 pounds. The airport has a single runway that is 4,000-feet long with lighting and non-precision navigational aids (**TRIDEC 2007a**).

Railroads

Railroad transportation to the Tri-Cities is available for passengers and freight. Amtrak provides daily passenger rail service into Pasco (**Amtrak 2007**). Mainline rail freight service is provided by the Burlington Northern/Santa Fe Railroad and the Union Pacific Railroad. Both of these railroads have inter-modal loading facilities in the Tri-Cities (**TRIDEC 2007a**). The Tri-City & Olympia Railroad Company provides freight rail interconnection from the Union Pacific and Burlington Northern Santa Fe Railroads to the USDOE Hanford Site (**TCRY 2008**).

Water Transportation

The Columbia and Snake Rivers provide a commercial waterway for the transport of manufactured goods and bulk commodities (e.g., petroleum, lumber, and grain). The Port of Kennewick has several waterfront facilities in Kennewick and east of the city. The Port of Pasco, with two miles of riverfront, has a 650-foot dock and facilities for loading and unloading containers and bulk cargo (**TRIDEC 2007a**).

Special shipments of large items to the USDOE Hanford Site are off-loaded at the Port of Benton dock in Richland at approximately river mile 343 (**TRIDEC 2007a**).

2.9.5 Housing

Table 2.9-8 presents information about the housing market in the two-county area based upon U.S. Census Bureau data for 2000 and 2006. Benton County had a total 55,963 housing units in the 2000 census. The number of housing units increased to 62,516 in 2006. Approximately 36,344 (68.7%) units were occupied by owners with 16,522 (31.3%) occupied by renters based on the 2000 census data. Corresponding occupancy estimates for 2006 were 39,048 (68.7%) for owners and 17,760 (31.2%) for renters. Almost 3,100 units (5.5%) were vacant in 2000 while 5,708 (9.1%) were vacant in 2006. Benton County median house values increased markedly from $119,900 to $156,100 between 2000 and 2006. These values, however, were significantly less than the state median values of $168,300 and $267,600 in 2000 and 2006 respectively (**USCB 2006**).

Franklin County had similar trends over the period. The number of total housing units and those occupied increased between 2000 and 2006, from 14,840 to 20,140 units.

The overall vacancy rate in Franklin County, unlike Benton County, was less in 2006 than in 2000 (6.7% vs. 7.7%) (**USCB 2006**). Median house values in Franklin County over the 2000 to 2006 period also increased markedly from $102,000 to $138,500 but the median house values, as in Benton County during the same period remained well below the state's median values.

Housing data and projected growth over the period 2000 through 2012 for the Tri-Cities area are provided in Table 2.9-9. Occupancy rates are not predicted to change substantially over the period, and annualized growth from 2007 to 2012 is projected to be about 2%, similar to that experienced over the period 1990 to 2000 (**TRIDEC 2007a**).

Table 2.9-1. Employment Estimates by Industry, 2000

Employment	Number / Percent			
	Benton County	Franklin County	Two-County Area Total	Washington
Population 16 years old and older	105,052	34,262	139,314	4,553,591
Total Labor Force				
Total Civilian	70,520	21,875	92,395	2,979,824
Employed	66,233 / 93.8%	19,513 / 89.2%	85,746 / 92.8%	2,793,722 / 92.3%
Unemployed	4,287 / 6.1%	2,362 / 10.8%	6,649 / 7.2%	186,102 / 6.1%
Armed Forces	63 / 0.1%	0 / 0.0%	63 / 0.05%	47,910 / 1.6%
Employment by Industry				
Agriculture, forestry, fishing & hunting, mining	2,744 / 4.1%	3,323 / 17.0%	6,067 / 7.1%	68,976 / 2.5%
Construction	4,848 / 7.3%	1,225 / 6.3%	6,073 / 7.1%	194,871 / 7.0%
Manufacturing	4,964 / 7.5%	2,264 / 11.6%	7,228 / 8.4%	348,646 / 12.5%
Wholesale Trade	2,024 / 3.1%	845 / 4.3%	2,869 / 3.3%	113,526 / 4.1%
Retail Trade	7,695 / 11.6%	2,063 / 10.6%	9,758 / 11.4%	338,772 / 12.1%
Transportation, warehousing, utilities	4,133 / 6.2%	1,256 / 6.4%	5,389 / 6.3%	150,985 / 5.4%
Information	1,304 / 2.0%	168 / 0.9%	1,472 / 1.7%	95,669 / 3.4%
Finance, insurance, real estate, & rental/leasing	2,519 / 3.8%	614 / 3.1%	3,133 / 3.7%	170,622 / 6.1%
Professional, scientific, management, admin, waste management	13,159 / 19.9%	1,932 / 9.9%	15,091 / 17.6%	272,466 / 9.8%
Educational, health, and social services	12,491 / 18.9%	3,035 / 15.6%	15,526 / 18.1%	541,214 / 19.4%
Arts, entertainment, recreation, accommodations, food service	4,388 / 6.6%	1,161 / 5.9%	5,549 / 6.5%	221,656 / 7.9%
Other services	2,886 / 4.4%	862 / 4.4%	3,748 / 4.4%	135,379 / 4.8%
Public administration	3,078 / 4.6%	765 / 3.9%	3,843 / 4.5%	140,940 / 5.0%

Source: **USCB 2000b**

Table 2.9-2. Employment Estimates by Industry, 2006

Employment	Number / Percent			
	Benton County	Franklin County	Two-County Area Total	Washington
Population 16 years old and older	122,114	47,384	169,498	5,050,544
Total Labor Force				
Total Civilian	82,383	32,423	114,806	3,296,812
Employed	75,435 / 91.5%	29,062 / 89.6%	104,497 / 91.0%	3,084,652 / 92.4%
Unemployed	6,948 / 8.4%	3,361 / 10.4%	10,309 / 9.0%	212,160 / 6.4%
Armed Forces	68 / 0.08%	0 / 0.0%	68 / 0.06%	40,901 / 1.2%
Employment by Industry				
Agriculture, forestry, fishing & hunting, mining	3,752 / 5.0%	4,837 / 16.6%	8,589 / 8.2%	82,660 / 2.7%
Construction	5,958 / 7.9%	1,721 / 5.9%	7,679 / 7.3%	245,348 / 8.0%
Manufacturing	6,209 / 8.2%	2,671 / 9.2%	8,880 / 8.5%	340,781 / 11.0%
Wholesale Trade	2,238 / 3.0%	497 / 1.7%	2,735 / 2.6%	109,179 / 3.5%
Retail Trade	7,098 / 9.4%	3,884 / 13.4%	10,982 / 10.5%	335,765 / 10.9%
Transportation, warehousing, utilities	3,266 / 4.3%	1,707 / 5.9%	4,973 / 4.8%	158,528 / 5.1%
Information	1,418 / 1.9%	438 / 1.5%	1,856 / 1.8%	91,452 / 3.0%
Finance, insurance, real estate, & rental/leasing	3,082 / 4.1%	946 / 3.3%	4,028 / 3.9%	207,203 / 6.7%
Professional, scientific, management, admin, waste management	15,857 / 21.0%	1,865 / 6.4%	17,722 / 17.0%	330,277 / 10.7%
Educational, health, and social services	13,523 / 17.9%	5,639 / 19.4%	19,162 / 18.3%	614,748 / 19.9%
Arts, entertainment, recreation, accommodations, food service	7,175 / 9.5%	2,256 / 7.8%	9,431 / 9.0%	260,802 / 8.5%
Other services	3,340 / 4.4%	1,364 / 4.7%	4,704 / 4.5%	147,444 / 4.8%
Public administration	2,519 / 3.3%	1,237 / 4.3%	3,756 / 3.6%	160,465 / 5.2%

Source: **USCB 2006**

Table 2.9-3. Major Employers in the Tri-Cities, April 2007

Employer	Product/Service Sector	Number of Employees
Battelle/PNNL	Research Laboratory	4,188
Fluor	Government Contractor	3,597
Bechtel National, Inc.	Government Contractor	2,400
ConAgra/Lamb Weston	Food Processing	1,685
Kadlec Medical Center	Hospital	1,486
Tyson Fresh Meats	Meat Packing	1,235
Energy Northwest	Electric Utility	1,072
CH2M Hill Hanford Group, Inc.	Government Contractor	1,060
Broetje Orchards (seasonal)	Agricultural Services	988
Kennewick General Hospital	Hospital	805
Tri-Cities Airport	Airport Services	703
Benton County	County Government	664
Lockheed Martin Services, Inc.	Information Technology Services	650
Lourdes Health Network	Hospital	640
AREVA, Inc.	Nuclear Fuel	625
Apollo, Inc.	Manufacturing/Contractor	490
USDOE Richland Operations	Federal Government	231
AgriNorthwest	Agricultural Services	200
USDOE Office of River Protection	Federal Government	102

Note: Excludes education employment.

Source: **TRIDEC 2007a**

Table 2.9-4. Income and Poverty Levels, 2000 Census Data

	Benton County	Franklin County	Washington
Annual Income			
Median Household:	$47,044	$38,991	$45,776
Median Family:	$54,146	$41,967	$53,760
Per Capita:	$21,301	$15,459	$22,973
% Below Poverty			
Families	7.8%	15.5%	7.3%
Individuals	10.3%	19.2%	10.6%

Source: **USCB 2000b**

Table 2.9-5. Estimated Income and Poverty Levels, 2006

	Benton County	Franklin County	Washington
Annual Income			
Median Household:	$50,688	$42,417	$52,583
Median Family:	$62,426	$45,900	$63,705
Per Capita:	$24,852	$17,382	$27,346
% Below Poverty			
Families	10.2%	21.3%	8.0%
Individuals	13.9%	24.9%	11.8%

Source: **USCB 2006**

Table 2.9-6. Municipal Water Systems in the Tri-Cities

Municipality	System Capacity (mgd)	Demand/Use (mgd/%)	
		Peak Daily	Average Daily
Kennewick	21.0	16.5 / 78.6%	9.4 / 44.8%
Pasco	23.0	12.0 / 52.2%	7.0 / 30.4%
Richland	41.0	39.0 / 95.1%	19.6 / 47.8%
West Richland	5.7	5.3 / 93.0%	5.0 / 87.7%

Source: **TRIDEC 2007a**

Table 2.9-7. Primary Highway Annual Average Daily Traffic, 2006

Highway/Location Description/Milepost	Average Weekday	Average Weekend Day	Annual Average Daily
U.S. Highway 395 south of Vineyard Drive in Pasco / m.p. 27.20 (Avg. LOS: B)			
Northbound	6,618	7,031	6,767
Southbound	6,578	6,957	6,745
Both Ways	13,196	13,988	13,512
U.S. Highway 395 at the Columbia River Bridge / m.p. 18.58 (Avg. LOS: A)			
Northbound	30,719	27,472	29,144
Southbound	28,879	26,111	27,495
Both Ways	59,605	53,583	56,635
Interstate 182 at the Columbia River Bridge in Pasco / m.p. 6.34 (Avg. LOS: B)			
Eastbound	23,972	19,904	21,992
Westbound	24,684	20,488	22,679
Both Ways	48,657	40,392	44,671
State Route 240 west of the Columbia Park Trail interchange in Richland / m.p. 37.53* (Avg. LOS: B)			
Eastbound	30,169		27,390
Westbound	30,204		27,070
Both Ways	60,374		54,460
State Route 24 at the Columbia River Bridge at Vernita / m.p. 43.50 (Avg. LOS: B)			
Eastbound	1,615	1,930	1,753
Westbound	1,622	1,950	1,766
Both Ways	3,238	3,880	3,519

Note: Data for SR 240 at m.p. 37.53 was not available for 2006, and only part of the data was available for 2005.

Sources: **WDOT 2005**, **WDOT2006**, and **WDOT 2009**

Table 2.9-8. Benton and Franklin County Housing

Housing Characteristic	Benton 2000	Benton 2006	Franklin 2000	Franklin 2006
Total Units	55,963	62,516	16,084	21,602
Occupied	52,866	56,808	14,840	20,140
Owner-occupied	36,344	39,048	9,740	13,738
Renter-occupied	16,522	17,760	5,100	6,402
Vacant	3,097	5,708	1,244	1,462
Total Vacancy Rate	5.5%	9.1%	7.7%	6.7%
Median House Value	$119,900	$156,100	$102,000	$138,500

Source: **USCB 2000a, USCB 2006**

Table 2.9-9. Tri-City Housing Estimates and Projections

Housing Characteristic	2000 Census	2007 Estimate	2012 Projection
Total Units	72,047	85,661	94,535
Owner-occupied	46,084 (64.0%)	57,768 (67.4%)	65,096 (68.9%)
Renter-occupied	21,622 (30.0%)	21,574 (25.2%)	21,876 (23.1%)
Vacant	4,341 (6.0%)	6,319 (7.4%)	7,563 (8.0%)
Median Value	$112,518	NA	NA

Source: **TRIDEC 2007a**

2.10 METEOROLOGY AND AIR QUALITY

2.10.1 Meteorology

The Cascade Mountains, which rise from 4,000 to over 10,000 feet in elevation, divide Washington State into two climatic regions, with several distinct climates within each region. East of the Cascades, where CGS is located, summers are warmer, winters are colder, and precipitation is less than western Washington (**WRCC 2007**). This is the result of the dominant air masses affecting the region, typically of maritime polar origin, being modified by the presence of these mountains (**EN 2007**, Section 2.3.1.1).

Regionally, the prevailing wind direction during most of the year is from the southwest or west. During the fall and winter, the frequency of northeasterly winds is greatest. Wind speeds ranging from 4-12 miles per hour (mph) can be expected 60-70 percent of the time. Wind speeds from 13-24 mph occur 15-24 percent of the time and those 25 mph or higher, occur 1-2 percent of the time. The strongest winds are frequently associated with rapidly moving weather systems. Annual precipitation and temperatures can vary widely, depending on location relative to the Cascade Mountains (**WRCC 2007**).

On the Hanford Site, the local mountains and ridges produce a prevailing wind direction from the northwest or west-northwest during the year, with an approximate average speed between 6 to 9 mph. Peak gusts, however, are typically from the southwest or south-southwest and average about 80 mph (**PNNL 2005b**, Table 5.1). Annual precipitation (as water equivalent) is about 7 inches, with over half the total occurring during the four–month period between November and February (**PNNL 2005b**, Section 4.1 and Table 4.1). The months of November, December and January typically are the wettest and the months of July and August the driest. The winter snowfall is about 15 inches, with December being the snowiest month and the months of May through September being snowless (**PNNL 2005b**, Table 4.6).

Monthly temperatures range from a normal daily maximum in December of 38˚F to a minimum of about 25˚F. In July, the daily average normal maximum is about 92˚F and the daily normal minimum is about 60˚F (**PNNL 2005b**, Table 3.10). There is an average of 202 sunny days per year (**PNNL 2005b** Section 6.1). Nearly 90 percent of fog and dense fog occurs during the late autumn and winter months (**PNNL 2005b**, Section 6.2). Both dust and blowing dust occur on the Hanford Site about 5 days per year. The condition is defined by a visibility reduction to six miles or less. In most cases, it is blowing dust, which occurs when dust is picked up locally by strong winds. Glaze (as freezing rain and drizzle) occurs 6 days per year on average (**PNNL 2005b,** Section 6.5).

Table 2.10-1 summarizes various climatology data from the Hanford Meteorological Monitoring Network. The values were computed from daily observations at 30

monitoring stations (including CGS) located within and near the Hanford Site during the period from 1945 through 2004 (**PNNL 2005b**, Section 1.0, Table 1.1, and Figure 1.1).

Site specific meteorological data relevant to the Severe Accident Mitigation Alternatives (SAMA) analysis are provided in Attachment E. The data were gathered from the site 245-ft meteorological tower, located approximately 2,500 ft west of the Reactor Building. Wind and temperature measurements are made at the top of the tower and at the 33-ft level by duplicate sets of instruments. One set of instruments is the primary measurement system and the other set is the backup instrumentation. Temperature instrumentation is also located at the 245 and 33-ft levels. Relative humidity is measured at the 33-ft level, while precipitation is measured at ground level using a tipping bucket rain gauge located about 40-ft west of the main tower. Barometric pressure is measured by a pressure transmitter located inside a building adjacent to the tower (**EN 2007**, Section 2.3.3.2.4).

2.10.2 Air Quality

The CGS is located in the South Central Washington Intrastate Air Quality Control Region (40 CFR 81.189), which includes both Benton and Franklin Counties. Since 1991, when the Washington State legislature expanded statewide air quality efforts, the overall air quality in Washington has greatly improved (**WDOE 2003**, Page 3). The improvements have included the reduction of motor vehicle emissions and toxic air pollutants throughout the state, and reduced smoke and dust in eastern Washington.

Both Benton and Franklin Counties, as noted in 40 CFR 81.348, are better than the national air quality standards for total suspended particulates (TSP) and sulfur dioxide (SO_2). The counties are in attainment for particulate matter less than 10 µm (PM_{10}) and considered unclassifiable/attainment for carbon monoxide (CO), ozone (O_3, including both the 1- and 8-hour average), and particulate matter less than 2.5 µm ($PM_{2.5}$). Nitrogen dioxide (NO_2) cannot be classified or is considered better than the national standards in the South Central Washington Intrastate Air Quality Control Region (40 CFR 81.348).

Particulate matter measurements have on occasion exceeded the PM_{10} standard at an air quality monitoring station 18 miles southeast of CGS. However, the high values occurred because of natural events and, therefore, do not affect attainment status (**WDOE 2004**, Page 6).

There are no air quality nonattainment areas within 50 miles of CGS. The closest is Shoshone County, Idaho, which is in nonattainment for PM_{10}, located approximately 180 miles northeast of CGS. There also are no designated mandatory Class I air quality protection areas within 50 miles of CGS. The closest is Goat Rocks Wilderness Area, located approximately 100 miles west of the CGS (**USEPA 2009**).

Table 2.10-1. Summary of Local Climatology Data

Parameter	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Temperature (deg F)													
Daily Maximum Normal[2]	39.0	47.1	57.8	66.8	75.7	83.6	91.6	90.7	80.6	65.8	48.5	38.4	65.5
Daily Minimum, Normal[2]	24.7	28.7	34.3	40.2	47.9	55.1	61.1	60.1	51.3	40.2	31.7	25.0	41.7
Monthly, Normal[2]	31.8	37.9	46.1	53.5	61.8	69.3	76.3	75.4	65.9	53.0	40.1	31.7	53.6
Record High[3]	72	72	83	94	104	111	113	113	106	89	76	69	113
Year	1971	1986	1960	1977	1986	1992	2002	1961	1987	2003	1999	1980	2002
Record Low[3]	-22	-23	6	21	28	37	39	41	30	7	-13	-14	-23
Year	1957	1950	1955	1975	1954	1984	1979	1960	1972	2002	1985	1968	1950
Precip. (inches, water equiv)													
Monthly, Normal[2]	0.87	0.68	0.58	0.44	0.55	0.41	0.27	0.27	0.33	0.49	0.98	1.11	6.98
Maximum Monthly	2.47	2.10	1.86	2.23	2.03	2.92	1.76	1.36	1.34	2.72	2.67	3.69	12.31
Year[3]	1970	1961	1957	2003	1972	1950	1993	1977	1947	1957	1996	1996	1995
Minimum Monthly	0.08	trace	0.02	trace	trace	trace	0	0	0	trace	trace	0.11	2.99
Year[3]	1977	1988	1968	1999	1992	2003	2003	1988	1999	1987	1976	1976	1976
Maximum in 24 hrs	1.17	0.72	0.53	1.24	1.39	1.24	1.39	0.89	0.54	1.91	1.70	1.04	1.91
Year[7]	2004	1961	1984	2003	1972	1950	1993	1977	1986	1957	1996	1995	1957
Snowfall[4] (inches)													
Monthly, Normal [2]	4.2	2.6	0.4	trace	-	-	-	-	-	0.1	2.3	5.8	15.4
Maximum Monthly	23.4	17.0	4.2	1.0	-	-	-	-	-	1.5	18.3	22.6	56.1
Year	1950	1989	1951	1982	-	-	-	-	-	1973	1985	1996	1992-93
Minimum Monthly	0	0	0	0	-	-	-	-	-	0	0	trace	0.3
Year[3]	1994	2004	2004	2004	-	-	-	-	-	2004	2003	1962	1957-58

Table 2.10-1. Summary of Local Climatology Data
(continued)

Parameter	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Wind[5] (mph)													
Average[6]	6.3	7.0	8.2	8.8	8.9	9.1	8.6	8.0	7.4	6.6	6.4	6.0	7.6
Direction	NW	NW	WNW	WNW	WNW	NW	NW	WNW	WNW	NW	NW	NW	NW
Highest Average	10.3	11.1	10.7	11.1	10.7	10.7	10.7	9.5	9.2	9.1	10.0	8.3	8.8
Year[3]	1972	1999	1977	1972	1983	1983	1983	1996	1961	1946	1990	1968	1999
Peak Gust	80	65	70	73	71	72	69	66	65	72	67	71	80
Direction	SW	SSW	SW	SSW	SSW	SW	WSW	SW	SSW	SW	WSW	SW	SW
Year	1972	1999	1956	1972	1948	1957	1979	1961	1953	1997	1993	1955	1972
Miscellaneous													
Sky Cover (tenths)[8]	8.0	7.4	6.8	6.3	5.9	5.1	3.0	3.2	3.9	5.5	7.5	8.0	5.9
Avg Number of Days[6]													
Fog (visibility ≤ 6 mi)	11.9	6.7	2.0	0.5	0.2	0.1	<0.1	0.1	0.3	2.0	9.8	14.3	47.8
Dense Fog (visibility ≤¼mi)	6.4	3.3	0.8	0.1	<0.1	<0.1	0	<0.1	0.1	1.0	5.7	7.5	25.1
Thunderstorms	0	≤0.1	0.2	0.8	1.6	2.3	2.1	2.0	0.7	0.2	0	≤0.1	9.8
Dust or blowing dust	0.4	0.4	0.5	0.6	0.6	0.4	0.4	0.2	0.5	0.3	0.2	0.2	4.5
Glaze	2.1	0.7	≤0.1	0	0	0	0	0	0	0	0.8	2.4	6.1

Notes:

(1) Source: **PNNL 2005b**, Tables 3.10, 4.1, 4.6, 4.9, 5.1, 6.1, 6.2 and 6.5.
(2) Based on the period 1971-2000
(3) Dates are the most recent occurrence
(4) Includes all frozen precipitation
(5) Measured at the 50-ft level of the Hanford Meteorology Station, 14 miles NW of CGS.
(6) Based on the period 1945-2004
(7) Based on the period 1947-2004
(8) Average from sunrise to sunset, 1946-2004

2.11 HISTORIC AND ARCHAEOLOGICAL RESOURCES

A considerable body of information on the cultural and historic resources of the Columbia Generating Station (CGS) environs exists due to archival research associated with the Hanford Site. Historic resources are managed by the U.S Fish and Wildlife Service (USFWS) within portions of the Hanford Site that are part of the Hanford Reach National Monument. Preservation of historic resources within areas that remain under USDOE control is guided by the Hanford Cultural Resources Management Plan. A primary purpose of this collaborative effort between the USFWS and the USDOE is to protect and restore the biological, cultural, geological and paleontological resources within and around the Hanford Site (**USFWS 2008a**, Section 1.1; **USDOE 2003**; Section 1.2; **PNNL 2008a**, Section 10.15).

Cultural information for the Columbia River basin is found in **ACOE 1995b** and **WDOE 2007**, Section 3.10.2). A detailed accounting of the Hanford Site cultural and historic resources is included in documents prepared for the USDOE (**PNNL 2007**, Section 4.6) and by the U.S. Fish and Wildlife Service (**USFWS 2008a**, Section 3.14). Documented historic sites are generally categorized by three broad periods: 1) pre-contact (prehistoric Native American cultures); 2) post-contact settlement by Euro-Americans; and 3) establishment of the Manhattan Project.

2.11.1 Native American Culture

When Euro-American explorers arrived during the 1800s, Native American habitation was found throughout the mid-Columbia River region. These people were collectively known as the Plateau Indians. Numerous tribes occupied or traveled through the area including the Cayuse, Columbia, Colville, Nez Perce, Umatilla, Walula, Walla Walla, Wanapum, Wauykma, Wayampum, and Yakama, among others. Native Americans in the region can be classified according to the two major linguistic groups – Sahaptin and Salish. Generally, the occupants of the Hanford Site region spoke the Sahaptin dialects. Archaeological finds suggest that Native Americans existed here, pre-contact, for more than 10,000 years. Present day tribal bands and nations in the region are the Wanapum Band, the Yakama Indian Nation, the Confederated Tribes of the Umatilla Reservation, and the Nez Perce Tribe (**PNNL 2007**, Section 4.6.1; **USFWS 2008a**, 3.14.1; **WDOE 2007**, Section 3.10.2).

For purposes of comparison, five major periods of Native American presence and culture have been established for the Columbia River Basin:

- Paleoindian Period (> 10,000 years before present [BP]),
- Early Period (10,000-6,000 BP),
- Middle Period (6,000-2,000 BP),

- Late Period (2,000-200 BP), and
- Historic Period (200 BP).

The classifications are based on periods of continental climate change, and increasing sophistication with respect to tools, settlement structures, agriculture and use of natural resources (**ACOE 1995a**, Section 2.2.2). The Early Period was characterized by native bands traveling to exploit seasonally available food sources. The Middle Period was characterized by continental warming and drying that influenced the distribution of vegetation. The Late Period begins the era of the bow and arrow, increased population density, food production, and food storage. The Historic Period is marked from the arrival of people of European descent and the spread of horses from the southwest.

The Pacific Northwest National Laboratory reports that approximately 720 pre-contact archaeological sites and isolated finds have been recorded at Hanford (**PNNL 2007**, Section 4.6.1.1). Common finds include pit house villages, campsites, hunting camps, fishing stations, game drive complexes, and quarries. The Hanford area is also thought to have been a center for Native American religious activities, and sites along the river remain sacred today. Plant and animal foods typical of the Hanford Site and region were used in tribal ceremonies. Traditional cultural sites include cemeteries, trails and pathways, campsites, fisheries, hunting grounds, plant gathering areas, holy lands, and landmarks.

A summary of the ethnographic characteristics of pre-contact Native Americans in the mid-Columbia River region has been provided by the USFWS (**USFWS 2008a**, Section 3.14.1.6) and the ACOE (**ACOE 1995a**, Section 2.2.2). The Hanford Reach is considered to have been a geographic center for regional Native American religious activities. Generally, movements and village locations were determined by the seasonal availability of foods. The type of shelter used as a seasonal residence was the conical mat house or tipi since it facilitated mobility. More permanent villages were composed of oval and circular housepits erected along terraces and islands. These were most frequently used for winter residences. Sweathouses constructed along streams and rivers were used for physical and spiritual purification, socializing, and physical curing. The larger long house was used for communal gatherings including council meetings, religious ceremonies, dances, and funerals.

The Columbia River provided an important fishery for Native Americans. Priest Rapids (river mile 397), the smaller Coyote Rapids (river mile 382), and Locke Island (river mile 371) were nearby fishing destinations. Fishing techniques consisted of spears, nets, traps and weirs. While fish provided a year-round source of food, annual salmon runs provided major destinations for annual collection and storage of food and related ceremonies.

2.11.2 Post-Contact, Euro-American

Exploration and settlement of the mid-Columbia River region began following the Lewis and Clark expedition in 1804, exploration of the Hanford Site by David Thompson in 1811, and the discovery of gold in nearby regions during the 1860s. Permanent settlement began in the late 1880s along with increased agriculture and cattle ranching. During this settlement period, the Columbia River provided an important transportation corridor until railroads provided additional access in 1913. Ferries were available at Richland, Hanford, Wahluke, and Vernita.

The development of irrigation projects stimulated further development. It is estimated that the Grand Coulee Dam provides irrigation water to 1.8 million acres of semi-arid lands. Today, the area is heavily farmed as a result of intensive use of the Columbia River for irrigation. Important crops include potatoes, grapes, apples, cherries, hops, and poplars (**Benke and Cushing 2005**, Section 13).

An important change to the Richland area and the region, generally, was the establishment of the Manhattan Project on the Hanford Site in 1943. This led to the razing of many pre-war structures and other activities as discussed below in Section 2.11.3. The post-contact archaeological record for the Hanford Site consists of approximately 650 historic sites including settlements, building foundations, agricultural equipment, farmsteads, irrigation features, roads, ferry landings and debris scatters. Traditional cultural places included town sites, homesteads, orchards, fields, and places of community activities. The remaining structures include the Hanford Irrigation and Power Company pumping plant, the Hanford Townsite high school, the White Bluffs bank, a fruit warehouse, and a blacksmith cabin. These artifacts provide an important record of both pre-and post-contact periods (**USFWS 2008a,** Section 3.14.5). None of these post-contact cultural features are on or near the CGS site.

2.11.3 Manhattan Project

Military activities began on the Hanford Site in 1943 and largely ended with the end of the cold war. Activities included plutonium production, military operations, research and development, waste management, and environmental monitoring. The buildings and structures associated with these activities are collectively referred to as the Hanford Site Manhattan Project and Cold War Era Historic District. Efforts are ongoing to determine eligibility of these features for inclusion in the National Historic Registry. Numerous structures from the Manhattan Project remain on the Hanford Site and have been extensively catalogued by the USDOE according to each of the major areas of the site (**PNNL 2007**, Section 4.6.3; **USDOE 1999**, Section 4.6). To date, a total of 528 Manhattan Project and Cold War era buildings/structures and complexes have been judged eligible for the National Register (**USFWS 2008a**, Section 3.1.4.5; **PNNL 2007**, Section 4.6.3). In August 2008 the Hanford B-Reactor, the world's first large-scale

nuclear reactor, was designated as a National Historic Landmark (**USDOE 2008**). The reactor is located about 18 miles northwest of CGS.

2.11.4 Historic Registry

For purposes of documenting historically significant sites and properties, the Washington Department of Archaeology & Historic Preservation maintains the Washington Heritage Register (**WDAHP 2008**). This state register includes the listings maintained by the U.S. Department of the Interior (**NRIS 2007**). Federally-recognized Hanford Site properties are listed in Table 2.11-1 and Table 2.11-2. State and federal listings for the three counties within which the Hanford Site is located are provided in Table 2.11-3, Table 2.11-4, and Table 2.11-5. None of the listed sites is near the CGS site or the associated transmission corridor. The site closest to CGS is the Wooded Island Archaeological District (Table 2.11-1 and Table 2.11-3). It is about four miles southeast of the plant and two miles downstream from the makeup water pumphouse.

2.11.5 Columbia Generating Station

The CGS site and the transmission line corridor are in an area of the Hanford Site that was generally undisturbed. The site was not used for homesteading or agriculture and was not developed with facilities supporting Manhattan Project. Use of the site area by Native Americans and early settlers appears to have been transitory and focused on the river shoreline.

An archaeological reconnaissance of the CGS site was performed in 1972 prior to construction. No archaeological features or historic structures were observed at the reactor site including the corridor between the river and the reactor site. Evidence of Native American presence was found in the vicinity of the makeup water pumphouse and water intake. Monitoring of the pumphouse construction in 1975 by an archaeologist revealed scattered fire-cracked rock but no substantive archaeological material. Two previously identified archaeological sites located downstream from the pumphouse were left undisturbed (**WPPSS 1980**, Section 2.6; **Rice 1983**, Pages 65-70).

Similar archaeological investigations were conducted for the adjacent sites of WPPSS Nuclear Projects Nos. 1 & 4 (WNP-1/4). The sites were surveyed in 1974 and detailed monitoring of the makeup water pumphouse construction was conducted in 1977. Monitoring at the WNP-1/4 pumphouse, located about 600 feet north (upstream) of the CGS pumphouse, resulted in the recording of a multi-component site containing both pre-contact and historic era material. Surface investigations revealed a ceramic Chinese rice bowl fragment. The bowl was assumed to be linked to Chinese placer mining that occurred in the area in the 1860s. Pre-contact materials were discovered during excavation for the makeup water intake pipes. Radiocarbon dating of a piece of sagebrush limb charcoal found in association with a fire hearth, cobble tools, and stone

flakes suggested the location was a late pre-contact fishing camp around 1600 AD (**Rice 1983**, Pages 66-73). Archaeological materials recovered from the WNP-1/4 pumphouse construction are stored in the USDOE Hanford Cultural and Historical Program curation and storage facility.

An additional cultural resources survey of a portion of the CGS site was performed in 2002 by the Hanford Cultural Resources Laboratory as part of a project to install security barriers around the station. A review of historic records covering an area within 0.6 miles of the project location indicated one prehistoric site. No historic structures or roads were found. A survey of the project area was performed and no cultural resources were located (**PNNL 2002**). A similar survey was performed in 2008 along the main CGS access right-of-way as part of a road-widening project (**PNNL 2008b**). There were no sites or cultural resources identified during the survey for the road widening project.

Energy Northwest does not plan further development of the site property but has preceduralized protections for review of land disturbing activities and response to inadvertent discovery of archeological or cultural materials. The procedure specifies the circumstances requiring coordination with archaeological professionals and the State Historic Preservation Officer.

Table 2.11-1. Historic Buildings, Archaeological Sites, and Districts in the National Register of Historic Places on the Hanford Site, Washington

Property Name	General Location	Landscape Association
Districts:		
Hanford North Archaeological District	100-F	Native American
Locke Island Archaeological District	100-H	Native American
Ryegrass Archaeological District	100-K	Native American
Savage Island Archaeological District	Ringold Flat	Native American
Snively Canyon Archaeological District	Rattlesnake Hills	Native American
Wooded Island Archaeological District	300 Area	Native American
Sites:		
Hanford Island Archaeological Site	Hanford Townsite	Native American
Paris Archaeological Site	Vernita Bridge	Native American
Rattlesnake Springs Sites	Rattlesnake Mountain	Native American
Building:		
105-B Reactor (Natl Historic Landmark)	100-B/C Area	Manhattan Project

Source: **PNNL 2007**, Section 4.6

Table 2.11-2. Historic Buildings, Archaeological Sites, and Districts Eligible for Listing in the National Register of Historic Places on the Hanford Site, Washington

Property Name	General Location
Native American:	
Wanawish fishing village	600 Area
Gable Mountain/Gable Butte Cultural District	200 East Area
Mooli Mooli	100-N Area
45BN423*	100-K Area
45BN431/432/433	100-F Area
45BN434	100-F Area
45BN446	100-K Area
45BN606	100-F Area
45BN888	100-D Area
45BN1422	100-B/C Area
45BN135	100-F Area
Early Settlers:	
Midway-Benton transmission line	600 Area
McGee Ranch/Cold Creek Valley District	Cold Creek Valley
Fry and Conforth farm	100-B/C Area
White Bluffs Road	200 West to White Bluffs Townsite
Richland Irrigation Canal	300 Area
First Bank of White Bluffs	White Bluffs Townsite
Bruggemann's Warehouse	100-B/C Area
Hanford Electrical Substation-Switching Station	Hanford Townsite
Hanford High School	Hanford Townsite
Coyote Rapids Hydroelectric Pumping Station	100-B/C Area
Manhattan Project/Cold War:	
Hanford Site Manhattan Project and Cold War Era Historic District	100, 200-E&W, 300, 400, 600, 700, & 1100 Areas
Five Anti-Aircraft Artillery sites	600 Area
Hanford Atmosphere Dispersion Test Facility	200 Area
Hanford Construction Camp Burn Pit	100 Areas

* Smithsonian Trinomial numbers are the standard designation for archaeological sites in the United States. 45 represents the State of Washington and BN represents Benton County. The number that follows indicates that the site was the nth archaeological site to be recorded.

Source: **PNNL 2007**, Section 4.6.

Table 2.11-3. Benton County Historic Registry

Name	Area	Address/Location	National Historic Places	Washington Heritage Register
Benton City-Kiona Bridge	Benton City	State Route 225 over Yakima River		✓
Charles Conway House	Kennewick	1119 West 53rd Ave		✓
Bateman Island	Kennewick vicinity	Restricted		✓
Pioneer Memorial Bridge "Blue Bridge"	Kennewick vicinity	State Route 395 over Columbia River		✓
Telegraph Island Petroglyphs	Paterson vicinity	Restricted	✓	✓
Columbia River Bridge at Umatilla	Plymouth vicinity	Southbound Interstate Route 82 over the Columbia River		✓
Benton County Courthouse	Prosser	Dudley Ave at Market Street	✓	✓
J. W. Carey House	Prosser	Byron Road, Route 3	✓	✓
US Post Office-Prosser Main	Prosser	1103 Meade Ave	✓	✓
Glade Creek Site	Prosser vicinity	Restricted	✓	✓
Hanford B Reactor	Richland vicinity	Route 6, Hanford	✓*	✓
Gold Coast Historic District	Richland	Roughly bounded by Willis St, Davison Ave, and George Washington Way	✓	✓
Snively Canyon Archaeological District	Richland	Restricted	✓	✓
Coyote Rapids Archaeological District	Richland vicinity	Restricted		✓
Gable Mountain Archaeological Site	Richland vicinity	Restricted		✓
Hanford Island Archaeological Site	Richland vicinity	Restricted	✓	✓
Hanford North Archaeological	Richland vicinity	Restricted	✓	✓

Table 2.11-3. Benton County Historic Registry
(continued)

Name	Area	Address/Location	National Historic Places	Washington Heritage Register
District				
Hanford South Archaeological District	Richland vicinity	Restricted		✓
Locke Island Archaeological District	Richland vicinity	Restricted	✓	✓
Rattlesnake Springs Sites	Richland vicinity	Restricted	✓	✓
Ryegrass Archaeological District	Richland vicinity	Restricted	✓	✓
Wahluke Archaeological District	Richland vicinity	Restricted		✓
Wooded Island Archaeological District	Richland vicinity	Restricted	✓	✓

* The USDOE B Reactor has special status as a National Historic Landmark.

Source: **WDAHP 2008**

Table 2.11-4. Franklin County Historic Registry

Name	Area	Address/Location	National Historic Places	Washington Heritage Register
Box Canyon Viaduct	Kahlotus vicintiy	Spans Box Canyon near the Snake River		✓
Marmes Rockshelter	Lyons Ferry vicinity	Restricted	✓	
Franklin County Courthouse	Pasco	1016 North Fourth Street	✓	✓
James Moore House	Pasco	200 Road 34	✓	✓
Pasco Carnegie Library	Pasco	305 North Fourth Street	✓	✓
Pasco-Kennewick/Columbia River Bridge	Pasco	Spans Columbia River		✓
Sacajawea State Park	Pasco	2503 Sacajawea Park Road	✓	✓
Ainsworth Townsite	Pasco vicinity	~3 miles SE of Pasco City limits, near the confluence of the Snake & Columbia Rivers		✓
Allen Rockshelter	Pasco vicinity	Restricted	✓	✓
Lower Snake River Archaeological District	Pasco vicinity	Restricted	✓	✓
Strawberry Island Village Archaeological Site	Pasco vicinity	Restricted	✓	✓
Savage Island Archaeological District	Richland vicinity	Restricted	✓	✓
Tri-Cities Archaeological District	Richland vicinity	Restricted	✓	✓
Wooded Island Archaeological District	Richland vicinity	Restricted	✓	✓
Lyons Ferry Boat	Starbuck vicinity	5 mile NW of Starbuck		✓
Palouse Canyon Archaeological District	Starbuck vicinity	Restricted	✓	✓

Table 2.11-4. Franklin County Historic Registry
(continued)

Name	Area	Address/Location	National Historic Places	Washington Heritage Register
Burr Cave	Walker vicinity	Restricted	✓	✓
Windust Caves Archaeological District	Windust vicinity	Restricted	✓	✓

Source: **WDAHP 2008**

Table 2.11-5. Grant County Historic Registry

Name	Area	Address/Location	National Historic Places	Washington Heritage Register
Beverly Railroad Bridge	Beverly	Spans Columbia River	✓	✓
Salishan Mesa	Coulee City vicinity	Restricted		✓
Bell Hotel	Ephrata	210 West Division Street	✓	✓
Grant County Courthouse	Ephrata	C Street Northwest	✓	✓
Samuel & Katherine Reiman House	Quincy	415 F Street SW		✓
Paris Archaeological Site	Richland vicinity	Restricted	✓	✓
Mesa 36	Soap Lake vicinity	Restricted	✓	✓
Stratford School	Stratford	Just off St Rt 7	✓	✓
Lind Coulee Archaeological Site	Warden vicinity	Restricted	✓	✓
Wilson Creek State Bank	Wilson Creek	Off St Rt 7	✓	✓

Source: **WDAHP 2008**

2.12 KNOWN AND REASONABLY FORESEEABLE PROJECTS IN SITE VICINITY

Given the location on the USDOE Hanford Site, any significant long-term projects in the vicinity of Columbia Generating Station will likely have some federal sponsorship. The following projects in the site vicinity have been identified that may contribute to cumulative environmental impacts of license renewal and extended plant operation.

Remediation of Hanford Waste Burial Grounds 618-10 and 618-11 is in the planning phase. As noted in Section 2.1, the 618-10 burial ground is about 3½ miles south of CGS. The 618-11 burial ground is adjacent to the CGS site and is a major source of tritium in the groundwater at the CGS site (see Section 2.3). High-activity wastes were buried there between 1962 and 1967. The work will likely involve the use of remote retrieval equipment and the erection of containment systems and will require close coordination with Energy Northwest on issues such as security, radiation monitoring, and emergency preparedness. The preliminary plan prepared by USDOE calls for the remediation work to be completed at 618-10 in 2014 and at 618-11 in 2018 (**FH 2003**, Page B-29).

The most significant projects on the Hanford Site address disposition of 53 million gallons of radioactive waste liquids and sludges in 177 large underground tanks. USDOE has commitments to commence treatment of the waste, which was generated during the production of defense related materials, by 2019. The key component of the remediation efforts is the Hanford Waste Treatment and Immobilization Plant (WTP) employing vitrification technology to immobilize the waste in a glass matrix. Construction of the WTP began in 2002. In early 2009, approximately 1,500 people were working at the 65-acre construction site in the Hanford 200 East Area at a location 10 miles northwest of CGS (**BNI 2009**).

Another project that was envisioned for the site vicinity was a Nuclear Fuel Recycling Center (NFRC) at the Hanford 400 Area (site of the FFTF) about 2¾ miles south-southwest of CGS. A siting study was prepared by a local consortium in response to the USDOE's sponsorship of the Global Nuclear Energy Partnership (GNEP). The consortium's proposal included an Advanced Recycling Reactor (ARR) to be located on Energy Northwest's WNP-1/4 site just east of CGS (**TRIDEC 2007b**). USDOE funding for GNEP has since been curtailed as the federal government is no longer pursuing commercial nuclear fuel reprocessing. Issuance of a programmatic environmental impact statement on the GNEP program has been cancelled (**USDOE 2009**). Consequently, projects proposed under the GNEP program are not considered reasonably foreseeable.

Lacking some other mission for the FFTF and other facilities at the 400 Area, the USDOE may dismantle the facilities at some time in the future. The FFTF has not operated since 1992 and has been secured with removal of nuclear fuel and sodium coolant. Alternatives for decommissioning FFTF will be addressed by USDOE in a

comprehensive environmental impact statement being prepared by USDOE on Hanford Site waste management and tank closure activities (**USDOE 2006**). Release of the draft report has been delayed pending reassessment of options for long-term disposal of high-level radioactive waste (**TCH 2009b**).

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3.0 PROPOSED ACTION

Regulatory Requirement: 10 CFR 51.53(c)(2)

"The report must contain a description of the proposed action...."

Energy Northwest proposes that the NRC renew the CGS operating license for an additional 20 years. Renewal would give Energy Northwest and the Bonneville Power Administration (BPA) the option of relying on CGS to meet future electricity needs. Section 3.1 discusses the plant in general. Sections 3.2 through 3.4 address potential changes that could occur as a result of license renewal.

There are no changes related to license renewal with respect to operation of the CGS that would significantly affect the environment during the period of extended operation.

3.1 GENERAL PLANT INFORMATION

CGS is a single unit nuclear power plant with a boiling water reactor (BWR). Principal structures consist of the reactor building, radwaste and control building, turbine building, diesel generator building, circulating water pumphouse, standby service water pumphouses, spray ponds, makeup water pumphouse, general service building, transformer yard, cooling towers, and the independent spent fuel storage installation (ISFSI). Figure 3.1-1 depicts the arrangement of most of the structures on the plant site. The location of the makeup water pumphouse is indicated in Figure 2.1-3.

The following subsections provide information on the principal features of CGS as described in the final environmental statement for operation of the plant (**NRC 1981**) and the CGS Final Safety Analysis Report (**EN 2007**).

3.1.1 Reactor and Containment Systems

The nuclear steam supply system, designed and supplied by General Electric Company utilizes a single-cycle, forced-circulation system and is designated a BWR/5 reactor. The reactor core produces heat that boils water, producing steam for direct use in a turbine-generator. Fuel for the reactor core consists of slightly enriched (less than 5% by weight) uranium dioxide pellets sealed in Zircaloy-2 tubes. Fuel design is such that individual rod average burnup (burnup averaged over the length of the fuel rod) will not exceed 62,000 MWd/MTU. The maximum rated power level limit of the reactor for the extended period of operation is 3,486 megawatts-thermal (MWt). The net and gross electrical power outputs are 1,190 and 1,230 megawatts-electric (MWe), respectively.

The containment consists of primary and secondary containment systems. The primary containment structure is a free-standing steel pressure vessel, containing a drywell and

a suppression chamber. The secondary containment structure consists of the reactor building, which completely encloses the primary containment. The reactor building has reinforced-concrete exterior walls up to the refueling floor. Above this level, the reactor building is a steel framed structure with insulated metal siding with sealed joints. The primary and secondary containments, in conjunction with engineered safety features, limit radiological effects of accidents resulting in the release of radioactive materials to the environs so that offsite doses will be below the limits stated in 10 CFR 50.67.

3.1.2 Cooling and Auxiliary Water Systems

Cooling water for the condenser is provided by the circulating water system. Removal of heat rejected from auxiliary equipment during normal operation is provided by the plant service water system. The standby service water system is a separate cooling water system designed to remove heat during a loss of coolant accident. This system also removes residual reactor heat during a normal shutdown.

3.1.2.1 Circulating Water System

The circulating water system is a closed-cycle cooling system that removes heat from the condenser and rejects it to the atmosphere by evaporation using six mechanical draft cooling towers. Water is circulated from the cooling towers through the condenser and back to the circulating water pumphouse at a rate of about 550,000 gpm. The temperature of the cooling water is increased by about 30°F across the condenser. Each tower rises about 60 feet above its basin and is about 200 feet in diameter at its base.

Makeup water to replenish water losses due to evaporation, drift, and blowdown is supplied from the makeup water pumphouse located at Columbia River approximately three miles east of the plant. The three 800-hp makeup water pumps are each designed to pump 12,500 gallons per minute (gpm), or half the system capacity, at the design head. Normally, two pumps are used to supply makeup water to the plant.

The intake system for the makeup water pumps includes two offshore perforated pipe inlets mounted above the riverbed and approximately parallel to the river flow. The paired sets of inlet screens consist of outer and inner perforated pipe sleeves. The 36-inch diameter inner sleeve, with ¾-inch diameter holes comprising about 7% of the surface area, is designed to distribute the inflow evenly along the surface of the 42-inch diameter outer sleeve that has 3/8-inch holes covering about 40% of the surface area.

Water is conveyed from the inlet screens to the pump well of the makeup water pumphouse through two 36-inch diameter buried pipes that are approximately 900 feet long. The intake system is designed for a withdrawal capacity of 25,000 gpm. Actual makeup water withdrawal during operating periods averages about 17,000 gpm. This is

about 0.1% of the minimum river flow in the vicinity of CGS or 0.03% of the average annual flow.

The circulating water system is chemically treated to control corrosion, scale, and biological growth and fouling of heat transfer surfaces. To control the buildup of dissolved solids in the circulating water system, a portion of the cooled water is released to the river as blowdown. On an annual basis, blowdown averages about 2,000 gpm.

The blowdown pipe is buried in the riverbed and terminates in an outfall port, about 175 feet from the shoreline at low river flow. At the outfall, the 18-inch diameter pipe transitions to an 8-inch by 32-inch rectangular orifice that emerges at a 15-degree angle to the riverbed and perpendicular to the river flow. The location of the makeup water and discharge lines for the circulating water system is indicated on Figure 2.1-3.

3.1.2.2 Plant Service Water System

The plant service water system is designed to function continuously during all modes of operation, except during a loss of coolant accident with loss of offsite power. The system consists of two 100 percent-capacity pumps that draw water from the circulating water system to supply cooling water to equipment located throughout the plant. Supplemental biocide is used to retard biological growth in addition to the biocide used to treat the circulating water system supply. Other chemical additives are used to minimize silt deposition, scale formation, and corrosion. Plant service water return is cooled by the circulating water system cooling towers.

3.1.2.3 Standby Service Water System

The standby service water system is designed to provide cooling water during a loss of coolant accident. Two concrete spray ponds, comprising the ultimate heat sink, are provided for emergency cooling. The square ponds are each 250 feet by 250 feet and 15 feet deep with a combined water inventory adequate to provide cooling water for 30 days without makeup. Makeup water required to account for small losses due to evaporation, drift, and occasional blowdown needed to maintain water chemistry, is normally taken from the cooling tower makeup water system or the potable water system. The concrete ponds provide suction and discharge points for the redundant pumping and spray facilities of the service water system. The two independent, 100 percent-capacity service water pumps are housed in separate pumphouses adjacent to the spray ponds, and supply water to the emergency core cooling system, essential plant equipment, and reactor shutdown cooling equipment. A third pump, located in one of the two pumphouses, provides supply water to high-pressure core spray system cooling equipment. The standby service water system is treated to control biological growth and to minimize corrosion.

The service water ponds do not provide cooling for the plant steam condenser and are not cooling ponds in the context of 10 CFR 51.53(c)(3)(iii) and Section 4.4 of the NRC GEIS for license renewal (**NRC 1996**).

3.1.2.4 Other Auxiliary Water Systems

A branch line of the cooling tower makeup system also supplies raw river water that is processed into potable water. The potable water system supplies drinking water throughout the CGS site, provides water to the plant demineralized water treatment system, and can be used to supply makeup water to the spray ponds. The plant fire protection system has the circulating water system (Section 3.1.2.1) as its primary source of water. An onsite groundwater well that is 695 feet deep and penetrates a confined aquifer is maintained as a backup source of water for the potable and demineralized water systems. The pumping capability of the well is about 250 gpm. The well is seldom used as a plant water source.

3.1.3 Radiological Waste Treatment Processes

Liquid, gaseous and solid radioactive wastes generated by plant operations are collected and processed to meet applicable regulations. The design and operational objectives of the radioactive waste management systems are to limit the release of radioactive effluents from the plant during normal operation and anticipated operational occurrences.

3.1.3.1 Liquid Waste Management System

The liquid waste management system collects, segregates, stores and disposes of radioactive liquid waste. The system is designed to reduce radioactive materials in liquid effluents to levels as low as reasonably achievable utilizing maximum recycle and minimum release objectives. Liquid wastes that accumulate in radwaste tanks or in sumps throughout the plant are transferred to collection tanks in the radwaste building and segregated into three categories: high purity waste, low purity waste, and chemical waste.

High purity wastes collect in the waste collector tank and are treated in the equipment drain subsystem. Radioactive material is removed from high purity liquid wastes using filtration and ion exchange. Sources of high purity wastes include:

- Drywell equipment drain sump
- Reactor building equipment drain sump
- Radwaste building equipment drain sump
- Turbine building equipment drain sump
- Reactor water cleanup system

- Residual heat removal system
- Cleanup phase separators (decant water)
- Condensate phase separators (decant water)
- Fuel pool seal rupture drains

Low purity wastes collect in the floor drain collector tank and are treated in the floor drain subsystem. Similar to high purity wastes, treatment of low purity wastes consists of filtration and ion exchange. Low purity liquid waste sources include:

- Drywell floor drain sump
- Reactor building floor drain sumps
- Radwaste building floor drain sumps
- Turbine building floor drain sump
- Waste sludge phase separator (decant water)

The chemical waste subsystem is used to treat liquid chemical wastes that collect in the chemical waste tank. Due to high conductivity and organic content, normal treatment by ion exchange is precluded. Therefore, chemical wastes may be treated using a neutralizing agent, and processed by routing to a backwash tank or phase separator and then to the floor drain subsystem for further processing. Chemical waste sources include:

- Detergent drains
- Shop decontamination solutions
- Reactor and turbine building decontamination drains
- Low purity wastes from either the equipment or floor drain subsystems
- Filter demineralizer element chemical cleaning solutions
- Battery room drains
- Chemical system overflows and tank drains
- Laboratory drains

All liquid radwaste process streams terminate in either a sample or distillate tank. Liquid wastes are processed on a batch basis so that each treated batch can be sampled. Depending on sample results, the waste is either reprocessed or returned to the condensate storage tanks for reuse in the plant. Excess processed water, within 10 CFR Part 20 release limits and 10 CFR Part 50 dose thresholds, can be discharged to the circulating water system blowdown and into the river. Water management practices are such that no discharge of liquid radwaste has occurred in over ten years.

Protection against accidental discharge of liquid radioactive waste is provided by design redundancy, detection instrumentation and alarms for abnormal conditions, and procedural control.

3.1.3.2 Gaseous Waste Management Systems

Gaseous waste management systems process and control the release of gaseous radioactive effluents to the site environs so that exposure to persons offsite are as low as reasonably achievable and do not exceed limits specified in 10 CFR Part 20 and 10 CFR Part 50, Appendix I.

Offgases from the main condenser are the major source of gaseous radioactive waste. Prior to release into the environment through the reactor building elevated release duct, treatment of the gases includes volume reduction through a catalytic recombiner to recombine hydrogen and oxygen, water vapor removal through a condenser, decay of short-lived radioisotopes through a holdup line, high efficiency particulate air (HEPA) filtration, adsorption of isotopes on activated charcoal beds, and further HEPA filtration.

Other radioactive gas sources include leakage from steam piping and equipment in the reactor building, turbine generator building, and radwaste building.

The following design precautions/features prevent uncontrolled releases of gaseous radioactivity:

- Welded piping connections, as appropriate;
- Valve types with extremely low leak rate characteristics (i.e., bellows seals);
- Stringent seat-leak characteristics for valves in lines discharging to the environment;
- Loop seals with enlarged discharge sections to avoid siphoning;
- Extremely stringent leak rate requirements placed on all equipment, piping and instruments;
- Establishment of negative pressure in potentially contaminated areas;
- HEPA filtration of exhaust air from the Radwaste and Reactor Buildings; and
- Continuous radiation monitors of Turbine, Radwaste, and Reactor Building emissions.

3.1.3.3 Solid Waste Management System

The solid waste management system collects, processes, and packages solid radioactive wastes for storage and offsite shipment and burial. The system is designed to process waste while maintaining occupational exposure as low as is reasonably achievable. To ensure compliance with applicable regulations in 10 CFR Parts 20, 61

and 71, characterization, classification, processing, waste storage, handling and transportation of solid wastes are controlled by the process control program.

CGS utilizes a portable dewatering/drying system to remove free standing liquids from wet solid wastes (e.g., filter residue, concentrated wastes, and spent resins). Dewatering is conducted in accordance with approved procedures and typically performed in the liner storage area of the radwaste building so that spills are routed to the existing floor drain sumps and the building ventilation filtration system prevents the release of unfiltered air. The waste is sluiced and then contained within resin liners or high integrity containers for offsite shipment. The excess sluice liquid is returned to the liquid waste management system.

Dry solid wastes (e.g., rags, paper, and air filters) are also processed in the radwaste building. Dry solid wastes are segregated and monitored to reduce volumes where practicable and may be compressed and packaged into steel containers. Non-compressible solid wastes are packaged in container vans or other containers suitable for shipment and may be shipped to a vendor for volume reduction. Wastes are handled and radiation levels monitored on a batch basis. If necessary, shipping containers are decontaminated prior to shipment. Irradiated reactor components, i.e., spent control rod blades, fuel channels, and in-core ion chambers, are stored in the spent fuel storage pool to allow for radioactive decay prior to shipment.

Although the types and quantities of solid radioactive waste generated at and shipped from CGS vary from year to year depending on plant activities, the radwaste processing capacity is sized to provide the needed capacity for anticipated occurrences and normal operation.

Mixed (radioactive and hazardous) wastes generated at CGS are shipped to permitted offsite facilities. The recurrent wastes have included:

- ethylene glycol/coolant (toxic) from maintenance and operation of off-gas chiller units;
- paint waste (flammable) from general in-plant painting activities; and
- liquid scintillation cocktails (toxic and flammable) from radiochemistry analyses.

Periodic cleaning of the cooling tower basins and the standby service water ponds results in sediment that has been found to contain low levels of radioactivity. The primary source of the radioactivity is believed to be radionuclides (e.g., cobalt-60 and cesium-137) in the cooling tower makeup water that become concentrated in the circulating water system. Another source may be the entrainment of CGS gaseous emissions in the induced draft cooling towers. Annually, roughly 25 to 100 cubic yards of cooling system sediment are disposed of onsite in a dedicated area south of the cooling towers. The conditions for disposal, including concentration limits and

monitoring requirements, are stipulated in a resolution of the State of Washington Energy Facility Site Evaluation Council (**EFSEC 2001a**).

Used nuclear fuel from the reactor is stored onsite in an independent spent fuel storage installation (ISFSI) located about 1,200 feet northwest of the reactor building. The fuel is stored in dry casks on concrete pads surrounded by a security fence. The ISFSI is licensed in accordance with 10 CFR Part 72.

3.1.4 Transportation of Radioactive Materials

Solid radioactive wastes are packaged and shipped from CGS in containers that meet the requirements established in 49 CFR Parts 171-180 for the Department of Transportation and 10 CFR Part 71 for the NRC. The radiation levels of the waste containers are monitored so that provisions can be made to ensure that radiation levels established by shipping regulations are not exceeded. Radioactive waste is transported to a commercial low-level radioactive waste disposal facility located near the center of the Hanford Site, approximately 12 miles west-northwest of CGS. The site is operated by US Ecology, a subsidiary of American Ecology Corporation, and serves the Northwest and Rocky Mountain Compacts for the disposal of regulated low-level radioactive waste. It is on about 100 acres of land leased to the State of Washington by the USDOE (**WDOE 2009**). Low activity waste may be transported from CGS to a vendor for volume reduction prior to disposal. Transportation activities are contained within the process control program for ensuring compliance with requirements governing the transportation and disposal of solid radioactive wastes. Records of reviews are retained for the duration of the operating license.

3.1.5 Nonradioactive Waste Systems

Non-radioactive waste is produced from plant operations and maintenance activities and consists of liquid, gaseous and solid effluents.

Non-radioactive liquid system effluents include circulating water blowdown, equipment and floor drains, storm water, treated raw water, and sanitary wastes. Discharges to the Columbia River and most discharges to the soil are controlled through operational and administrative procedures implemented to meet National Pollutant Discharge Elimination System (NPDES) permit requirements for CGS (Attachment B to this ER). Discharge monitoring is performed to control and minimize adverse impacts.

Radioactive and non-radioactive equipment and floor drains within the plant are segregated. Equipment and floor drains in the service building and those in the diesel generator building are routed to the storm water drainage system. However, due to the possibility of low-level contamination, non-radioactive floor drains in the turbine building collect in sumps that are routed to the liquid radwaste management system for processing. In addition to non-radioactive floor drain water, the storm water drainage

system collects storm water runoff from plant roofs, potable water treatment filter backwash, air wash water from HVAC units, water from fire protection system flushes, and wastewater from demineralized water production. Water collected by the storm water drainage system is piped to a small unlined evaporation/percolation pond, approximately 1,500 feet northeast of the plant.

The outfall to the pond is designated as Outfall 002 in the CGS NPDES permit. The permit includes restrictions on discharges and sets monitoring requirements. The pond was also marked as a radioactive materials area following the discharge in 1992 of Turbine Building sump water that was found to contain elevated concentrations of iodine-131, cesium-137, and tritium (**WPPSS 1992**). Plant equipment and operating procedures were subsequently changed such that the sumps are discharged to the radwaste system for processing. Nonetheless, the pond continues to receive tritium that is washed off the plant roofs and walls and is collected by the stormwater system. Discharges to the pond are sampled as part of the radiological environmental monitoring program.

Sanitary wastes are directed to a central sanitary waste treatment facility that uses aerated lagoons and two 2.4-acre lined stabilization ponds. The treatment facility is located about 2,500 feet southeast of the reactor building and also services CGS support facilities, the IDC, and the Hanford 400 Area. Treated wastewater in the lagoons is discharged to percolation beds once or twice per year. The discharge limitations and monitoring requirements are stipulated in a resolution of the Energy Facility Site Evaluation Council (**EFSEC 2001b**).

Non-radioactive gaseous effluents result from testing and operating the plant's three standby diesel generators and auxiliary boiler, and include sulfur dioxide, nitrogen oxides and particulates. Gaseous effluents emitted from these sources conform to an order implementing the Energy Facility Site Evaluation Council's Site Certification Agreement (**EFSEC 1996**). The order is, effectively, a synthetic minor air operating permit that limits the consumption of diesel fuel oil.

Non-radioactive solid wastes are managed in accordance with environmental compliance procedures that provide the administrative and technical controls for pollution prevention and waste minimization, chemical storage and use, and hazardous substance spills and cleanup. Normal refuse (e.g., office paper, packaging material, scrap wood, aluminum cans) is collected onsite and disposed of offsite at licensed disposal and recycling facilities. Some construction debris (e.g., concrete rubble) is placed in an onsite inert waste landfill that is operated in accordance with a state-approved operating plan. Scrap metal, used oil, antifreeze, and universal wastes are collected and stored temporarily onsite and recycled or recovered at offsite facilities.

Hazardous wastes make up a small percentage of the wastes generated on site and include excess laboratory reagents, painting wastes, cleaning solvents, mercury-containing lamps, and other corrosive, reactive, toxic, and ignitable materials. These

wastes are accumulated in controlled areas until they are removed by a licensed transporter and disposed of or recycled offsite at permitted facilities.

3.1.6 Maintenance, Inspection, and Refueling Activities

Maintenance and inspection activities are performed to ensure that plant equipment is functioning properly to support plant operations. Routine maintenance and inspection activities are performed during normal operation of the plant; other maintenance and inspection activities are performed during scheduled refueling outages. Maintenance, inspection and refueling activities are conducted in accordance with various plant programs (e.g., the Inservice Testing Program Plan) implemented to comply with industry codes and standards, including the following:

- 10 CFR Part 50, Appendix B, Quality Assurance;
- 10 CFR 50.55a, American Society of Mechanical Engineers Boiler and Pressure Vessel Code;
- 10 CFR 50.65, The Maintenance Rule; and
- Electric Power Research Institute Guidelines for Permanent BWR Hydrogen Water Chemistry Installations.

In addition, periodic maintenance and inspection procedures have been initiated in response to NRC generic communications. Periodic maintenance, inspection, testing, and monitoring is also performed to meet Technical Specification surveillance requirements and for managing the effects of aging on systems, structures and components.

3.1.7 Power Transmission Systems

Energy produced at CGS is delivered to the BPA at the H.J. Ashe Substation located 0.5 mile north of the station. The BPA, an agency of the U.S. Department of Energy, markets wholesale electrical power produced by 31 federal hydroelectric projects, several small non-federal power plants, and CGS. The BPA provides electricity to various cooperatives, municipalities, and public and private utilities within a 300,000 square mile area of the Pacific Northwest. About three fourths of the high voltage transmission network in the region is operated by the BPA (**BPA 2008**).

The CGS main generator output is transmitted to Ashe Substation via the step-up main transformer bank and a 2,900-ft long 500-kV tie line. The four CGS main power transformers (one is a spare) increase the generator output from 25 kV to 500 kV. The plant start-up transformer, with the capacity to supply power for plant startup, normal operating auxiliary loads, and engineered safety feature shutdown loads, is connected to the Ashe Substation via a 230-kV line. The 230-kV and 500-kV overhead lines run

approximately parallel in a 280-ft wide corridor. The lines between CGS and Ashe Substation comprise the transmission intertie that is within the scope of license renewal.

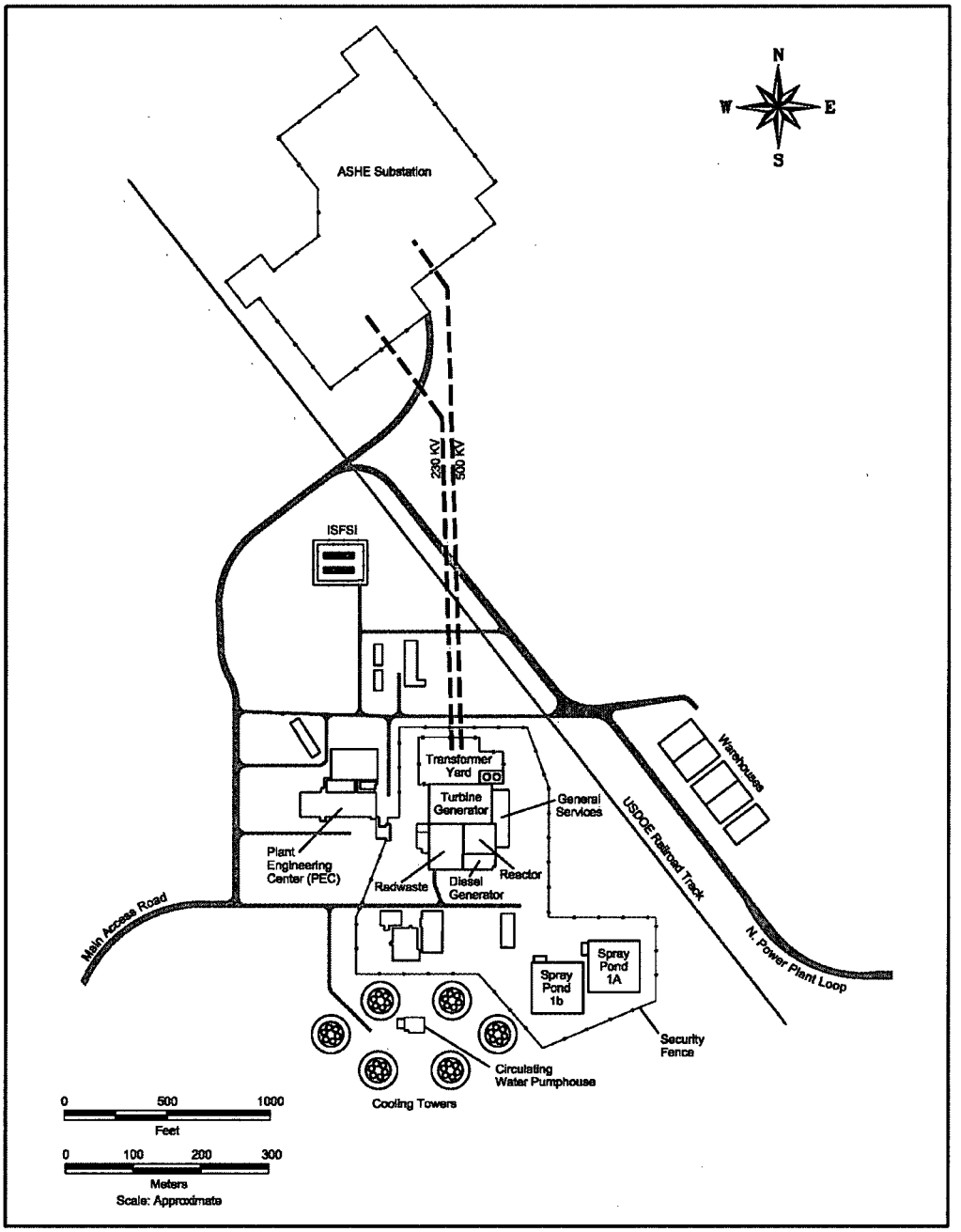
At the time of the NRC's review of the construction permit application in 1972, the station connection to the BPA transmission grid was intended to be via a 500-kV line between CGS and the Hanford Substation 18 miles to the northwest (**AEC 1972**, Section III.D). Subsequent to the construction permit review BPA decided to construct Ashe Substation as a major node in the Northwest transmission system. The environmental assessment of the construction and operation of the Ashe Substation and the associated transmission lines was prepared by BPA (**BPA 1974a, BPA 1974b**). In the operating license review, the NRC noted that BPA was responsible for the NEPA assessments relative to the transmission interconnection (**NRC 1981**, Section 4.2.5).

The 500-kV line from Ashe to the Hanford Substation was constructed by BPA. In fact, the Ashe Substation 500-kV bus is tied into the BPA transmission network by four 500-kV lines that connect to the Hanford, Lower Monumental, Slatt, and Marion Substations. BPA operates and maintains these lines as part of the regional grid and they will remain in service after CGS ceases operation. Distances between Ashe and the Hanford, Lower Monumental, Slatt, and Marion Switchyards are 18, 41, 72, and 224 miles, respectively.

The third line supporting CGS was a 115-kV power source during construction and now serves as a backup power source for safe shutdown under accident conditions. This line has a right-of-way width of 90 feet and runs between the CGS switchyard and a tap off the 115-kV line that runs from the Benton Switchyard to FFTF. This tap is located about 1.8 miles southeast of the plant.

The transmission lines that were constructed to distribute CGS power to the grid and to supply plant startup power are shown on Figure 3.1-1.

Figure 3.1-1. General Plant Layout



3.2 REFURBISHMENT ACTIVITIES

Regulatory Requirement: 10 CFR 51.53(c)(2)

"The report must contain a description of ... the applicant's plans to modify the facility or its administrative control procedures as described in accordance with 10 CFR 54.21. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment...."

Energy Northwest has addressed refurbishment activities in accordance with NRC regulations and complementary information in the GEIS. In particular, NRC requirements for the renewal of operating licenses for nuclear power plants include the preparation of an Integrated Plant Assessment (IPA) in accordance with 10 CFR 54.21. The IPA must identify and list systems, structures, and components subject to an aging management review. Items that are subject to aging and might require refurbishment include, for example, the reactor vessel piping, supports, and pump casings, as well as items that are not subject to periodic replacement.

In addition, the GEIS (**NRC 1996**, Section 2.6) provides information on the scope and preparation of refurbishment activities to be evaluated in this environmental report. It describes major refurbishment activities that utilities might perform for license renewal that would necessitate changing administrative control procedures and modifying the facility. The GEIS analysis assumes that an applicant would begin any major refurbishment work shortly after NRC grants a renewed license and would complete the activities during five outages, including one major outage at the end of the 40th year of operation. The GEIS refers to this as the refurbishment period.

Energy Northwest has completed the IPA of structures and components as required by 10 CFR 54.21 and has incorporated the findings in the body of the CGS License Renewal Application. The IPA did not identify the need to undertake any major refurbishment or replacement actions to maintain the functionality of important systems, structures, and components during the CGS license renewal period, or other facility modifications associated with license renewal that would affect the environment or plant effluents.

Routine plant operation and maintenance activities will continue during the license renewal period. Energy Northwest does not consider these activities refurbishments as described in Sections 2.4 and 3.1 of the GEIS and will manage them in accordance with applicable Energy Northwest programs and procedures.

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3.3 PROGRAMS AND ACTIVITIES FOR MANAGING THE EFFECTS OF AGING

Regulatory Requirement: 10 CFR 51.53(c)(2)

"The report must contain a description of ... the applicant's plans to modify the facility or its administrative control procedures...."

The IPA required by 10 CFR 54.21 identifies the programs and inspections for managing aging effects at CGS during the additional 20 years beyond the initial license term. These programs are described in the body of the CGS License Renewal Application as part of Aging Management Programs and Activities.

In addition to implementation of the specific programs and inspections identified in the IPA, some enhancements to CGS administrative control procedures may be required in association with license renewal. The additional programs and inspection activities, and the potential enhancements to administrative control procedures, are consistent with normal plant component inspections and, for that reason, are not expected to cause environmental impact.

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3.4 EMPLOYMENT

3.4.1 Current Workforce

The non-outage work force at CGS, as of March 2009, consists of approximately 1,075 Energy Northwest employees and 70 supplemental personnel. Over 95% of the employees reside in either Benton or Franklin counties, with most living in the cities of Richland, Kennewick, and Pasco. Table 3.4-1 shows the estimated distribution of the residences of plant personnel by government jurisdiction.

The CGS reactor is on a 24-month refueling cycle. During refueling outages, which typically last 35 to 45 days, site employment is supplemented with the addition of 1,100 to 1,500 temporary workers.

3.4.2 License Renewal Increment

The GEIS estimated that an additional 60 employees would be necessary for operation during the period of extended operation. Energy Northwest, however, believes that it will be able to manage the necessary programs with existing staff.

Most of the new activities are one-time inspections that will be performed prior to entering the period of extended operation. The few new ongoing programs that will continue into the period of extended operation are not expected to require plant resources beyond the current staffing. Therefore, Energy Northwest has no plans to add non-outage employees to support plant operations during the extended license period. The number of workers required on-site for normal plant outages during the period of extended operation also is expected to be consistent with the number of additional workers used for past outages at the site.

As a result, there is no anticipated incremental effect to indirect employment or population associated with renewal of the CGS license.

Table 3.4-1. Estimated Distribution of CGS Personnel, March 2009

City of Residence	State	County	Plant Personnel
Yakima	WA	Yakima	8
Moxee	WA	Yakima	1
Toppenish	WA	Yakima	1
Zillah	WA	Yakima	2
Sunnyside	WA	Yakima	6
Grandview	WA	Yakima	5
Prosser	WA	Benton	7
Benton City	WA	Benton	59
West Richland	WA	Benton	131
Richland	WA	Benton	404
Kennewick	WA	Benton	341
Pasco	WA	Franklin	164
Connell	WA	Franklin	1
Burbank	WA	Walla Walla	9
Touchet	WA	Walla Walla	1
Walla Walla	WA	Walla Walla	1
Othello	WA	Adams	1
Moses Lake	WA	Grant	1
Pomeroy	WA	Garfield	1
Umatilla	OR	Umatilla	1
		Total	**1,145**

3.5 REFERENCES

AEC 1972. Final Environmental Statement Related to the Proposed Hanford Number Two Nuclear Power Plant, Washington Public Power Supply System, Docket No. 50-397, U.S. Atomic Energy Commission, Directorate of Licensing, December 1972.

BPA 1974a. Draft Supplement to the Environmental Statement, Fiscal Year 1975 Proposed Program, Ashe-Hanford 500 KV Transmission Line, Bonneville Power Administration, March 8, 1974.

BPA 1974b. Draft Supplement to the Environmental Statement, Fiscal Year 1975 Proposed Program, Richland Area Electrical Service Transmission Lines and Substations, Bonneville Power Administration, March 1974.

BPA 2008. 2007 BPA Facts, Pub. No. DOE/BP-3891, Bonneville Power Administration, May 2008, available at: http://www.bpa.gov/corporate/About%5FBPA/, accessed September 2, 2008.

EFSEC 1996. EFSEC Order No. 672, State of Washington Energy Facility Site Evaluation Council, January 8, 1996.

EFSEC 2001a. EFSEC Resolution No. 299 – Columbia Cooling System Sediment Disposal, State of Washington Energy Facility Site Evaluation Council, August 23, 2001.

EFSEC 2001b. EFSEC Resolution No. 300 – Sanitary Waste Treatment Facility, State of Washington Energy Facility Site Evaluation Council, September 10, 2001.

EN 2007. Columbia Generating Station Final Safety Analysis Report, Amendment No. 60, Energy Northwest.

NRC 1981. Final Environmental Statement (FES-OL) Related to the Operation of WPPSS Nuclear Project No. 2, Docket No. 50-397, Washington Public Power Supply System, NUREG-0812, Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, December 1981.

NRC 1996. Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants (GEIS), NUREG-1437, Volumes 1 and 2, Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, May 1996.

WDOE 2009. About the Commercial Low-Level Radioactive Waste Disposal Facility, Washington Department of Ecology, Website: http://www.ecy.wa.gov/programs/nwp/llrw/use.htm, accessed May 11, 2009.

WPPSS 1992. "Radiological Environmental Monitoring Program Special Report", Letter from G.C. Sorensen, Washington Public Power Supply System, to J.B. Martin, Nuclear Regulatory Commission, July 30, 1992.

4.0 ENVIRONMENTAL CONSEQUENCES OF PROPOSED ACTION AND MITIGATING ACTIONS

Regulatory Requirement: 10 CFR 51.53(c)(2)

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

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

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

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

Chapter 4 assesses the environmental consequences associated with the renewal of the Columbia Generating Station (CGS) operating license. The assessment is based on the 92 environmental issues that the NRC has identified, analyzed, and considers to be associated with nuclear power plant license renewal. The NRC has designated the issues as Category 1, Category 2, or NA (not applicable).

Category 1 issues met the following criteria:

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

NRC rules do not require analyses of Category 1 issues that NRC resolved using generic findings (10 CFR 51, Appendix B, Table B-1) as described in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (**NRC 1996**). An applicant may reference the generic findings or GEIS analyses for Category 1 issues.

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

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

Attachment A of this report lists the 92 issues and identifies the environmental report section that addresses each issue applicable to CGS. For organization and clarity, Energy Northwest has assigned a number to each issue and uses the issue numbers throughout the environmental report.

Category 1 License Renewal Issues

Energy Northwest has determined that, of the 69 Category 1 issues, seven are not applicable to CGS because they apply to design or operational features that do not exist at the facility. In addition, because Energy Northwest does not plan to conduct refurbishment activities, the NRC findings for the seven Category 1 issues applicable to refurbishment do not apply.

With respect to the remaining 55 Category 1 issues, Energy Northwest has not identified any new and significant information that would invalidate the NRC findings (at 10 CFR 51, Appendix B, Table B-1). Therefore, Energy Northwest adopts by reference the NRC findings for these Category 1 issues.

Category 2 License Renewal Issues

NRC designated 21 issues as Category 2. Sections 4.1 through 4.20 address these Category 2 issues, beginning with a statement of the issue. Nine Category 2 issues apply to operational features that CGS does not have. In addition, four Category 2 issues apply only to refurbishment activities. If the issue does not apply to CGS, the section explains the basis for inapplicability.

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

- SMALL – Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has

concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

- MODERATE – Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.
- LARGE – Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

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

NRC determined that its categorization and impact-finding definitions did not apply to two issues. NRC noted that applicants do not need to submit information on chronic effects from electromagnetic fields (10 CFR 51, Table B-1, Note 5). For the environmental justice issue, NRC does not require information from applicants, but notes that it will be addressed in individual license renewal reviews (10 CFR 51, Table B-1, Note 6). Energy Northwest has included environmental justice information in Sections 2.6.2 and 4.21 and both issues are listed in Attachment A, Table A-1.

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4.1 WATER USE CONFLICTS

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(A)

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow."

The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on instream and riparian communities near these plants could be of moderate significance in some situations. See 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 13. The issue, however, is largely dependent on river size and the corresponding annual river flow rate.

As discussed in Section 3.1.2, CGS has a closed-cycle heat dissipation system that uses mechanical draft cooling towers for which make-up water is pumped from the Columbia River. Based on USGS data, the annual mean flow of the Columbia River below Priest Rapids Dam, the nearest upstream gage station, was 3.73×10^{12} ft^3/year (118,263 cfs) during water years 1960 through 2008 (see Section 2.2.1.1). During the period of plant operation (1984 to 2008) the annual flow averaged 3.61×10^{12} ft^3/year (114,410 cfs) (**USGS 2009**). Both values are greater than the threshold of 3.15×10^{12} ft^3/year. Therefore, the Columbia River does not meet the NRC definition of a small river. As a result, this issue does not apply to CGS and no further analysis is required.

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4.2 ENTRAINMENT OF FISH AND SHELLFISH IN EARLY LIFE STAGES

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(B)

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

The issue of entrainment of fish and shellfish in early life stages applies to plants with once-through cooling or cooling pond heat dissipation systems. As discussed in Section 3.1.2, CGS has a closed-cycle heat dissipation system that uses mechanical draft cooling towers. As a result, this issue does not apply to CGS and no further analysis is required.

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4.3 IMPINGEMENT OF FISH AND SHELLFISH

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(B)

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

The issue of impingement of fish and shellfish applies to plants with once-through cooling or cooling pond heat dissipation systems. As discussed in Section 3.1.2, CGS has a closed-cycle heat dissipation system that uses mechanical draft cooling towers. As a result, this issue does not apply to CGS and no further analysis is required.

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4.4 HEAT SHOCK

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(B)

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act... 316(a) variance in accordance with 40 CFR Part 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock ...."

The issue of heat shock applies to plants with once-through cooling or cooling pond heat dissipation systems. As discussed in Section 3.1.2, CGS has a closed-cycle heat dissipation system that uses mechanical draft cooling towers. As a result, this issue does not apply to CGS and no further analysis is required.

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4.5 GROUNDWATER USE CONFLICTS

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(C)

"If the applicant's plant...pumps more than 100 gallons (total onsite) of groundwater per minute, an assessment of the impact of the proposed action on groundwater use must be provided."

The issue of groundwater use conflicts applies to plants that use more than an annual average of 100 gpm (6 L/s) of groundwater. As discussed in Section 2.3, groundwater onsite at CGS is pumped from a single well quarterly for about one-half hour. Also discussed in Section 2.3 is the occasional supply of groundwater for the CGS potable water system from two offsite wells. Because the annual average withdrawal rate from these sources is much less than 100 gpm, this issue is not applicable to CGS.

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

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(A)

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow."

The issue has been a concern at nuclear power plants with cooling towers. Impacts may result, for example, from surface water withdrawals from small water bodies during low flow conditions, which may affect aquifer recharge. See 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 34. The issue, however, is dependent on river size and the corresponding annual river flow rate.

CGS has a closed-cycle heat dissipation system that uses mechanical draft cooling towers with make-up water pumped from the Columbia River (see Section 3.1.2). As noted in Section 4.1, the Columbia River at CGS has a flow rate greater than the threshold of 3.15×10^{12} ft^3/year. Therefore, this issue does not apply to CGS and no further analysis is required.

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4.7 GROUNDWATER USE CONFLICTS (PLANTS USING RANNEY WELLS)

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(C)

"If the applicant's plant uses Ranney wells...an assessment of the impact of the proposed action on groundwater use must be provided."

The issue applies to plants using Ranney wells for cooling tower make up water. As discussed in Section 3.1.2, CGS has a closed-cycle heat dissipation system that uses mechanical draft cooling towers with make-up water pumped from the Columbia River. CGS does not use Ranney wells. Therefore, this issue does not apply to CGS and no further analysis is required.

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4.8 DEGRADATION OF GROUNDWATER QUALITY

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(D)

"If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided."

The issue applies to plants at inland sites with cooling ponds. As discussed in Section 3.1.2, CGS has a closed-cycle heat dissipation system that uses mechanical draft cooling towers that withdraw make-up water from and discharge blowdown to the Columbia River. Therefore, this issue does not apply to CGS and no further analysis is required.

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4.9 IMPACTS OF REFURBISHMENT ON TERRESTRIAL RESOURCES

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(E)

"All license renewal applicants shall assess the impact of refurbishment and other license renewal-related construction activities on important plant and animal habitats."

As discussed in Section 3.2, Energy Northwest did not identify the need for refurbishment of structures or components related to license renewal. As a result, there are no plans for refurbishment or other license-renewal-related construction activities at CGS. Therefore, this issue does not apply to CGS and no further analysis is required.

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4.10 THREATENED AND ENDANGERED SPECIES

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(E)

"Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act."

The NRC has found that plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. Consultation by the NRC with appropriate agencies at the time of license renewal confirms whether threatened or endangered species are likely to be in the site area and whether they would be adversely affected. See 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 49.

Section 2.2 of this ER describes the aquatic environment of the Columbia River near CGS and Section 2.4 describes the terrestrial environment of the CGS site and, more generally, the Hanford Site within which CGS is located. Section 2.5 discusses threatened and endangered species that occur or may occur in the vicinity of the CGS and the associated transmission line corridor.

With the exception of species identified in Section 2.5, Energy Northwest is not aware of any threatened or endangered terrestrial or aquatic species that occur near CCS and its associated transmission lines. Current operations of CGS and the associated transmission lines do not adversely affect any special-status species or important habitats. As noted in Section 3.1.7, the corridor for the transmission lines that connect the plant to the power transmission system crosses a developed area of the CGS site and a short strip of shrub-steppe habitat. The corridor does not require vegetation management practices such as trimming and mowing. Plant operations and transmission line maintenance practices are not expected to change significantly during the license renewal term.

As discussed in Section 3.2 of this ER, Energy Northwest did not identify the need for refurbishment of structures or components related to license renewal. Consequently, there would be no refurbishment-related impacts to threatened and endangered species.

Energy Northwest has written to the U.S. Fish and Wildlife Service, the National Marine Fisheries Service, the Washington Department of Fish & Wildlife Service, and the Washington Department of Natural Resources requesting information on any listed species or critical habitats that might occur in the vicinity of the CGS site, with particular emphasis on species that might be adversely affected by continued operation over the license renewal period. Agency responses, which did not identify new information regarding threatened and endangered species, are provided in Attachment C.

Because Energy Northwest has no plans to alter operations and maintenance of CGS and the associated transmission lines, Energy Northwest concludes that impacts to threatened or endangered species from license renewal would be SMALL and do not warrant mitigation.

4.11 AIR QUALITY DURING REFURBISHMENT (NONATTAINMENT AREAS)

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(F)

"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."

As discussed in Section 3.2, Energy Northwest has no plans for refurbishment of structures or components related to license renewal. Furthermore, the plant is not located in or near a nonattainment area. The nearest nonattainment area is approximately 180 miles northeast of CGS (Section 2.10.2). Therefore, this issue does not apply to CGS and no further analysis is required.

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4.12 IMPACT ON PUBLIC HEALTH OF MICROBIOLOGICAL ORGANISMS

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(G)

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

The issue is dependent on river size and the corresponding annual river flow rate. As noted in Section 4.1, CGS discharges into the Columbia River that has a flow rate greater than the threshold of 3.15×10^{12} ft^3/year. Therefore, this issue does not apply to CGS and no further analysis is required

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4.13 ELECTROMAGNETIC FIELDS – ACUTE EFFECTS

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(H)

"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 Electric Safety Code 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."

The NRC has concluded that electrical shock from energized conductors or from induced charges in metallic structures is not a problem at most operating plants and is not likely 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. See 10 CFR 51, Subpart A, Table B-1, Issue 59.

NRC made impacts of electric shock from transmission lines a Category 2 issue because, without a review of each plant's transmission line conformance with the National Electrical Safety Code (NESC) criteria, NRC could not determine the significance of the electrical shock potential. The NESC standards establish minimum line clearances such that induced currents will not exceed 5 milliamperes (mA) in the largest vehicle under the line. In the case of CGS, there have been no previous NRC or NEPA analyses of transmission-line-induced current hazards. Therefore, this section provides an analysis of the plant's transmission lines' conformance with the NESC standard.

Objects located near transmission lines can become electrically charged due to their immersion in the lines' electric field. This charge results in a current that flows through the object to the ground. The current is called "induced" because there is no direct connection between the line and the object. The induced current can also flow to the ground through the body of a person who touches the object. An object that is insulated from the ground can actually store an electrical charge, becoming what is called "capacitively charged." A person standing on the ground and touching a vehicle or a fence receives an electrical shock due to the sudden discharge of the capacitive charge through the person's body to the ground. After the initial discharge, a steady-state current can develop of which the magnitude depends on several factors, including the following: (1) the strength of the electric field (which depends on the voltage, height, and geometry of the transmission line); (2) the size of the object on the ground; and (3) the extent to which the object is grounded.

As described in Section 3.1.7, the CGS output is delivered to the Bonneville Power Administration (BPA) at the H.J. Ashe Substation located 0.5 miles north of the plant via an elevated 500-kV line. Plant startup power comes from the Ashe Substation to the

CGS transformer yard on a 230-kV parallel line. These are the lines that connect the plant to the BPA northwest power grid and are within the scope of license renewal.

BPA has developed an electric field strength policy for the design and operation of its transmission system (**BPA 1979**). The policy is intended to minimize shock hazards consistent with the National Electric Safety Code (NESC) and sets the following levels as the maximum field strengths under and adjacent to transmission lines:

- In the right-of-way 9 kV/m
- At the edge of the right-of-way 5 kV/m
- At road crossings 5 kV/m
- At shopping center parking lots 3.5 kV/m
- At commercial/industrial parking lots 2.5 kV/m

These levels are measured one meter above the ground at 49°C (120°F) conductor temperature and maximum operating voltage. In addition, the BPA policy limits short circuit currents from the largest vehicle or equipment anticipated to be exposed to 5 mA (rms), as then specified in the NESC.

The relationship between electric field strength and short circuit currents induced in vehicles of various sizes is shown in Table 4.13-1, which is taken from the BPA policy. BPA noted the possibility that a primary shock level current exceeding the 5 mA criterion could be induced in a large truck (65-foot single trailer, or 75-foot double trailer) under a BPA transmission line with a field strength exceeding 5 kV/m. However, the BPA policy notes that this type of vehicle is not anticipated in the right-of-way at any location other than a road crossing where field strengths are limited to 5 kV/m. The BPA policy also notes that the largest type of vehicle that would be expected to be exposed to field strengths over 5 kV/m could be a farm-type vehicle or equipment. These vehicles, however, are of a physical size that would not couple short circuit currents above the 5 mA NESC limit in an electric field of 9 kV/m (**BPA 1979**).

BPA has reviewed the design of the CGS transmission lines and calculated the electric field profiles based on conductor spacing and minimum ground clearances (BPA 2008). These calculations showed the maximum field strength within the right-of-way under the CGS transmission lines was 4.5 kV/m. From the correlations with induced current in Table 4.13-1, it can be determined that the largest vehicle parked in this field would have a short circuit current of about 4.4 mA.

The CGS transmission line corridor crosses developed portions of the CGS site and open range type space. No land use changes are anticipated in the vicinity of the corridor. Energy Northwest and BPA surveillance of the transmission system assure that ground clearances will not change.

Based on the above considerations, Energy Northwest concludes that the potential for electric shock of is of SMALL significance and mitigation measures are not warranted.

Table 4.13-1. Currents Induced into Vehicles from A-C Electric Fields

Vehicle	Short Circuit Current (mA per kV/m)	Short Circuit Current (mA) in an Electric Field of			
		9 kV/m	5 kV/m	3.5 kV/m	2.5 kV/m
Sedan	0.11	1.0	0.9	0.4	0.3
Pickup – with camper	0.28	2.5	1.4	1.0	0.7
School bus – 28 ft.	0.33	3.0	1.7	1.2	0.8
Truck – 28 ft. flatbed	0.20	1.8	1.0	0.7	0.5
Truck – 28 ft. – covered van	0.50	4.5	2.5	1.8	1.3
Truck – 65 ft. single trailer	0.92	8.3	4.6	3.2	2.3
Truck – 75 ft. double trailer	0.98	8.8	4.9	3.4	2.5

Source: **BPA 1979**, Table One

4.14 HOUSING IMPACTS

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(I)

"An assessment of the impact of the proposed action on housing availability...within the vicinity of the plant must be provided."

Housing impacts depend on local conditions. Impacts result when the demand for housing, caused by the project-related population increase, approaches or exceeds the number of available housing units in the vicinity of the plant. The magnitude of the impacts is determined by the number of additional workers associated with refurbishment activities or continued operation and maintenance, and by the population and housing inventory within the region.

As discussed in Supplement 1 to Regulatory Guide 4.2, if there will be no refurbishment or if refurbishment involves no additional workers, then there will be no impact on housing and no further analysis is required (**NRC 2000**, Section 4.14.1). As described in Section 3.2, CGS does not plan to perform refurbishment and concludes there would be no refurbishment-related impacts to area housing, and no analysis is therefore required.

Sections 2.6.1.1 and 2.8 indicate that CGS is located in a medium population area that, although it is subject to growth planning, is not subject to control measures that limit housing development. NRC regulatory criteria at 10 CFR 51, Subpart A, Table B-1, Issue 63, indicate that housing impacts are expected to be of small significance at plants located in a medium or high population area and in an area where growth control measures that limit housing development are not in effect. Furthermore, Energy Northwest does not anticipate a need for additional full-time workers during the license renewal period (Section 3.4).

Energy Northwest concludes that, since there would be no increase in staffing, the impact to housing from the continued operation of CGS in the license renewal period is SMALL and does not warrant mitigation.

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4.15 PUBLIC UTILITIES: PUBLIC WATER SUPPLY AVAILABILITY

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(I)

"[T]he applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply."

Impacts on public utility services, as noted in the GEIS, are considered small if little or no change occurs in the ability to respond to the level of demand. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs and large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services (**NRC 1996,** Section 3.7.4.5).

The NRC analysis of impacts to public water systems considered both plant demand and demand growth attributable to plant-related population growth. The CGS plant has its own potable water system for which the primary source is the Columbia River (see Section 3.1.2.4). As discussed in Section 2.3.2, the CGS potable water system has a cross-tie to the neighboring IDC system. Both potable water systems are classified as non-transient, non-community public water systems by the Washington Department of Health. The IDC system has a 400,000 gallon reservoir tank and the system was built to supply the construction force for two large nuclear power projects. The occasional supply of water to CGS does not stress the system. Furthermore, Energy Northwest has identified no changes during the CGS license renewal period that would increase the demand for water at CGS.

Energy Northwest has no plans for refurbishment (Section 3.2) and does not anticipate a need for additional full-time workers during the license renewal period (Section 3.4). Therefore, license renewal will not result in incremental impacts to the public water supplies in the two-county area near the plant. As discussed in Section 2.9.4, local municipal water systems have unused capacity.

Energy Northwest concludes, therefore, that impacts to public water supplies will continue to be SMALL and no evaluation of mitigation measures is warranted.

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4.16 EDUCATION IMPACTS FROM REFURBISHMENT

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(I)

"An assessment of the impact of the proposed action on...public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided."

Impacts to education are a product of additional demand on the public education system resulting from refurbishment-related population growth and the capacity of the education system to absorb additional students. Because, as discussed in Section 3.2, Energy Northwest has no plans for refurbishment, this issue does not apply to CGS and no further analysis is required .

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4.17 OFFSITE LAND USE

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(I)

"An assessment of the impact of the proposed action on...land use...within the vicinity of the plant must be provided."

Impacts to off-site land use take place when pressures resulting from projected related population or tax revenue increases result in changes to local land use and development patterns. These impacts could occur during either refurbishment or the license renewal period.

4.17.1 Refurbishment

As discussed in Section 3.2, Energy Northwest did not identify the need for refurbishment of structures or components related to license renewal. As a result, there are no plans for refurbishment or other license-renewal-related construction activities at CGS. This issue, therefore, is not applicable to CGS.

4.17.2 License Renewal

During the license renewal term, new land use impacts could, as noted in the GEIS, result from plant-related population growth or from the use of tax payments from the plant by local government to provide public services that encourage development (**NRC 1996**, Section 4.7.4.1).

Population-Related Impacts

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

Energy Northwest agrees with the NRC conclusion and judges that new population-driven land use changes at CGS during the license renewal term will, therefore, be SMALL. Furthermore, Energy Northwest does not anticipate that additional workers will be employed at CGS during the period of extended operations. As a result, there will be no impact to the offsite land use from plant-related population growth during the license renewal period.

Tax Revenue-Related Impacts

NRC has determined that the significance of tax payments as a source of local government revenue would be (**NRC 1996**, Section 4.7.2.1):

- SMALL – if the payments are less than 10 percent of the taxing jurisdiction's revenue
- MODERATE – if payments are 10 to 20 percent
- LARGE – if payments represent greater than 20 percent of revenue

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

- SMALL – very little new development and minimal changes to an area's land-use pattern
- MODERATE – considerable new development and some changes to land-use pattern
- LARGE – large-scale new development and major changes in land-use pattern

CGS Taxes. As explained in Section 2.7, because Energy Northwest is exempt from property taxes, its tax payments consist principally of sales taxes and a "privilege" tax based on annual electricity generation. Taxes are paid to the Washington State Department of Revenue for redistribution to various local jurisdictions.

Table 2.7-3 shows that the relative contribution of taxes derived from CGS to the general fund revenue of local jurisdictions in 2007 was on the order of 1%. Using the NRC's criteria listed above, CGS's tax payments are of small significance to the jurisdictions surrounding the plant.

Energy Northwest is not aware of any prospective changes to the tax structure that would cause the relative contribution of CGS to increase during the license renewal term. Also, as described in Section 3.2, Energy Northwest does not anticipate refurbishment or license renewal-related construction during the license renewal period. Therefore, Energy Northwest does not anticipate any increase in generation capacity of CGS due to refurbishment-related improvements, or any related tax-increase-driven changes to offsite land use and development patterns.

Land Use in the CGS Region. The dominant land uses in the region surrounding CGS are open federal lands of the USDOE Hanford Site and agriculture on the lands east of the Columbia River. Population centers, with concentrations of residential, commercial, and industrial land uses, are south to southeast of the CGS site at distances of about 10 to 20 miles. As noted in Sections 2.6 and 2.8, portions of the two-county area surrounding the plant have experienced substantial development of residential and commercial property. Much of this development has occurred on land converted from

open space and agriculture. Notable areas of development are west Pasco, south and southwest Kennewick, south and northwest Richland, and West Richland.

The land use changes that have occurred in the region surrounding CGS could be characterized according to the NRC criteria listed above as small to moderate. These changes have occurred in the urbanized areas and designated urban growth areas that comprise a relatively small percentage of the land area of Benton and Franklin Counties. These changes have not been driven by CGS tax payments which have remained fairly stable.

Conclusion

As discussed above, land use changes stemming from population growth related to renewal of the CGS license would be small. Also, although land use changes have occurred and may continue to occur in parts of the region around CGS, taxes paid by CGS are a minor contributor to the changes. Therefore, Energy Northwest concludes that the land use impacts of CGS license renewal would be SMALL and mitigation is not warranted.

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4.18 TRANSPORTATION

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(J)

"All applicants shall assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license."

Transportation impacts, as discussed in the GEIS, would continue to be of small significance at all sites during operations and would be of small or moderate significance during scheduled refueling and maintenance outages. However, because impacts are determined primarily by road conditions existing at the time of the project, the impact significance needs to be determined at the time of license renewal (**NRC 1996,** Section 4.7.3.2).

There are no refurbishment activities anticipated for the license renewal period and no expected increase in the number of employees required to support plant operation during the license renewal period (Sections 3.2 and 3.4). Additionally, LOS road designations in the CGS vicinity are adequate (Section 2.9.4.2). The main feeder road to CGS, for example, is SR-240, which is designated LOS B. Similarly, the major commuter roads in the Tri-Cities area, US 395 and I-182, are LOS A and B, respectively. As noted in Regulatory Guide 4.2, Supplement 1, roads with LOS A and B are associated with small impacts because operation of individual users is not substantially affected by the presence of other users. At this level, no delays occur and no improvements are needed (**NRC 2000**, Section 4.18).

Energy Northwest concludes that impacts to transportation due to continued operation of CGS during the license renewal period would be SMALL and mitigation would not be warranted.

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4.19 HISTORIC AND ARCHAEOLOGICAL RESOURCES

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(K)

"All applicants shall assess the impact of whether any historic or archaeological properties will be affected by the proposed project."

The NRC has concluded that, generally, plant refurbishment and continued operation are expected to have only 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. See 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71.

As discussed in Section 2.11, an archaeological and historic resources survey of the CGS site was performed prior to construction. No archaeological features or historic structures were observed at the reactor site or in the corridor between the river pumphouse and the reactor site. Evidence of Native American presence was found in the vicinity of the pumphouse and water intake. Other materials related to pre-contact and post-contact use of the area were found during construction of the adjacent pumphouse for the terminated WNP-1/4 projects. Focused surveys of portions of the site have been conducted during plant operation with no observations of cultural or historic materials.

Energy Northwest contacted the Washington Department of Archaeology and Historic Preservation (WDAHP) for information related to any known archaeological resources in the vicinity of the CGS site. WDAHP did not provide information regarding the presence of sites of historical or archaeological importance in the vicinity. Correspondence on the subject is included in Attachment D.

No refurbishment activities have been identified to support continued operation of CGS beyond the end of the existing operating license (Section 3.2), therefore, there will be no impact on historic or archaeological properties from refurbishment activities. Furthermore, Energy Northwest is not aware of any historic or archaeological resources that have been affected by CGS operations, including operation and maintenance of transmission lines. Energy Northwest has procedural controls in place to ensure that reviews are conducted for protection of cultural resources prior to engaging in land-disturbing construction activities on the site. These controls include activities involving disturbance of previously undisturbed surface or subsurface land areas.

Energy Northwest concludes that the potential impact of continued operation of CGS during the period of the renewed license on historic or archaeological resources will be SMALL and mitigation is not warranted.

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4.20 SEVERE ACCIDENT MITIGATION ALTERNATIVES

Regulatory Requirement: 10 CFR 51.53(c)(3)(ii)(L)

"If the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment, a consideration of alternatives to mitigate severe accidents must be provided."

This section summarizes Energy Northwest's analysis of alternative ways to mitigate the impacts of severe accidents at CGS. A detailed description of the severe accident mitigation alternative (SAMA) analysis is provided in Attachment E.

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

The NRC concluded that the generic analysis summarized in the GEIS applies to all plants and 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. However, not all plants have performed a site-specific analysis of measures that could mitigate severe accidents. Consequently, severe accidents are a Category 2 issue for plants that have not performed a site-specific consideration of severe accident mitigation and submitted that analysis for Commission review (**NRC 1996**, Section 5.5.2.5).

The Level 1 probabilistic safety assessment (PSA) and Level 2 PSA models for CGS (as discussed in Attachment E Sections 3, 4, and 5) were used to estimate the core damage frequency (CDF) and release category (RC) frequencies. The RC frequency and characterizations (using the MAAP code) from the Level 2 PSA were provided as input to the subsequent Level 3 PSA. The Level 2 PSA results are combined with CGS-specific parameters (e.g., population, meteorological data, topography, and economic data) for the Level 3 PSA to estimate the off-site dose and off-site property losses. Then, based on NRC guidance in NUREG/BR-0184 (**NRC 1997**), the maximum achievable benefit for any SAMA candidate at CGS was estimated. This value provided an upper bound of any potential SAMA candidate benefit and was used to eliminate a SAMA candidate from any further analysis. The following provides a summary of the steps used during the SAMA process:

- Level 3 PSA Analysis – The Level 3 PSA model developed to support this cost-benefit evaluation used the MELCOR Accident Consequence Code System (MACCS2), which simulates the impact of severe accidents at nuclear power plants on the surrounding environment. The results of the Level 3 PSA model are vectors of off-site exposure and off-site property costs associated with each RC. These consequence vectors were combined with the results of the Level 2 PSA model (i.e., RC frequencies) to yield the probabilistic off-site dose and probabilistic off-site property losses. The final results of the Level 3 PSA evaluation for each SAMA candidate were the value of the cumulative dose expected to be received by off-site individuals and the value of the expected off-site property losses due to severe accidents given the plant configuration under evaluation. Sensitivity analyses were performed to assess the impact of assumptions associated with the site population, meteorological conditions, and evacuation timing when defining the input parameters to MACCS2. The Level 3 PSA is discussed in Attachment E, Sections 6 and 7.
- Cost of Severe Accident Risk – The cost of severe accident risk was estimated using guidance from NEI 05-01 (**NEI 2005**) and NUREG/BR-0184. The cost of severe accident risk was defined as the maximum achievable benefit a SAMA candidate could achieve if it eliminated all risk. The maximum achievable benefit was obtained by evaluating the total risk in U.S. dollars considering the risk of dose to the public and workers, off-site and on-site economic impacts, and replacement power costs. Any SAMA candidate for which the implementation cost was greater than the maximum achievable benefit was eliminated from any further cost-benefit analysis. The severe accident risk cost calculation is provided in Attachment E, Section 8.
- Candidate SAMA Identification – SAMA candidates are defined as potential enhancements to the plant design, operating procedures, inspection programs, or maintenance programs that have the potential to prevent core damage and prevent significant releases from the CGS containment. A comprehensive initial list of SAMA candidates was developed by reviewing industry guidance documents, SAMA analyses of other plants, CGS Individual Plant Examination (IPE), CGS Individual Plant Examination External Events (IPEEE), CGS Level 1 PSA (Revision 6.2), and CGS Level 2 PSA (Revision 6.2). The PSA results were reviewed for the dominant cutsets, system importance, significant contributors to Level 2 RCs, and any insights or recommendations provided. The list of initial SAMA candidates is discussed in Attachment E, Section 9.
- Phase I SAMA Analysis (Screening) – A qualitative screening was performed for each of the candidates identified on the initial SAMA candidate list. Several SAMA candidates were screened on the basis the candidate was not applicable to CGS, was already implemented at CGS, required excessive implementation cost, or had very little perceived (risk) benefit. If SAMA candidates were similar, one was subsumed into the more risk beneficial candidate. The screening process for each SAMA candidate is discussed in Attachment E, Section 10.

- Phase II SAMA Analysis (Cost-Benefit) – Those SAMA candidates that passed the qualitative screening were selected for a detailed cost-benefit analysis that compared the estimated benefit in dollars of implementing the SAMA candidate to the estimated cost of implementation. The methodology used for this evaluation was based on regulatory guidance for cost-benefit evaluation (**NRC 1997**). The estimated benefit was determined by applying a bounding modeling assumption in the PSA model. For example, if a SAMA candidate would reduce the likelihood of a specific human error, the human error probability would be set to zero in the PSA model. This would result in eliminating the human error for the SAMA candidate, thus overestimating the potential benefit. This bounding treatment is conservative for a SAMA evaluation because underestimating the risk in the modified PSA case makes the modification look more beneficial than it may be. The costs to implement SAMA candidates considered for further evaluation were estimated. If the estimated benefit exceeded the estimated implementation cost, the SAMA candidate was considered viable for implementation. The cost-benefit evaluation is discussed in Attachment E, Section 11.
- Sensitivity Analysis – Sensitivity cases were performed to investigate the sensitivity of the results to certain modeling assumptions in the CGS SAMA analysis. Five sensitivity cases were investigated. These cases examined the impact of assuming damaged plant equipment is repaired and refurbished following an accident, lower discount rate, higher discount rate, on-site dose estimates, and total on-site cleanup cost. Details on the sensitivity cases are discussed in Attachment E, Section 12.

The results of the evaluation of 150 SAMA candidates did not identify any cost beneficial enhancements at CGS. However, assuming a lower discount rate identified three potential cost beneficial SAMA candidates. None of the three cases identified in the sensitivity analysis are related to plant aging. Therefore, the identified cost beneficial SAMA candidates are not required modifications for the license renewal period. Nevertheless, these candidates will be considered through normal processes for evaluating possible changes to the plant.

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4.21 ENVIRONMENTAL JUSTICE

Regulatory Requirement: 10 CFR 51.53, Subpart A, Appendix B, Table B1

"The need for and the content of an analysis of environmental justice will be addressed in plant specific reviews."

Environmental justice was not reviewed in the GEIS. However, Executive Order 12898, issued in 1994, is intended to focus the attention of federal agencies on the human health and environmental conditions in minority and low income communities.

The consideration of environmental justice is required to assure that federal programs and activities will not have disproportionately high and adverse human health or environmental effects on minority and low-income populations. Accordingly, the NRC's Nuclear Reactor Regulation (NRR) Office has a procedure for incorporating environmental justice into the licensing process **(NRC 2004)**.

As the NRR procedure recognizes, if no significant off-site impacts occur in connection with the proposed action, then no member of the public will be substantially affected. Thus, no disproportionate impact on minority or low-income populations would occur from the proposed action.

Section 2.6.2 presents demographic information to assist the NRC in its environmental justice review.

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4.22 CUMULATIVE IMPACTS

Energy Northwest considered potential cumulative impacts in its environmental analysis associated with CGS operations during the license renewal period. For the analysis, past actions are those related to the resources at the time of plant licensing and construction; present actions are those related to the resources at the time of current operation of the power plant; and future actions are those that are reasonably foreseeable through the end of plant operation, which would include the 20-year license renewal term.

The impacts of license renewal are combined with other past, present, and reasonably foreseeable future actions regardless of what agency (federal or non-federal) or person undertakes such other actions. These combined impacts are defined as "cumulative" in 40 CFR 1508.7 and include individually minor, but collectively significant actions taking place over a period of time. It is possible that an impact that may be SMALL by itself could result in a MODERATE or LARGE impact when considered in combination with the impacts of other actions on the affected resource. Likewise, if a resource is regionally declining or imperiled, even a SMALL individual impact could be important if it contributes to or accelerates the overall resource decline.

Energy Northwest has considered the principal past, present, and reasonably foreseeable future actions potentially impacting the environment affected by CGS. In the immediate vicinity of CGS, future activity could occur at the adjacent IDC site where Energy Northwest is promoting industrial development, including power generation. As noted in Section 2.1, the IDC is the site of two terminated 1,200 MWe nuclear power construction projects (WNP-1/4). Cleanup and decommissioning of USDOE facilities on the Hanford Site are present and future activities occurring in the area. Remediation of Burial Ground 618-11 on the west side of CGS is one such activity. The dismantlement of the Fast Flux Test Facility (FFTF) at the USDOE 400 Area south-southwest of CGS is another possible future activity. Energy Northwest is not aware of any other significant projects or land use changes in the site area on either side of the Columbia River.

4.22.1 Cumulative Impacts on Surface Water and Aquatic Resources

Withdrawal of Columbia River water is an issue of some significance as resource agencies strive to accommodate the needs of communities, industries, agriculture, hydropower, and aquatic life. Of particular concern are the aquatic species deemed in such stress as to be given protected status. Operation of CGS could contribute to cumulative impacts attributable to all users of the water resource.

As discussed in Sections 2.2 and 3.1.2, CGS is located at RM 352 of the Columbia River and withdraws water to replenish losses in the evaporative cooling system and to supply water needed for plant processes and drinking. The mean annual flow of the river at RM 352 is 118,263 cfs. The river water withdrawn by CGS is equivalent to

0.03% of the Columbia's mean annual flow and 0.1% of the minimum instantaneous release from Priest Rapids Dam 45 miles upstream.

There are no other substantial withdrawals of Columbia River water in the vicinity of CGS. The only significant reasonably foreseeable future action potentially affecting the water resource is the development of a project at the IDC site. The WNP-1/4 in-river intake and pumphouse are about 650 ft upstream of the CGS water withdrawal facilities. Presumably, if a project materialized for the IDC that required substantial water, the sponsor would seek a surface water right and complete the intake facilities, which were designed to supply two large nuclear projects. If a project is built at the IDC the potential impacts to the Columbia River include the intake and consumption of water and the possible discharge of wastewater or cooling water blowdown.

Energy Northwest believes that the cumulative impact of CGS and reasonably foreseeable projects on the resources of the Columbia River will be small. Withdrawals at CGS are a very small fraction of the river flow and have not been shown to cause impingement or entrainment of organisms at the intake (see Section 2.2.2.2). A foreseeable project at the IDC would use the same type of intake facilities and would most likely have a withdrawal equivalent to CGS or less. The cumulative impact to aquatic resources caused by these withdrawals would be minor compared to impacts attributable to other stressors such as mainstem dams and irrigated agriculture.

The discharge of cooling tower blowdown from CGS averages about 2,000 gpm, or less than 0.004% of the long-term average river flow, and is not a significant source of thermal or chemical pollutants. The cumulative impact of this discharge when considered with a comparable discharge from the IDC and other dischargers, including irrigation return flows, is not significant.

Energy Northwest concludes that the cumulative impacts to aquatic resources of the Columbia River related to license renewal would be SMALL.

4.22.2 Cumulative Impacts on Terrestrial Resources

As noted in Section 2.4, the USDOE Hanford Site serves as an important refuge for the shrub-steppe ecosystem, due largely to its protected status since 1943. This habitat type is designated as priority habitat for conservation by State of Washington resource agencies because such a large percentage has been converted to agriculture and other uses. Operation of CGS could contribute to cumulative impacts attributable to all land users that convert and occupy the terrestrial resource.

Impacts to terrestrial resources caused by CGS are largely associated with the disruption and occupation of the shrub-steppe and grassland habitat caused by construction of the plant and supporting facilities. Additional impacts to undisturbed areas can result from the spread of invasive species such as cheatgrass (*Bromus*

tectorum) and Russian thistle (*Salsola tragus*). Energy Northwest does not expect that there will be a need to disturb additional habitat on the CGS site and believes that impacts attributable to CGS are stabilized. Control of vegetation under transmission lines is not required.

Most of the land in the vicinity of CGS on the west side of the Columbia River is undeveloped, but is crisscrossed with roads and transmission lines. Land on the west side of the river is developed for agriculture in fields, vineyards, and orchards. Energy Northwest is not aware of any substantial planned changes in land use in the site area. Land uses on the Hanford Reach National Monument, particularly in the river corridor, will be subject to controls that limit disruption of the terrestrial resource. If a future project were developed at the IDC or the USDOE 400 Area, incremental impacts to the terrestrial resource would be minimal because a new project would most likely be located within the previously disturbed areas.

Energy Northwest concludes that the cumulative impacts to terrestrial resources of the site vicinity related to license renewal would be SMALL.

4.22.3 Cumulative Human Health Impacts

As described in Section 4.13, the electric-field-induced currents from the CGS transmission lines are below the NESC recommendations for preventing electric shock from induced currents. The CGS transmission lines, therefore, do not detectably affect the overall potential for electric shock from induced currents within the analysis area.

The radiological dose limits for protection of the public and workers have been developed by the USEPA and the NRC to address the cumulative impact of acute and long-term exposure to radiation and radioactive material. These dose limits are codified in 40 CFR Part 190 and 10 CFR Part 20. The only other significant radioactive emissions sources with a 50-mile radius of CGS are on the Hanford Site. These sources are associated with former fuel processing facilities and waste storage tanks.

Energy Northwest has conducted a radiological environmental monitoring program around the CGS site since 1978. The results of the operational phase Radiological Environmental Monitoring Program (REMP) are reported to the NRC in the Annual Radiological Environmental Operating Report. The REMP measures radiation and radioactive materials from all sources, including CGS, and thus measures cumulative radiological impacts.

Based on REMP results, Energy Northwest concludes that impacts of radiation exposure on the public and workers (occupational) from operation of CGS during the renewal term would be small. With respect to the future, the REMP sampling locations shown in the CGS Offsite Dose Calculation Manual has not identified increasing levels or the accumulation of radioactivity in the environment over time. As described in

Section 2.12, the reasonably foreseeable projects in the vicinity of CGS involve the remediation of radioactive wastes or the decommissioning of reactor facilities. In the short term these activities could contribute to cumulative radiological impacts. The NRC, USDOE, and the State of Washington, however, would regulate any future actions in the vicinity of the site that could contribute to cumulative radiological impacts.

Energy Northwest concludes that the cumulative impacts to human health related to license renewal would be SMALL.

4.22.4 Cumulative Socioeconomic Impacts

The impacts to housing, local public services/utilities, education, offsite land use, and transportation as measures of socioeconomic indicators for counties in the site area were evaluated separately in Sections 4.14 through 4.18, respectively. As discussed in each section, continued operation of CGS during the license renewal term would have small impact on socioeconomic conditions in the region beyond those already being experienced.

As described in Sections 3.2 and 3.4, Energy Northwest has no plans for plant refurbishment or hiring additional non-outage workers during the license renewal term. Therefore, overall expenditures and employment levels at CGS would be expected to remain relatively constant with no additional demand for permanent housing, public utilities, and public services.

In addition, since employment levels and the value of CGS would not change, there would be no population and tax revenue-related land use impacts. There would also be no disproportionately high and adverse health and environmental impacts on minority and low income populations in the region.

Energy Northwest concludes that the cumulative socioeconomic impacts related to license renewal would be SMALL.

4.22.5 Cumulative Impacts on Groundwater Use and Quality

As discussed in Section 2.3, the characteristics of the groundwater at the CGS site are largely influenced by historical and ongoing activities on the USDOE Hanford Site. These activities have resulted in widespread contamination of the unconfined aquifer. Elevated concentrations of tritium and nitrate extend under the CGS site in plumes issuing from distant (e.g., USDOE 200 East Area) and nearby sources (i.e., Burial Ground 618-11). With the cessation of the fuel processing activities and associated wastewater discharges to ground in the central Hanford Site, the spread of the larger plumes has been somewhat retarded.

Discharges to ground at the CGS site have the potential to alter the quality of the groundwater in the unconfined aquifer. For example, discharges of stormwater contain tritium from plant roofs but the concentrations are less than in the groundwater such that there is an apparent dilution effect. Both USDOE and Energy Northwest sample the groundwater in the vicinity of CGS to support various monitoring programs. Monitoring of the deep wells at the IDC that supply a non-transient, non-community water system has not shown any contamination. Over the long-term, as USDOE remediates the contamination sources (with projects discussed in Section 2.12) and the tritium decays, there should be a trend of lower contaminant concentrations.

Groundwater issues in the vicinity of CGS are related to quality, not quantity. There are few users of the unconfined aquifer and no new project with a substantial demand for groundwater is anticipated. It is possible that a future development on the IDC site or in the 400 Area could use the groundwater resource but it would not likely be competing with any other users.

Energy Northwest concludes that, because the characteristics of the groundwater in the site area are noticeably altered by USDOE activities, the cumulative impacts to groundwater resources could be characterized as SMALL to LARGE, depending on location. The incremental contribution of CGS to cumulative impacts to the groundwater resource from operation during the license renewal term would be SMALL.

4.22.6 Conclusion

Energy Northwest considered the potential impacts from CGS operations during the license renewal term and other past, present, and future actions in the vicinity of the site. Energy Northwest's conclusion is that the potential contribution to cumulative impacts resulting from CGS operations during the license renewal term would be SMALL and, therefore, mitigation measures are not warranted.

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4.23 REFERENCES

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5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

Regulatory Requirement: 10 CFR 51.53(c)(3)(iv)

"The environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware."

5.1 DESCRIPTION OF PROCESS

The NRC licenses the operation of domestic nuclear power plants and provides for license renewal, requiring a license renewal application that includes an environmental report (10 CFR 54.23). NRC regulations, 10 CFR 51, prescribe the environmental report content and identify the specific analyses the applicant must perform. In an effort to 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 issues.

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those environmental issues that have been generically resolved (10 CFR 51.53(c)(3)(i)), the regulations do require that an applicant identify any new and significant information of which the applicant is aware (10 CFR 51.53(c)(3)(iv)). The purpose of this requirement is to alert the NRC staff to such information so that the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. The NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of GEIS conclusions (**NRC 1996a**, Page C9-13).

Energy Northwest expects that new and significant information would include:

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

The NRC's interpretation of the term "significant" is consistent with guidance in Council on Environmental Quality (CEQ) regulations for the preparation of environmental impact statements. 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 definition of "significantly" that requires consideration of the context of the action, and the intensity or severity of the impact(s)

(40 CFR 1508.27). Energy Northwest assumes that moderate or large impacts, as defined by the NRC, would be significant. Chapter 4 presents the NRC definitions of "moderate" and "large" impacts.

Energy Northwest has implemented an environmental management system (EMS) that has been registered by an independent third party as conforming to the international standard ISO 14001. Key elements of the EMS are tiered departmental procedures that govern review of environmental issues.

New issues related to environmental matters are identified by CGS Environmental and Regulatory Programs personnel using the following resources:

- Regulatory agencies (e.g., U.S. EPA and Washington Department of Ecology)
- Industry utility groups (e.g., NEI)
- Non-utility trade groups/associations (e.g., APPA Environmental ListServ)
- Seminars, workshops, and courses
- Technical newsletters/magazines

If an issue is applicable to the CGS site, appropriate changes are made to the site and program procedures.

The identification of new and significant information for preparation of the CGS license renewal application included the following:

- Review of documents related to environmental issues at CGS and the site environs;
- Review of current site activities and interview of site personnel;
- Review of internal procedures for reporting to the NRC events that could have environmental impacts;
- Credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies;
- Participation in review of other licensees' environmental reports, audits, and industry initiatives; and
- Review of supplemental GEISs that the NRC has prepared for other license renewal applications.

5.2 ASSESSMENT

Based on its processes for staying apprised of new information and changing conditions, Energy Northwest is not aware of any new and significant information regarding the environmental impacts of CGS license renewal. However the issues discussed below have significance apart from renewal of the CGS license.

Nuclear Plant Security

Energy Northwest is aware that a ruling of the U.S. Ninth Circuit Court of Appeals has inserted terrorism as an environmental issue in at least one NRC licensing action (**USCT 2006**) even though the NRC has held that license renewal applicants need not consider the impacts of terrorism (**NRC 2007a**). Since issuance of the Ninth Circuit decision, the U.S. Court of Appeals for the Third Circuit issued another NEPA-terrorism decision, reaching a different conclusion in the context of a power reactor license renewal. The Third Circuit ruled that the GEIS adequately assesses environmental impacts from internally-generated events and that an applicant has no obligation under NEPA to analyze terrorist activities (**USCT 2009**). Nevertheless, because CGS is located in the Ninth Circuit, Energy Northwest has included the following discussion of the issue.

The consideration of risk for an operating nuclear generating facility is not necessarily the same as for a new facility. Thus, the consideration of possible environmental impacts of a terrorist attack at an existing facility such as CGS must take into account the protections afforded an existing facility and recognize that it is already sited and has been operating for over 25 years. It is important to note that the possibility of a terrorist attack affecting the operation of CGS is very remote and that postulating environmental impacts from an attack involves substantial speculation.

In this regard, CGS has a trained, armed security force and multiple physical barriers surrounding the plant. State-of-the-art motion sensors and cameras monitor the Owner Controlled Area and Protected Area boundaries. The plant and site perimeter fences are monitored on a 24-hour basis by dedicated security staff. Contingency plans have been developed for potential security threats and plans are tested through drills and exercises. Unescorted access to the Protected Area and vital areas of the plant is restricted based on the needs of the employment position. All personnel seeking access to the Owner Controlled Area must demonstrate a need and are subject to search. Employees with access to the Protected Area must undergo a detailed background check. Details of security procedures and systems are restricted to those employees with a need to know.

In response to the attacks of September 2001, the NRC imposed more stringent security requirements on its licensees. CGS has complied with those requirements. Thus, it is highly unlikely that a hostile force could gain entry to vital areas of the plant,

and even less likely that they could do this quickly enough to prevent operators from placing the plant in a safe shutdown mode.

As compared to a land-based assault, an attack using hijacked aircraft is a threat that is perhaps more frequently identified by the public or media. Such a threat has been carefully studied. The Nuclear Energy Institute (NEI) commissioned the Electric Power Research Institute (EPRI) to conduct an impact analysis of a large jet airliner being purposefully crashed into sensitive nuclear facilities, including reactor containment buildings, used fuel storage pools, used dry fuel storage facilities, and used fuel transportation containers. The EPRI analysis was peer reviewed upon completion. Using conservative analyses, EPRI concluded there would be no release of radionuclides from nuclear facilities or containers, as they are already designed to withstand potentially destructive events.

Nuclear reactor containment buildings, for example, have thick concrete walls with heavy reinforcing steel. They are designed to withstand, among other things, large earthquakes, extreme overpressures, and tornado and hurricane-force winds. Using computer simulation, a large transport category multi-engine jet aircraft was crashed into containment structures that were representative of all U.S. nuclear power containment types. The containment suffered some crushing and chipping but were not breached. The results of this analysis are summarized in an NEI paper entitled, "Aircraft Crash Impact Analyses Demonstrate Nuclear Power Plant's Structural Strength" (**NEI 2002**).

The EPRI analysis is fully consistent with research conducted by the NRC. When the NRC considered such threats in rulemaking in 2007, then-Commissioner McGaffigan observed:

> *As NRC has said repeatedly, our research showed that in most (the vast majority of) cases an aircraft attack would not result in anything more than a very expensive industrial accident in which no radiation release would occur. In those few cases where a radiation release might occur, there would be no challenge to the emergency planning basis currently in effect to deal with <u>all</u> beyond-design-basis events, whether generated by mother nature, or equipment failure, or terrorists.* (**NRC 2007b**)

In the remote possibility that a terrorist attack did breach the physical and other safeguards at CGS resulting in the release of radionuclides, the consequences of such a release are reasonably encompassed by the GEIS discussion (**NRC 1996b**, Page 5-18). In the GEIS the NRC discussed sabotage as a potential initiator of a severe accident and determined the risk to be of small significance for all nuclear power plants. The GEIS analysis of severe accident consequences bounds the potential consequences that would result from a large radiological release, irrespective of the initiating event. Energy Northwest is aware of no new information that would contribute to an understanding of the potential environmental impacts of a terrorist attack.

Importantly, no matter how small the risk of a radiological emergency, the NRC requires all nuclear power plants to have and periodically test emergency plans that are coordinated with federal, state, and local responders. The goal of preparedness is to reduce the risk to the public. In an emergency, the NRC and Energy Northwest would activate their incident response plans to evaluate the situation and identify ways to mitigate and end the emergency. If a release occurred, the Energy Northwest would make protective action recommendations to state and local officials, such as selective evacuation, to ameliorate the situation.

Groundwater Contamination

The CGS site is somewhat unique among commercial power reactor sites in that the groundwater under the site is contaminated due to activities largely unrelated to the operation of the nuclear plant. The groundwater of the USDOE Hanford Site in the vicinity of CGS is described in Section 2.3. A primary mission for USDOE activities on the Hanford Site is the remediation of the groundwater and the removal or stabilization of contamination sources. In the vicinity of CGS these efforts will include an ongoing groundwater monitoring program and the remediation of the neighboring waste burial site (see Section 2.12).

As noted in Sections 2.3 and 3.1, CGS has discharges of rainwater and wastewater to ground. Energy Northwest has implemented its own monitoring programs that are intended to characterize the effects of these discharges and to detect unanticipated leakage from plant components.

Although groundwater quality is a focus of considerable interest in the CGS site area, the water produced at the nearest downgradient water supply wells on the IDC site has not been affected (see Section 2.3.2). Energy Northwest will continue to monitor contaminants of concern in these wells and USDOE will continue to monitor the quality of the area-wide aquifer. Energy Northwest does not believe the groundwater issue is a new and significant issue in the context of 10 CFR 51.53(c)(3)(iv). License renewal would not cause a discernable change to the groundwater quality in the site area.

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5.3 REFERENCES

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USCT 2006. San Luis Obispo Mother for Peace v. NRC, U.S. Court of Appeals, Ninth Circuit, Case No. 03-74628, NRC Nos. CLI-03-01/CLI-02-23, June 2, 2006.

USCT 2009. New Jersey Department of Environmental Protection v. NRC & Amergen Energy Company, U.S. Court of Appeals, Third Circuit, Case No. 07-2271, March 31, 2009.

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6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

This section summarizes in tabular form the environmental impacts related to license renewal for the CGS operating license for Category 2 issues discussed in Chapter 4.

As shown in Table 6.1-1, the Category 2 issues evaluated are either not applicable or have impacts that would be small.

Table 6.1-1. Environmental Impacts Related to License Renewal at CGS

No.	Category 2 Issue	Environmental Impact
Surface Water Quality, Hydrology, and Use (for all plants)		
13	Water use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow) 10 CFR 51.53(c)(3)(ii)(A)	**NONE**. This issue does not apply because the Columbia River does not meet the NRC definition of a small river, i.e., a river whose annual flow rate is less than 3.15×10^{12} ft^3/year.
Aquatic Ecology (for plants with once-through or cooling pond heat dissipation systems)		
25	Entrainment of fish and shellfish in early life stages 10 CFR 51.53(c)(3)(ii)(B)	**NONE**. This issue does not apply because CGS does not use a once-through or cooling pond heat dissipation system for condenser cooling water.
26	Impingement of fish and shellfish 10 CFR 51.53(c)(3)(ii)(B)	**NONE**. This issue does not apply because CGS does not use a once-through or cooling pond heat dissipation system for condenser cooling water.
27	Heat shock 10 CFR 51.53(c)(3)(ii)(B)	**NONE**. This issue does not apply because CGS does not use a once-through or cooling pond heat dissipation system for condenser cooling water.
Groundwater Use and Quality		
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use >100 gpm) 10 CFR 51.53(c)(3)(ii)(C)	**NONE**. This issue does not apply because CGS uses less than 100 gpm of groundwater.
34	Groundwater use conflicts (plants using cooling towers or cooling ponds and withdrawing makeup water from a small river) 10 CFR 51.53(c)(3)(ii)(A)	**NONE**. This issue does not apply because the Columbia River does not meet the NRC definition of a small river, i.e., a river whose annual flow rate is less than 3.15×10^{12} ft^3/year.
35	Groundwater use conflicts (Ranney wells) 10 CFR 51.53(c)(3)(ii)(C)	**NONE**. This issue does not apply because CGS does not use Ranney wells.
39	Groundwater quality degradation (cooling ponds at inland sites) 10 CFR 51.53(c)(3)(ii)(D)	**NONE**. This issue does not apply because CGS does not use cooling ponds.
Terrestrial Resources		
40	Refurbishment impacts 10 CFR 51.53(c)(3)(ii)(E)	**NONE**. No impacts are anticipated because Energy Northwest has no plans to undertake refurbishment at CGS.

Table 6.1-1. Environmental Impacts Related to License Renewal at CGS
(continued)

No.	Category 2 Issue	Environmental Impact
Threatened or Endangered Species		
49	Threatened or endangered species 10 CFR 51.53(c)(3)(ii)(E)	**SMALL**. No significant concerns identified by resource agencies contacted by Energy Northwest about license renewal impacts. Additionally, operation and maintenance of the plant and associated transmission lines are not expected to change significantly during the license renewal term.
Air Quality		
50	Air quality during refurbishment (non-attainment and maintenance areas) 10 CFR 51.53(c)(3)(ii)(F)	**NONE**. No impacts are expected because Energy Northwest has no plans to undertake refurbishment at CGS.
Human Health		
57	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river) 10 CFR 51.53(c)(3)(ii)(G)	**NONE**. This issue does not apply because the Columbia River does not meet the NRC definition of a small river, i.e., a river whose annual rate is less than 3.15×10^{12} ft^3/year.
59	Electromagnetic fields, acute effects (electric shock) 10 CFR 51.53(c)(3)(ii)(H)	**SMALL**. The largest induced current under the CGS lines is less than 5 milliamperes. Therefore, the CGS transmission lines conform to the National Electrical Safety Code (NESC) provisions for preventing electric shock from induced current.
Socioeconomics		
63	Housing impacts 10 CFR 51.53(c)(3)(ii)(I)	**SMALL**. No refurbishment activities are planned and no additional workers are anticipated during the period of extended operation. Therefore, no additional impacts to housing are expected due to continued operation of CGS.
65	Public services: public utilities 10 CFR 51.53(c)(3)(ii)(I)	**SMALL**. No refurbishment activities are planned and no additional workers are anticipated during the period of extended operation. Therefore, there should be no impact to public utility system capacities in the area.
66	Public services: education (refurbishment) 10 CFR 51.53(c)(3)(ii)(I)	**NONE**. No impacts are expected because CGS has no plans to undertake refurbishment.
68	Offsite land use (refurbishment) 10 CFR 51.53(c)(3)(ii)(I)	**NONE**. No impacts are expected because CGS has no plans to undertake refurbishment.

Table 6.1-1. Environmental Impacts Related to License Renewal at CGS
(continued)

No.	Category 2 Issue	Environmental Impact
69	Offsite land use (license renewal term) 10 CFR 51.53(c)(3)(ii)(I)	**SMALL**. No plant-induced changes to offsite land use are expected from license renewal because CGS taxes are less than 10% of total tax revenues to the regional jurisdictions that receive tax revenues.
70	Public services: transportation 10 CFR 51.53(c)(3)(ii)(J)	**SMALL**. No refurbishment activities are planned and no increases in total number of employees during the period of extended operation are expected. Thus, there should be no increase in traffic or adverse impact to the level of service in the vicinity of CGS.
71	Historic and archaeological resources 10 CFR 51.53(c)(3)(ii)(K)	**SMALL**. Continued operation of CGS would not require land-altering construction. Therefore, license renewal should have no impact on historic or archaeological resources.
Postulated Accidents		
76	Severe accident mitigation alternatives 10 CFR 51.53(c)(3)(ii)(L)	**SMALL**. The benefit/cost evaluation of SAMA candidates identified no enhancements to be cost beneficial for implementation at CGS. The sensitivity cases performed for this analysis, however, found three SAMA candidates to be cost beneficial for implementation under the assumption of a lower discount rate. None of these three candidates were related to managing the effects of aging during the period of extended operation.

6.2 MITIGATION

Regulatory Requirement: 10 CFR 51.53(c)(3)(iii)

"The report must contain a consideration of alternatives for reducing adverse impacts, as required by 10 CFR 51.45(c), for all Category 2 license renewal issues in Appendix B to subpart A of this part. No such consideration is required of Category 1 issues in Appendix B to subpart A of this part."

When adverse environmental effects are identified, 10 CFR 51.45(c) requires consideration of alternatives available to reduce or avoid these adverse effects. Furthermore, "mitigation alternatives are to be considered no matter how small the adverse impact; however, the extent of the consideration should be proportional to the significance of the impact" (**NRC 2000**, Page 4.2-S-5).

As discussed in Chapter 4 and summarized in Table 6.1-1, the impacts of license renewal for all Category 2 issues, are SMALL and do not require mitigation. For these issues, the current permits, practices, and programs (e.g., radiological monitoring and environmental review programs) that mitigate the environmental impacts of plant operations are adequate.

As a result, no additional mitigation measures are sufficiently beneficial to warrant implementation.

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6.3 UNAVOIDABLE ADVERSE IMPACTS

Regulatory Requirement: 10 CFR 51.45(b)(2)

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

Chapter 4 contains the results of Energy Northwest's review and analyses of Category 2 issues, as required by 10 CFR 51.53(c)(3)(ii). These reviews take into account the information that has been provided in the GEIS, Appendix B to Subpart A of 10 CFR Part 51, and information specific to CGS.

The environmental impacts to be evaluated for license renewal are those associated with refurbishment and continued operation during the renewal term. This differs from the environmental impacts reviewed in support of a construction permit because the facility is in existence at the license renewal stage and has operated for a number of years. Adverse impacts associated with the initial construction, therefore, have been avoided, have been mitigated, or have already occurred.

Energy Northwest's review and analyses of Category 2 issues associated with refurbishment and continued operation of CGS did not identify any significant adverse environmental impacts. Additionally, the evaluation of structures and components, required by 10 CFR 54.21, did not identify any plant refurbishment activities, outside the bounds of normal plant component replacement and inspections, to support continued operation of CGS beyond the end of the existing operating license.

Based on these reviews and analyses, Energy Northwest is not aware of significant adverse environmental effects that cannot be avoided upon renewal of the CGS operating license.

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6.4 IRREVERSIBLE AND IRRETRIEVABLE RESOURCE COMMITMENTS

Regulatory Requirement: 10 CFR 51.45(b)(5)

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

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

- Nuclear fuel that is used in the reactor and is converted to radioactive waste.
- Land required to dispose of spent nuclear fuel offsite and low-level radioactive wastes generated as a result of plant operations.
- Water that is consumed in plant processes and loss to evaporation.
- Elemental materials that will become radioactive.
- Materials used for the normal industrial operations of the plant that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

Other than the above, there are no major refurbishment activities or changes in operation of CGS planned during the period of extended operation that would irreversibly or irretrievably commit environmental components of land, water, and air.

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

Regulatory Requirement: 10 CFR 51.45(b)(4)

The environmental report shall discuss ..."[t]he relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity" as adopted by 10 CFR 51.53(c)(2).

The current balance between short-term use and long-term productivity at CGS was established with the decision to set aside a portion of the USDOE Hanford Site for the development of a commercial nuclear power plant. The Final Environmental Statements (FESs) related to construction (**AEC 1972**) and operation (**NRC 1981**) evaluated the impacts of constructing and operating CGS. Natural resources that would be subjected to short-term use include land and water.

With the exception of neighboring sites for abandoned Energy Northwest projects WNP-1 and WNP-4, the area surrounding the CGS site is largely undeveloped. Of the 1,089 acres leased from USDOE for CGS, approximately 235 acres are occupied by the station and the supporting facilities (e.g., office buildings, warehouses, roads, parking lots). An additional 30 acres outside the site property boundary are used for security-related facilities.

Although CGS consumes water from the Columbia River, the impacts are minor and would cease once the reactor ceases operation. Given the configuration of the water intake and the relative quantity withdrawn, the productivity of the aquatic community in the Columbia River in the vicinity of CGS is not significantly affected by the water use.

The period of extended operation will not change the short-term uses of the environment from the uses previously evaluated in the FESs. The period of extended operation will postpone the availability of the land and water resources for other uses. However, extending operations will not adversely affect the long-term uses of the site.

There are no major refurbishment activities or changes in operation of CGS planned for the period of extended operation that would alter the evaluation of the FESs for the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity of these resources.

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

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

6.6 REFERENCES

AEC 1972. Final Environmental Statement Related to the Proposed Hanford Number Two Nuclear Power Plant, Washington Public Power Supply System, Docket No. 50-397, Atomic Energy Commission, Directorate of Licensing, December 1972.

NRC 1981. Final Environmental Statement (FES-OL) Related to the Operation of WPPSS Nuclear Project No. 2, Docket No. 50-397, Washington Public Power Supply System, NUREG-0812, Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, December 1981.

NRC 2000. Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses; Supplement 1 to Regulatory Guide 4.2, Nuclear Regulatory Commission, Office of Nuclear Reactor Research, September 2000.

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7.0 ALTERNATIVES TO THE PROPOSED ACTION

Regulatory Requirement: 10 CFR 51.45(b)(3)

The environmental report shall discuss "Alternatives to the proposed action." [adopted by reference at 10 CFR 51.53(c)(2)].

This chapter assesses alternatives to the proposed license renewal of the Columbia Generating Station (CGS). It includes discussions of the no-action alternative and alternatives that meet system generating needs. Descriptions are provided in sufficient detail to facilitate comparison of the impacts of the alternatives to those of the proposed action. In considering the level of detail and analysis that it should provide for each category, Energy Northwest relied on the NRC decision-making standard for license renewal:

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

As noted in 10 CFR 51.53(c)(2), a discussion is not required of need for power or economic costs and benefits of the proposed action or 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.

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7.1 NO-ACTION ALTERNATIVE

The no-action alternative is to not renew the CGS operating license. With this alternative, Energy Northwest expects CGS would continue to operate until the expiration of the existing operating license in December 2023, at which time plant operations would cease, decommissioning would begin, and upon expiration of the lease the land returned to the USDOE reservation.

Decommissioning, as defined in the Generic Environmental Impact Statement (GEIS), is the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license (**NRC 1996**, Section 7.1). Considering that current regulations require that decommissioning be completed within 60 years, appropriate decommissioning options for CGS include rapid decontamination and dismantlement (DECON), and safe storage of the stabilized and de-fueled facility (SAFSTOR), followed by final decontamination and dismantlement (**NRC 1996**, Section 7.2.2).

The boiling water reactor decommissioning analysis discussed in the GEIS was based on CGS as the "reference" reactor (**NRC 1996**, Section 7.1) and includes an evaluation of anticipated occupational and public radiation doses, waste management, water quality, ecological, economic, and socioeconomic impacts. The NRC has provided additional analysis of the environmental impacts associated with decommissioning in the Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities (**NRC 2002**). Except for issues that were site-specific, environmental impacts, including radiological releases and doses from decommissioning activities, were assessed to be small (**NRC 2002**, Sections 4.3 and 6.1).

Regardless of the NRC decision on license renewal, Energy Northwest will have to decommission CGS; license renewal would only postpone decommissioning for an additional 20 years. In the GEIS, the NRC concludes that there should be little difference between the environmental impacts from decommissioning at the end of 40 years of operation versus those associated with decommissioning after an additional 20 years of operation under a renewed license (**NRC 1996**, Section 7.4).

By reference, Energy Northwest adopts the NRC findings regarding environmental impacts of decommissioning in the license renewal GEIS (**NRC 1996**) and in the decommissioning GEIS (**NRC 2002**), and concludes that environmental impacts under the no-action alternative would be similar to those that occur following license renewal. Decommissioning impacts would be temporary and occur at the same time as those associated with the operation of replacement generating source(s).

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7.2 ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

If the CGS operating license is not renewed, the Pacific Northwest region would lose its only nuclear generating resource and approximately 1,150[(2)] megawatts-electric (MWe) of baseload capacity (**BPA 2007**, Table 5). Energy Northwest believes that any alternative would be unreasonable if it did not consider replacement of the energy resource. Replacement could be met by 1) building new generating baseload capacity, 2) purchasing power from the wholesale market, or 3) reducing power requirements through demand reduction.

7.2.1 Alternatives Considered

To identify alternative generating sources, Energy Northwest considered current regional energy resources. Based on the Bonneville Power Administration (BPA)'s 2007 Pacific Northwest Loads & Resources Study, firm energy resources (and their corresponding 12-month annual percent average) for the Pacific Northwest were as follows (**BPA 2007**, Table 10):

- Hydro (45.0%)
- Coal (19.7%)
- Combustion turbines (12.3%)
- Cogeneration (8.3%)
- Imports (4.6%)
- Nuclear (3.9%)
- Non-utility generation (5.0%)
- Other miscellaneous resources (1.2%)

The mix of energy sources for the generation of electricity sold to Washington State consumers in 2007 is estimated to be (**WCTED 2009**):

- Hydro (66%)
- Coal (17%)
- Natural Gas (10%)
- Nuclear (5%)
- Wind (0.6%)
- Biomass (0.5%)
- Waste (0.3%)
- Other (e.g., petroleum) (0.2%)

[(2)] The capacity of 1,150 MWe is used in Chapter 7, rather than 1,190 MWe as noted in ER Section 3.1.1, since this is the capacity that the Bonneville Power Administration plans for CGS to provide.

Regional and state energy alternatives were evaluated further to determine their overall feasibility and grouped into two categories: those that do not require new generating capacity and those that do.

While many methods are available for generating electricity, the GEIS indicates that a "reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable" (**NRC 1996**, Section 8.1). Considering that CGS serves as a large baseload generator, Energy Northwest considers reasonable alternatives to be those that would also be able to generate baseload power. The NRC has noted that, while there are many methods available for generating electricity and many combinations of alternative power generation sources that could provide baseload capacity, such an expansive consideration of alternatives would be too unwieldy (**NRC 1996**, Section 8.1). Nonetheless, Energy Northwest has included a plausible combination of generating sources in the analysis of alternatives that follows, with the specific intent of minimizing potential environmental impacts.

7.2.1.1 Alternatives Not Requiring New Generating Capacity

This section discusses the economic and technical feasibility of supplying replacement energy without constructing new baseload generating capacity. Specific alternatives include:

- Conservation measures (including implementing demand side management (DSM) actions);
- Reactivating or extending the service life of existing plants (i.e., delayed retirement); and
- Purchasing power from other utilities equivalent to the output of CGS (i.e., eliminating the need for license renewal).

Conservation Programs

Since the formation of the Northwest Power and Conservation Council in 1980, there has been a regional emphasis on energy conservation. The council's first power plan, adopted in 1983, called upon the BPA and the region's utilities to develop and implement an array of conservation programs. As a result, it is estimated that the BPA and utility conservation programs have saved over 1,425 average megawatts (aMW) of electricity between 1980 and 2002. In addition, the Northwest Energy Efficiency Alliance Program, formed in 1996 and sponsored by the BPA and the region's utilities, has contributed another 110 aMW of savings, for a combined total of 1,535 aMW (**NWPCC 2005**, Page 3-6).

Through DSM, the region's conservation programs are designed to reduce both peak demands and daily energy consumption and include the following tools:

- Load management – the reduction or shifting of peak electricity consumption; and
- Energy efficiency – long-term electric energy consumption.

On a national basis, DSM has shown great potential in reducing peak demand (maximum power requirement of a system at a given time). In 2007, a peak load reduction of 30,276 MWe was achieved, an increase of 11.1% from 2006; however, DSM costs increased by 23.2%. DSM costs can vary significantly from year to year because of business cycle fluctuations and regulatory changes. Since costs are reported as they occur, while program effects may appear in future years, DSM costs and effects may not always show a direct relationship. Since 2003, nominal DSM expenditures have increased at 18.1% average annual growth rate. During the same period, actual peak load reductions have grown at a 7.2% average annual rate from 22,904 MW to 30,276 MW (**EIA 2009**, Page 10).

Although it is believed that energy generation savings can continue to be increased from DSM practices, the variability in associated costs makes DSM a less desirable option. Consequently, Energy Northwest does not see DSM as a practicable offset for the baseload capacity of CGS.

Delayed Retirement

Energy Northwest is not aware of any planned retirements of generating units in the Northwest that would approach, individually or cumulatively, the capacity contributed by CGS. Even without retiring any generating units, based on data published by the Northwest Power and Conservation Council, electricity demand in the four-state planning region (Washington, Oregon, Idaho and Montana) is projected to grow from 20,080 aMW in 2000 to 25,423 aMW by 2025 (medium forecast). This represents a modest average annual growth rate of almost 1% per year, further increasing Washington's need for additional electricity sources (**NWPCC 2005**, Page 2-4).

For these reasons, the delayed retirement of non-nuclear generating units is not considered by Energy Northwest as a reasonable alternative to the renewal of CGS's license.

Purchasing Electric Power

Washington State is a major net electricity exporter, supplying electricity to the Canadian power grid and U.S. markets as far away as California. The state transmits large amounts of inexpensively produced hydroelectric power via the western U.S. interconnection that runs from northern Oregon to southern California. The system,

also known as the Pacific Intertie, is the largest single electricity transmission program in the U.S. Although the Pacific Intertie was originally designed to transmit electricity south during California's peak summer demand season, flow is sometimes reversed overnight and has occasionally been reversed during periods of reduced hydroelectric generation in the Northwest (**EIA 2008a**).

Based on the 2005 winter electric power market conditions, the generating and supply capacity of power resources for the Northwest Power Pool Area, which includes all or most of Washington, Oregon, Idaho, Utah, Nevada, Montana, Wyoming, and part of California, was adequate to provide electricity in excess of in-region needs. In most years, the Northwest sells surplus power into California and the Southwest (**FERC 2008**). Thus, purchased power is a feasible alternative to CGS license renewal in theory. However, there is no assurance that sufficient capacity or energy would be available during the entire license renewal period of 2023 through 2043 to replace the approximately 1,150 MWe of base-load generation.

If power to replace CGS capacity were to be purchased, Energy Northwest assumes that the generating technology used to produce the purchased power would be one of those described in the GEIS. Thus, the environmental impacts of purchased power would still occur, but would be located elsewhere within the region.

7.2.1.2 Alternatives Requiring New Generating Capacity

Since the current mix of power generation options in Washington and surrounding states is an indicator of feasible choices for electric generation technology within the state, Energy Northwest evaluated both the capacity (i.e., potential output) and utilization (i.e., extent of actual use) characteristics of Washington's electric generating sources. At present, central-station generation projects comprise the majority of generating capacity in the Northwest and are also expected to comprise the bulk of new capacity to meet forecasted regional load growth through 2025 (**NWPCC 2005**, Page 5-1). As such, the following power plant types are evaluated in this section as potential alternatives to license renewal:

- New Nuclear Reactor
- Petroleum Liquids (Oil)
- Coal
- Natural Gas

Rapid growth in renewable energy production, partly as a result of state mandates for renewable electricity generation, is also projected (**EIA 2007b**, Page 8). With the passage of State Initiative 937 in 2006, Washington requires large utilities to obtain 15% of their electricity from new renewable sources by 2020. Renewable alternative energy evaluated as potential alternatives, include the following (**EERE 2008a**, **NRC 1996**, Chapter 8):

- Hydropower[3]
- Wind
- Solar
- Geothermal
- Biomass (Wood)
- Municipal Solid Waste
- Energy Crops
- Fuel Cells

The potential alternative technologies are consistent with national policy goals for energy use and are not prohibited by federal or state regulations. To determine if the potential energy alternatives represent a reasonable alternative, each is discussed relative to the following criteria:

- The alternative is developed and proven;
- The alternative provides baseload generating capacity equivalent to CGS;
- The alternative does not impact the environment more than CGS; and
- The alternative is economically feasible.

New Nuclear Reactor

With energy demands forecasted to increase and public opposition to new carbon-fueled power plants, some utilities are pursuing permits and licenses to build and operate new nuclear reactors to meet the country's future energy needs. At present, a number of combined license applications for new nuclear reactors have been submitted and are under review by the NRC (e.g., Calvert Cliffs Unit 3). However, although orders for new nuclear power plants are likely to be placed in the coming years, the EIA projects that oil, coal, and natural gas will still have the same 86 percent share of the total U.S. primary energy supply in 2030 as in 2005. Despite projections in total nuclear generation growth from 780 billion kilowatt-hours in 2005 to 896 billion kilowatt-hours in 2030, the nuclear share of total electricity is expected to fall from 19 percent to 15 percent during this same time period (**EIA 2007b**, Pages 2 and 3). In consideration of projected market share, high costs, and time required for planning, licensing, and constructing, Energy Northwest has no current plans to build a new nuclear power plant at the CGS site or at an alternative site. Therefore, a new nuclear reactor is not considered a reasonable alternative to renewal of CGS's operating license.

[3] State Initiative 937 does not count new hydroelectric projects on the state's rivers and streams as eligible renewable resources.

Petroleum Liquids (Oil)

Washington's total petroleum demand is high, with jet fuel consumption among the highest in the country. Although Washington has no indigenous crude oil production, it is a principal refining center for the Pacific Northwest. With Alaskan production in decline, Washington refineries are becoming more dependent on oil imports from Canada and other countries (**EIA 2008a**).

Although oil is an important source of power, oil-fired generation has experienced a significant decline since the early 1970s. Increases in world oil prices have forced utilities to use less expensive fuels (**NRC 1996**, Section 8.3.11). From 2002 to 2007, the average cost of petroleum for power generation increased by more than 100% (**EIA 2009**, Table 4.5).

Environmental impacts from oil-fired plant operations would be similar to those from a coal-fired plant (**NRC 1996**, Section 8.3.11). However, future technology developments (e.g., carbon capturing and storage) may reduce such emissions.

Based on the above, Energy Northwest does not consider oil-fired generation a viable alternative to renewal of CGS's operating license.

Coal

Persistently high natural gas prices have reinvigorated the competition between coal and natural gas. Coal is the major source of electric power in the U.S. as a whole, and the second largest component (23%) of the western power supply. Abundant supplies of low sulfur coal are found in western North America and there is sufficient coal in the region to support all electric power needs in the Pacific Northwest based on the current 20-year plan (i.e., 2005-2025) by the Northwest Power and Conservation Council. Production costs are low enough to permit coal to be shipped economically hundreds of miles by rail or thousands of miles by barge. The coal fields near Centralia, Washington (southwest part of the state), the location of the state's only coal fired plant and coal mine, appear to have insufficient capacity to fuel additional plants beyond the existing coal plant (**NWPCC 2005**, Chapter 5).

Conventional coal-fired plants generally include two or more generating units and have total capacities ranging from 100 MWe to more than 2,000 MWe. Due to performance improvements and increased market competition, the capital cost of conventional coal steam-electric plants declined about 25% in constant dollars since the early 1990s with little or no sacrifice to electrical efficiency or reliability. Despite this cost trend, combined-cycle gas turbines have surpassed coal-fired steam-electric technology in economic, technical, and environmental attributes (**NWPCC 2005**, Chapter 5).

Integrated Gasification Combined Cycle (IGCC) is an emerging, advanced technology for generating electricity with coal that combines modern coal gasification technology

with both gas turbine and steam turbine power generation. The technology is substantially cleaner than conventional pulverized coal plants because major pollutants can be removed from the gas stream prior to combustion. In 2006, Energy Northwest submitted an application to construct and operate a 680-MWe IGCC plant named the Pacific Mountain Energy Center (or PMEC) in Cowlitz County, Washington. Subsequent to the passage of Washington State Senate Bill 6001 in 2007 requiring carbon sequestration plans (i.e., pumping carbon dioxide into the ground) for new baseload plants, further review of the IGCC application by the Washington Energy Facility Site Evaluation Council was suspended (**EFSEC 2007**).

Environmental impacts of constructing a typical coal-fired plant are well known. The impacts of constructing a 1,000 MWe coal plant at a greenfield site (i.e., not previously developed) can be substantial. An estimated 1,700 acres would be needed, resulting in the loss of the same amount of natural habitat and/or agricultural land for the plant site alone, excluding land required for mining and other fuel cycle impacts (**NRC 1996**, Section 8.3.9). Concerns over adverse human health effects from coal combustion have also led to important federal legislation (i.e., the Clean Air Act and Amendments). Carbon dioxide has been identified as a leading cause of global warming, sulfur dioxide has been identified with acid rain, and nitrogen oxides are major components of smog. Substantial solid waste (fly ash and scrubber sludge) would also be produced. However, the positive socioeconomic benefits can be considerable for surrounding communities in the form of hundreds of new jobs, tax revenues, and plant spending.

Based on well-known power generation technology and generally understood environmental impacts associated with construction and operation, Energy Northwest considers a coal-fired plant a reasonable alternative to renewal of the CGS operating license. The viability of this alternative is contingent upon the availability of a long-term fuel supply. More importantly, for sites in the State of Washington, the viability of coal-fired plants is linked to technological advancements in the capture and storage of carbon dioxide emissions.

Natural Gas

Low fuel prices and advances in turbine designs led to a surge of construction of gas-fired combined cycle power plants in the early 1990s and again during the energy crisis of 2000 and 2001. Natural gas powered plants currently represent about 13% of the generating capacity in the Pacific Northwest (**NWPCC 2005**, Page 5-18).

The Pacific Northwest is not regarded as having significant future natural gas supplies. However, the region has excellent pipeline access to important western North American natural gas producing areas (**NWPCC 2005**, Page 5-17). Washington relies heavily on natural gas produced in Canada. The residential sector leads Washington's natural gas consumption, followed closely by the industrial and electric power generating sectors. Roughly one third of Washington households use natural gas as their primary energy

source for heating. Natural gas is supplied to eastern Washington via the Gas Transmission Northwest Line (**EIA 2008a**).

Most of the environmental impacts of constructing natural gas-fired plants are similar to those of other large central generating stations. Land-use requirements for gas-fired plants are small, at 110 acres for a 1,000 MWe plant, so site development impacts should be relatively small. Siting at a greenfield location would require new transmission lines and increased land-related impacts. In addition, gas-fired plants (particularly combined cycle and gas turbine facilities) take much less time to construct than other plants (**NRC 1996**, Section 8.3.10).

Although economics of constructing gas-fired plants will be negatively influenced by the volatile cost of natural gas, it is well-known technology, has fuel availability, and has generally understood environmental impacts associated with construction and operation. Energy Northwest considers a gas-fired combined cycle plant a reasonable alternative to renewal of CGS's operating license.

Hydropower

Accounting for close to three-fourths of electricity generation, hydroelectric power dominates the electricity market in Washington (**EIA 2008a**). According to a study by the Idaho National Engineering and Environmental Laboratory, Washington has 562 possible hydropower sites. Of these sites, 11 are developed with a combined adjusted power-generating capacity of 875 MWe, 238 are developed but without power with a possible generating capacity of 1,777 MWe, and 313 are undeveloped sites with a possible combined generating capacity of 762 MWe (**INEEL 1998**, Table 4).

Thus, hydropower is a feasible alternative to CGS license renewal in theory. However, to ensure a baseload capacity of approximately 1,150 MWe will require multiple hydropower projects. For example, the 11 developed hydropower facilities noted above have an average nameplate capacity of approximately 100 MWe (**INEEL 1998**, Table 4). Thus, it would take 11 or more individual projects to replace CGS's baseload capacity. Each project would be required to obtain an individual license or permit to operate, which would be problematic given the environmental constraints related to hydropower development. As a result, developing a hydropower baseload capacity of approximately 1,150 MWe is not considered by Energy Northwest to be a reasonable alternative to renewal of CGS's operating license.

Wind

Wind power (utility-scale) is considered to have substantial potential as a source of new generation to help to meet future energy demands of the Pacific Northwest (**NWPCC 2005**, Page 7-20).

Wind energy is one of the lowest-priced renewable energy technologies available; however, the technology requires a higher initial investment than fossil-fueled plants. If the federal renewable energy production tax credit applies, wind power projects in the Pacific Northwest can be developed at a cost of between $40 and $60 per MWh (in 2007 dollars). For a public power developer such as Energy Northwest, for whom the production tax credit is not available, the project cost will be in the range of $50 to $85 or more per MWh depending on the amount of support available from the USDOE Renewable Energy Production Incentive program (**EERE 2005; EERE 2008b**, Page 17).

Due to generally smaller project sizes and higher overall capital costs, interconnection with the grid is a key consideration for a project's economic viability. Costs for connection to the transmission grid may be high since a wind project would need to be sited to optimize energy production, but that location may be far from the nearest transmission system connection. One study of wind energy transmission infrastructure estimates the cost of building a 115-kV transmission line to range from $200,000 to $400,000 per mile (in 2008 dollars). The same study estimates that a new substation to service a windfarm could range from $10 million to $60 million (**LBNL 2009**, Page 38).

The Washington Wind Resource Map indicates that the state has wind resources consistent with utility-scale production, with the central part of the state considered to have the largest contiguous area of good to excellent wind resources (**EERE 2008c**). The state's potential power output has been estimated to be in the range of 3,400 MWe and 5,000 MWe (**EIA 1995**, Table 31; **NWPCC 2005**, Table 5-1). However, when looking at the windiest and most developable locations, actual wind generating capacity would be less.

The major challenge to using wind as a source of power is that it is intermittent (i.e., not available all of the time), resulting in low capacity factors. As such, it is not a firm source of baseload capacity. As of October 2008, the three wind power projects that had been placed in service in Washington in the preceding 12 months had a combined potential capacity of 369 MWe, but an average expected energy production of only 113 MWe (**NWPCC 2008**). In addition, this technology is currently too expensive to permit wind power plants to serve as large sources of baseload capacity (**NRC 1996**, Section 8.3.1).

Environmentally, wind turbine generators produce no air emissions, consume no water for cooling, result in zero wastewater discharges, require no drilling, mining or transportation of fuel, and produce no hazardous or solid wastes other than used lubrication oil that can be recycled. However, the amount of land needed for operation can be significant. An estimated 270 square miles of land are needed to generate 1,150 MWe of power, although much of the land could be used for other resources (i.e., solar energy production, agriculture) (**NRC 1996**, Section 8.3.1). Noise produced by the rotor blades, visual impacts, and bird and bat fatalities are also of some concern (**EERE 2005**).

Considering that wind conditions are variable, energy storage technologies do not currently allow supply to more closely match demand, and large land requirements and associated aesthetic impacts, Energy Northwest does not consider a utility-scale commercial wind power project a reasonable alternative to CGS license renewal.

Solar Power

Solar power depends on the availability and strength of sunlight and is considered an intermittent source of energy. Two common methods for capturing the sun's energy are concentrating collectors and flat-plate collectors.

Concentrating collectors produce electric power by converting solar energy into high temperatures by focusing the sun using various mirror configurations. Concentrating collectors are typically on a tracker and face the sun directly. Since they focus the sun, they only use rays coming straight from the sun. Southeastern Washington receives approximately 4,000 to 4,500 Watt-hours of solar radiation per square meter per day (W-hr/m^2/day) that can be collected using concentrating collectors (**EERE 2008a**).

Flat-plate collectors use solar cells or photovoltaic (PV) cells, converting sunlight directly into energy. PV cells are typically combined to form a module consisting of about 40 PV cells. About ten modules are typically mounted to form a PV array, measuring up to several meters on a side. Ten to 20 PV arrays can provide enough power for a household; for large electric utility or industrial applications, hundreds of arrays can be interconnected to form a single, large PV system. Flat plate collectors are typically mounted at a fixed angle, facing south, or they can be mounted on a tracking device that follows the sun (**NREL 2008**). Since flat-plate collectors use all available sunlight, they are better suited for northern states. In southeastern Washington, approximately 4,000 to 5,000 W-hr/m^2/day of solar radiation can be collected using flat-plate collectors (**EERE 2008a**).

Most solar power stations are small and use photovoltaic technology. Energy Northwest operates the 30-kW White Bluffs Solar Station consisting of 242 solar panels. The station occupies about 6,000 square feet on the IDC site east of CGS. The largest solar facility in the Pacific Northwest, the 500-kilowatt Wild Horse Solar Facility, began producing electricity In November 2007. This facility is comprised of 2,733 flat solar panels erected within the 229-MWe Wild Horse Wind Farm about 125 miles east-southeast of Seattle (**PSE 2008**).

Land required for solar power generation is significant. When allowances are made for efficiencies and spacing of the collector arrays, the land required would be about 7.4 acres per MWe for flat-plate photovoltaic and about 4.9 acres per MWe for a concentrating system (**NREL 2004**). The land required to match the 1,150-MWe capacity of CGS could range from 5,600 acres to more than 8,500 acres. The estimated land requirement does not account for the fact that capacity factors for a solar plant would only be in the range of 20% to 30%. In addition, although solar

technologies produce no air pollution, little or no noise, and require no transportable fuels, many solar power technologies are still in the demonstration phase of development and cannot be considered competitive with fossil or nuclear-based technologies in grid-connected applications, due to high costs per kilowatt of capacity (**NRC 1996**, Section 8.3.2). Lastly, since the output of solar generated power is dependent on the availability of sunlight, supplement energy sources would be required to meet the baseload capacity of CGS.

For the reasons noted, Energy Northwest does not consider solar power to be a reasonable alternative to renewal of CGS's operating license.

Geothermal

Several known and potential geothermal regions are located in southeastern Washington. However, geothermal energy is not currently being used to generate electricity in the state, since most of the accessible geothermal resource areas do not have potential for high temperatures, including those in the Columbia basin. At present, most of the state's geothermal reservoirs are in the form of hot-springs developed for therapeutic and recreational purposes. Estimates derived by the U.S. Geological Survey indicate that Washington's geothermal resources have the potential for 127 MWe for electricity generation (**EERE 2007**). However, many of the best geothermal locations are in areas that will be off-limits to development (e.g., National Forests, National Parks) and inaccessible to transmission facilities. Therefore, geothermal energy is not a reasonable alternative to renewal of CGS's operating license.

Biomass Energy

Biomass is any organic material made from plants or animals. Agricultural and wood wastes such as forestry residues, particularly paper mill residues, are the most common biomass resources used for generating electricity. Washington is considered to have excellent biomass resources (**EERE 2008a, EERE 2008d**).

Most biomass plants use direct-fired systems by burning biomass feedstocks to directly produce steam for conventional steam turbine conversion technology. The construction impacts of a wood-fired plant would be similar to those for a coal-fired plant, although facilities using wood waste for fuel would be built on smaller scales. Since biomass technology is expensive and relatively inefficient, biomass plants at modest scales (≤50 MWe) make economic sense if there is a readily available supply of low-cost wood wastes and residues nearby so that feedstock delivery costs are minimal. Like coal-fired plants, wood-waste plants require large areas for fuel storage and processing. The operation of wood-fired plants also creates impacts to land and water resources, primarily associated with soil disturbance and runoff, in addition to air emissions (**NRC 1996**, Section 8.3.6).

Energy Northwest intends to pursue development of one or more 50-MWe scale wood waste projects in the Pacific Northwest through a partnership with a company specialized in biopower technologies (**ADAGE 2009**). However, due to the relatively small scale of potential projects and uncertainties in securing long-term fuel supplies, biomass is not considered by Energy Northwest to be a reasonable alternative to replace CGS's baseload power generation.

Municipal Solid Waste

Municipal solid waste (MSW) facilities that convert waste to energy use technology comparable to steam-turbine technology for wood waste plants, although the capital costs are greater due to the need for specialized separation and handling equipment (**NRC 1996**, Section 8.3.7). The decision to burn MSW for energy is typically made due to insufficient landfill space, rather than energy considerations.

There are 89 operational MSW energy conversion plants in the United States, generating approximately 2,500 MWe, or about 0.3% of total national power generation **(USEPA 2008)**. At an average capacity of about 28 MWe, numerous MSW-fired power plants would be needed to replace the baseload capacity of CGS. In 2005, about 4% of the total MSW disposal in the State of Washington was burned for energy (**WDOE 2006**, Table 5-6).

Construction impacts for a waste-to-energy plant are estimated to be similar to those for a coal-fired plant. Air emissions are potentially harmful. Increased construction costs for new plants and economic factors (i.e., strict regulations and public opposition) may limit the growth of MSW energy generation (**NRC 1996**, Section 8.3.7; **USEPA 2008**).

For reasons stated, MSW is not considered by Energy Northwest to be a reasonable alternative to renewal of CGS's operating license.

Energy Crops

Biomass power based on energy crops include fast maturing woody crops (i.e., hybrid poplar and hybrid willow) and herbaceous crops (i.e., switchgrass). Other crops grown for energy conversion include those used to produce biofuels (i.e., ethanol). In 1999, the estimated annual cumulative quantity of energy crops for the State of Washington was zero. At present, energy crops are not as profitable as using land for traditional agricultural crops and, therefore, dedicated energy crops are not produced in the United States. Currently, biofuels are typically used as an additive for liquid transportation fuels. Since energy crop technologies are not competitive on a large scale basis (**NRC 1996**, Section 8.3.8; **ORNL 2000**), they are not considered by Energy Northwest to be a reasonable alternative to renewal of CGS's operating license.

Fuel Cells

Fuel cells are electrochemical devices that generate electricity without combustion and without water and air pollution. Fuel cells began supplying electric power for the space shuttle in the 1960s. Today, they are being developed for more commercial applications. The U.S. Department of Energy (USDOE) is currently partnering with several fuel cell manufactures to develop more practical and affordable designs for the stationary power generation sector. If successful, fuel cell power generation should prove to be efficient, reliable, and virtually pollution free. At present, progress has been slow and costs high. The most widely marketed fuel cell is currently about $4,500 per kilowatt (kW) compared to $800 to $1,500 per kW for a diesel generator and about $400 per kW or less for a natural gas turbine. By the end of this decade, the goal of the USDOE is to reduce costs to as low as $400 per kW (**USDOE 2008**).

At present, fuel cells are not economically or technologically competitive with other alternatives for baseload capacity and therefore, are not considered by Energy Northwest to be a reasonable alternative to renewal of CGS's operating license.

Combination of Alternatives

Many combinations of alternatives could theoretically replace the 1,150 MWe baseload capacity of CGS. These combinations could include renewable sources (e.g., wind, solar, biomass) and, thus, be consistent with the intent of State Initiative 937. As discussed above, renewable energy sources, by themselves, would not provide a reasonable alternative to the baseload power to be produced by CGS. However, renewables combined with conventional fossil fuel generation and, perhaps, other sources provides a reasonable alternative to the nuclear power generation of CGS.

The fossil-fuel-fired portion of the combination would be sized such that it would produce the needed power if the renewable resource is unavailable; the extra fossil fuel capacity would be displaced when the renewable resource is available. For example, if the renewable portion is some amount of potential wind power generation and that resource became available, then the output of the fossil fuel power generation of the combination alternative could be lowered to offset the increased generation from wind power. Thus, a renewable energy source, in combination with conservation, hydropower, and fossil fuel power generation, could be a reasonable alternative to the CGS baseload generation.

Conclusion

Of the alternatives for providing new generating capacity considered above, new coal-fired and gas-fired plants as well a combination of alternatives that includes a fossil fuel plant were determined to be reasonable alternatives to license renewal.

7.2.2 Environmental Impacts of Alternatives

Environmental impacts are evaluated in this section for the alternatives determined by Energy Northwest to be reasonable compared to renewal of CGS's operating license:

- Purchasing Electric Power
- Coal-Fired Generation
- Gas-Fired Generation
- Combination of Alternatives

The impacts are characterized as being SMALL, MODERATE, or LARGE. The definitions of these impact descriptions are the same as presented in the introduction to Chapter 4, which in turn are consistent with the criteria established in 10 CFR 51, Appendix B to Subpart A, Table B-1, Footnote 3. Energy Northwest believes the environmental impacts associated with the construction and operation of new generating capacity at a greenfield site would exceed those for the same type plants located at CGS or at another existing disturbed site, i.e., brownfield site.

7.2.2.1 Purchasing Electric Power

Based on the evaluation in Section 7.2.1.1, if power to replace CGS were to be purchased, it is likely to originate from a source within the Pacific Northwest and be one of the alternative generating technologies described in the GEIS. The descriptions of the environmental impacts for those technologies are representative for the purchased power alternative. Of these technologies, coal fueled plants at a benchmark cost of $43 per megawatt-hour (MWh)[4] and natural gas combined cycle plants at a benchmark cost of $46/MWh are the most cost effective for providing baseload capacity (**NWPCC 2005**, Table 5-1). Environmental impacts associated with the construction and operation of new coal-fired or gas-fired generating capacity for purchased power at a greenfield site would exceed those described in the following sections for a coal-fired or gas-fired plant located at CGS or at another existing disturbed, i.e., brownfield site.

7.2.2.2 Coal-Fired Generation

For this impact analysis, Energy Northwest considered locating hypothetical new coal-fired units at the existing CGS site because environmental impacts would be minimized by building on previously disturbed land and the existing infrastructure (i.e., roads, office buildings, transmission lines, cooling system components) would be utilized to the extent possible. The adjacent IDC site is an alternative brownfield site with access to existing infrastructure. Environmental impacts from coal-fired generation alternatives were evaluated in the GEIS (**NRC 1996**, Sec. 8.3.9). Table 7.2-1 presents the basic coal-fired alternative emission control characteristics.

[4] Year 2000 dollars.

Land Use

As stated in Section 7.2.1.2, land area requirements for a coal-fired plant of similar capacity to CGS would be approximately 1.7 acres per MWe (**NRC 1996**, Section 8.3.9), or 1,955 acres for a 1,150 MWe plant. This requirement exceeds the 1,089 acres of land occupied by CGS. Presumably, the additional land needed for siting a new coal-fired plant could be acquired from the uncompleted nuclear projects (WNP-1/4) adjacent to CGS.

The new plant should also be able to connect to the existing transmission grid network and coal delivery could be by existing rail (i.e., via tracks serving the neighboring Hanford Site), so that additional land disturbance in the site vicinity would be minimal.

As concluded by the NRC in the GEIS, impacts for siting a new coal-fired plant at an existing nuclear plant would reduce adverse impacts to the environment. However, over the plant operating life an estimated 22 acres of land per MWe would be impacted from mining the coal and disposing of the wastes, compared to approximately one acre per MWe for mining and processing uranium during the operating life of a nuclear power plant (**NRC 1996**, Sections 8.3.9 and 8.3.12).

In consideration of the above, land use impacts associated with a coal-fired plant are characterized as MODERATE.

Water Use and Quality

Presumably, a coal-fired plant would utilize the existing closed cycle cooling system or one comparable to CGS. Withdrawal of river water and discharge to the Columbia River would be regulated by a NPDES permit. The river would likely supply water during construction since the CGS pumphouse should be available. As such, impacts on water use and quality would be SMALL for the coal-fired alternative.

Air Quality

Air quality impacts of coal-fired generation differ considerably from those of nuclear generation. A coal-fired plant emits sulfur oxides (SO_x), nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO), all of which are regulated pollutants. Additionally, there are substantial emissions of carbon dioxide (CO_2), a greenhouse gas, although future developments such as carbon capture and storage and co-firing with biomass have the potential to reduce the carbon footprint of coal-fired electricity generation (**POST 2006**).

Estimated SO_x, NO_x, PM, and CO emissions for a coal-fired generation facility were based on the emission factors contained in USEPA Document AP-42 (**USEPA 1998**). The use of sub-bituminous coal fired in a circulating fluidized bed combustor (FBC) was assumed. Emission mitigation measures include the use of lime in the combustor unit,

a wet scrubber system to control acid gas emissions, selective non-catalytic reduction to minimize NO_x emissions, and a baghouse to control PM. Air emissions produced by the coal-fired alternative are summarized in Table 7.2-2.

Per the GEIS, operating impacts of a new coal plant include concerns over adverse human health effects, such as increased cancer and emphysema. Additionally, global warming and acid rain are identified by the NRC as potential impacts related to gaseous emissions from coal-fired plants. Washington Senate Bill 6001, enacted into law in 2007, imposes strict limitations on emissions from new power plants in hopes of reducing greenhouse gases. The law establishes rigorous goals for greenhouse gas emissions from instate sources. By 2020, emissions are to be lowered to 1990 levels and additional reductions are targeted for subsequent years.

Based on the emissions generated by a coal-fired facility (Table 7.2-2), air impacts would be MODERATE. The impacts would be noticeable, but they would not destabilize air quality in the area.

Ecological Resources

Considering that the sites of CGS and WNP-1/4 are already disturbed, and that a coal-fired facility will utilize the existing or a similar cooling water system, impacts to terrestrial biota and aquatic ecology are likely to be SMALL.

Human Health

Concerns over adverse human health effects from coal combustion have led to important federal legislation, such as the Clean Air Act and Amendments (CAAA). Although new technology has improved the quality of emissions from coal-fired facilities, health concerns remain. Air quality would be degraded by the release of regulated pollutants, carbon dioxide, and radionuclides such as uranium and thorium. Therefore, human health impacts are characterized as SMALL to MODERATE.

Socioeconomics

The peak workforce during construction of the coal-fired plant alternative is estimated to range between 1.2 to 2.5 workers per MWe and the workforce required during operation is estimated to be 0.25 workers per MWe (**NRC 1996**, Section 8.3.9, Table 8.1 and Table 8.2). For a plant with a capacity of 1,150 MWe, workforces of approximately 1,380 to 2,875 construction workers and 288 permanent employees would be required.

As noted in the GEIS, socioeconomic impacts at a rural site would be larger than at an urban site, since more of the peak construction workforce would need to move to the area to work. During construction, educational facilities and health care and social services in nearby communities might be adversely impacted by the influx of a large,

temporary workforce, whereas area businesses would benefit from increased spending. Therefore, socioeconomic impacts during construction are considered to be SMALL.

The selection of the coal plant alternative would result in the reduction in the permanent workforce by approximately 75% (refer to Section 3.4). This would result in adverse socioeconomic impacts; however, due to the site's proximity to the cities of Richland, Kennewick, Pasco, West Richland, these impacts are judged to be SMALL.

Waste Management

Substantial solid waste, especially ash and scrubber sludge, would be produced and would require constant management. For example, the NRC staff has estimated that an 850-MWe coal-fired power plant would generate as much as 277,200 tons of ash and scrubber waste per year. Although much of this waste could be recycled, onsite or offsite landfill disposal of the remaining waste would still require approximately 159 acres over 40 years of operation (**NRC 2009**, Section 8.1.7). For a 1,150-MWe plant to replace CGS, the equivalent annual waste would be approximately 375,000 tons, which would require approximately 215 acres for disposal over the life of the plant. In addition, the December 2008 failure of the dike used to contain fly ash at the Tennessee Valley Authority Kingston Fossil Plant in Roane County, Tennessee, and subsequent cleanup highlight other waste management issues (**USEPA 2009**).

In consideration of the above, waste management impacts are characterized as MODERATE.

Aesthetics

Although atmosphere dispersion modeling studies would need to be performed to determine the flue gas stack height needed to comply with local air pollution regulations, typical flue gas stacks range between 500 to 600 feet tall for dispersing flue gas components into the atmosphere. The stack(s) would be substantially taller than the CGS reactor building, which rises about 230 feet above plant grade, and would be potentially visible for many miles in a relatively undeveloped area. Two large new power plant buildings would also need to be constructed.

Although the site is in a relatively remote location, considering that coal delivery and waste removal is likely to be by rail, noise impacts from a coal-fired plant are anticipated to exceed those associated with CGS.

Overall aesthetic impacts associated with a new coal-fired plant are considered to be MODERATE.

Cultural Resources

Considering that the CGS site and the adjacent site of WNP-1/4 are already disturbed, impacts to cultural resources are anticipated to be SMALL.

7.2.2.3 Natural Gas-Fired Generation

As with the coal-fired alternative (Section 7.2.2.2), a hypothetical gas-fired plant would be located at the CGS site. Although a major high-pressure pipeline is not readily available, most environmental impacts related to constructing natural gas-fired plants should be the same for conventional steam, gas-turbine, and combined-cycle and similar to other large central generating stations. Environmental impacts from gas-fired generation alternatives, focusing on combined-cycle plants, are evaluated in the GEIS (**NRC 1996**, Section 8.3.10). Compared to other fossil fuel technologies of equal capacity, environmental impacts associated with operating gas-fired facilities are generally less. Basic emission control characteristics for the gas-fired alternative are provided in Table 7.2-3.

Land Use

Approximately 0.11 acres of land would be required per MWe, equating to approximately 127 acres for a gas-fired plant with a capacity of 1,150 MWe (**NRC 1996**, Table 8.1). Hence, land impacts for the plant site would be less for a gas-fired plant than those for CGS. Impacts on land use due to construction of a fuel pipeline would be substantial given the distance to the nearest gas transmission line located about 15 miles east of CGS. Discounting land use associated with the fuel delivery pipeline, land use impacts associated with a gas-fired plant are anticipated to be SMALL.

Water Use and Quality

Due to the use of existing cooling water components, impacts to aquatic resources and water quality would be similar to those for CGS and would be offset by the concurrent shutdown of CGS. As such, water use and quality impacts should be SMALL.

Air Quality

Natural gas is a relatively clean-burning fuel with nitrogen oxides being the primary focus of combustion emission controls. A natural gas-fired plant would also emit small quantities of sulfur oxides, carbon monoxide, and particulate matter, all of which are regulated pollutants. In addition, carbon dioxide, a greenhouse gas, is emitted in significant quantities, though much less than the comparably-sized coal plant.

Referring to Table 7.2-4, air emissions were estimated for a 1,150 MWe natural gas-fired generation facility based on the emission factors contained in USEPA Document AP-42 (**USEPA 2000**). Use of a combined cycle gas turbine was assumed, with water

injection and selective catalytic reduction for controlling emissions of nitrogen oxides. The estimated emissions generated from a natural gas-fired facility, although less than a coal-fired facility, are still substantial. As a result, the emissions would likely alter local air quality. Consequently, air quality impacts are anticipated to be MODERATE, but smaller than those of coal-fired generation.

Ecological Resources

Construction of a gas-fired plant at the existing CGS site and utilization of existing cooling water components will have SMALL impacts on terrestrial and aquatic habitats due to the relatively small foot print and already disturbed site area.

Human Health

Some health risks such as emphysema may be attributable to increased NO_x emissions, which contribute to ozone formation. Nonetheless, natural gas combustion produces fewer uncontrolled pollutants than other fossil fuels. Based on the emissions, human health effects are expected to be SMALL.

Socioeconomics

The estimated numbers of peak construction workers and workers required to operate a gas-fired plant with a capacity of 1,150 MWe are 1,380 and 173 workers, respectively (**NRC 1996**, Tables 8.1 and 8.2). Socioeconomic impacts would be similar to those discussed for the coal-fired alternative and, hence, would be SMALL.

Waste Management

Gas-fired generation would result in minimal waste generation, producing minor (if any) impacts (**NRC 1996**, Section 8.3.10). As a result, waste management impacts would be SMALL.

Aesthetics

A large new turbine building and flue gas stack(s) would need to be constructed. Based on stack heights for the Coyote Springs Cogeneration Project in Boardman, Oregon and the Hermiston Power Project in Hermiston, Oregon, it is estimated that several stacks with an approximate height of 200 feet would be required for the discharge of flue gases (**OEFSC 2004**, Page 3; **OEFSC 2005**, Page 2). Although these structures would be noticeable, their overall impact is anticipated to be SMALL.

Cultural Resources

Impacts to cultural resources are anticipated to be SMALL since the site and surrounding areas are already disturbed.

7.2.2.4 Combination of Alternatives

In performing its assessment, Energy Northwest selected alternatives that in combination minimize potential environmental impacts at the CGS site or other previously disturbed sites. For a combination of alternatives that total 1,150 MWe, Energy Northwest chose renewable energy equal to 175 MWe (15%), hydropower equal to 175 MWe (15%), conservation equal to 115 MWe (10%), and fossil fuel power equal to 685 - 860 MWe (60-75%).

The range of values for the fossil fuel power contribution is to account for when the renewal energy source is not available. Alternatively, a fossil fuel baseload of 685 MWe could be used, with the remaining 115 MWe assumed to be available as purchased power when needed. However, Energy Northwest assumes that the environmental impact of such an option is similar or greater than a fossil fuel baseload of 860 MWe (see Section 7.2.2.1).

For comparison of impacts, Energy Northwest assumed wind power would be the renewable energy source. This is consistent Energy Northwest's project development interests, although it is also pursuing biofuel (wood waste) and operates a small solar plant. It is assumed that the hydropower portion of the replacement energy would be acquired through powering previously developed but unpowered sites. The assumed conservation component of the combination alternative would have to come from numerous initiatives by BPA and the region's utilities. The bulk of the replacement is assumed to be a natural gas-fired plant as the fossil fuel source. Based on the comparative impacts of coal and natural gas shown in Table 8.0-1, Energy Northwest concludes that a natural gas power generating facility would have less of an environmental impact than a comparably sized coal-fired generating facility.

Impacts related to the assumed combination of alternatives are summarized in the following paragraphs.

<u>Land Use</u>

New structures for the natural gas plant could be constructed on the existing CGS site or the adjacent IDC site without the need to clear previously undisturbed land. However, construction on undisturbed land will be needed for the wind turbines and the natural gas pipeline connection with the nearest gas transmission line, located about 15 miles east of CGS. In addition, construction of transmission facilities for the hydropower and wind portions of the resource combination will likely require some amount of land disturbance. Depending on the site location, land use impacts should be SMALL to MODERATE.

Water Use and Quality

Surface water withdrawal and discharge of effluents from the natural gas-fired plant will be less than or the same as the existing CGS. Groundwater use will be unaffected and domestic water consumption should decline due to fewer overall employees. As such, water use and quality impacts should be SMALL.

Air Quality

Although natural gas is a relatively clean-burning fuel, carbon dioxide, which is a greenhouse gas, is emitted in significant quantities. The air quality impacts on a scaled basis, however, will be less than those attributable to the alternative for which only a single large natural gas-fired plant was assumed (see Section 7.2.2.3 and Table 7.2-4). As a result, air quality impacts should be SMALL to MODERATE.

Ecological Resources

The natural gas plant effects to aquatic and terrestrial habitats should be less than or the same as the existing CGS because of less water intake and discharge flows and a smaller footprint. Transmission lines connecting to hydropower facilities in forested locations could require active right-of-way maintenance programs. The siting of most wind turbine projects in the Pacific Northwest is such that the transmission corridors do not require vegetation management. Interaction of avian species with wind turbines is a concern. Overall, however, ecological impacts of the combination should be SMALL.

Human Health

Some health risks may be attributable to increase ozone-forming emissions such as NO_x. The air quality impacts on a scaled basis, however, will be less than the natural gas-fired plant alternative (see Section 7.2.2.3). Additionally, the GEIS notes that conservation approaches can affect indoor air quality, but can be mitigated. As a result, human health impacts should be SMALL.

Socioeconomics

Although there will be a reduced workforce, the adverse impact should be minimized due to the large size of the surrounding communities and established infrastructure such as roads and public services. With a dispersed siting of resources, the combination alternative spreads the socioeconomic impacts over a wide area. Socioeconomic impacts, therefore, should be SMALL.

Waste Management

As noted in Section 7.2.2.3, a natural gas-fired plant results in minimal waste generation. Likewise, the wind and hydropower energy sources will have minimal, if any, waste. As a result, waste management impacts should be SMALL.

Aesthetics

Most structures will be similar in size to the existing CGS plant. CGS is about 230 ft high while newer large wind power turbines have heights (to rotor tip) of 250 ft to 300 ft. Therefore, aesthetics impacts, in general, should be SMALL, but depending on the location and viewpoint, impacts may be considered SMALL to MODERATE due to the presence of the wind turbines.

Cultural Resources

Construction and operation of the natural gas-fired plant will occur on previously disturbed CGS land. Construction of a natural gas pipeline, wind turbines, and transmission lines for hydropower and wind resources, however, will likely occur on undisturbed land. As a result, impacts to cultural resources should be SMALL to MODERATE.

7.2.3 Conclusion

Energy Northwest has considered a coal-fired power plant, a gas-fired power plant, and a combination of sources, including renewables and conservation, as reasonable alternatives to renewal of the CGS operating license. Each of these alternatives would entail an equivalent or greater environmental impact as compared to continued operation of CGS.

Table 7.2-1. Coal-Fired Alternative Emission Control Characteristics

Characteristic	Basis
Net capacity = 1,150 MW	Equivalent to CGS.
Boiler type = circulating fluidized bed combustor (FBC).	FBCs have gained popularity in the last decade. Circulating bed FBCs achieve higher combustion efficiencies and better sorbent utilization than bubbling bed unit FBCs. (**USEPA 1998**, Section 1.1.2)
Fuel type = sub-bituminous coal	Typical for coal in Washington State. (**EIA 2007c**, Table 4.A)
Fuel heating value = 8,532 Btu/lb	2006 value for coal used in Washington State. (**EIA 2007c**, Table 15.A)
Fuel sulfur content by weight = 0.69%	2006 average quality of coal used in Washington. (**EIA 2007c**, Table 15.A)
Uncontrolled SO_X emission = 31S lb/ton (where 'S' is weight % sulfur content of coal [i.e., S = 0.69])	Assumes that no calcium-based sorbents are used and that the bed material is inert with respect to sulfur capture. (**USEPA 1998**, Table 1.1-3, Notes b and j)
Uncontrolled NO_X emission = 5.0 lb/ton Uncontrolled CO emission = 18 lb/ton	Typical for circulating FBC. (**USEPA 1998**, Table 1.1-3)
Uncontrolled PM emission = 17 lb/ton Uncontrolled PM_{10} emission = 12.4 lb/ton	No data available for FBCs. Emissions are assumed to be comparable to a spreader stoker with multiple cyclones and re-injection. (**USEPA 1998**, Table 1.1-4, Note m)
Heat rate = 10,164 Btu/kWh	Typical for coal-fired, steam turbine units. (**EIA 2007a**, Table A6)
Capacity factor = 0.85	Typical for large coal-fired units.
SO_X control = wet scrubber system (lime in the combustor unit – 95% removal efficiency)	Best available for minimizing SO_X. (**USEPA 1998**, Table 1.1-1)
NO_X control = selective non-catalytic reduction – 60% reduction	Best available technology for fluidized bed boilers. (**USEPA 1998**, Table 1.1-2)
PM control = fabric filters (baghouse – 99.9% removal efficiency)	Best available for minimizing particulate emissions. (**USEPA 1998**, Section 1.1.4.1)
CO_2 emission coefficient = 3,716 lb/ton	Greenhouse gas emission coefficient for sub-bituminous coal. (**EIA 2008b**)

Table 7.2-1. Coal-Fired Alternative Emission Control Characteristics
(continued)

Notes:
Btu – British thermal unit
lb – pound
kWh – kilowatt-hour
MW – megawatt
SO_X – oxides of sulfur
NO_X – nitrogen oxides
CO – carbon monoxide
PM – particulate matter
PM_{10} – PM with a diameter less than 10 microns
CO_2 – carbon dioxide

Table 7.2-2. Air Emissions from Coal-Fired Alternative

Parameter	Calculation	Result
Annual Coal Consumption	$\frac{1{,}150\ \text{MW} \times 10{,}164\ \text{Btu}}{\text{kWhr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times \frac{\text{lb}}{8{,}532\ \text{Btu}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{days}}{\text{year}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times 0.85$	5,100,400 tons of coal per year
SO_X	$\frac{5{,}100{,}400\ \text{tons}}{\text{year}} \times \frac{0.69 \times 31\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100\% - 95\%}{100\%}$	2,730 tons SO_X per year
NO_X	$\frac{5{,}100{,}400\ \text{tons}}{\text{year}} \times \frac{5\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100\% - 60\%}{100\%}$	5,100 tons of NO_X per year
CO	$\frac{5{,}100{,}400\ \text{tons}}{\text{year}} \times \frac{18\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}}$	45,900 tons of CO per year
PM	$\frac{5{,}100{,}400\ \text{tons}}{\text{year}} \times \frac{17\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100\% - 99.9\%}{100\%}$	44 tons of PM per year
PM_{10}	$\frac{5{,}100{,}400\ \text{tons}}{\text{year}} \times \frac{12.4\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100\% - 99.9\%}{100\%}$	32 tons of PM_{10} per year
CO_2	$\frac{5{,}100{,}400\ \text{tons}}{\text{year}} \times \frac{3{,}716\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}}$	9,480,000 tons of CO_2 per year

Notes:

SO_X – sulfur oxides
NO_X – nitrogen oxides
CO – carbon monoxide
PM – particulate matter
PM_{10} – PM having a diameter less than 10 microns
CO_2 – carbon dioxide

Table 7.2-3. Gas-Fired Alternative Emission Control Characteristics

Characteristic	Basis
Net capacity = 1,150 MW	Equivalent to CGS.
Fuel type = natural gas	Assumed to be a combined cycle gas turbine generator.
Fuel heating value = 1,028 Btu/ft^3	2006 value for gas used in Washington. (**EIA 2007c**, Table 14.A)
SO_X content = 0.0034 lb/MMBtu	(**USEPA 2000**, Table 3.1-2a, Note h)
NO_X control = water-steam injection combustion and selective catalytic reduction.	Demonstrated to effectively suppress NO_X emissions. (**USEPA 2000**, Sections 3.1.4.1 and 3.1.4.3)
NO_X content = 0.0109 lb/MMBtu	Typical for natural gas-fired turbines with water-steam injection and SCR. (**USEPA 2000**, Section 3.1–Database)
CO content = 0.0023 lb/MMBtu	Typical for large SCR-controlled gas-fired units with water-steam injection. (**USEPA 2000**, Section 3.1–Database)
PM (filterable) content = 0.0019 lb/MMBtu	Based on combustion turbines using water-steam injection. (**USEPA 2000**, Table 3.1-2a, Note l)
Heat rate = 7,502 Btu/kWh	Typical for gas-fired, combined cycle units. (**EIA 2007a**, Table A6)
Capacity factor = 0.85	Assumed based on performance of modern plants. Typically, gas turbines are operated at high loads (i.e., greater than or equal to 80 percent of rated capacity). (**USEPA 2000**, Section 3.1.3)
CO_2 emission coefficient = 110 lb/MMBtu	Greenhouse gas emission coefficient for natural gas. (**USEPA 2000**, Table 3.1-2a)

Table 7.2-3. Gas-Fired Alternative Emission Control Characteristics
(continued)

Notes:

MW – megawatt
Btu – British thermal unit
ft^3 – cubic feet
lb – pound
MMBtu – million British thermal units
kWh – kilowatt-hour
SCR – selective catalytic reduction
SO_X – oxides of sulfur (i.e., mainly SO_2) (**USEPA 2000**, Section 3.1.3)
NO_X – nitrogen oxides
CO – carbon monoxide
PM – particulate matter
CO_2 – carbon dioxide

Table 7.2-4. Air Emissions from Gas-Fired Alternatives

Parameter	Calculation	Result
Annual Gas Consumption	$1{,}150\ \text{MW} \times \frac{7{,}502\ \text{Btu}}{\text{kW x hr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times \frac{\text{ft}^3}{1{,}028\ \text{Btu}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{days}}{\text{yr}} \times 0.85$	62,500,000,000 ft^3 of gas per year
Annual Btu Input	$\frac{62{,}500{,}000{,}000\ \text{ft}^3}{\text{year}} \times \frac{1{,}028\ \text{Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}}$	64,250,000 MMBtu per year
SO_X	$\frac{0.0034\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{64{,}250{,}000\ \text{MMBtu}}{\text{year}}$	109 tons of SO_X per year
NO_X	$\frac{0.0109\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{64{,}250{,}000\ \text{MMBtu}}{\text{year}}$	350 tons of NO_X per year
CO	$\frac{0.0023\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{64{,}250{,}000\ \text{MMBtu}}{\text{year}}$	74 tons of CO per year
PM	$\frac{0.0019\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{64{,}250{,}000\ \text{MMBtu}}{\text{year}}$	61 tons of filterable PM per year
CO_2	$\frac{110\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{64{,}250{,}000\ \text{MMBtu}}{\text{year}}$	3,533,750 tons of CO_2 per year

Notes:

SO_X – sulfur oxides (i.e., mainly SO_2) (**USEPA 2000**, Section 3.1.3)
NO_X – nitrogen oxides
CO – carbon monoxide
PM – particulate matter
CO_2 – carbon dioxide

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8.0 COMPARISON OF ENVIRONMENTAL IMPACT OF LICENSE RENEWAL WITH THE ALTERNATIVES

Regulatory Requirement: 10 CFR 51.45(b)(3)

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

Chapter 4 analyzes environmental impacts of CGS license renewal and Chapter 7 analyzes impacts from renewal alternatives. Table 8.0-1 summarizes environmental impacts of the proposed action (license renewal) and the alternatives, for comparison purposes. The environmental impacts compared in Table 8.0-2 are those that are either Category 2 issues for the proposed action or are issues that the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (**NRC 1996**) identified as major considerations in an alternatives analysis. For example, although the U. S. Nuclear Regulatory Commission (NRC) concluded that air quality impacts from the proposed action would be small (Category 1), the GEIS identified major human health concerns associated with air emissions from alternatives (Section 7.2.2). Therefore, Table 8.0-1 compares air impacts from the proposed action to the alternatives. Table 8.0-2 is a more detailed comparison of the alternatives.

Table 8.0-1. Impacts Comparison Summary

Impact [b]	Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives [a]		
			With Coal-Fired Generation	With Gas-Fired Generation	With Combination of Alternatives
Land Use	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL
Air Quality	SMALL	SMALL	MODERATE	MODERATE [c]	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	SMALL to MODERATE	SMALL	SMALL
Socioeconomics	SMALL	SMALL	SMALL	SMALL	SMALL
Waste Management	SMALL	SMALL	MODERATE	SMALL	SMALL
Aesthetics	SMALL	SMALL	MODERATE	SMALL	SMALL
Cultural Resources	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE

Notes:

a) Environmental impacts associated with the construction and operation of new coal-fired or gas-fired generating capacity at a greenfield site for supplying purchased power would exceed those described in Table 8.0-2 for a coal-fired or gas-fired plant located at CGS or at another existing disturbed site, i.e., brownfield.

Table 8.0-1. Impacts Comparison Summary (continued)

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

c) Moderate, but less than with coal-fired generation.

Table 8.0-2. Impacts Comparison Detail

Proposed Action (License Renewal)	Base (Decommissioning)	No Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Combination of Alternatives
Alternative Descriptions				
CGS license renewal for 20 years, followed by decommissioning. 1,145 plant workers (Section 3.4).	Decommissioning following expiration of current CGS license. Adopting by reference, as bounding CGS decommissioning, GEIS description (NRC 1996, Section 7.1).	New construction at the CGS site. Existing rail spur. Use existing switchyard and transmission lines. 1,150-MW, equivalent to CGS; capacity factor 0.85. Existing CGS intake/ discharge system. Circulating fluidized bed combustor (FBC); sub-bituminous coal; 8,532 Btu/lb; 0.69% sulfur.	New construction at the CGS site. Existing natural gas pipelines need extension and capacity increase. Use existing switchyard and transmission lines. 1,150-MW, equivalent to CGS; capacity factor 0.85. Existing CGS intake/ discharge system. Natural gas, 1,028 Btu/ft^3; 7,502 Btu/kWh; 0.0034 lb SO_x/MMBtu; 0.0109 lb NO_x/MMBtu.	New construction at the CGS site and vicinity, e.g., IDC site. Existing natural gas pipelines need extension and capacity increase. Use existing switchyard and transmission lines, plus new transmission lines for hydro and wind power. 1,150-MW, equivalent to CGS; capacity factor 0.85. Existing CGS intake/ discharge system.

Table 8.0-2. Impacts Comparison Detail
(continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Combination of Alternatives
		SO_x control: wet scrubber system (lime in the combustor unit – 95% removal efficiency); fabric filters (99.9% removal efficiency). NO_x control: selective non-catalytic reduction – 60% reduction. 288 workers (Section 7.2.2.2).	NO_x control: water steam injection combustion and selective catalytic reduction. 173 workers (Section 7.2.2.3).	Same as gas-fired generation, but on a scaled basis for 860 MWe, plus 175 MWe wind power, 175 MWe, hydropower, and 115 MWe conservation On a scaled basis, less than gas-fired generation.

Table 8.0-2. Impacts Comparison Detail
(continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Combination of Alternatives
Land Use Impacts				
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 52, 53).	SMALL – Not an impact evaluated by GEIS (NRC 1996).	MODERATE – 1,955 acres required for the powerblock and associated facilities; net 25,000 acres for mining and disposal (Section 7.2.2.2).	SMALL – 127 acres for facility at CGS location; gas pipeline would connect to existing nearby gas pipeline (Section 7.2.2.3).	SMALL to MODERATE – Gas-fired plant could be constructed on previously disturbed CGS site or adjacent IDC site; however, construction on undisturbed land likely for wind turbines and natural gas pipeline connection as well as construction of transmission facilities for the hydro and wind power (Section 7.2.2.4).
Water Quality Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 3, 6-11 and 32). Five Category 2 water quality and supply issues do not apply (Section 4.1, Issue 13; Section 4.5, Issue 33; Section 4.6, Issue 34; Section 4.7, Issue 35; and Section 4.8, Issue 39).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 89).	SMALL – Operational impacts minimized by use of existing closed cycle cooling system that withdraws make-up water from the Columbia River (Section 7.2.2.2).	SMALL – Operational impacts minimized by use of existing closed cycle cooling system that withdraws make-up water from the Columbia River (Section 7.2.2.3).	SMALL – Surface water withdrawal and discharge of effluents will be less than or the same as the existing CGS; groundwater use will be unaffected; and domestic water consumption should decline (Section 7.2.2.4).

Table 8.0-2. Impacts Comparison Detail
(continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Combination of Alternatives
Air Quality Impacts				
SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 51). Category 2 issue not applicable (Section 4.11, Issue 50).	SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issue 88).	MODERATE – 2,730 tons SO_X/yr 5,100 tons NO_X/yr 45,900 tons CO/yr 44 tons PM/yr 32 tons PM_{10}/yr 9.48×10^6 tons CO_2/yr (Section 7.2.2.2).	MODERATE – 109 tons SO_X/yr 350 tons NO_X/yr 74 tons CO/yr 61 tons PM/yr 3.53×10^6 tons CO_2/yr (Section 7.2.2.3).	SMALL to MODERATE – On a scaled basis, less than gas-fired generation (Section 7.2.2.4).
Ecological Resource Impacts (including Threatened and Endangered Species)				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 15-24,28-30, 41-43, and 45-48). Four Category 2 issues not applicable (Section 4.2, Issue 25; Section 4.3, Issue 26; Section 4.4, Issue 27; and Section 4.9, Issue 40). No terrestrial threatened or endangered species are known to occur at the CGS site or along the transmission corridor. (Section 4.10, Issue 49)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 90). Impact to threatened and endangered species not evaluated by GEIS (NRC 1996)	SMALL – Site already disturbed; use of existing cooling system minimizes terrestrial and aquatic impacts (Section 7.2.2.2).	SMALL – Site already disturbed; use of existing cooling system minimizes terrestrial and aquatic impacts (Section 7.2.2.3).	SMALL – Site already disturbed; use of existing cooling system minimizes terrestrial and aquatic impacts; but new ROW maintenance for hydropower transmission lines (Section 7.2.2.4).

Table 8.0-2. Impacts Comparison Detail
(continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Combination of Alternatives
Human Health Impacts				
SMALL – Adopting by reference Category 1 issues (Table A-1, Issues 56, 58, 61, 62). Risk due to transmission-line induced currents minimal due to conformance with consensus code (Section 4.13, Issue 59). One Category 2 issue does not apply (Section 4.12, Issue 57).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 86).	SMALL to MODERATE – Adopting by reference GEIS conclusion that moderate risks such as cancer and emphysema from emissions are likely (NRC 1996).	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (NRC 1996).	SMALL – On a scaled basis, less than gas-fired generation.

Table 8.0-2. Impacts Comparison Detail
(continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Combination of Alternatives
Socioeconomic Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 64, 67). Two Category 2 issues are not applicable (Section 4.16, Issue 66 and Section 4.17.1, Issue 68). As there will be no refurbishment and no additional workers during the license renewal period, there will be no impact on housing (Section 4.14, Issue 63). Plant tax payments represent about 1% or less of local jurisdictions total tax revenues (Section 4.17.2, Issue 69). Capacities of public water supplies and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65 and Section 4.18, Issue 70).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 91).	SMALL – Reduction in permanent work force at CGS could adversely affect surrounding counties, but would be mitigated by CGS's proximity to Tri-Cities metropolitan area (Section 7.2.2.2).	SMALL – Reduction in permanent work force at CGS could adversely affect surrounding counties, but would be mitigated by CGS's proximity to Tri-Cities metropolitan area (Section 7.2.2.3).	SMALL – Reduction in permanent work force at CGS could adversely affect surrounding counties, but would be mitigated by CGS's proximity to Tri-Cities metropolitan area and dispersal of alternative energy resources (Section 7.2.2.4).

Table 8.0-2. Impacts Comparison Detail
(continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Combination of Alternatives
Waste Management Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 77-85).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 87).	MODERATE –375,000 tons waste per year; 215 acres for disposing of the waste over coal plant operational life (Section 7.2.2.2).	SMALL – Solid waste is minimal (Section 7.2.2.3).	SMALL – Solid waste is minimal (Section 7.2.2.4).
Aesthetic Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 73, 74).	SMALL – Not an impact evaluated by GEIS (NRC 1996).	MODERATE – The coal-fired power block buildings and the exhaust stacks would be visible from a moderate offsite distance and noise from rail delivery of coal and ash removal (Section 7.2.2.2).	SMALL–A large turbine building and stacks would create visual impacts comparable to those from existing CGS facilities (Section 7.2.2.3).	SMALL – Large turbine building, stacks, and wind power turbines would create visual impacts comparable to those from existing CGS facilities (Section 7.2.2.4).
Cultural Resource Impacts				
SMALL –License renewal does not require additional land disturbance (Section 4.19, Issue 71).	SMALL – Not an impact evaluated by GEIS (NRC 1996).	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.2).	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.3).	SMALL to MODERATE – Impacts likely due to construction on undisturbed land for natural gas pipeline and transmission lines for hydropower and wind resources (Section 7.2.2.4).

Table 8.0-2. Impacts Comparison Detail
(continued)

Table Legend:

Btu	=	British thermal unit	MW	=	megawatt
CO	=	carbon monoxide	NO_X	=	nitrogen oxides
ft^3	=	cubic foot	PM	=	particulate matter
GEIS	=	Generic Environmental Impact Statement (NRC 1996)	PM_{10}	=	particulates having diameter less than 10 microns
kWh	=	kilowatt hour	SO_X	=	oxides of sulfur
lb	=	pound	yr	=	year
MM	=	million			

Notes:

a) Environmental impacts associated with the construction and operation of new coal-fired or gas-fired generating capacity at a greenfield site for supplying purchased power would exceed those described in the table above for a coal-fired or gas-fired plant located at CGS or at another existing disturbed site, i.e., brownfield.

b) From 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.

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

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8.1 REFERENCES

NRC 1996. Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants (GEIS), NUREG-1437, Volumes 1 and 2, Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, May 1996.

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9.0 STATUS OF COMPLIANCE

This chapter lists and discusses the compliance status of the requirements in connection with the proposed action as well as the alternatives.

9.1 PROPOSED ACTION

Regulatory Requirement: 10 CFR 51.45(d) and 51.53(c)(2)

"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. ..."

Table 9.1-1 lists the various federal and state environmental permits, licenses, approvals, or other entitlements that CGS has obtained for current operations. As needed, Energy Northwest intends to seek timely renewal of these authorizations during the current license period and throughout the period of extended operation.

As part of the CGS Environmental Management System (EMS) and its goal of continuous improvement, Energy Northwest performs periodic assessments to assess conformance to the EMS and compliance with regulatory requirements (Section 5.1). Based on the most recent assessments, and communication with federal and state environmental protection agencies, Energy Northwest concludes that CGS is in compliance with applicable environmental standards and requirements.

Table 9.1-2 lists additional environmental consultations related to NRC renewal of the CGS license to operate. As indicated, Energy Northwest anticipates needing relatively few such authorizations and consultations. These items are discussed in more detail below.

Water Quality (401) Certification

Federal Clean Water Act Section 401 requires an applicant for a federal license who conducts an activity that might result in a discharge into navigable waters to provide the licensing agency a certification from the state that the discharge will comply with applicable Clean Water Act requirements (33 USC 1341).

In July 2006, the State of Washington Energy Facility Site Evaluation Council (EFSEC) issued a renewal to the CGS National Pollutant Discharge Elimination System (NPDES)

permit (**EFSEC 2006**). NRC has indicated in its Generic Environmental Impact Statement for License Renewal (**NRC 1996**, Section 4.2.1.1) that issuance of a NPDES permit implies certification by the state. Energy Northwest is applying to NRC for license renewal to continue CGS operations. Consistent with the GEIS, Energy Northwest is providing CGS's NPDES permit as evidence of state water quality (401) certification (see Attachment B).

Threatened or Endangered Species

Section 7 of the Endangered Species Act (16 USC 1531 et seq.) requires federal agencies to ensure that agency action is not likely to jeopardize any species that is listed, or proposed for listing as endangered, or threatened. Depending on the action involved, the Act requires consultation with the U.S. Fish and Wildlife Service (USFWS) regarding effects on non-marine species, the National Marine Fisheries Service (NMFS) for marine species, or both. USFWS and NMFS have issued joint procedural regulations at 50 CFR 402, Subpart B, that address consultation, and FWS maintains the joint list of threatened and endangered species at 50 CFR 17.

Although not required of an applicant by federal law or NRC regulation, Energy Northwest has solicited comment from federal and state resource agencies regarding potential effects that CGS license renewal might have on species of concern. Attachment C includes copies of Energy Northwest correspondence with USFWS, NMFS, Washington Department of Fish and Wildlife (WDFW), and the Washington Department of Natural Resources (WDNR). The WDFW maintains lists of animals it believes are imperiled in the State of Washington. The WDNR, through its Washington Natural Heritage Program, lists rare species and natural communities that should be given priority for conservation. Copies of the correspondence are included in Attachment C.

Historic Preservation

Section 106 of the National Historic Preservation Act (16 USC 470 et seq.) requires federal agencies having the authority to license any undertaking to, prior to issuing the license, take into account the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Council regulations provide for the State Historic Preservation Officer (SHPO) to have a consulting role (35 CFR 800.2). Although not required of an applicant by federal law or NRC regulation, Energy Northwest invited comment on the proposed action by the Washington SHPO. The SHPO asked to be apprised of any related surveys and consultations but did not express concerns. Copies of the correspondence are included in Attachment D.

Table 9.1-1. Environmental Authorizations for Current CGS Operations

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Authorized
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10CFR50.10	License to operate	NPF-21	Issued: 12/20/1983 Expires: 12/20/2023	Operation of CGS
US Dept. of Energy	Atomic Energy Community Act of 1955	Lease contract	AT(45-1)-2269	Issued: 12/10/1971 Expires: Parcel A 01/01/2022; Parcel B 01/01/2052	Construction and operation of CGS on USDOE land
US Dept. of Energy	42 USC 2201(q)	Easement		Issued: 06/16/1981	Use of USDOE land for CGS access road
US Dept. of Energy	42 USC 2201(q)	Easement	Contract R006-02ES-14208	Issued: 06/11/2002 Expires: 06/11/2012	Use of USDOE land for CGS security barrier
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	State permit to construct and operate	N/A	Issued: 05/17/1972	Construction and operation of CGS
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	122	Issued: 06/27/1977	Multipurpose use of cooling water
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	244	Issued: 08/22/1988	Site restoration plan
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	260	Issued: 01/13/1992	Radiological environmental monitoring program

Table 9.1-1. Environmental Authorizations for Current CGS Operations
(continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Authorized
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	273	Issued: 09/12/1994	Reactor power uprate from 3,323 MW thermal (MWt) to 3,486 MWt
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	288	Issued: 11/10/1997	Operation of inert waste landfill
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	295	Issued: 09/11/2000	Construction and operation of ISFSI
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	299	Issued: 08/3/2001	Onsite disposal of cooling system sediment
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	300	Issued: 09/10/2001	Operation of sanitary waste treatment facility
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	302	Issued: 12/15/2003	Fulfillment of wildlife mitigation requirements
Washington Energy Facility Site Evaluation Council	RCW 80.50, WAC Title 463	Resolution	303	Issued: 02/18/2003	Construction and operation of hydrogen storage facility
Washington Energy Facility Site Evaluation Council	Clean Water Act (33 USC 1251), RCW 90.48, WAC 173-216, 173-220, & 463-76	Permit	WA-002515-1	Issued: 05/25/2006 Expires: 05/25/2011	Wastewater discharge

Table 9.1-1. Environmental Authorizations for Current CGS Operations
(continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Authorized
U.S. Army Corps of Engineers	Sec. 10 of Rivers and Harbors Act (33 USC 403), 33 CFR 330	Permit	071-OYC-1-000221-75-9	Issued: 03/14/1975	Construction and maintenance of river intake and discharge structures
Washington Department of Natural Resources	RCW 79.90 & 79.96	Easement	51-076659	Issued: 04/02/2005 Expires: 04/01/2035	Use of aquatic lands (riverbed and shoreline) for construction and operation of in-river structures
Washington Department of Ecology	RCW 90.03, 90.16, & 43.21A, WAC 173-152 & 508-12	Certificate	S3-20141C	Issued: 02/04/1983	Withdrawal and consumption of surface water
Washington Department of Ecology	RCW 90.03, 90.16, & 43.21A, WAC 173-152 & 508-12	Certificate	G3-20142C	Issued: 02/05/1979	Withdrawal and consumption of groundwater
Washington Department of Ecology	RCW 70.105, WAC 173-303-060	Notification of Regulated Waste Activity	WAD980738488	Issued: 08/11/1982	Hazardous waste generation and accumulation
Washington Energy Facility Site Evaluation Council	RCW 70.94 & 80.50, WAC 173-401-300, 173-400-091 & 463-39.	Order	672	Issued: 01/08/1996	Air emissions
Washington Energy Facility Site Evaluation Council	RCW 70.94 & 80.50, WAC 173-400, 173-460, and 463-39	Order	837	Issued: 02/11/2009	Air emission from painting and blasting
Washington Department of Health (through Dept of Licensing)	RCW 70.98, WAC 246-224	Registration	03311	Annual registration (typically expiring in August)	Operation of miscellaneous X-ray sources

Table 9.1-1. Environmental Authorizations for Current CGS Operations
(continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Authorized
Washington Department of Ecology (through Dept of Licensing)	RCW 90.76, WAC 173-360	Registration	034 003 333	Annual registration (typically expiring in January)	Operation of underground storage tanks
Washington Department of Health	RCW 70.119A, WAC 246-294	Permit	920240	Annual registration (typically expiring in November)	Operation of public water system
Washington Department of Health	WAC 246-292	Certification	11452	Annual renewal (typically expiring in January)	Operation of public water system
Washington Department of Ecology	WAC 173-230	Certification	5835	Annual renewal (typically expiring in December)	Operation of wastewater treatment system
Washington Department of Ecology	WAC 173-300	Certification	42551	Expires: 04/08/10	Operation of solid waste landfill
Washington Department of Ecology	RCW 43-200, WAC 173-326	Permit	G1018	Annual permit (typically expiring in February)	Use of commercial low-level radwaste disposal facility
Washington Department of Ecology	WAC 173-50	Certification	11242	Annual renewal (typically expiring in August)	Operation of accredited laboratory
Washington Department of Health	WAC 246-232	License	WN-L0217-1	Expires: 01/31/10	Use of radioactive material in laboratory

Table 9.1-2. Environmental Consultations Related to License Renewal

Agency	Authority	Activity
U.S. Fish and Wildlife Service & National Marine Fisheries Service	Endangered Species Act Section 7 (16 USC 1536)	Requires federal agency issuing a license to consult with US Fish and Wildlife Service (USFWS) regarding terrestrial and freshwater species, and National Marine Fisheries Service (NMFS) regarding marine species (including anadromous fishes)
Washington Department of Archaeology & Historic Preservation	National Historic Preservation Act, Section 106 (16 USC 470f)	Requires federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (SHPO), who must concur that license renewal will not affect any sites listed or eligible for listing
Washington Energy Facility Site Evaluation Council (EFSEC)	Clean Water Act (CWA), Section 401 (33 USC 1341)	State issuance of NPDES permit which constitutes 401 certification that discharge would comply with CWA standards

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9.2 ALTERNATIVES

Regulatory Requirement: 10 CFR 51.45(d) and 51.53(c)(2)

"...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."

The coal, gas, and purchased power alternatives discussed in Section 7.2.1 would be constructed and operated to comply with applicable environmental quality standards and requirements. Energy Northwest notes, however, that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. The coal-fired alternative would be particularly problematic since Washington State has imposed a stringent performance standard for limiting emissions of greenhouse gases from new baseload generating units.

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9.3 REFERENCES

EFSEC 2006. "Reissuance of Columbia Generating Station's NPDES Permit," Letter from M. Mills, State of Washington Energy Facility Site Evaluation Council, to J. V. Parrish, Energy Northwest, May 26, 2006.

NRC 1996. Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants (GEIS), NUREG-1437, Volumes 1 and 2, Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, May 1996.

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ATTACHMENT A

NRC NATIONAL ENVIRONMENTAL POLICY ACT ISSUES FOR LICENSE RENEWAL OF NUCLEAR

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ATTACHMENT A: NRC NATIONAL ENVIRONMENTAL POLICY ACT ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER

Energy Northwest has prepared this environmental report in accordance with the requirements of U.S. Nuclear Regulatory Commission (NRC) regulation 10 CFR 51.53. NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants. Table A-1 lists these 92 issues and identifies the section of the environmental report in which an applicable issue is addressed. For organization and clarity, Energy Northwest has assigned a number to each issue and uses the issue numbers throughout the environmental report.

Table A-1. CGS Environmental Report Discussion of License Renewal NEPA Issues

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Surface Water Quality, Hydrology, and Use (for all plants)			
1. Impacts of refurbishment on surface water quality	1	NA	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.
2. Impacts of refurbishment on surface water use	1	NA	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.
3. Altered current patterns at intake and discharge structures	1	4.0	4.2.1.2.1/4-5
4. Altered salinity gradients	1	NA	Issue applies to a plant feature, discharge to saltwater, that CGS does not have.
5. Altered thermal stratification of lakes	1	NA	Issue applies to a plant feature, discharge to a lake, that CGS does not have.
6. Temperature effects on sediment transport capacity	1	4.0	4.2.1.2.3/4-8
7. Scouring caused by discharged cooling water	1	4.0	4.2.1.2.3/4-6
8. Eutrophication	1	4.0	4.2.1.2.3/4-9
9. Discharge of chlorine or other biocides	1	4.0	4.2.1.2.4/4-10
10. Discharge of sanitary wastes and minor chemical spills	1	4.0	4.2.1.2.4/4-10
11. Discharge of other metals in waste water	1	4.0	4.2.1.2.4/4-10
12. Water use conflicts (plants with once-through cooling systems)	1	NA	Issue applies to a plant feature, once-through cooling, that CGS does not have.
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	NA, and discussed in Section 4.1	Issue applies to features, cooling ponds or water withdrawals from a small river, that CGS does not have.

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	NA	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.
15. Accumulation of contaminants in sediments or biota	1	4.0	4.2.1.2.4/4-10
16. Entrainment of phytoplankton and zooplankton	1	4.0	4.2.2.1.1/4-15
17. Cold shock	1	4.0	4.2.2.1.5/4-18
18. Thermal plume barrier to migrating fish	1	4.0	4.2.2.1.6/4-19
19. Distribution of aquatic organisms	1	4.0	4.2.2.1.6/4-19
20. Premature emergence of aquatic insects	1	4.0	4.2.2.1.7/4-20
21. Gas supersaturation (gas bubble disease)	1	4.0	4.2.2.1.8/4-21
22. Low dissolved oxygen in the discharge	1	4.0	4.2.2.1.9/4-23
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.0	4.2.2.1.10/4-24
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4.0	4.2.2.1.11/4-25
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)			
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.2	Issue applies to a plant feature, once-through cooling or a cooling pond, that CGS does not have.
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.3	Issue applies to a plant feature, once-through cooling or a cooling pond, that CGS does not have.
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.4	Issue applies to a plant feature, once-through cooling or a cooling pond, that CGS does not have.

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)			
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	4.0	4.3.3/4-33
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	4.0	4.3.3/4-33
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	4.0	4.3.3/4-33
Groundwater Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	NA	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	4.0	4.8.1.1/4-116
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	NA, and discussed in Section 4.5	Issue applies to an operational feature, annual average groundwater withdrawals greater than 100 gpm, that CGS does not have.
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	NA, and discussed in Section 4.6	Issue applies to a feature, withdrawals from a small river; that CGS does not have.
35. Groundwater use conflicts (Ranney wells)	2	NA, and discussed in Section 4.7	Issue applies to a feature, Ranney wells, that CGS does not have.
36. Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney wells, that CGS does not have.
37. Groundwater quality degradation (saltwater intrusion)	1	NA	Issue applies to a feature, location in a coastal area, that CGS does not have.
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Issue applies to a feature, cooling ponds, that CGS does not have.
39. Groundwater quality degradation (cooling ponds at inland sites)	2	NA, and discussed in Section 4.8	Issue applies to a feature, cooling ponds at inland sites, that CGS does not have.

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Terrestrial Resources			
40. Refurbishment impacts to terrestrial resources	2	NA, and discussed in Section 4.9	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.
41. Cooling tower impacts on crops and ornamental vegetation	1	4.0	4.3.4/4-34
42. Cooling tower impacts on native plants	1	4.0	4.3.5.1/4-42
43. Bird collisions with cooling towers	1	4.0	4.3.5.2/4-45
44. Cooling pond impacts on terrestrial resources	1	NA	Issue applies to a feature, cooling ponds, that CGS does not have.
45. Power line right-of-way management (cutting and herbicide application)	1	4.0	4.5.6.1/4-71
46. Bird collisions with power lines	1	4.0	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.0	4.5.6.3/4-77
48. Floodplains and wetlands on power line right-of-way	1	4.0	4.5.7/4-81
Threatened or Endangered Species (for all plants)			
49. Threatened or endangered species	2	4.10	4.1/4-1
Air Quality			
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	NA, and discussed in Section 4.11	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.
51. Air quality effects of transmission lines	1	4.0	4.5.2/4-62
Land Use			
52. Onsite land use	1	4.0	3.2/3-1
53. Power line right-of-way land use impacts	1	4.0	4.5.3/4-62
Human Health			
54. Radiation exposures to the public during refurbishment	1	NA	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
55. Occupational radiation exposures during refurbishment	1	NA	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.
56. Microbiological organisms (occupational health)	1	4.0	4.3.6/4-48
57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	NA, and discussed in Section 4.12	Issue applies to features – cooling pond, cooling lake, or discharges to a small river – that CGS does not have.
58. Noise	1	4.0	4.3.7/4-49
59. Electromagnetic fields, acute effects (electric shock)	2	4.13	4.5.4.1/4-66
60. Electromagnetic fields, chronic effects	NA	4.0	The categorization and impact finding definitions do not apply to this issue.
61. Radiation exposures to public (license renewal term)	1	4.0	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	1	4.0	4.6.3/4-95
Socioeconomics			
63. Housing impacts	2	4.14	3.7.2/3-10 (refurbishment) 4.7.1/4-101 (renewal term)
64. Public services: public safety, social services, and tourism and recreation	1	4.0	Refurbishment 3.7.4/3-14 (public services) 3.7.4.3/3-18 (safety) 3.7.4.4/3-19 (social) 3.7.4.6/3-20 (tourism, rec.) Renewal Term 4.7.3/4-104 (public services) 4.7.3.3/4-106 (safety) 4.7.3.4/4-107 (social) 4.7.3.6/4-107 (tourism, rec.)
65. Public services: public utilities	2	4.15	3.7.4.5/3-19 (refurbishment) 4.7.3.5/4-107 (renewal term)
66. Public services: education (refurbishment)	2	NA, and discussed in Section 4.16	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.
67. Public services: education (license renewal term)	1	4.0	4.7.3.1/4-106
68. Offsite land use (refurbishment)	2	NA, and discussed in Section 4.17.1	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
69. Offsite land use (license renewal term)	2	4.17.2	4.7.4/4-107
70. Public services: transportation	2	4.18	3.7.4.2/3-17 (refurbishment) 4.7.3.2/4-106 (renewal term)
71. Historic and archaeological resources	2	4.19	3.7.7/3-23 (refurbishment) 4.7.7/4-114 (renewal term)
72. Aesthetic impacts (refurbishment)	1	NA	Issue applies to an activity, refurbishment, that CGS has no plans to undertake.
73. Aesthetic impacts (license renewal term)	1	4.0	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	1	4.0	4.5.8/4-83
Postulated Accidents			
75. Design basis accidents	1	4.0	5.3.2/5-11 (design basis) 5.5.1/5-114 (summary)
76. Severe accidents	2	4.20	5.3.3/5-12 (probabilistic analysis) 5.3.3.2/5-19 (air dose) 5.3.3.3/5-49 (water) 5.3.3.4/5-65 (groundwater) 5.3.3.5/5-96 (economic) 5.4/5-106 (mitigation) 5.5.2/5-114 (summary)
Uranium Fuel Cycle and Waste Management			
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4.0	6.2/6-8
78. Offsite radiological impacts (collective effects)	1	4.0	Not in GEIS.
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4.0	Not in GEIS.
80. Nonradiological impacts of the uranium fuel cycle	1	4.0	6.2.2.6/6-20 (land use) 6.2.2.7/6-20 (water use) 6.2.2.8/6-21 (fossil fuel) 6.2.2.9/6-21 (chemical)
81. Low-level waste storage and disposal	1	4.0	6.4.2/6-36 (low-level definition) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)
82. Mixed waste storage and disposal	1	4.0	6.4.5/6-63

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
83. Onsite spent fuel	1	4.0	6.4.6/6-70
84. Nonradiological waste	1	4.0	6.5/6-86
85. Transportation	1	4.0	6.3/6-31, as revised by Addendum 1, August 1999.
Decommissioning			
86. Radiation doses (decommissioning)	1	4.0	7.3.1/7-15
87. Waste management (decommissioning)	1	4.0	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88. Air quality (decommissioning)	1	4.0	7.3.3/7-21 (air) 7.4/7-25 (conclusion)
89. Water quality (decommissioning)	1	4.0	7.3.4/7-21 (water) 7.4/7-25 (conclusion)
90. Ecological resources (decommissioning)	1	4.0	7.3.5/7-21 (ecological) 7.4/7-25 (conclusion)
91. Socioeconomic impacts (decommissioning)	1	4.0	7.3.7/7-24 (socioeconomic) 7.4/7-25 (conclusion)
Environmental Justice			
92. Environmental justice	NA	2.6.2 and 4.21	The categorization and impact finding definitions do not apply to this issue.

Notes:

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

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

NEPA = National Environmental Policy Act.
NA = Not Applicable

ATTACHMENT B

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM PERMIT

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GI2-06-090

STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL
PO Box 43172 • Olympia, Washington 98504-3172

May 26, 2006

Mr. J.V. Parrish
Chief Executive Officer
Energy Northwest
P.O. Box 968 (MD: 1023)
Richland, Washington 99352-0968

Subject: **Reissuance of Columbia Generating Station's NPDES Permit**

Dear Mr. Parrish:

During its regular meeting of May 9, 2006, the Energy Facility Site Evaluation Council (Council) approved reissuance of the National Pollutant Discharge Elimination System (NPDES) wastewater discharge permit for Energy Northwest's Columbia Generating Station. The Council's decision to reissue the NPDES permit, effective through May 25, 2011, allows the Columbia Generating Station to discharge non-process wastewaters and storm water associated with nuclear-fueled steam electric power generation to the Columbia River and to ground water, in accordance with the approved permit conditions.

Enclosed for your records is the final NPDES permit for the Columbia Generating Station, along with the responses to written comments (Appendix E to Fact Sheet). If you have any questions, please contact me at (360) 956-2151.

Sincerely,

Mike Mills
Compliance Manager

Enclosures

cc: Doug Coleman, ENW
Mot Hedges, ENW

(360) 956-2121 *Telefax (360) 956-2158*

STATE OF WASHINGTON

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM
(NPDES)
WASTEWATER DISCHARGE PERMIT

For The

COLUMBIA GENERATING STATION

Issued By The

ENERGY FACILITY SITE EVALUATION COUNCIL

Effective Date: July 1, 2006

NPDES Permit No. WA-002515-1 Page 1 of 33

Issuance Date: May 25, 2006
Effective Date: July 1, 2006
Expiration Date: May 25, 2011

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM WASTE DISCHARGE PERMIT No. WA-002515-1

For

ENERGY NORTHWEST'S
COLUMBIA GENERATING STATION
PO Box 968
Richland, Washington 99352-0968

Issued by

State of Washington
ENERGY FACILITY SITE EVALUATION COUNCIL
Olympia, Washington 98504-3172

In compliance with the provisions of
The State of Washington Water Pollution Control Law
Chapter 90.48 Revised Code of Washington
Chapters 173-201A, 200, 204, 205, 216, and 220 Washington Administrative Code
and
The State of Washington Energy Siting Law
Chapter 80.50 Revised Code of Washington
Chapter 463-76 Washington Administrative Code
and
The Federal Water Pollution Control Act
(The Clean Water Act)
Title 33 United States Code, Section 1251 et seq.

COLUMBIA GENERATING STATION		
Facility Location	Receiving Water	
Hanford Reservation –	Outfall 001: Columbia River (River Mile 351.75)	
Township 11N, Range 28E, Section 5	Outfalls 002 & 003: Ground Water	
Water Body I.D. No. (Outfall 001)	Discharge Locations	
WA-CR-1030	Outfall 001	Latitude: 46° 28' 17" N
		Longitude: 119° 15' 45" W
	Outfall 002	Latitude: 46° 28' 26" N
		Longitude: 119° 19' 43" W
	Outfall 003	Latitude: 46° 28' 03" N
		Longitude: 119° 19' 48" W
Industry Type		
Steam-Electric Power Generation (SIC 4911)		

The Columbia Generating Station is authorized to discharge in accordance with the special and general conditions which follow.

Jim Luce, Chair
Energy Facility Site Evaluation Council

5/25/2006

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SUMMARY OF PERMIT REPORT SUBMITTALS

Refer to the Special and General Conditions of this permit for additional submittal requirements.

Permit Section	Submittal	Frequency	First Submittal Date
S2.A.1.b	Characterization of Blowdown for Asbestos Fibres—Outfall 001	1/permit cycle	With the application for permit renewal
S3.A.1	Discharge Monitoring Report—Outfall 001	Monthly	
S3.A.2	Discharge Monitoring Reports—Outfalls 002 and 003	Annually	
S3.E	Noncompliance Notification	As necessary	As necessary
S4.B	Reporting Bypasses	As necessary	As necessary
S5.	Application for Permit Renewal	1/permit cycle	{At least 180 days before permit expiration}
S6.C	Solid Waste Control Plan	1/permit cycle	With the application for permit renewal
S6.C	Modification to Solid Waste Plan	As necessary	As necessary
S7.	Best Management Practices Plan	1/permit cycle	With the application for permit renewal
S7.	Modification to Best Management Practices Plan	As necessary	As necessary
S8.C	Mixing Zone Plan of Study	1/permit cycle	30 days prior to start of study
S8.C and S11.A.2	Effluent Mixing Report	1/permit cycle	{two years after permit effective date}
S9.B.9	Acute Toxicity Characterization Data	4/permit cycle	60 days after each subsequent sampling event
S9.B.10	Acute Toxicity Effluent Test Results with Permit Renewal Application	1/permit cycle	With the application for permit renewal
S10.B.9	Chronic Toxicity Characterization Data	4/permit cycle	60 days after each subsequent sampling event

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Permit Section	Submittal	Frequency	First Submittal Date
S10.B.10	Chronic Toxicity Effluent Test Results with Permit Renewal Application	1/permit cycle	With the next application for permit renewal
S11.A.1	Schedule of Compliance-Outfall Evaluation	1/permit cycle	{one year after permit effective date}
S11.A.2 and S8.C	Schedule of Compliance-Effluent Mixing Study Report	1/permit cycle	{two years after permit effective date}
S11.A.3, S9. and S10.	Schedule of Compliance-WET Testing Reports	1/permit cycle	See S9 and S10
S11.B.1	Schedule of Compliance-Ground Water Quality Study Scope of Work	1/permit cycle	{one year after permit effective date}
S11.B.2	Schedule of Compliance-Ground Water Quality Study Quality Assurance Project Plan	1/permit cycle	{two years after permit effective date}
S11.B.4	Schedule of Compliance-Ground Water Quality Study Report	1/permit cycle	With the next application for permit renewal
S11.C	Schedule of Compliance-Schedule of Compliance Final Report	1/permit cycle	With the next application for permit renewal
S11.D	Schedule of Compliance-Request of Extension of the Schedule of Compliance	As necessary	As necessary
G1.	Notice of Change in Authorization	As necessary	As necessary
G4.	Permit Application for Substantive Changes to the Discharge	As necessary	As necessary
G5.	Engineering Report for Construction or Modification Activities	As necessary	As necessary
G7.	Notice of Permit Transfer	As necessary	As necessary
G20.	Reporting Anticipated Non-compliance	As necessary	As necessary
G21.	Reporting Other Information	As necessary	As necessary

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SPECIAL CONDITIONS

S1. DISCHARGE LIMITATIONS

Beginning on **{the effective date of this permit}** and lasting through **{the expiration date}**, the Permittee is authorized to discharge treated wastewater at the permitted locations subject to the following limitations:

A. General

All discharges and activities authorized by this permit shall be consistent with the terms and conditions of this permit.

The discharge of any pollutant not specifically authorized by this permit in concentrations which cause or contribute to a violation of water quality standards established under Section 307(a) of the Clean Water Act or Chapter 173-201A Washington Administrative Code (WAC) shall also be a violation of this permit and the Clean Water Act.

There shall be no discharge in wastewater of radioactive materials in excess of the limitations on radioactive effluents established by the Nuclear Regulatory Commission in the facility operating license and in 10 CFR Parts 20 and 50.

The discharge of any of the pollutants in this permit condition more frequently than, or at a level in excess of, that identified and authorized by this permit shall constitute a violation of the terms and conditions of this permit.

This permit contains a Schedule of Compliance (Special Condition S11). Data generated during this permit cycle may result in revisions of effluent limits at the next permit renewal.

B. Outfall 001 - Circulating Cooling Water Blowdown Discharges

Effluent Limitations

Discharges of condenser cleaning effluent, radioactive waste treatment system effluent, and cooling water blowdown from the circulating water system or discharge from the standby service water system, or both, at the location shown on the cover sheet, are subject to complying with the following effluent limitations:

EFFLUENT LIMITATIONS: OUTFALL 001		
Parameter	**Average Monthly[1]**	**Maximum Daily[2]**
Temperature	Not Applicable	(Note 3)
Total Residual Halogen[4]	Not Applicable	0.1 mg/L
pH, standard units[5]	Not Applicable	Between 6.5 and 9.0
Copper[6] (Dec. – Feb.)	70 µg/L	108 µg/L
Copper[6] (Mar. – Nov.)	223 µg/L	345 µg/L
Flow	5.6 MGD	9.4 MGD

[1] The average monthly effluent limitation is defined as the highest allowable average daily discharges over a calendar month, calculated as the sum of all daily discharges measured during a calendar month divided by the number of daily discharges measured during that month.
[2] The maximum daily effluent limitation is defined as the highest allowable daily discharge.
[3] The temperature of the circulating cooling water blowdown shall not exceed, at any time, the lowest temperature of the circulating cooling water, prior to the addition of makeup water, except that the temperature of the blowdown may be less than the temperature of the river.
[4] There shall be no discharge of cooling water from Outfall 001 during biofouling treatments nor until the concentration of total residual halogens is less than 0.1 mg/L for at least 15 minutes.
[5] Indicates the range of permitted values. When pH is continuously monitored, excursions as low as 5.0 or as high as 9.5 shall not be considered violations provided no single excursion exceeds 60 minutes in length and total excursions do not exceed 7 hours and 26 minutes per month.
[6] Copper limitations are for total recoverable metal.

There shall be no discharge of polychlorinated biphenyl compounds. There shall be no detectable amount of priority pollutants (listed in 40 CFR Part 423, Appendix A) in the effluent from chemicals added for cooling system maintenance.

C. Outfall 002

Discharge of storm water runoff, wastewater from potable and demineralized water production, intake air wash unit blowdown, and water from non-radioactive equipment dewatering, leakage, cleaning, and flushing, at the approximate location described on the cover sheet, shall not cause a violation of the ground water standards (Chapter 173-200 WAC). Existing and future beneficial uses of ground water shall be protected.

D. Outfall 003

Discharges of service water filter backwash, and pond sediment and water during pond cleaning, at the approximate location shown on the cover sheet, shall not cause a

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violation of the ground water standards (Chapter 173-200 WAC). Existing and future beneficial uses of ground water shall be protected.

E. Mixing Zone Descriptions

The maximum boundaries of the mixing zones for discharges from Outfall 001 are defined as follows:

The chronic mixing zone shall extend no more than 100 feet upstream, nor more than 306 feet downstream of the outfall. The chronic mixing zone shall extend no more than 175 feet to either side of the centerpoint of the outfall. The chronic dilution factor is 50.

The acute mixing zone shall extend no more than 31 feet downstream of the outfall. The acute dilution factor is calculated to be 11.

S2. MONITORING REQUIREMENTS

A. Monitoring Schedule

1. Outfall 001

a. Circulating Cooling Water Blowdown Discharges

Beginning **{on the effective date of this permit}** and lasting **{through the expiration date}**, the Permittee shall monitor the discharge of circulating cooling water blowdown at Outfall 001 as follows:

Parameter	Units	Sample Point[1]	Minimum Sampling Frequency	Sample Type
Flow	MGD	Blowdown	Continuous[2]	Meter
pH	S. U.'s	Circulating Water	Continuous[2,3]	Meter
Temperature	°C	Blowdown	Continuous[2]	Meter
Turbidity	NTU	Circulating Water or Blowdown	Monthly	Grab
Total Residual Halogen	mg/L	Circulating Water	Twice per treatment	Grab
Total Copper	µg/L	Circulating Water or Blowdown	Monthly	Grab
Total Chromium	µg/L	Circulating Water or Blowdown	Twice per year	Grab

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Parameter	Units	Sample Point[1]	Minimum Sampling Frequency	Sample Type
Total Zinc	µg/L	Circulating Water or Blowdown	Twice per year	Grab

[1] During a maintenance outage, sample point may be relocated to reflect temporary reconfiguration of the circulating water system.
[2] Continuous means uninterrupted - except for brief lengths of time for calibration, power failure, or for unanticipated equipment repair or maintenance. If monitoring equipment fails, Permittee shall implement manual monitoring and diligently pursue equipment repair/replacement.
[3] For facilities which continuously monitor and record pH values, the number of minutes the pH value was below or above the permitted range shall be recorded for each day and the total minutes for the month reported, the durations when values were above and below the permitted range shall be reported separately. The instantaneous maximum and minimum pH shall be reported monthly.

b. Characterization of Blowdown for Asbestos Fibres

The Permittee shall sample blowdown once during the permit cycle and test for asbestos fibre concentration. The sample shall be a grab sample taken when the circulating water cooling system is operating at an average number of cycles of concentration and only blowdown is being discharged. Test results shall be submitted **with the application for permit renewal**. The Council may remove this requirement if Energy Northwest presents a schedule to replace asbestos fill material in the cooling towers.

c. Standby Service Water Discharges

The Permittee shall monitor service water discharges made directly to the blowdown line according to the following schedule:

Parameter	Units	Sample Point	Minimum Sampling Frequency	Sample Type
Volume	MGD	Pond to be Discharged	Continuous[1] or Volume Estimate[2]	Meter or Estimate
pH	S. U.'s	Pond to be Discharged	Daily[3]	Grab

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Parameter	Units	Sample Point	Minimum Sampling Frequency	Sample Type
[1]Continuous means uninterrupted - except for brief lengths of time for calibration, power failure, or for unanticipated equipment repair or maintenance. If monitoring equipment fails, Permittee shall implement manual monitoring and diligently pursue equipment repair/replacement. [2]Volumes of batch releases of water for pond draining may be estimated based on level measurements. Feed-and-bleed discharges to the blowdown line shall be measured by flow meter. [3]Prior to commencement of discharges, Permittee shall verify that pH is within specified limits. Measurements shall be taken daily while discharge is in progress.				

2. Outfall 002

Two 24-hour composite samples shall be taken representative of typical facility discharge to the unlined pond. One sample shall be taken annually between March 15 – May 15 and one sample shall be taken annually between September 15 – November 15. Effluent shall be tested for:

Parameter	Test Method[1]
Chromium[2]	EPA 200.8
Lead[2]	EPA 200.8
Fluoride	EPA 300.0
Nitrate-Nitrite (as N)	EPA 300.0
Copper[2]	EPA 200.8
Nickel[2]	EPA 200.8
Iron[2]	EPA 200.8
Manganese[2]	EPA 200.8
Zinc[2]	EPA 200.8
Chloride	EPA 300.0
Sulfate	EPA 300.0
Total Dissolved Solids	SM 2540C
pH	Field Metered
Conductivity	Field Metered
[1] Methods for the Chemical Analysis of Water and Wastewater, EPA 600/4-79-020; other EPA approved methods that provide as good or better detection level may be substituted. [2] Metals as Total Recoverable.	

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Effluent quantity shall be monitored continuously and recorded each month. If flow instrumentation fails, Permittee shall estimate effluent quantities and diligently pursue equipment repair/replacement. Monitoring and analysis requirements for Outfall 002 may be modified by the Council based on the results of at least two years of monitoring data.

3. Outfall 003

Permittee shall monitor effluent to Outfall 003, a surface depression. Each pond cleaning that results in discharge of water or water/sediment slurry shall be sampled at least once. The quantity and duration of the discharge shall be recorded. Filter backwash effluent shall be sampled at a frequency of at least once every six (6) weeks of operation. Discharge frequency, duration, and quantity shall be reported. Discharge quantity may be a reasonable estimate rather than direct measurement.

Samples shall be tested as follows:

Parameter	Test Method[1]	Sample Type
Total Recoverable Lead	EPA 200.8	Grab
Dissolved Lead	EPA 200.8	Grab

[1] Other EPA approved methods that provide as good or better detection level may be substituted.

B. Sampling and Analytical Procedures

Samples and measurements taken to meet the requirements of this permit shall be representative of the volume and nature of the monitored parameters, including representative sampling of any unusual discharge or discharge condition, including bypasses, upsets, and maintenance-related conditions affecting effluent quality.

Sampling and analytical methods used to meet the monitoring requirements specified in this permit shall conform to the latest revision of the *Guidelines Establishing Test Procedures for the Analysis of Pollutants* contained in 40 CFR Part 136. All analytical methods used shall have reporting levels/practical quantitation levels at least one magnitude below the applicable water quality criteria, except for total residual halogen.

C. Flow Measurement

Appropriate flow measurement devices and methods consistent with accepted scientific practices shall be selected and used to ensure the accuracy and reliability of measurements of the quantity of monitored flows. The devices shall be installed, calibrated, and maintained to ensure that the accuracy of the measurements are consistent with the accepted industry standard for that type of device. Frequency of calibration shall be in conformance with manufacturer's recommendations and at a

minimum frequency of at least one calibration per year. Calibration records shall be maintained for at least three years and shall be made available to authorized inspectors upon request.

D. Laboratory Accreditation

All monitoring data required by the Council shall be prepared by a laboratory registered or accredited under the provisions of, *Accreditation of Environmental Laboratories*, Chapter 173-50 WAC. Flow, temperature, settleable solids, conductivity, pH, turbidity, and internal process control parameters are exempt from this requirement. Conductivity and pH shall be accredited if the laboratory must otherwise be registered or accredited.

S3. REPORTING AND RECORDKEEPING REQUIREMENTS

The Permittee shall monitor and report in accordance with the following conditions. The falsification of information submitted to the Council shall constitute a violation of the terms and conditions of this permit.

A. Reporting

1. Outfall 001

The first monitoring period begins on the effective date of the permit. Monitoring results for circulating cooling water blowdown discharges to Outfall 001 (Condition S2.A.1.a) shall be submitted monthly. Monitoring data obtained during each monitoring period shall be summarized and reported on a Discharge Monitoring Report (DMR) form approved, by the Council. DMR forms shall be submitted no later than the 15th day of the month following the completed monitoring period, unless otherwise specified in this permit. Monitoring results for service water discharges to Outfall 001 (Condition S2.A.1.c) shall be reported on the DMR for the month(s) in which they occur.

DMRs shall be submitted monthly whether or not the facility was discharging. If there was no discharge during a given month, the Permittee shall submit the form with the words "no discharge" entered in place of the monitoring results.

2. Outfalls 002 and 003

Monitoring results for discharges to Outfall 002 (Condition S2.A.2) and Outfall 003 (Condition S2.A.3) shall be compiled in an annual reports that are submitted no later than March 1 of the following year.

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All reports shall be sent to:

EFSEC PO Box 43172 Olympia, WA. 98504-3172	Department of Ecology Richland Office Attn: Columbia Generating Station Monitoring 3100 Port of Benton Blvd. Richland, WA 99354

B. Records Retention

The Permittee shall retain records of all monitoring information for a minimum of three (3) years. Such information shall include all calibration and maintenance records and all original recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit. This period of retention shall be extended during the course of any unresolved litigation regarding the discharge of pollutants by the Permittee or when requested by the Council.

C. Recording of Results

For each measurement or sample taken, the Permittee shall record the following information: (1) the date, exact place, method, and time of sampling or measurement; (2) the individual who performed the sampling or measurement; (3) the dates the analyses were performed; (4) the individual who performed the analyses; (5) the analytical techniques or methods used; and (6) the results of all analyses.

All laboratory reports providing data for organic and metal parameters shall include the following information: sampling date, sample location, date of analysis, parameter name, CAS number, analytical method/ number, method detection limit (MDL), laboratory practical quantitation limit (PQL), reporting units, and concentration detected. Analytical results from samples sent to a contract laboratory must have information on the chain of custody, the analytical method, QA/QC results, and documentation of accreditation for the parameter.

D. Additional Monitoring by the Permittee

If the Permittee monitors any pollutant more frequently than required by this permit using test procedures specified by Condition S2. of this permit, then the Permittee shall include the results of this monitoring in the calculation and reporting of the data submitted in the Permittee's DMR.

E. Twenty-four Hour Notice of Noncompliance Reporting

1. The Permittee shall report the following occurrences of noncompliance by telephone to the Council's office at (360) 956-2121, the next business day after the Permittee becomes aware of any of the following circumstances:

   a. any noncompliance that may endanger health or the environment;

b. any unanticipated bypass that exceeds any effluent limitation in the permit (See Condition S4.B., "Bypass Procedures");

c. any upset that exceeds any effluent limitation in the permit (See G.15, "Upset"); or,

d. any violation of a maximum daily or instantaneous maximum discharge limitation for any of the pollutants in Condition S1.B.

2. The Permittee shall also provide a written submission within five days of the time that the Permittee becomes aware of any event required to be reported under subpart 1, above. The written submission must contain:

a. a description of the noncompliance and its cause;

b. the period of noncompliance, including exact dates and times;

c. the estimated time noncompliance is expected to continue if it has not been corrected; and,

d. steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

3. The Council may waive the written report on a case-by-case basis if the oral report has been received within 24 hours of the noncompliance.

4. Reports must be submitted to the address provided in Condition S3.A.2.

F. Other Noncompliance Reporting.

The Permittee shall report all instances of noncompliance, not required to be reported within 24 hours, at the time that monitoring reports for S3.A ("Reporting") are submitted. The reports must contain the information listed in paragraph E above, ("Twenty-four Hour Notice of Noncompliance Reporting"). Compliance with these requirements does not relieve the Permittee from responsibility to maintain continuous compliance with the terms and conditions of this permit or the resulting liability for failure to comply.

G. Maintaining a Copy of This Permit

The Permittee shall keep a copy of this permit at the facility and make it available upon request to the Council or Department of Ecology inspectors.

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S4. OPERATION AND MAINTENANCE

A. Proper Operation and Maintenance

The Permittee shall, at all times, properly operate and maintain all facilities or systems of treatment and control (and related appurtenances) which are installed to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance also includes adequate laboratory controls and appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems, which are installed by the Permittee only when the operation is necessary to achieve compliance with the conditions of this permit.

B. Bypass Procedures

Bypass, which is the intentional diversion of waste streams from any portion of a treatment process, is prohibited, and the Council may take enforcement action against a Permittee for bypass unless one of the following circumstances (1, 2, or 3) is applicable.

1. Bypass for Essential Maintenance without the Potential to Cause Violation of Permit Limits or Conditions.

   Bypass is authorized if it is for essential maintenance and does not have the potential to cause violations of limitations or other conditions of this permit, or adversely impact public health as determined by the Council prior to the bypass. The Permittee shall submit prior notice at least ten (10) days before the date of the bypass.

2. Bypass Which is Unavoidable, Unanticipated, and Results in Noncompliance of this Permit.

   This bypass is permitted only if:

   a. Bypass is unavoidable to prevent loss of life, personal injury, or severe property damage. "Severe property damage" means substantial physical damage to property, damage to the treatment facilities which would cause them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass.

   b. There are no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, stopping production, maintenance during normal periods of equipment downtime (but not if adequate backup equipment should have been installed in the exercise of reasonable engineering judgement to prevent a bypass which occurred during normal periods of equipment downtime or preventative maintenance), or transport of untreated wastes to another treatment facility.

c. The Council is properly notified of the bypass as required in Condition S3E of this permit.

3. Bypass which is Anticipated and has the Potential to Result in Noncompliance of this Permit.

The Permittee shall notify the Council at least thirty (30) days before the planned date of bypass. The notice shall contain (1) a description of the bypass and its cause; (2) an analysis of all known alternatives which would eliminate, reduce, or mitigate the need for bypassing; (3) a cost-effectiveness analysis of alternatives including comparative resource damage assessment; (4) the minimum and maximum duration of bypass under each alternative; (5) a recommendation as to the preferred alternative for conducting the bypass; (6) the projected date of bypass initiation; (7) a statement of compliance with SEPA; (8) a request for modification of water quality standards as provided for in WAC 173-201A-110, if an exceedance of any water quality standard is anticipated; and (9) steps taken or planned to reduce, eliminate, and prevent reoccurrence of the bypass.

For probable construction bypasses, the need to bypass shall be identified as early in the planning process as possible. The analysis required above shall be considered during preparation of the engineering report or facilities plan and plans and specifications and shall be included to the extent practical. In cases where the probable need to bypass is determined early, the Permittee shall continue to analyze up to and including the construction period in an effort to minimize or eliminate the bypass.

The Council will consider the following prior to issuing an administrative order for this type bypass:

a. If the bypass is necessary to perform construction or maintenance-related activities essential to meet the requirements of this permit.

b. If there are feasible alternatives to bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, stopping production, maintenance during normal periods of equipment down time, or transport of untreated wastes to another treatment facility.

c. If the bypass is planned and scheduled to minimize adverse effects on the public and the environment.

After consideration of the above and the adverse effects of the proposed bypass and any other relevant factors, the Council will approve or deny the request. The public shall be notified and given an opportunity to comment on bypass incidents of significant duration, to the extent feasible. Approval of a request to bypass will be by administrative order issued by the Council under RCW 90.48.

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C. Duty to Mitigate

The Permittee is required to take all reasonable steps to minimize or prevent any discharge or sludge use or disposal in violation of this permit that has a reasonable likelihood of adversely affecting human health or the environment.

S5. APPLICATION FOR PERMIT RENEWAL

The Permittee shall submit an application for renewal of this permit **at least one hundred eighty (180) days prior to the expiration date**.

S6. SOLID WASTE DISPOSAL

A. Solid Waste Handling

The Permittee shall handle and dispose of all solid waste material in such a manner as to prevent its entry into state ground or surface water.

B. Leachate

The Permittee shall not allow leachate from its solid waste material to enter state waters without providing all known, available, and reasonable methods of prevention, control, and treatment (AKART), nor allow such leachate to cause violations of the state Surface Water Quality Standards, Chapter 173-201A WAC, or the state Ground Water Quality Standards, Chapter 173-200 WAC. The Permittee shall apply for a permit or permit modification as may be required for such discharges to state ground or surface waters.

C. Solid Waste Control Plan

The Permittee shall submit all proposed revisions or modifications to the Solid Waste Control Plan to the Council. The Permittee shall comply with any plan modifications. The Permittee shall submit an update of the plan **with the application for permit renewal one hundred eighty (180) days prior to the expiration date of the permit**.

S7. BEST MANAGEMENT PRACTICES PROGRAM

The "Oil and Hazardous Substances Spill Prevention, Control and Counter-Measure Plan", dated 11/12/04, submitted with the permit application, is incorporated by reference into this section as the Best Management Practices (BMP) Plan.

The Permittee shall amend the BMP Plan whenever there is a change in facility design, construction, operation or maintenance that materially affects the facility's potential for discharge of significant amounts of toxic or hazardous pollutants into waters of the state.

Proposed modifications to the BMP Plan which affect the discharger's permit obligations shall be submitted to the Council for approval. The Permittee shall comply with any plan modifications. The Permittee shall submit an update of the plan **with the application for**

permit renewal one hundred eighty (180) days prior to the expiration date of the permit.

S8. EFFLUENT MIXING STUDY

A. General Requirements

The Permittee shall determine the degree of effluent and receiving water mixing which occurs within the mixing zone (as defined in permit condition S1.E). The degree of mixing shall be determined during critical conditions, as defined in WAC 173-201A-020 Definitions-"Critical Condition," or as close to critical conditions as reasonably possible.

If the results of the mixing study, toxicity tests, and chemical analysis indicate that the concentration of any pollutant(s) exceeds or has a reasonable potential to exceed the state Water Quality Standards, Chapter 173-201A WAC, the Council may issue a regulatory order to require a reduction of pollutants or modify this permit to impose effluent limitations to meet the Water Quality Standards.

B. Assessment

The critical condition scenarios shall be established in accordance with *Guidance for Conducting Mixing Zone Analyses* (Ecology, 1996). The Permittee shall measure the dilution ratio in the field with dye using study protocols specified in the *Guidance*, section 5.0 "Conducting a Dye Study," as well as other protocols listed in subpart C. Protocols. The use of mixing models is an acceptable alternative or adjunct to a dye study if the Permittee knows, or will establish the critical ambient conditions necessary for model input with field studies; and if the diffuser is visually inspected for integrity or has been recently tested for performance by the use of tracers. The *Guidance* shall be consulted when choosing the appropriate model. The use of models is also required if critical condition scenarios that need to be examined are quite different from the set of conditions present during the dye study.

Validation (and possibly calibration) of a model may be necessary and the Permittee shall validate the model in accordance with the *Guidance* mentioned above - in particular subsection 5.2 "Quantify Dilution." The Permittee shall apply the resultant dilution ratios for acute and chronic boundaries in accordance with directions found in Ecology's *Permit Writer's Manual* (Ecology publication 92-109, most current version) - in particular Chapter VI.

The federally recommended technology-based chromium and zinc effluent guideline limits shall be assessed for compliance with the water quality standards using the revised dilution factors. Chromium in the discharge shall be characterized into trivalent and hexavalent species to allow assessment of compliance with the water quality criteria for trivalent and hexavalent chromium. In addition, the Permittee shall evaluate phosphorus, temperature and turbidity in the discharge for compliance with the water quality standards.

The Permittee shall assess the discharge for compliance with those portions of the state's Surface Water Quality Standards contained in Chapter 173-201A WAC, 2003 revision, that have been approved by the EPA.

The Permittee shall assess the discharge for compliance with the human health criteria, contained in the Federal Register, November 9, 1999.

In the event the Permittee desires water quality-based copper limits other than those determined by the effluent mixing study, the Permittee shall conduct a water effects ratio study as part of the mixing study. The Permittee shall use the procedures specified in the most recent, EPA-approved water effects ratio guidance available.

The Permittee shall use a consistent method of fixing and reporting the location of the outfall and mixing zone boundaries (i.e., triangulation off the shore, microwave navigation system, or using Loran or Global Positioning System (GPS) coordinates). The Permittee shall identify the method of fixing station location and the actual station locations in the report.

C. Reporting Requirements

A Plan of Study shall be submitted to the Council for review **thirty (30) days prior** to initiation of the effluent mixing study.

The Permittee shall submit results of the effluent mixing study in the Effluent Mixing Report, and shall submit the report to the Council for approval by **{two years after the effective date}**.

During the course of this study, if the Permittee identifies information on the background physical conditions or background concentration of chemical substances (for which there are criteria in Chapter 173-201A WAC) in the receiving water, the Permittee shall submit this information to the Council as part of the Effluent Mixing Report.

D. Protocols

The Permittee shall determine the dilution ratio using protocols outlined in the following references, approved modifications thereof, or by another method approved by the Council:

-Akar, P.J. and G.H. Jirka, *Cormix2: An Expert System for Hydrodynamic Mixing Zone Analysis of Conventional and Toxic Multiport Diffuser Discharges*, USEPA Environmental Research Laboratory, Athens, GA, Draft, July 1990.

-Baumgartner, D.J., W.E. Frick, P.J.W. Roberts, and C.A. Bodeen, *Dilution Models for Effluent Discharges*, USEPA, Pacific Ecosystems Branch, Newport, OR, 1993.

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-Doneker, R.L. and G.H. Jirka, *Cormix1: An Expert System for Hydrodynamic Mixing Zone Analysis of Conventional and Toxic Submerged Single Port Discharges*, USEPA, Environmental Research Laboratory, Athens, GA. EPA/600-3-90/012, 1990.

-Ecology, *Permit Writer's Manual*, Water Quality Program, Department of Ecology, Olympia WA 98504, July 1994, including most current addenda.

-Ecology, *Guidance for Conducting Mixing Zone Analyses*, Permit Writer's Manual, (Appendix 6.1), Water Quality Program, Department of Ecology, Olympia WA 98504, October, 1996.

-Kilpatrick, F.A., and E.D. Cobb, Measurement of Discharge Using Tracers, Chapter A16, *Techniques of Water-Resources Investigations of the USGS, Book 3, Application of Hydraulics*, USGS, U.S. Department of the Interior, Reston, VA, 1985.

-Wilson, J.F., E.D. Cobb, and F.A. Kilpatrick, Fluorometric Procedures for Dye Tracing, Chapter A12, *Techniques of Water-Resources Investigations of the USGS, Book 3, Application of Hydraulics*, USGS, U.S. Department of the Interior, Reston, VA, 1986.

S9. ACUTE TOXICITY

A. Effluent Characterization

The Permittee shall conduct acute toxicity testing on the final effluent to determine the presence and amount of acute (lethal) toxicity. The Permittee shall conduct the two acute toxicity tests listed below on each sample taken for effluent characterization.

The Permittee shall conduct effluent characterization for acute toxicity quarterly for one year. Acute toxicity testing shall follow protocols, monitoring requirements, and quality assurance/quality control procedures specified in this section, including a dilution series consisting of a minimum of five concentrations and a control. This series of dilutions shall include the acute critical effluent concentration (ACEC), which shall be determined in the Effluent Mixing Study required by Special Condition S8 of this permit. The series shall be used to estimate the concentration lethal to 50% of the organisms (LC_{50}). The Permittee shall also report percent survival in 100% effluent.

The Permittee shall begin testing shall begin **no later than January 2009**.

Acute toxicity tests shall be conducted with the following species and protocols:

1. Fathead minnow, *Pimephales promelas* (96-hour static-renewal test, method: EPA-821-R-02-012).

2. Daphnid, *Ceriodaphnia dubia*, *Daphnia pulex*, or *Daphnia magna* (48-hour static test, method: EPA-821-R-02-012). The Permittee shall choose one of the three species and use it consistently throughout effluent characterization.

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B. Sampling and Reporting Requirements

1. The Permittee shall submit all reports for effluent characterization or compliance monitoring in accordance with the most recent version of Department of Ecology Publication # WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria* in regards to format and content. Reports shall contain bench sheets and reference toxicant results for test methods. If the lab provides the toxicity test data on floppy disk for electronic entry into the Department's database, then the Permittee shall send the disk to the Department along with the test report, bench sheets, and reference toxicant results.

2. The Permittee shall conduct testing on composite samples. The Permittee shall cool composite samples taken for toxicity testing to 0 - 6 degrees Celsius while being collected and shall send samples to the lab immediately upon completion. Samples must be 0 - 6° C at receipt. The lab shall begin the toxicity testing as soon as possible but no later than 36 hours after sampling ended. The lab shall store all samples at 0 - 6° C in the dark from receipt until completion of the test.

3. All samples and test solutions for toxicity testing shall have water quality measurements as specified in Department of Ecology Publication #WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria* or most recent version thereof.

4. All toxicity tests shall meet quality assurance criteria and test conditions in the most recent versions of the EPA manual listed in subsection A. and the Department of Ecology Publication #WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria*. If the Council determines test results are invalid or anomalous, the Permittee shall repeat testing with freshly collected effluent.

5. Control water and dilution water shall meet the requirements of the EPA manual listed in subsection A or pristine natural water of sufficient quality for good control performance.

6. Final effluent samples for whole effluent toxicity testing shall be chemically dechlorinated with sodium thiosulfate just prior to test initiation. No more sodium thiosulfate shall be added than is necessary to neutralize the chlorine.

7. The Permittee may choose to conduct a full dilution series test during compliance monitoring to determine dose response. In this case, the series must have a minimum of five effluent concentrations and a control. The series of concentrations must include the ACEC.

8. The Permittee shall repeat all whole effluent toxicity tests, effluent screening tests, and rapid screening tests that involve hypothesis testing and do not comply with the acute statistical power standard of 29% as defined in WAC 173-205-020 on a fresh sample with an increased number of replicates to increase the power.

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9. The Permittee shall submit reports of individual characterization or compliance test results to the Council **within sixty (60) days after each sample date.**

10. The Permittee shall submit the **Acute Toxicity Summary Report** to the Council **with the next application for permit renewal.**

S10. CHRONIC TOXICITY

A. Effluent Characterization

The Permittee shall conduct chronic toxicity testing on the final effluent using the three chronic toxicity tests listed below on each sample taken for effluent characterization.

The Permittee shall begin testing **no later than January 2009.**

The Permittee shall conduct effluent testing for chronic toxicity quarterly for one year. The Permittee shall conduct chronic toxicity testing during effluent characterization on a series of at least five concentrations of effluent in order to determine appropriate point estimates. This series of dilutions shall include the chronic critical effluent concentration (CCEC), which shall be determined in the Effluent Mixing Study required by Special Condition S8 of this permit. This series of dilutions shall include the ACEC. The Permittee shall compare the ACEC to the control using hypothesis testing at the 0.05 level of significance as described in Appendix H, EPA/600/4-89/001.

The Permittee shall conduct chronic toxicity tests with the following three species and the most recent version of the following protocols:

Freshwater Chronic Test	Species	Method
Fathead minnow survival and growth	*Pimephales promelas*	EPA-821-R-02-013
Water flea survival and reproduction	*Ceriodaphnia dubia*	EPA-821-R-02-013
Alga	*Selenastrum capricornutum*	EPA-821-R-02-013

B. Sampling and Reporting Requirements

1. The Permittee shall submit all reports for effluent characterization or compliance monitoring in accordance with the most recent version of Department of Ecology Publication #WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria* in regards to format and content. Reports shall contain bench sheets and reference toxicant results for test methods. If the lab provides the toxicity test data on floppy disk for electronic entry into the Department's database,

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then the Permittee shall send the disk to the Department along with the test report, bench sheets, and reference toxicant results.

2. The Permittee shall conduct testing on composite samples. Composite samples taken for toxicity testing shall be cooled to 0 - 6 degrees Celsius while being collected and shall be sent to the lab immediately upon completion. Samples must be 0 - 6° C at receipt. The lab shall begin the toxicity testing as soon as possible but no later than 36 hours after sampling ended. The lab shall store all samples at 0 - 6° C in the dark from receipt until completion of the test.

3. All samples and test solutions for toxicity testing shall have water quality measurements as specified in Department of Ecology Publication #WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria* or most recent version thereof.

4. All toxicity tests shall meet quality assurance criteria and test conditions in the most recent versions of the EPA manual listed in subsection A. and the Department of Ecology Publication #WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria*. If the Council determines test results are invalid or anomalous, the Permittee shall repeat testing with freshly collected effluent.

5. Control water and dilution water shall meet the requirements of the EPA manual listed in subsection A or pristine natural water of sufficient quality for good control performance.

6. Final effluent samples for whole effluent toxicity testing shall be chemically dechlorinated with sodium thiosulfate just prior to test initiation. No more sodium thiosulfate shall be added than is necessary to neutralize the chlorine.

7. The Permittee may choose to conduct a full dilution series test during compliance monitoring to determine dose response. In this case, the series must have a minimum of five effluent concentrations and a control. The series of concentrations must include the ACEC and the CCEC.

8. The Permittee shall repeat all whole effluent toxicity tests, effluent screening tests, and rapid screening tests that involve hypothesis testing, and do not comply with the chronic statistical power standard of 39% as defined in WAC 173-205-020, on a fresh sample with an increased number of replicates to increase the power.

9. The Permittee shall submit reports of individual characterization or compliance test results shall be submitted to the Council **within sixty (60) days after each sample date.**

10. The Permittee shall submit the **Chronic Toxicity Summary Report** to the Council **with the next application for permit renewal.**

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S11. SCHEDULE OF COMPLIANCE

The Permittee shall be in compliance with the state's Surface Water Quality Standards and Ground Water Quality Standards, contained in Chapters 173-201A and 173-200 WAC, respectively, by **{the permit expiration date}**. This Schedule of Compliance requires the Permittee to submit a series of reports as specified in Parts A, B, C, and D of this permit condition. The submittals are subject to review and approval by the Council.

A. Discharge to Surface Water

1. Outfall Evaluation

   The Permittee shall inspect the exposed portion of the outfall line and diffuser to document its integrity and continued function. The Permittee shall assess the riverbed in the vicinity of the diffuser for deposition of sediments. The report shall include photographic verification. The inspection shall be conducted prior to the Effluent Mixing Study required by Special Condition S8. The Outfall Evaluation Report shall be received by the Council for review and approval by **{one year after the effective date}**.

2. Effluent Mixing Study

   The Permittee shall conduct an Effluent Mixing Study in accordance with the requirements in Special Condition S8 of this permit. The Permittee shall submit the Effluent Mixing Study Report to the Council for review and approval by **{two years after the effective date}**.

3. Whole Effluent Toxicity (WET) Testing

   The Permittee shall conduct WET Testing of the discharge in accordance with Special Conditions S9 and S10 of this permit. The Permittee shall submit WET reports to the Council for review and approval in accordance with the dates in S9.B.9 and 10 and S10.B9 and 10.

B. Discharges to Ground Water

1. Scope of Work

   The Permittee shall submit a scope of work for the ground water quality study to the Council for review and approval by **{one year after the effective date}**.

2. Quality Assurance Project Plan

   The Permittee shall submit a quality assurance project plan (QAPP) to the Council for review and approval by **{two years after the effective date}**. The Plan shall be developed in substantial accordance with *Guidelines for Preparing Quality Assurance Project Plans for Environmental Studies*, Ecology Publ. No. 01-03-003 and the appropriate sections of *Implementation Guidance for the Ground Water Quality Standards*, Ecology Publ. No. 96-02.

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3. Ground Water Quality Study

The Permittee shall conduct the ground water quality study during the third year of the permit cycle. Sampling of ground water shall be conducted upgradient and downgradient of the outfalls.

4. Ground Water Quality Study Report

The Permittee shall submit the Ground Water Quality Study Report as part of the Schedule of Compliance Final Report **{with the next application for permit renewal}**.

C. Schedule of Compliance Final Report

The Permittee shall submit a Schedule of Compliance Final Report, for review and approval, **{with the next application for permit renewal}**. The summary report shall integrate the results of the discrete tasks of the compliance schedule and, as necessary, propose numerical effluent limits or any additional measures to be taken to assure compliance with the water quality standards. In the event any of the facility's discharges are not in compliance with the applicable water quality standards, the report will contain a plan and a schedule to achieve compliance.

D. Request of Extension of the Schedule of Compliance

In the event more time is necessary to complete the tasks required in this Schedule of Compliance, the Permittee may request that the Council grant an extension. The request shall be by formal written letter and shall contain: (1) an explanation of why more time is needed, and (2) a revised schedule for completing the remaining tasks. The extension shall be granted at the Council's discretion through an administrative order or permit modification.

GENERAL CONDITIONS

G1. SIGNATORY REQUIREMENTS

All applications, reports, or information submitted to the Council shall be signed and certified.

A. All permit applications shall be signed by either a responsible corporate officer of at least the level of vice president of a corporation, a general partner of a partnership, or the proprietor of a sole proprietorship.

B. All reports required by this permit and other information requested by the Council shall be signed by a person described above or by a duly authorized representative of that person. A person is a duly authorized representative only if:

1. The authorization is made in writing by a person described above and submitted to the Department.

2. The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility, such as the position of plant manager, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters. (A duly authorized representative may thus be either a named individual or any individual occupying a named position.)

C. Changes to authorization. If an authorization under paragraph B.2 above is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph B.2 above must be submitted to the Council prior to or together with any reports, information, or applications to be signed by an authorized representative.

D. Certification. Any person signing a document under this section shall make the following certification:

> 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 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.

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G2. RIGHT OF INSPECTION AND ENTRY

The Permittee shall allow an authorized representative of the Council, upon the presentation of credentials and such other documents as may be required by law:

A. To enter upon the premises where a discharge is located or where any records must be kept under the terms and conditions of this permit.

B. To have access to and copy - at reasonable times and at reasonable cost - any records required to be kept under the terms and conditions of this permit.

C. To inspect - at reasonable times - any facilities, equipment (including monitoring and control equipment), practices, methods, or operations regulated or required under this permit.

D. To sample or monitor - at reasonable times - any substances or parameters at any location for purposes of assuring permit compliance or as otherwise authorized by the Clean Water Act.

G3. PERMIT ACTIONS

This permit may be modified, revoked and reissued, or terminated either at the request of any interested person (including the permittee) or upon the Council's initiative. However, the permit may only be modified, revoked and reissued, or terminated for the reasons specified in 40 CFR 122.62, 122.64 or WAC 173-220-150 according to the procedures of 40 CFR 124.5.

A. The following are causes for terminating this permit during its term, or for denying a permit renewal application:

1. Violation of any permit term or condition.

2. Obtaining a permit by misrepresentation or failure to disclose all relevant facts.

3. A material change in quantity or type of waste disposal.

4. A determination that the permitted activity endangers human health or the environment or contributes to water quality standards violations and can only be regulated to acceptable levels by permit modification or termination [40 CFR part 122.64(3)].

5. A change in any condition that requires either a temporary or permanent reduction or elimination of any discharge or sludge use or disposal practice controlled by the permit [40 CFR part 122.64(4)].

6. Nonpayment of fees assessed pursuant to RCW 90.48.465.

7. Failure or refusal of the permittee to allow entry as required in RCW 90.48.090.

B. The following are causes for modification but not revocation and reissuance except when the permittee requests or agrees:

1. A material change in the condition of the waters of the state.

2. New information not available at the time of permit issuance that would have justified the application of different permit conditions.

3. Material and substantial alterations or additions to the permitted facility or activities which occurred after this permit issuance.

4. Promulgation of new or amended standards or regulations having a direct bearing upon permit conditions, or requiring permit revision.

5. The Permittee has requested a modification based on other rationale meeting the criteria of 40 CFR Part 122.62.

6. The Council has determined that good cause exists for modification of a compliance schedule, and the modification will not violate statutory deadlines.

7. Incorporation of an approved local pretreatment program into a municipality's permit.

C. The following are causes for modification or alternatively revocation and reissuance:

1. Cause exists for termination for reasons listed in A1 through A7, of this section, and the Council determines that modification or revocation and reissuance is appropriate.

2. The Council has received notification of a proposed transfer of the permit. A permit may also be modified to reflect a transfer after the effective date of an automatic transfer (General Condition G8) but will not be revoked and reissued after the effective date of the transfer except upon the request of the new permittee.

G4. REPORTING PLANNED CHANGES

The Permittee shall, as soon as possible, but no later than sixty (60) days prior to the proposed changes, give notice to the Council of planned physical alterations or additions to the permitted facility, production increases, or process modification which will result in: 1) the permitted facility being determined to be a new source pursuant to 40 CFR 122.29(b); 2) a significant change in the nature or an increase in quantity of pollutants discharged; or 3) a significant change in the Permittee's sludge use or disposal practices. Following such notice, and the submittal of a new application or supplement to the existing application, along with required engineering plans and reports, this permit may be modified, or revoked and reissued pursuant to 40 CFR 122.62(a) to specify and limit any pollutants not previously limited. Until such modification is effective, any new or increased discharge in excess of permit limits or not specifically authorized by this permit constitutes a violation.

G5. PLAN REVIEW REQUIRED

Prior to constructing or modifying any wastewater control facilities, an engineering report and detailed plans and specifications shall be submitted to the Council for approval in accordance with Chapter 173-240 WAC. Engineering reports, plans, and specifications shall be submitted at least one hundred eighty (180) days prior to the planned start of construction unless a shorter time is approved by the Council. Facilities shall be constructed and operated in accordance with the approved plans.

G6. COMPLIANCE WITH OTHER LAWS AND STATUTES

Nothing in this permit shall be construed as excusing the Permittee from compliance with any applicable federal, state, or local statutes, ordinances, or regulations.

G7. TRANSFER OF THIS PERMIT

In the event of any change in control or ownership of facilities from which the authorized discharge emanate, the Permittee shall notify the succeeding owner or controller of the existence of this permit by letter, a copy of which shall be forwarded to the Council.

A. Transfers by Modification

Except as provided in paragraph B below, this permit may be transferred by the Permittee to a new owner or operator only if this permit has been modified or revoked and reissued under 40 CFR 122.62(b)(2), or a minor modification made under 40 CFR 122.63(d), to identify the new Permittee and incorporate such other requirements as may be necessary under the Clean Water Act.

B. Automatic Transfers

This permit may be automatically transferred to a new Permittee if:

1. The Permittee notifies the Council at least 30 days in advance of the proposed transfer date.
2. The notice includes a written agreement between the existing and new Permittee's containing a specific date transfer of permit responsibility, coverage, and liability between them.
3. The Council does not notify the existing Permittee and the proposed new Permittee of its intent to modify or revoke and reissue this permit. A modification under the subparagraph may also be minor modification under 40 CFR 122.63. If this notice is not received, the transfer is effective on the date specified in the written agreement.

G8. REDUCED PRODUCTION FOR COMPLIANCE

The Permittee, in order to maintain compliance with its permit, shall control production and/or all discharges upon reduction, loss, failure, or bypass of the treatment facility until

the facility is restored or an alternative method of treatment is provided. This requirement applies in the situation where, among other things, the primary source of power of the treatment facility is reduced, lost, or fails.

G9. REMOVED SUBSTANCES

Collected screenings, grit, solids, sludges, filter backwash, or other pollutants removed in the course of treatment or control of wastewaters shall not be resuspended or reintroduced to the final effluent stream for discharge to state waters.

G10. DUTY TO PROVIDE INFORMATION

The Permittee shall submit to the Council, within a reasonable time, all 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 submit to the Council upon request, copies of records required to be kept by this permit.

G11. OTHER REQUIREMENTS OF 40 CFR

All other requirements of 40 CFR 122.41 and 122.42 are incorporated in this permit by reference.

G12. ADDITIONAL MONITORING

The Council may establish specific monitoring requirements in addition to those contained in this permit by administrative order or permit modification.

G13. PAYMENT OF FEES

The Permittee shall submit payment of fees associated with this permit as assessed by the Council.

G14. PENALTIES FOR VIOLATING PERMIT CONDITIONS

Any person who is found guilty of willfully violating the terms and conditions of this permit shall be deemed guilty of a crime, and upon conviction thereof shall be punished by a fine of up to ten thousand dollars ($10,000) and costs of prosecution, or by imprisonment in the discretion of the court. Each day upon which a willful violation occurs may be deemed a separate and additional violation.

Any person who violates the terms and conditions of a waste discharge permit shall incur, in addition to any other penalty as provided by law, a civil penalty in the amount of up to ten thousand dollars ($10,000) for every such violation. Each and every such violation shall be a separate and distinct offense, and in case of a continuing violation, every day's continuance shall be deemed to be a separate and distinct violation.

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G15. UPSET

Definition – "Upset" means 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. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

An upset constitutes an affirmative defense to an action brought for noncompliance with such technology-based permit effluent limitations if the requirements of the following paragraph are met.

A Permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs or other relevant evidence that: 1) an upset occurred and that the Permittee can identify the cause(s) of the upset; 2) the permitted facility was being properly operated at the time of the upset; 3) the Permittee submitted notice of the upset as required in Condition S3.E; and 4) the Permittee complied with any remedial measures required under Condition S4.C of this permit.

In any enforcement proceedings the Permittee seeking to establish the occurrence of an upset has the burden of proof.

G16. PROPERTY RIGHTS

This permit does not convey any property rights of any sort, or any exclusive privilege.

G17. DUTY TO COMPLY

The Permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Clean Water Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or denial of a permit renewal application.

G18. TOXIC POLLUTANTS

The Permittee shall comply with effluent standards or prohibitions established under Section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that establish those standards or prohibitions, even if this permit has not yet been modified to incorporate the requirement.

G19. PENALTIES FOR TAMPERING

The Clean Water Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than two years per violation, or by both. If a conviction of a person is for a violation committed after a first conviction of such person under this

Condition, punishment shall be a fine of not more than $20,000 per day of violation, or by imprisonment of not more than four (4) years, or by both.

G20. REPORTING ANTICIPATED NON-COMPLIANCE

The Permittee shall give advance notice to the Council by submission of a new application or supplement thereto at least one hundred and eighty (180) days prior to commencement of such discharges, of any facility expansions, production increases, or other planned changes, such as process modifications, in the permitted facility or activity which may result in noncompliance with permit limits or conditions. Any maintenance of facilities, which might necessitate unavoidable interruption of operation and degradation of effluent quality, shall be scheduled during non-critical water quality periods and carried out in a manner approved by the Council.

G21. REPORTING OTHER INFORMATION

Where the Permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Council, it shall promptly submit such facts or information.

G22. COMPLIANCE SCHEDULES

Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than fourteen (14) days following each schedule date.

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ATTACHMENT C

SPECIAL-STATUS SPECIES CORRESPONDENCE

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ENERGY NORTHWEST

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April 10, 2008
GO2-08-058

Suzanne Audet, Wildlife Biologist
Upper Columbia Fish & Wildlife Office
U.S. Fish and Wildlife Service
11103 East Montgomery Drive
Spokane, WA 99206

Subject: **REQUEST FOR INFORMATION ON THREATENED OR ENDANGERED SPECIES**

Dear Ms. Audet:

Energy Northwest (EN) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Columbia Generating Station (CGS). The renewal term would be for an additional 20 years beyond the current license expiration date in 2023.

As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will also request, under Section 7 of the Endangered Species Act (16 USC 1531), an informal consultation with your office at a later date. By contacting you early in the application process, EN wishes to identify any potential issues that need to be addressed or information that your office may require to expedite the NRC consultation. We are making similar requests to the National Marine Fisheries Service, the Washington Department of Fish and Wildlife, and the Washington Department of Natural Resources.

CGS is located in Benton County, Washington in the southeastern portion of the U.S. Department of Energy's Hanford Site. The station is about 3¼ miles west of the Columbia River in Section 5 of Township 11N, Range 28E, Willamette Meridian. The latitude/longitude coordinates are 46° 28' 18" north, 119° 19' 58" west and the approximate Universal Transverse Mercator coordinates are 5,148,840 meters north, 320,930 meters east. The cooling water intake facilities are on the west bank of the river at river mile 352. The station is tied to the Bonneville Power Administration's H.J. Ashe Substation with one-half mile of high-voltage transmission lines. The site location is indicated on the enclosed USFWS map.

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Page 2

Energy Northwest has no plans to alter current CGS operations over the license renewal period. In addition, maintenance activities necessary to support license renewal would be limited to previously disturbed areas on site. License renewal at CGS would require neither the expansion of existing facilities nor additional land disturbance.

Specifically, we are requesting information on the occurrence or concerns regarding any federally-listed species or critical habitats in the site area. We plan to include a copy of this letter and a copy of your response with the license renewal application submitted to the NRC. We would greatly appreciate receiving your reply within 60 days of receipt of this letter to provide ample time to evaluate and incorporate the information into our application.

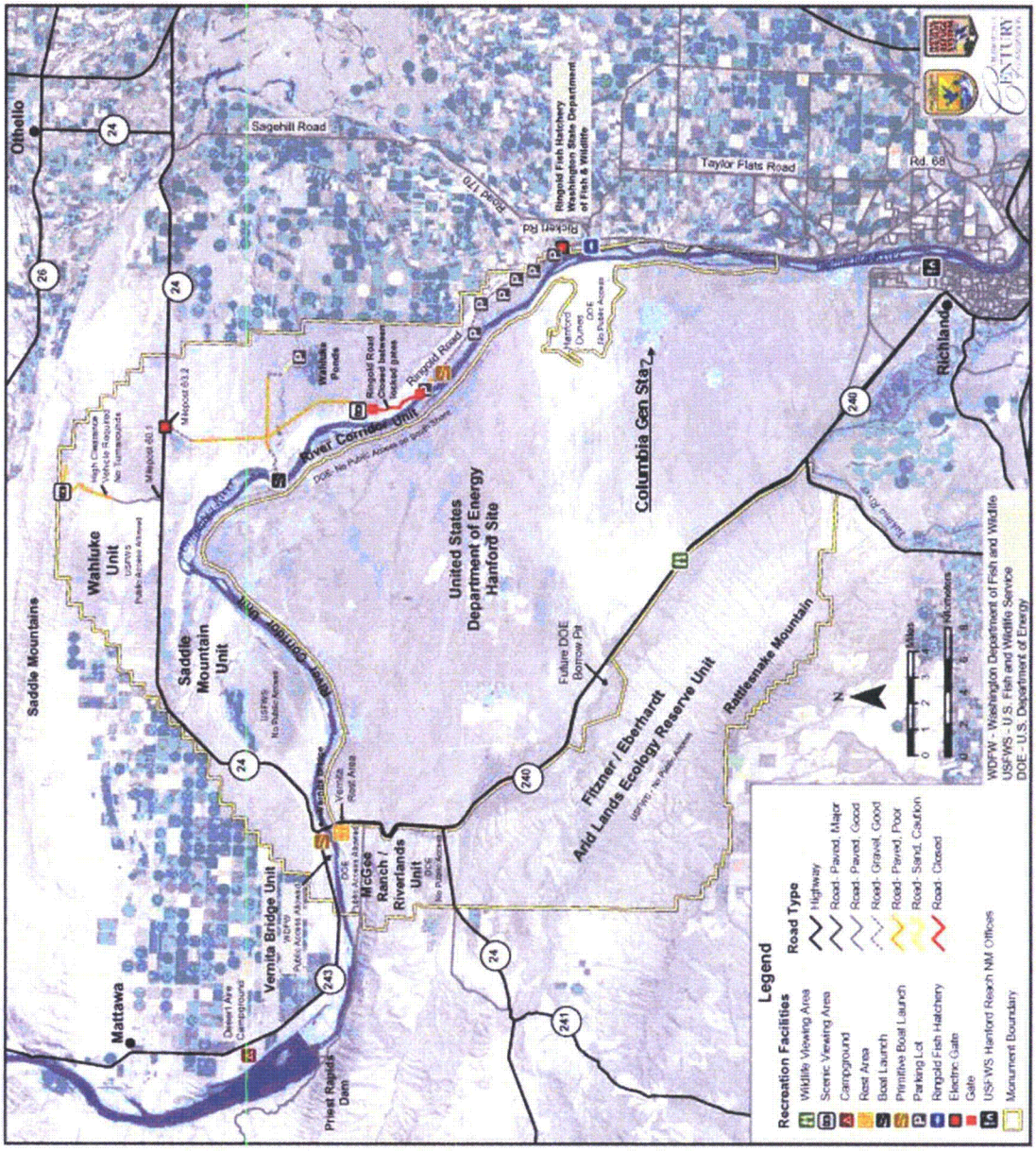
Please contact Abbas Mostala, License Renewal Project Manager, by telephone at (509) 377-4197 or e-mail at aamostala@energy-northwest.com if you have questions or require additional information concerning this request. Thank you for your assistance.

Respectfully,

Gregory V. Cullen

G.V. Cullen
Manager, Regulatory Programs

Enclosure: Location Map



Location Map - Columbia Generating Station

United States Department of the Interior

TAKE PRIDE IN AMERICA

FISH AND WILDLIFE SERVICE

RECEIVED MAY 06 2008

Upper Columbia Fish and Wildlife Office
11103 East Montgomery Drive
Spokane, WA 99206

GI2-08-069

Apr 28, 2008

Gregory V. Cullen
Energy Northwest, Regulatory Programs
P.O. Box 968, Mail Drop PE20
Richland, WA 99352-0968

Subject: Species List for the Operating License Renewal for Columbia Generating Station in Benton County, WA

Dear Mr. Cullen:

This responds to your recent request for a list of threatened and endangered species. For your convenience, updated countywide species and habitat listings are now available on our website at http://easternwashington.fws.gov. To view the listings in your area of concern, select "county species lists" within the ESA programs page, and then select the county of interest. The lists available on our website are compliant with Section 7(c) of the Endangered Species Act of 1973, as amended (Act), and are the most current available listings of endangered, threatened and proposed species and critical habitats in a given area. For optional consideration, the lists also contain updated candidate species.

When you submit a request for Section 7 consultation, we request that you include your downloaded species list and the date it was downloaded, as an attachment. If applicable, please also include the United States Fish and Wildlife Service reference number on your consultation request. This will document your compliance with 50 CFR 402.12 (c).

Should your project plans change significantly, or if the project is delayed more than 90 days, you should update your species lists through our website and through the above listed agencies.

Thank you for your efforts to protect our nation's species and their habitats. If you have any questions concerning the above information, please contact Suzanne Audet at (509) 893-8002, or via email at Suzanne_Audet@fws.gov.

Sincerely,

Suzanne Audet

for Supervisor

ENERGY NORTHWEST

Gregory V. Cullen
Regulatory Programs
P.O. Box 968, Mail Drop PE20
Richland, WA 99352-0968
Ph. 509-377-6105 F. 509-377-4317
gvcullen@energy-northwest.com

April 10, 2008
GO2-08-057

Dale Bambrick, Chief
Eastern Washington Habitat Division
National Marine Fisheries Service
304 S. Water St., Suite 201
Ellensburg, WA 98926

Subject: **REQUEST FOR INFORMATION ON THREATENED OR ENDANGERED SPECIES**

Dear Mr. Bambrick:

Energy Northwest (EN) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Columbia Generating Station (CGS). The renewal term would be for an additional 20 years beyond the current license expiration date in 2023.

As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will also request, under Section 7 of the Endangered Species Act (16 USC 1531), an informal consultation with your office at a later date. By contacting you early in the application process, EN wishes to identify any potential issues that need to be addressed or information that your office may require to expedite the NRC consultation. We are making similar requests to the U.S. Fish and Wildlife Service, the Washington Department of Fish and Wildlife, and the Washington Department of Natural Resources.

CGS is located in Benton County, Washington in the southeastern portion of the U.S. Department of Energy's Hanford Site. The station is about 3¼ miles west of the Columbia River in Section 5 of Township 11N, Range 28E, Willamette Meridian. The latitude/longitude coordinates are 46° 28' 18" north, 119° 19' 58" west and the approximate Universal Transverse Mercator coordinates are 5,148,840 meters north, 320,930 meters east. The cooling water intake facilities are on the west bank of the river at river mile 352. The station is tied to the Bonneville Power Administration's H.J. Ashe Substation with one-half mile of high-voltage transmission lines. The site location is indicated on the enclosed USFWS map.

REQUEST FOR INFORMATION
ON THREATENED OR ENDANGERED SPECIES
Page 2

Energy Northwest has no plans to alter current CGS operations over the license renewal period. In addition, maintenance activities necessary to support license renewal would be limited to previously disturbed areas on site. License renewal at CGS would require neither the expansion of existing facilities nor additional land disturbance.

Specifically, we are requesting information on the occurrence or concerns regarding any federally-listed species or critical habitats in the site area. We plan to include a copy of this letter and a copy of your response with the license renewal application submitted to the NRC. We would greatly appreciate receiving your reply within 60 days of receipt of this letter to provide ample time to evaluate and incorporate the information into our application.

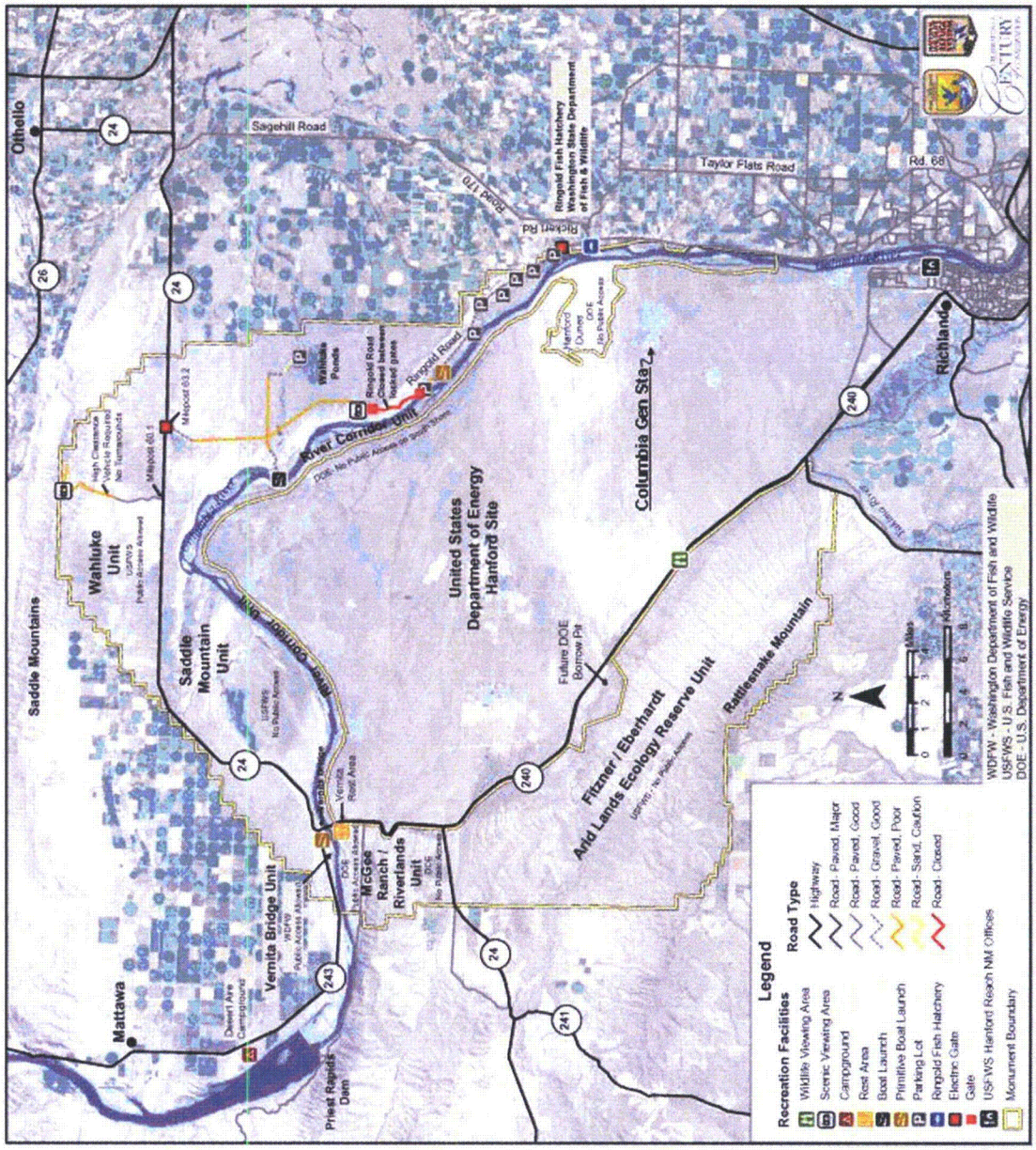
Please contact Abbas Mostala, License Renewal Project Manager, by telephone at (509) 377-4197 or e-mail at aamostala@energy-northwest.com if you have questions or require additional information concerning this request. Thank you for your assistance.

Respectfully,

Gregory V. Cullen

G.V. Cullen
Manager, Regulatory Programs

Enclosure: Location Map



Location Map - Columbia Generating Station

MOSTALA, ABBAS A.

From: Diane Driscoll [Diane.Driscoll@noaa.gov]
Sent: Monday, April 21, 2008 12:10 PM
To: MOSTALA, ABBAS A.
Cc: Diane Driscoll
Subject: ESA info

Mr. Mostala,
This email is a response to a letter our office received requesting information on the "occurrence or concerns regarding any federally-listed species or critical habitats in the site area." Because of time and workload we do not send letters of reply for information requests, this email should be considered NMFS official reply.
I am going to refer you to our website where you will find all the species and critical habitat information.
NMFS NWR homepage
Based on the map included in your letter (site is several miles upstream of the Yakima River correct?) it looks like the species of concern for you are Endangered Upper Columbia River steelhead: UCR steelhead and Endangered Upper Columbia Spring-Run Chinook: UCR Chinook . The Columbia River is critical habitat for both species. The links I have included should provide you with all the information you need, albeit with some additional digging on your part. If I was incorrect on the location of the project, please call me as areas downstream of the Yakima River will include many more species and I will need to give you additional information.

As always, if you need additional information please call me at the number below.

--
Diane Driscoll
NMFS
304 S. Water St.
Ste. 201
Ellensburg, WA 98926
1-509-962-8911 x227
Fax: 1-509-962-8544

"When I get a little money, I buy books; and if any is left, I buy food and clothes"

4/29/2008

ENERGY NORTHWEST

Gregory V. Cullen
Regulatory Programs
P.O. Box 968, Mail Drop PE20
Richland, WA 99352-0968
Ph. 509-377-6105 F. 509-377-4317
gvcullen@energy-northwest.com

April 10, 2008
GO2-08-059

Perry Harvester
Regional Habitat Program Manager
Washington Department of Fish & Wildlife
1701 S. 24th Avenue
Yakima, WA 98902

Subject: **REQUEST FOR INFORMATION ON SPECIAL STATUS SPECIES AND HABITATS**

Dear Mr. Harvester:

Energy Northwest (EN) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Columbia Generating Station (CGS). The renewal term would be for an additional 20 years beyond the current license expiration date in 2023.

As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC may also confer with your office regarding this licensing action at a later date. By contacting you early in the application process, we wish to identify any potential issues that need to be addressed or information that your office may require to expedite the NRC review. We are making similar requests to the U.S. Fish & Wildlife Service, the National Marine Fisheries Service, and the Washington Department of Natural Resources.

CGS is located in Benton County in the southeastern portion of the U.S. Department of Energy's Hanford Site. The station is about 3¼ miles west of the Columbia River in Section 5 of Township 11N, Range 28E, Willamette Meridian. The latitude/longitude coordinates are 46° 28' 18" north, 119° 19' 58" west and the approximate Universal Transverse Mercator coordinates are 5,148,840 meters north, 320,930 meters east. The cooling water intake facilities are on the west bank of the river at river mile 352. The station is tied to the Bonneville Power Administration's H.J. Ashe Substation with one-half mile of high-voltage transmission lines. The site location is indicated on the enclosed USFWS map.

REQUEST FOR INFORMATION
ON SPECIAL STATUS SPECIES AND HABITATS
Page 2

Energy Northwest has no plans to alter current CGS operations over the license renewal period. In addition, maintenance activities necessary to support license renewal would be limited to previously disturbed areas on site. License renewal at CGS would require neither the expansion of existing facilities nor additional land disturbance.

Specifically, we are requesting information on the occurrence or concerns regarding any state-listed species or critical habitats in the site area. We plan to include a copy of this letter and a copy of your response with the license renewal application submitted to the NRC. We would greatly appreciate receiving your reply within 60 days of receipt of this letter to provide ample time to evaluate and incorporate the information into our application.

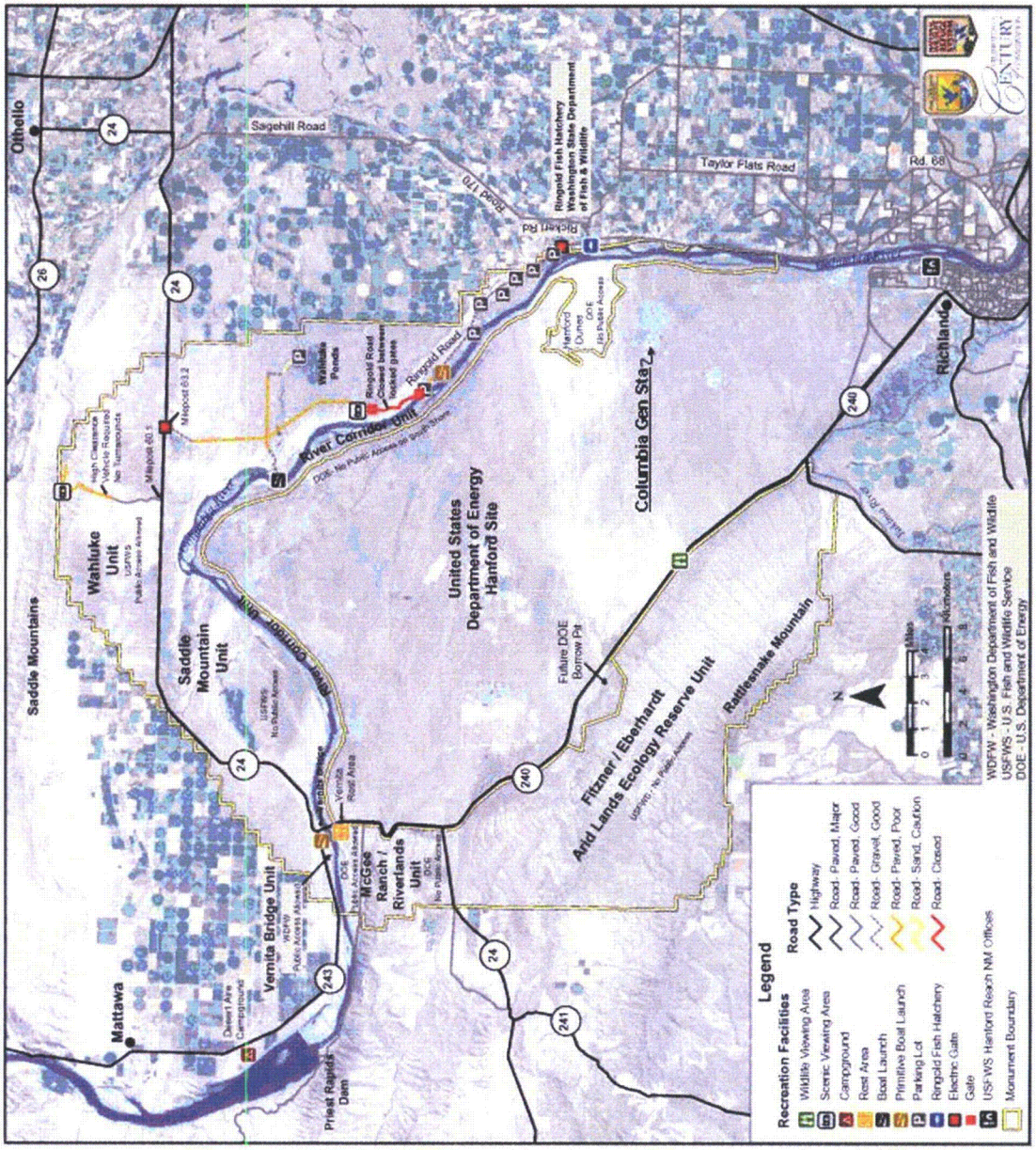
Please contact Abbas Mostala, License Renewal Project Manager, by telephone at (509) 377-4197 or e-mail at aamostala@energy-northwest.com if you have questions or require additional information concerning this request. Thank you for your assistance.

Respectfully,

Gregory V. Cullen

G.V. Cullen
Manager, Regulatory Programs

Enclosure: Location Map



Location Map - Columbia Generating Station

ENERGY NORTHWEST

Gregory V. Cullen
Regulatory Programs
P.O. Box 968, Mail Drop PE20
Richland, WA 99352-0968
Ph. 509-377-6105 F. 509-377-4317
gvcullen@energy-northwest.com

July 31, 2008
GO2-08-116

Perry Harvester
Regional Habitat Program Manager
Washington Department of Fish & Wildlife
1701 S. 24th Avenue
Yakima, WA 98902

Subject: **REQUEST FOR INFORMATION ON SPECIAL STATUS SPECIES AND HABITATS**

Reference: Letter GO2-08-059, dated April 10, 2008, G.V. Cullen (EN) to P. Harvester (WDFW), same subject

Dear Mr. Harvester:

Our referenced letter requested information relevant to the renewal of the Columbia Generating Station operating license. Subsequently, Mark Teske of your Ellensburg District Office visited the site on June 17, 2008. During the visit we indicated that we intended to expand the area encompassed by the request to include transmission lines constructed, operated, and maintained by the Bonneville Power Administration (BPA). We are adding these lines to the project "footprint" because they were included as part of the original project description.

The three transmission lines that are added to our previous description are shown on the enclosed map that depicts a large portion of the U.S. Department of Energy Hanford Site and the Columbia River between river miles 380 and 351. The primary 500-kV line is a nearly straight route between BPA's Ashe Substation and the Hanford Substation 17½ miles to the northwest. The right-of-way width is 350 ft for the first 7¼ miles out of Ashe, 230 ft for about the next 8 miles, and about 125 feet for the last 2¼ miles. It is shown as a red line on the map. Plant startup power is supplied via a 230-kV line that shares the 500-kV right-of-way for 7¼ miles and then runs north for about 2½ miles with a right-of-way width of 125 feet. This line is shown as a green line. The third line is a 115-kV back-up power source that taps off another line at a point about 1.8 miles southeast of the plant. The right-of-way width is 90 feet. It is the blue line on the map. The one-half mile segments of 230-kV and 500-kV lines between the power plant and Ashe Substation were described in the referenced letter and are also shown on the enclosed map.

REQUEST FOR INFORMATION
ON SPECIAL STATUS SPECIES AND HABITATS
Page 2

As previously discussed, Energy Northwest has no plans to alter current Columbia Generating Station operations over the license renewal period. Additionally, we have no reason to believe that continued operation would cause changes to the operation and maintenance of the BPA transmission lines.

Please contact Abbas Mostala, License Renewal Project Manager, by telephone at (509) 377-4197 or e-mail at aamostala@energy-northwest.com if you have questions or require additional information concerning this request. Thank you again for your assistance.

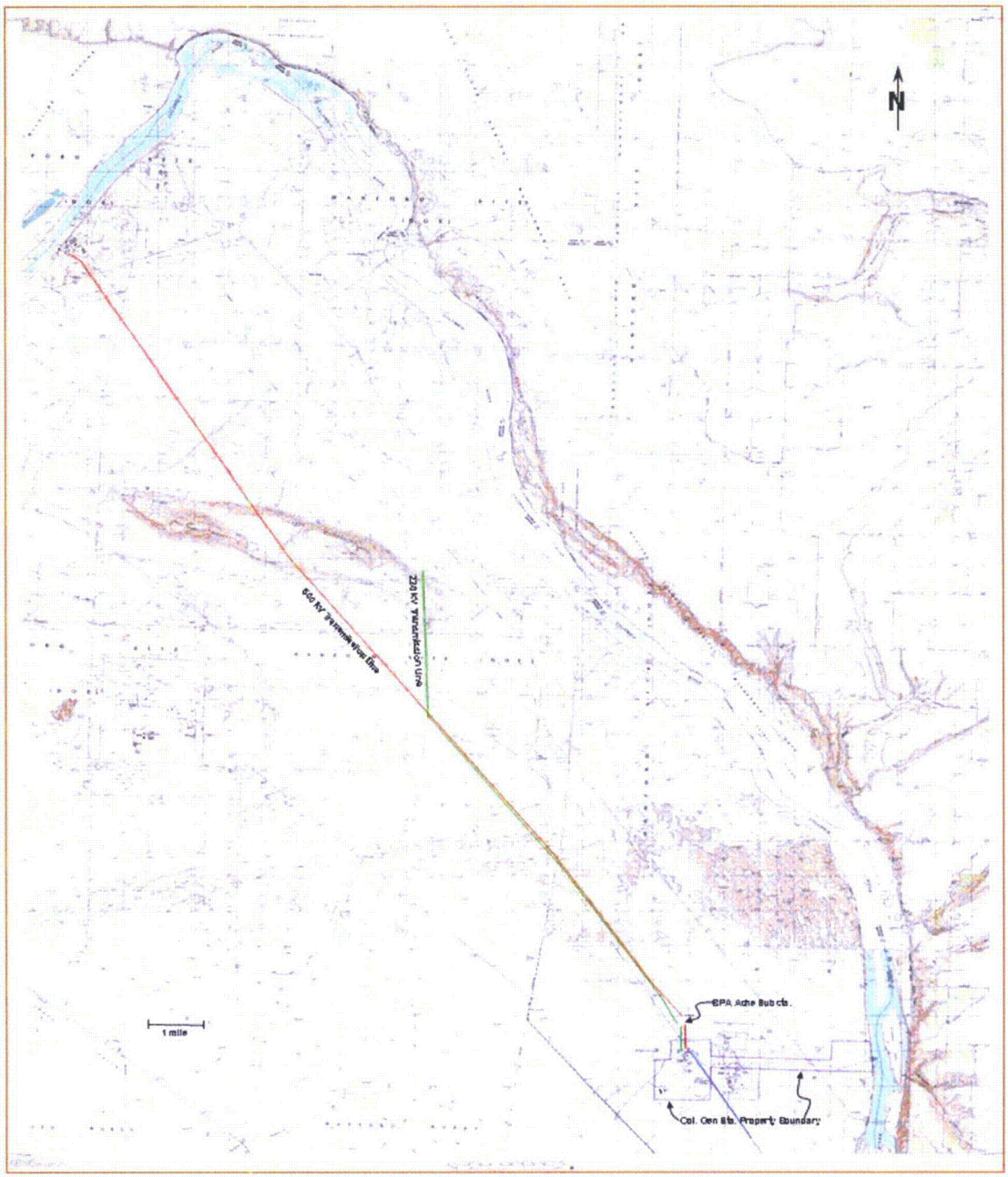
Respectfully,

Gregory V. Cullen

G.V. Cullen
Manager, Regulatory Programs

Enclosure: Property Boundary and Transmission Line Routing Map

cc: M. Teske (WDFW)



Columbia Generating Station

Property Boundary and Transmission Line Routing

ENERGY NORTHWEST

Gregory V. Cullen
Regulatory Programs
P.O. Box 968, Mail Drop PE20
Richland, WA 99352-0968
Ph. 509-377-6105 F. 509-377-4317
gvcullen@energy-northwest.com

April 10, 2008
GO2-08-056

Sandy Swope Moody
Washington Natural Heritage Program
Washington Department of Natural Resources
P.O. Box 47014
Olympia, WA 98504-7014

Subject: **REQUEST FOR INFORMATION ON RARE SPECIES AND THREATENED PLANT COMMUNITIES**

Dear Ms. Moody:

Energy Northwest is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Columbia Generating Station (CGS). The renewal term would be for an additional 20 years beyond the current license expiration date in 2023.

As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC may also confer with your office regarding this licensing action at a later date. By contacting you early in the application process, we wish to identify any potential issues that need to be addressed or information that your office may require to expedite the NRC review. We are making similar requests to the U.S. Fish & Wildlife Service, the National Marine Fisheries Service, and the Washington Department of Fish & Wildlife.

CGS is located in Benton County in the southeastern portion of the U.S. Department of Energy's Hanford Site. The station is about 3¼ miles west of the Columbia River in Section 5 of Township 11N, Range 28E, Willamette Meridian. The latitude/longitude coordinates are 46° 28' 18" north, 119° 19' 58" west and the approximate Universal Transverse Mercator coordinates are 5,148,840 meters north, 320,930 meters east. The cooling water intake facilities are on the west bank of the river at river mile 352. The station is tied to the Bonneville Power Administration's H.J. Ashe Substation with one-half mile of high-voltage transmission lines. The site location is indicated on the enclosed USFWS map.

REQUEST FOR INFORMATION
ON RARE SPECIES AND THREATENED ECOSYSTEMS
Page 2

Energy Northwest has no plans to alter current CGS operations over the license renewal period. In addition, maintenance activities necessary to support license renewal would be limited to previously disturbed areas on site. License renewal at CGS would require neither the expansion of existing facilities nor additional land disturbance.

Specifically, we are requesting information on the occurrence or concerns regarding any rare species or threatened plant communities in the site area. We plan to include a copy of this letter and a copy of your response with the license renewal application submitted to the NRC. We would greatly appreciate receiving your reply within 60 days of receipt of this letter to provide ample time to evaluate and incorporate the information into our application.

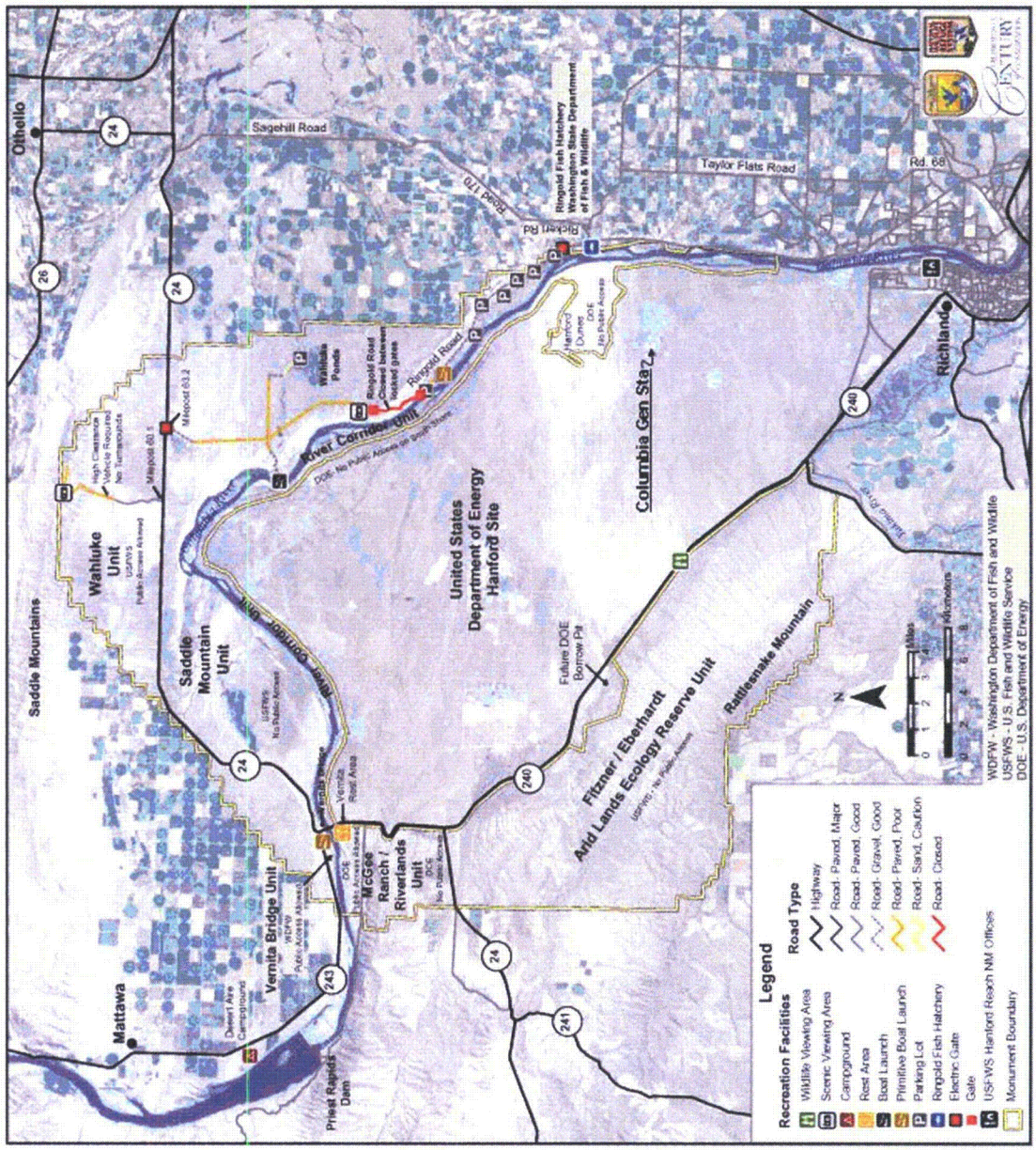
Please contact Abbas Mostala, License Renewal Project Manager, by telephone at (509) 377-4197 or e-mail at aamostala@energy-northwest.com if you have questions or require additional information concerning this request. Thank you for your assistance.

Respectfully,

Gregory V. Cullen

G.V. Cullen
Manager, Regulatory Programs

Enclosure: Location Map



Location Map - Columbia Generating Station

ENERGY NORTHWEST

Gregory V. Cullen
Regulatory Programs
P.O. Box 968, Mail Drop PE20
Richland, WA 99352-0968
Ph. 509-377-6105 F. 509-377-4317
gvcullen@energy-northwest.com

July 31, 2008
GO2-08-115

Sandy Swope Moody
Washington Natural Heritage Program
Washington Department of Natural Resources
P.O. Box 47014
Olympia, WA 98504-7014

Subject: **REQUEST FOR INFORMATION ON RARE SPECIES AND THREATENED PLANT COMMUNITIES**

Reference: Letter GO2-08-056, dated April 10, 2008, G.V. Cullen (EN) to S. Swope Moody (WDNR), same subject

Dear Ms. Moody:

Our referenced letter requested information relevant to the renewal of the Columbia Generating Station operating license. As was discussed in a May 27, 2008 phone conversation with Energy Northwest's Jim Chasse, we are expanding the area encompassed by the request to include transmission lines constructed, operated, and maintained by the Bonneville Power Administration (BPA). We are adding these lines to the project "footprint" because they were included as part of the original project description.

The three transmission lines that are added to our previous description are shown on the enclosed map that depicts a large portion of the U.S. Department of Energy Hanford Site and the Columbia River between river miles 380 and 351. The primary 500-kV line is a nearly straight route between BPA's Ashe Substation and the Hanford Substation 17½ miles to the northwest. The right-of-way width is 350 ft for the first 7¼ miles out of Ashe, 230 ft for about the next 8 miles, and about 125 feet for the last 2¼ miles. It is shown as a red line on the map. Plant startup power is supplied via a 230-kV line that shares the 500-kV right-of-way for 7¼ miles and then runs north for about 2½ miles with a right-of-way width of 125 feet. This line is shown as a green line. The third line is a 115-kV back-up power source that taps off another line at a point about 1.8 miles southeast of the plant. The right-of-way width is 90 feet. It is the blue line on the map. The one-half mile segments of 230-kV and 500-kV lines between the power plant and Ashe Substation were described in the referenced letter and are also shown on the enclosed map.

REQUEST FOR INFORMATION
ON RARE SPECIES AND THREATENED PLANT COMMUNITIES
Page 2

As previously discussed, Energy Northwest has no plans to alter current Columbia Generating Station operations over the license renewal period. Additionally, we have no reason to believe that continued operation would cause changes to the operation and maintenance of the BPA transmission lines.

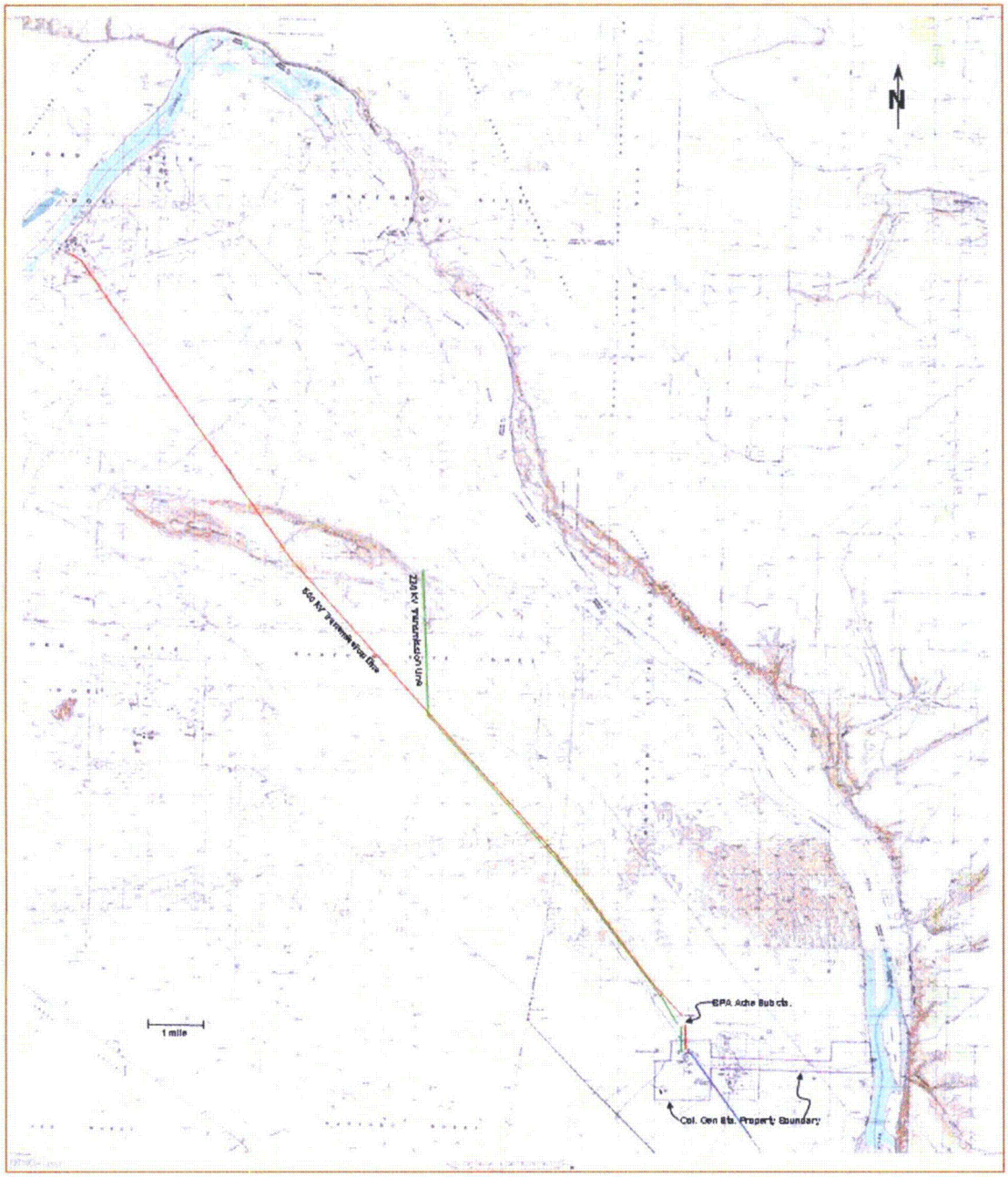
Please contact Abbas Mostala, License Renewal Project Manager, by telephone at (509) 377-4197 or e-mail at aamostala@energy-northwest.com if you have questions or require additional information concerning this request. Thank you again for your assistance.

Respectfully,

Gregory V. Cullen

G.V. Cullen
Manager, Regulatory Programs

Enclosure: Property Boundary and Transmission Line Routing Map



Columbia Generating Station

Property Boundary and Transmission Line Routing

WASHINGTON STATE DEPARTMENT OF
Natural Resources
Doug Sutherland - Commissioner of Public Lands

Caring for
your natural resources
... now and forever

September 17, 2008

GIZ-08-145

GV Cullen
Energy Northwest
PO Box 968
Mail Drop PE20
Richland WA 99352-0968

SUBJECT: Columbia Generating Station Relicensing (T11N R28E S05)

Thank you for the opportunity to review the renewal of the Columbia Generating Station operating license for information on rare plants and high quality ecosystems. We have no information on significant natural features in the area of the Columbia Generating Station.

However, there are numerous rare plant species along the transmission lines associated with this project, and in general these rare plant locations have not been revisited for 10-12 years. A revisit to check on the status of the rare plant populations would greatly help the accuracy and currency of our database. We would be happy to discuss with you alternatives to accomplish this.

Even though there are no plans to alter current operations over the license renewal period, current maintenance activities (such as road usage and maintenance, weed control, etc.) may be affecting these rare plant populations. Updated surveys of these rare plant populations, and monitoring them at intervals, would give a clearer picture of whether changes in maintenance activities are warranted.

The Washington Natural Heritage Program is responsible for information on the state's rare plants as well as high quality ecosystems. For information on animal species of concern, please contact Priority Habitats and Species, Washington Department of Fish and Wildlife, 600 Capitol Way N, Olympia WA 98501-1091, or by phone (360) 902-2543.

The information provided by the Washington Natural Heritage Program is based solely on existing information in the database. There may be significant natural features in your study area of which we are not aware. The Natural Heritage Program has no regulatory authority.

1111 WASHINGTON ST SE ▮ MS 47000 ▮ OLYMPIA, WA 98504-7000
TEL (360) 902-1000 ▮ FAX (360) 902-1775 ▮ TTY (360) 902-1125 ▮ TRS 711 ▮ **WWW.DNR.WA.GOV**
EQUAL OPPORTUNITY EMPLOYER

GV Cullen
September 17, 2008
Page 2

Please feel free to call me at (360) 902-1697, or by e-mail at sandra.moody@dnr.wa.gov, if you have any questions, or would like to discuss opportunities for revisiting rare plant populations in the project area. For more information on the Natural Heritage Program, please visit our website at http://www.dnr.wa.gov/ResearchScience/Topics/NaturalHeritage/Pages/amp_nh.aspx.

Sincerely,

Sandy Swope Moody

Sandy Swope Moody, Environmental Review Coordinator
Washington Natural Heritage Program
Asset Management & Protection Division
PO Box 47014
Olympia WA 98504-7014

ATTACHMENT D

STATE HISTORIC PRESERVATION OFFICER CORRESPONDENCE

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TABLE OF CONTENTS

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ENERGY NORTHWEST

Gregory V. Cullen
Regulatory Programs
P.O. Box 968, Mail Drop PE20
Richland, WA 99352-0968
Ph. 509-377-6105 F. 509-377-4317
gvcullen@energy-northwest.com

April 10, 2008
GO2-08-055

Allyson Brooks, PhD
State Historic Preservation Officer
Department of Archaeology & Historic Preservation
1063 South Capitol Way, Suite 106
Olympia, WA 98501

Subject: **REQUEST FOR INFORMATION ON ARCHAEOLOGICAL AND HISTORIC RESOURCES**

Dear Dr. Brooks:

Energy Northwest is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Columbia Generating Station (CGS). The renewal term would be for an additional 20 years beyond the current license expiration date in 2023.

As part of the license renewal process, the NRC requires license applicants to "assess whether any historic or archaeological properties will be affected by the proposed project" (10 CFR 51.53). The NRC may also request, under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470) and Federal Advisory Council on Historic Preservation regulations (36 CFR 800), an informal consultation with your office at a later date. By contacting you early in the application process, we hope to identify any potential issues that need to be addressed or information that your office may require to expedite the NRC consultation.

CGS is located in Benton County in the southeastern portion of the U.S. Department of Energy's Hanford Site. The station is about 3¼ miles west of the Columbia River in Section 5 of Township 11N, Range 28E, Willamette Meridian. The latitude/longitude coordinates are 46° 28' 18" north, 119° 19' 58" west and the approximate Universal Transverse Mercator coordinates are 5,148,840 meters north, 320,930 meters east. The cooling water intake facilities are on the west bank of the river at river mile 352. The station is tied to the Bonneville Power Administration's H.J. Ashe Substation with one-half mile of high-voltage transmission lines. The site location is indicated on the enclosed map.

REQUEST FOR INFORMATION
ON ARCHAEOLOGICAL AND HISTORIC RESOURCES
Page 2

Energy Northwest has no plans to alter current CGS operations over the license renewal period. In addition, maintenance activities necessary to support license renewal would be limited to previously disturbed areas on site. License renewal at CGS would require neither the expansion of existing facilities nor additional land disturbance.

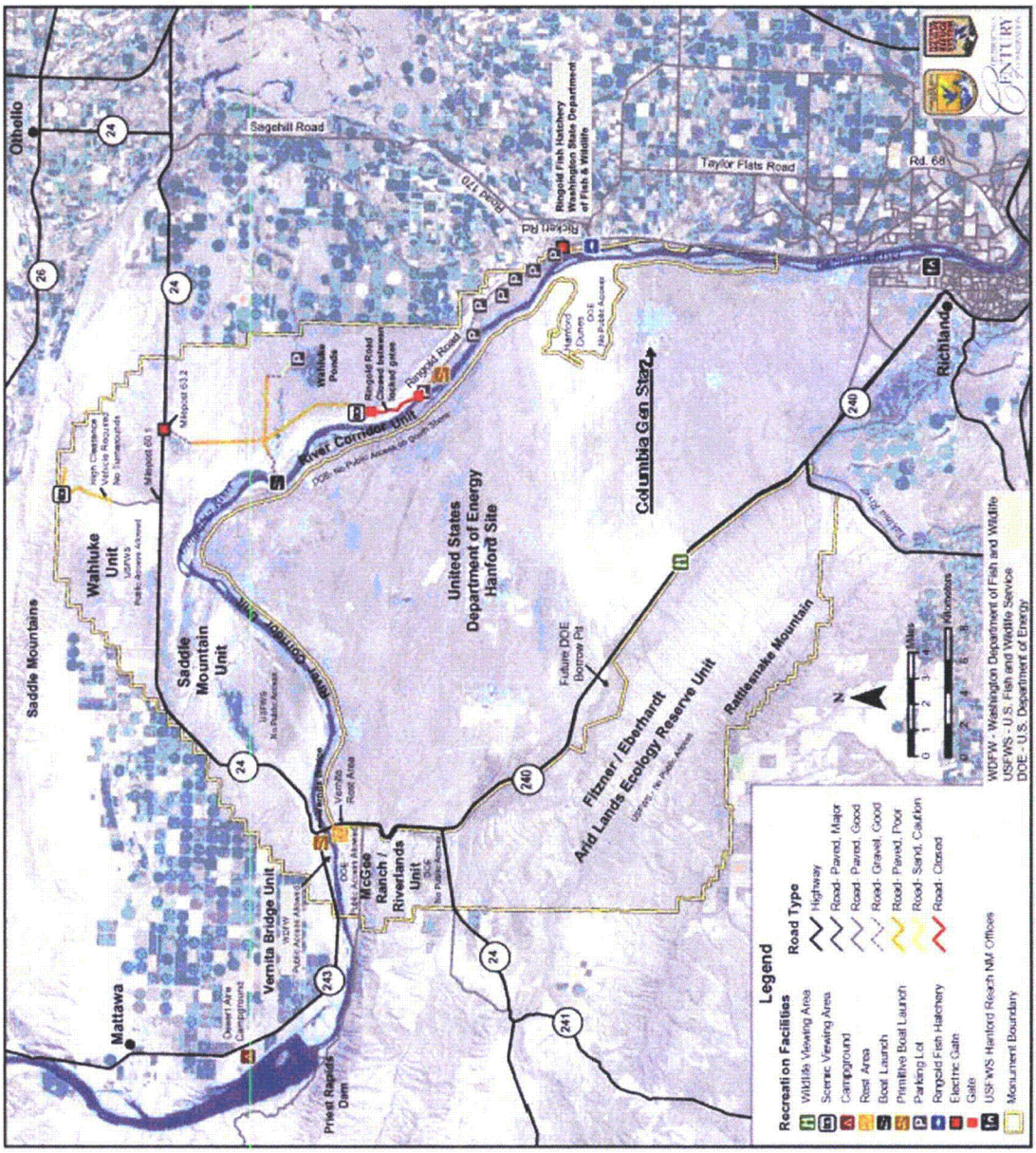
Specifically, we are requesting information on the occurrence or concerns regarding archaeological or historic resources in the site area. We plan to include a copy of this letter and a copy of your response with the license renewal application submitted to the NRC. We would greatly appreciate receiving your reply within 60 days of receipt of this letter to provide ample time to evaluate and incorporate the information into our application.

Please contact Abbas Mostala, License Renewal Project Manager, by telephone at (509) 377-4197 or e-mail at aamostala@energy-northwest.com if you have questions or require additional information concerning this request. Thank you for your assistance.

Respectfully,

G.V. Cullen
Manager, Regulatory Programs

Enclosure: Location Map



Location Map - Columbia Generating Station

GIZ-08-062

STATE OF WASHINGTON

DEPARTMENT OF ARCHAEOLOGY & HISTORIC PRESERVATION

1063 S. Capitol Way, Suite 106 • Olympia, Washington 98501
Mailing address: PO Box 48343 • Olympia, Washington 98504-8343
(360) 586-3065 • Fax Number (360) 586-3067 • Website: www.dahp.wa.gov

April 21, 2008

Mr. Gregory V. Cullen
Energy Northwest
PO Box 968, MS- PE20
Richland, Washington 99352-0968

Re: Columbia Generating Station Project
Log No.: 121007-20-NRC

Dear Mr. Cullen:

Thank you fro contacting our Department. We have reviewed the materials you provided for the proposed Columbia Generating Station Project License at the Hanford Site, Benton County, Washington.

Please provide us your proposed description of the Area of Potential Effect (APE) that conforms with 36CFR 800.16 and 8000.4. We look forward receiving the requested materials illustrating the actual project footprint and the areas subject to planning purposes for response and associated mitigation or treatment.

We would also appreciate receiving any correspondence or comments from concerned tribes or other parties that you receive as you consult under the requirements of 36CFR800.4(a)(4).

These comments are based on the information available at the time of this review and on behalf of the State Historic Preservation Officer in compliance with the Section 106 of the National Historic Preservation Act, as amended, and its implementing regulations 36CFR800.4. Should additional information become available, our assessment may be revised, including information regarding historic properties that have not yet been identified. Thank you for the opportunity to comment and we look forward to receiving the reports on the results of your investigations.

Sincerely,

Robert G. Whitlam, Ph.D.
State Archaeologist
(360)586-3080
email: rob.whitlam@dahp.wa.gov

DEPARTMENT OF ARCHAEOLOGY & HISTORIC PRESERVATION
Protect the Past, Shape the Future

ENERGY NORTHWEST

Gregory V. Cullen
Regulatory Programs
P.O. Box 968, Mail Drop PE20
Richland, WA 99352-0968
Ph. 509-377-6105 F. 509-377-4317
gvcullen@energy-northwest.com

May 8, 2008
GO2-08-072

Robert G. Whitlam, PhD
State Archaeologist
Department of Archaeology & Historic Preservation
P.O. Box 48343
Olympia, WA 98504-8343

Subject: **REQUEST FOR INFORMATION ON ARCHAEOLOGICAL AND HISTORIC RESOURCES**

References:
1. Letter dated April 10, 2008, G.V. Cullen (EN) to A. Brooks (DAHS), same subject
2. Letter dated April 21, 2008, R.G. Whitlam (DAHS) to G.V. Cullen (EN) re: Log No. 121007-20-NRC

Dear Dr. Whitlam:

Thank you for the quick response (Reference 2) to our request for information relevant to the possible renewal of the Columbia Generating Station (CGS) operating license. Although the site location was described in some detail in our letter (Reference 1), I can appreciate that the map we provided was not very useful for discerning the project footprint. Hopefully, the attached property map will provide the requested detail. I have also included a vertical photo showing the location of CGS relative to other features in the site area.

As stated previously, our intent is to seek renewal of the current plant operating license. We have no plans to modify the plant or the supporting facilities to accommodate extended operation. To assist in the preparation of the application to be submitted to the U.S. Nuclear Regulatory Commission (NRC), we are requesting information on the occurrence or concerns regarding archaeological or historic resources in the site area. The Department of Archaeology and Historic Preservation can reasonably expect to be approached by the NRC at a later date during the environmental review process.

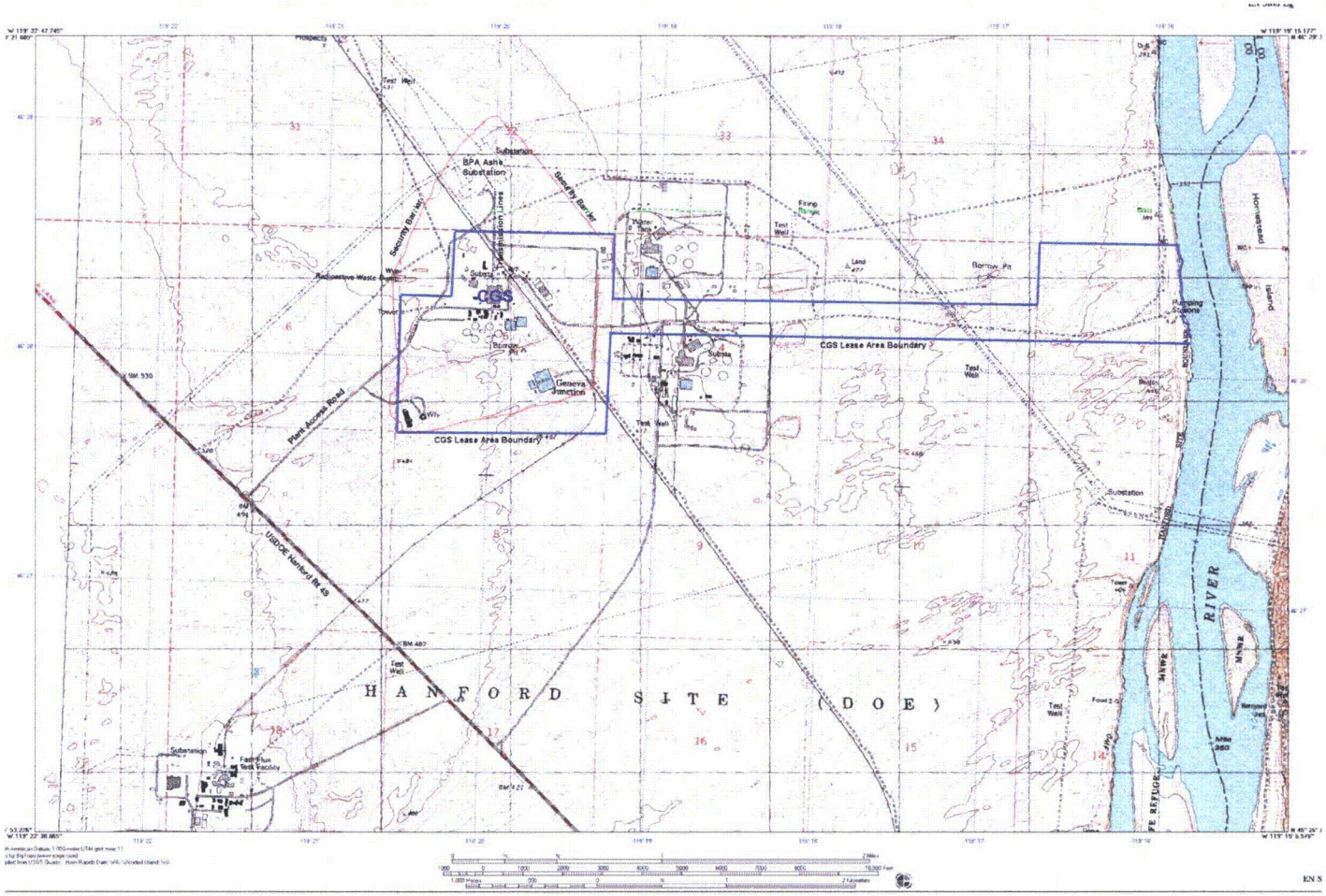
Please contact Abbas Mostala, License Renewal Project Manager, by telephone at (509) 377-4197 or e-mail at aamostala@energy-northwest.com if you require additional information. Thank you again for the assistance.

Respectfully,

Gregory V. Cullen

G.V. Cullen
Manager, Regulatory Programs

Enclosures: Vertical Photo and CGS Site Property Map



Columbia Generating Station – Site Property Map

Columbia Generating Station – Location

STATE OF WASHINGTON GIZ-08-083

DEPARTMENT OF ARCHAEOLOGY & HISTORIC PRESERVATION

1063 S. Capitol Way, Suite 106 • Olympia, Washington 98501
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(360) 586-3065 • Fax Number (360) 586-3067 • Website: www.dahp.wa.gov

May 21, 2008

Mr. G. V. Cullen
Energy Northwest
PO Box 968, MD: PE20
Richland, Washington 99352-0968

Re: Columbia Generating Station License
Log No.: 121007-20-NRC

Dear Mr. Cullen;

Thank you for contacting our department. We have reviewed the materials you provided for the proposed Columbia Generating Station License at the Hanford Site, Benton County, Washington.

We concur with the determination of the Area of Potential Effect (APE). We look forward to receiving the results of your review, consultations with the concerned tribes, and on-site archaeological survey.

We would also appreciate receiving any correspondence or comments from concerned tribes or other parties that you receive as you consult under the requirements of 36CFR800.4(a)(4).

These comments are based on the information available at the time of this review and on behalf of the State Historic Preservation Officer in compliance with the Section 106 of the National Historic Preservation Act, as amended, and its implementing regulations 36CFR800.4.

Should additional information become available, our assessment may be revised, including information regarding historic properties that have not yet been identified. Thank you for the opportunity to comment and we look forward to receiving the professional report on the results of your investigations.

Sincerely,

Robert G. Whitlam, Ph.D.
State Archaeologist
(360)586-3080
email: rob.whitlam@dahp.wa.gov

DEPARTMENT OF ARCHAEOLOGY & HISTORIC PRESERVATION
Protect the Past. Shape the Future

ENERGY NORTHWEST

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gvcullen@energy-northwest.com

July 31, 2008
GO2-08-114

Robert G. Whitlam, PhD
State Archaeologist
Department of Archaeology & Historic Preservation
P.O. Box 48343
Olympia, WA 98504-8343

Subject: **REQUEST FOR INFORMATION ON ARCHAEOLOGICAL AND HISTORIC RESOURCES**

References:
1. Letter GO2-08-055, dated April 10, 2008, G.V. Cullen (EN) to A. Brooks (DAHP), same subject
2. Letter dated April 21, 2008, R.G. Whitlam (DAHP) to G.V. Cullen (EN) re: Log No. 121007-20-NRC
3. Letter GO2-08-072, dated May 8, 2008, G.V. Cullen (EN) to R.G. Whitlam (DAHP), same subject

Dear Dr. Whitlam:

The referenced correspondence concerns our request for information relevant to the preparation of an application for renewal of the operating license for the Columbia Generating Station (CGS). As was discussed in a June 4, 2008 phone conversation with Energy Northwest's Jim Chasse, we are expanding the area encompassed by the request to include three transmission lines constructed, operated, and maintained by the Bonneville Power Administration (BPA). We are adding these lines to the project "footprint" because they were included as part of the original project description.

The three transmission lines that are added to our previous description are shown on the enclosed map that depicts a large portion of the U.S. Department of Energy Hanford Site and the Columbia River between river miles 380 and 351. The primary 500-kV line is a nearly straight route between BPA's Ashe Substation and the Hanford Substation 17½ miles to the northwest. The right-of-way width is 350 ft for the first 7¼ miles out of Ashe, 230 ft for about the next 8 miles, and about 125 feet for the last 2¼ miles. It is shown as a red line on the map. The second line is a 230-kV line that shares the 500-kV right-of-way for 7¼ miles and then runs north for about 2½ miles with a right-of-way width of 125 feet. This line is shown as a green line. The third line is a 115-kV back-up power source that taps off another line at a point about 1.8 miles southeast of the plant. The right-of-way width is 90 feet. It is the blue line on the map. The one-half mile segments of 230-kV and 500-kV lines between the power plant and Ashe Substation (described in the Reference 1 and shown on the site property map enclosed with Reference 3) are also shown on the enclosed map.

REQUEST FOR INFORMATION
ON ARCHAEOLOGICAL AND HISTORIC RESOURCES
Page 2

A review of the on-line database maintained by the Department of Archaeology & Historic Preservation confirms that there are no properties on the National Register of Historic Places in the immediate site area. The closest listed property is the Wooded Island Archaeological District located about two miles downstream (south) of the CGS makeup water pumphouse at Columbia River mile 352. We note that the 500-kV transmission line crosses Gable Mountain, a location listed on the Washington State register. We are also aware that pre-construction surveys of the mid-1970s noted the presence of two archaeological sites (Nos. 45BN113 and 45BN114) on the west bank of the river approximately one-quarter mile downstream from the pumphouse.

We do not expect continued operation of CGS through the 20-year license renewal period to have an adverse impact on cultural resources because we have no plans to expand the plant or the supporting facilities to accommodate extended operation. Additionally, we have no reason to believe that continued operation would result in changes to the operation and maintenance of the BPA transmission lines. These transmission lines would remain in service as part of the BPA network even if the plant operating license is not renewed.

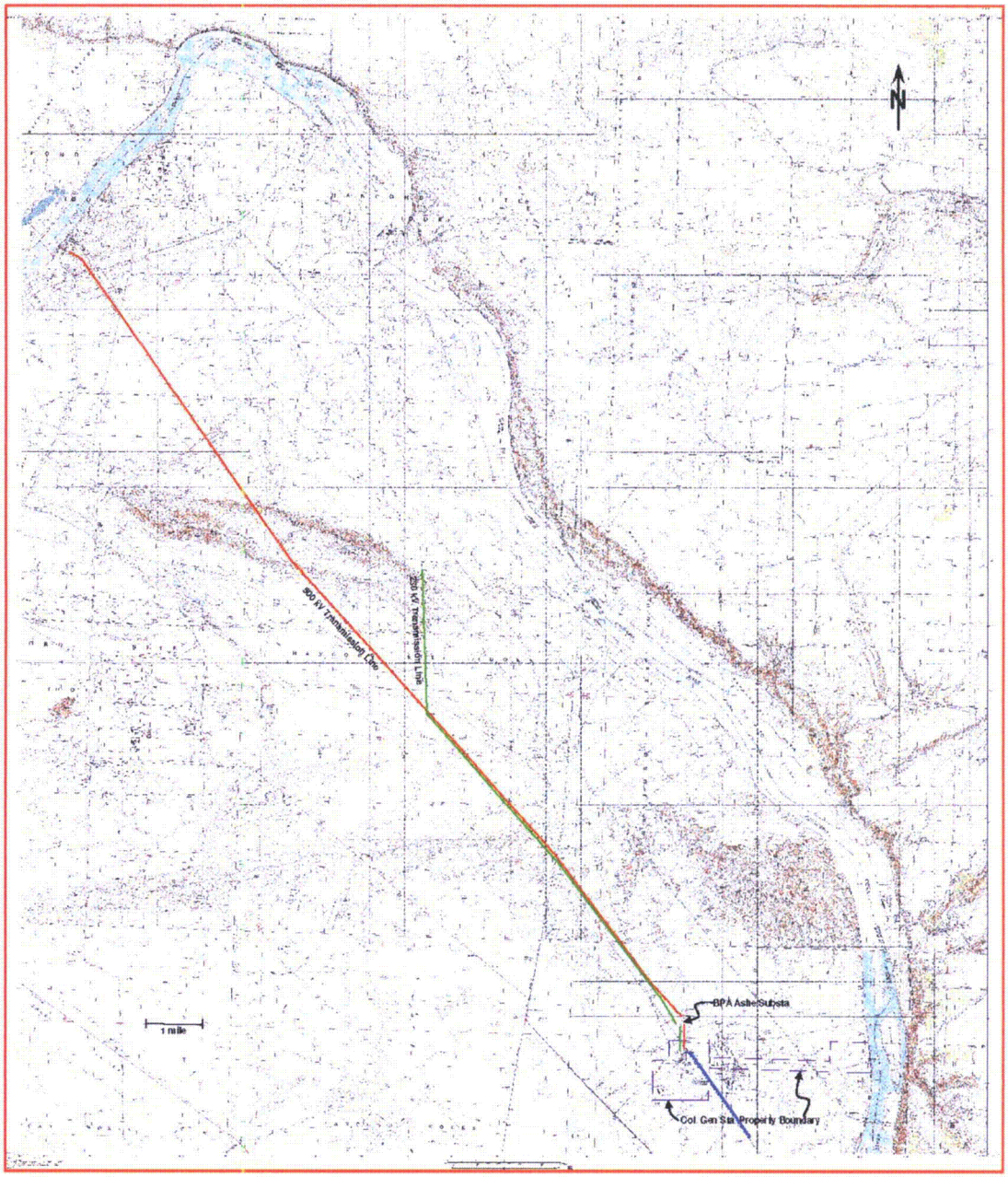
As stated in our previous letters, we would very much appreciate learning of any concerns you may have regarding our license renewal application. Please contact Abbas Mostala, License Renewal Project Manager, by telephone at (509) 377-4197 or e-mail at aamostala@energy-northwest.com if you require additional information. Thank you again for the assistance.

Respectfully,

Gregory V. Cullen

G.V. Cullen
Manager, Regulatory Programs

Enclosure: Property Boundary and Transmission Line Routing Map



Columbia Generating Station

Property Boundary and Transmission Line Routing

GI2-08-124

STATE OF WASHINGTON

DEPARTMENT OF ARCHAEOLOGY & HISTORIC PRESERVATION

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Mailing address: PO Box 48343 • Olympia, Washington 98504-8343
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August 5, 2008

Mr. G. V. Cullen
Energy Northwest
PO Box 968, MD: PE20
Richland, Washington 99352-0968

Re: Columbia Generating Station License
Log No.: 121007-20-NRC

Dear Mr. Cullen;

Thank you for contacting our department. We have reviewed the additional materials you provided for the proposed Columbia Generating Station License at the Hanford Site, Benton County, Washington.

We concur with the revised determination of the Area of Potential Effect (APE). We look forward to receiving the results of your review, consultations with the concerned tribes, and on-site archaeological survey.

We would also appreciate receiving any correspondence or comments from concerned tribes or other parties that you receive as you consult under the requirements of 36CFR800.4(a)(4).

These comments are based on the information available at the time of this review and on behalf of the State Historic Preservation Officer in compliance with the Section 106 of the National Historic Preservation Act, as amended, and its implementing regulations 36CFR800.4.

Should additional information become available, our assessment may be revised, including information regarding historic properties that have not yet been identified. Thank you for the opportunity to comment and we look forward to receiving the professional report on the results of your investigations.

Sincerely,

Robert G. Whitlam, Ph.D.
State Archaeologist
(360)586-3080
email: rob.whitlam@dahp.wa.gov

DEPARTMENT OF ARCHAEOLOGY & HISTORIC PRESERVATION
Protect the Past, Shape the Future

ATTACHMENT E

SEVERE ACCIDENT MITIGATION ALTERNATIVES ANALYSIS

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Acronyms and Abbreviations

AC	Alternating Current
ADS	Automatic Depressurization System
AMSAC	ATWS Mitigation System Actuation Circuitry
ANS	American Nuclear Society
AOC	Averted Off-site Property Damage Costs
AOE	Averted Occupational Exposure
AOSC	Averted On-site Costs
AOT	Allowed Outage Time
APE	Averted Public Exposure
ASME	American Society of Mechanical Engineers
AST	Alternative Source Term
ATWS	Anticipated Transient Without Scram
BED	Basic Event Data
BOP	Balance of Plant
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
CAS	Control Air System
CCF	Common Cause Failure
CDF	Core Damage Frequency
CET	Containment Event Trees
CGS	Columbia Generating Station
CIA	Containment Instrument Air System
CIV	Containment Isolation Valve
CRD	Control Rod Drive
CST	Condensate Storage Tank
DC	Direct Current
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
EPZ	Emergency Planning Zone
F&O	Fact and Observation

Acronyms and Abbreviations
(continued)

F-V	Fussell-Vesely
GDS	Graphics Display System
GL	Generic Letter
HCLPF	High-Confidence-Low-Probability-of-Failure
HEP	Human Error Probability
HPCS	High Pressure Core Spray
HPCI	High Pressure Coolant Injection
HPME	High Pressure Melt Ejection
HRA	Human Reliability Analysis
HVAC	Heating, Ventilation, and Air Conditioning
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination – External Events
ISLOCA	Interfacing System Loss of Coolant Accident
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-site Power
LPCI	Low Pressure Core Injection
LPCS	Low Pressure Core Spray
MAAP	Modular Accident Analysis Program
MACCS2	MELCOR Accident Consequence Code System
MCC	Motor Control Center
MFW	Main Feedwater
MOC	Mechanism Operated Cell
MSIV	Main Steam Isolation Valve
MSO	Multiple Spurious Equipment Operations
MSPI	Mitigating System Performance Indicator
NC-FTRC	Normally Closed – Fail to Remain Closed
NEI	Nuclear Energy Institute
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
OOS	Out of Service
PCPL	Primary Containment Pressure Limit

Acronyms and Abbreviations
(continued)

PCS	Power Conversion System (Main Turbine)
PDS	Plant Damage State
PFSS	Post Fire Safe Shutdown
PGA	Peak Ground Acceleration
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
PWR	Pressurized Water Reactor
RAI	Request for Additional Information
RAW	Risk Achievement Worth
rem	roentgen equivalent man
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPV	Reactor Pressure Vessel
RRW	Risk Reduction Worth
RWCU	Reactor Water Cleanup
SAG	Severe Accident Guidelines
SAMA	Severe Accident Mitigation Alternative(s)
SAMDA	Severe Accident Mitigation Design Alternative(s)
SBGT	Standby Gas Treatment
SBO	Station Blackout
SDS	Seismic Damage Accident Sequence
SER	Safety Evaluation Report
SLC	Standby Liquid Control
SORV	Stuck Open Relief Valve
SPDS	Safety Parameter and Display System
SPSA	Seismic Probabilistic Safety Assessment
SRV	Safety Relief Valve
SSE	Safe Shutdown Earthquake
SSW	Standby Service Water
TI	Temporary Instruction
TSW	Plant Service Water System

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E.1 INTRODUCTION

E.1.1 PURPOSE

The purpose of the analysis was to identify severe accident mitigation alternative (SAMA) candidates at Columbia Generating Station (CGS) that have the potential to reduce severe accident risk and to determine if implementation of each SAMA candidate is cost beneficial. The cost-benefit evaluation is required by the Nuclear Regulatory Commission (NRC) regulations governing the license renewal process.

E.1.2 REQUIREMENTS

As part of the Environment Report prepared to support CGS's License Renewal Application, Part 51 contains the requirements to perform a SAMA analysis, as noted below.

10 CFR 51.53(c)(3)(ii)(L)

The environmental report must contain a consideration of alternatives to mitigate severe accidents

> ... if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment ...

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

> ...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....

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E.2 METHODOLOGY

The SAMA analysis consisted of the following steps.

- **Determine Severe Accident Risk**

  Level 1 and 2 Probabilistic Safety Assessment (PSA) Model

  The results of the CGS Level 1 PSA and Level 2 PSA models were used as input to a Level 3 PSA analysis. The Level 2 PSA defined release categories that have been characterized using the Modular Accident Analysis Program (MAAP) computer code. Output from MAAP was used to generate input for the Level 3 PSA. In addition, the release category frequency vector from the Level 2 PSA was used as input to the SAMA analysis. CGS PSA models include contributions from internal events, fires, and seismic events.

  Level 3 PSA Model

  The results of the Level 1 PSA and the Level 2 PSA, and CGS-specific meteorological, demographic, land use, and emergency response data were used as input for a Level 3 PSA. One set of consequence results were used to estimate the maximum achievable benefit, i.e., off-site dose and economic impacts of a severe accident.

- **Determine Cost of Severe Accident Risk / Maximum Benefit**

  The NRC regulatory analysis techniques in NUREG/BR-0184 [**1**] were used to estimate the cost of severe accident risk. The maximum benefit that a SAMA could achieve if it eliminated all risk i.e., the maximum benefit, was estimated.

- **SAMA Identification**

  Potential SAMA candidates (that prevent core damage and that prevent significant releases from containment) were identified from the PSA models, Individual Plant Examination (IPE) and IPE – External Events (IPEEE) recommendations, and industry documentation. The list of potential SAMA candidates in the Boiling Water Reactor (BWR) Table 13 of NEI 05-01 (Rev. A) [**2**] was the initial list and was supplemented with insight from the CGS PSA models. As has been demonstrated by past SAMA analyses, SAMA candidates are not likely to prove cost-beneficial if they only mitigate the consequences of events that present a low risk to the plant. Therefore, risk importance analyses play a key role in the SAMA identification process.

- **Preliminary Screening (Phase I SAMA Analysis)**

  Potential SAMA candidates were screened out that were not applicable to the CGS plant design, were already implemented at CGS, were identified as having extreme cost, or were identified as having very little (risk) benefit. Some SAMA candidates were subsumed into other identified SAMA candidates. Those SAMA candidates that were not screened out were considered for further evaluation.

- **Final Screening (Phase II SAMA Analysis)**

  The benefit of severe accident risk reduction to each remaining SAMA candidate was estimated and compared to an implementation cost estimate to determine net cost-benefit. To determine the benefit, the PSA was modified to determine the delta core damage frequency (CDF) and change in the release category frequency vector. To estimate the cost of implementation, costs associated with adopting the SAMA candidate were considered; these included costs related to design, engineering, safety analysis, installation, long-term maintenance, calibrations, and training. As has been demonstrated by past SAMA analyses, cost-beneficial SAMA candidates were limited to procedure changes and minimal hardware changes.

- **Sensitivity Analysis**

  A number of assumptions and input parameters used in the Level 3 PSA and SAMA analysis were subject to a sensitivity analysis to determine the cost-benefit sensitivity.

- **Identify Conclusions**

  The results of the cost-benefit analysis were summarized. There were no potential SAMA candidates for which the cost-benefit analysis showed that the SAMA candidates were cost beneficial. However, the sensitivity analysis identified some SAMA candidates that were potentially beneficial when considered in the context of the sensitivity analysis.

E.3 CGS PSA MODEL – LEVEL 1 PSA SUMMARY

The PSA model used for the SAMA analysis was CGS PSA Revision 6.2, which includes Level 1 and Level 2 internal events, fire, and seismic risk models. The PSA Internal Events Model is Revision Number 6.2 [**3**]. The Fire [**4**] and Seismic [**5**] PSA models are based on the Internal Events Model. The failure and unavailability data were updated to reflect plant history by Bayesian update. All peer review comments have been resolved from the most recent Internal Events Level 1 and Level 2 peer review (pilot RG 1.200 trial use and ASME RA-Sa-2003) [**6**] and those significant to CGS risk evaluations have been incorporated. Issues of lower importance are scheduled for incorporation into the next PSA upgrade. The results of the 2004 peer review [**7**] were documented in Facts and Observations (F&Os) potentially impacting the Diesel Generator Completion Time Technical Specification Amendment Request (i.e., the application being reviewed by the RG 1.200 pilot project). The F&Os have all been addressed as stated in Columbia Diesel Generator Completion Time submittal to the NRC [**8**]. In response to a request for additional information (RAI) from the NRC, CGS further addressed/resolved 15 less significant F&Os [**9**]. Additionally, the Internal Events Level 1 Model has been updated to the Mitigation System Performance Indicator (MSPI) requirements. In 2006, for supporting of MSPI Project implementation, an additional 45 PSA supporting requirements and the associated F&Os have been reviewed and resolved per NEI 99-02 Appendix G requirements. The NRC inspection of the MSPI implementation is docketed under Accession Number ML070450252 and detailed in Section E.5.2 below.

Table E.3-1 provides the documentation revision number, the date of incorporation of plant changes, the date of the plant data Bayesian update, and baseline CDF or Large Early Release Frequency (LERF) for each of PSA models. Where CDF or LERF metrics are used they are given in per reactor-year units.

The cutset truncation limits for Internal Events, Fire and Seismic models used in the quantification of the CDF and LERF results are provided in Table E.3-2.

E.3.1 INTERNAL EVENT LEVEL 1 PSA SUMMARY

Table E.3-3 through Table E.3-6 provides a breakdown of the internal events CDF by major contributors. Table E.3-3 lists the core damage contribution for all initiating events and shows each initiating event contribution to the total CDF.

Table E.3-4 lists the top 24 sequences, which comprise 80% of the most important accident sequences, and identifies their contribution to the total CDF. Table E.3-5 shows the distribution of Accident Sequence Class or Plant Damage State (PDS) frequency and primary sequences contributing to each PDS.

There are six initiating events that contribute more than 5% to CDF. They are:

- Station Blackout with RCIC unavailable (SBO-R)
- Station Blackout with RCIC available (SBO-I)
- Loss of Switchgear Room Cooling (SG1HV)
- Loss of Off-site Power(T(E)N)
- Reactor Pressure Vessel Rupture (RPVR)
- Reactor Building Flood, with RHR Train A break (IE-F1)

Three of these, SBO-R, SBO-I, and T(E)N, are associated with the loss of off-site power (LOOP) and Station Blackout (SBO) initiating events and contribute about 40% of the total plant CDF. Internal flooding initiating events contribute about 15% of the total CDF. The Anticipated Transient without Scram (ATWS) initiating events contributes approximately 1.8% of the total CDF.

The top 24 sequences contributing to CDF are shown in Table E.3-4 and of these, the sequences that contribute more than 5% to total CDF (3 sequences) are shown in Table E.3-6.

E.3.1.1 Vulnerability Screening

The CGS PSA Revision 6.2 identified no new vulnerabilities in the plant design or operation. For CGS, vulnerability screening is based on:

- Sequence groups with CDF >1E-6 per reactor-year that require modifications
- Total CDF must be within the NRC's safety goal of 1E-4
- Sequences that indicate a plant specific feature as an outlier to comparable BWR PSAs

None of the sequence groups indicate a frequency that would require modification to plant hardware or procedures per the NUMARC 91-04 guidelines [**10**]. The actions that operators are required to take in response to a LOOP are contained in plant procedures, and the recommendations on insights from other sequences in the 1E-5 to 1E-6 per reactor-year range contributed to the Boiling Water Reactor Owners' Group. (BWROG) development of severe accident management guidelines. The total CDF is well within the NRC's safety goal [**11**] and provides adequate margin to accommodate the other external events contribution. Several comparable BWR PSAs have been examined, and CGS does not exhibit any plant-specific feature that could be considered an outlier. Therefore, it is concluded that CGS PSA has not identified any new vulnerabilities from the PSA Revision 6.2. Table E.3-4 shows the top 24 sequences that

contribute to the total CDF. Each sequence is composed of basic events and the importance of a basic event is proportional to the number of sequences it impacts, as well as the basic event's magnitude. By studying the characteristics of the basic event importance, it can be determined whether or not the basic event should be considered a vulnerability.

The Fussell-Vesely Importance/Risk Reduction Worth (F-V/RRW) is indicative of those basic events whose decrease in unavailability or probability of occurrence would most decrease the CDF. The risk importance measure for component level recommended by Electric Power Research Institute's (EPRI) "Final PSA Applications Guide" [**12**] is F-V > 0.005. Excluding the initiating events, the important basic events are:

- Common cause failures (CCF) of diesel generators, switchgear room cooling, or service water
- Failure to recover off-site power in a timely manner
- Operator failure to depressurize for low pressure injection
- Unavailability or failure of high pressure core spray (HPCS) and reactor core isolation cooling (RCIC), including HPCS failure at containment failure (CF-FAILS-INJECT), and HPCS diesel generator failures
- Safety relief valve failure to reclose

The Risk Achievement Worth (RAW) shows the amount CDF would be increased if the event in question was guaranteed to occur. The risk importance measure for component level recommended by EPRI's "Final PSA Applications Guide" for RAW is > 2. The basic events that satisfy both RAW > 2 and F-V > 0.005 are:

- Initiating events: Reactor Vessel Rupture, LOOP, Reactor Building Flooding Cases 6, 2, 8, E, 3, and 1, and loss of coolant accident (LOCA) Outside Containment
- Systems out of service (OOS) due to test and maintenance: HPCS, SWHPCS, SW-B and RHR-B, SW-A, RCIC, RHR-C, RHR-A, DG-1 and DG-2
- Basic events or CCF associated with switchgear and emergency core cooling system (ECCS) room cooling, breaker mechanism operated cell (MOC) switches, diesel generators, scram rods, service water filters and valves, HPCS, RCIC, ASHE substation, and main steam isolation valve (MSIVs)
- Operator actions: failure to depressurize the reactor pressure vessel (RPV), and failure to recover off-site power and on-site power, failure to establish alternate switchgear room cooling, and dependent failures of operator actions

E.3.1.2 Insights Obtained from the Importance Study

The insights obtained from the importance study are summarized as follows:

Operator Action Importance

The PSA identified the following operator actions to be particularly important to the risk significance at CGS:

- Recover on-site and off-site power following LOOP
- Initiate Automatic Depressurization System (ADS) manually during non-ATWS events
- Failure to establish alternate Switchgear Room Cooling
- Miscalibration of RCIC low pressure sensor PIS-1
- Terminate flooding events

Importance of Common Cause Failures

CCFs typically have high RRW. This is due to the process of calculation, wherein the CCF event is set to 1.0. CCFs can be very important to plant risk, but their probabilities are typically very small. The common cause component groups with high RAW ranking are:

- Switchgear room cooling fans
- Components in the Standby Service Water (SSW) System including: pumps (SW-P-1A/B), discharge check valves (SW-V-1A/B), pump discharge valves (SW-V-2A/B and V-29), return valves (SW-V-12A/B), and pump cooling water strainers (SW-ST-3A/B)
- Diesel Generators 1, 2 and 3, fuel oil transfer pumps and the output breakers for these diesels
- Battery chargers and batteries
- Components in the Residual Heat Removal (RHR) system including: RHR pumps, breaker MOC assemblies, heat exchangers, heat exchanger inlet (RHR-V- 47A/B), heat exchanger outlet (RHR-V-3A/B), heat exchanger service water outlet (RHR-V-68A/B), test line isolation (RHR-V-24A/B), minimum flow bypass (RHR-V-64A/B/C), and pump suction (RHR-V-6A/B/C)

- Calibration of reactor pressure switches (MS-PS-413A/B/C/D) for Low Pressure Core Injection (LPCI)/Low Pressure Core Spray (LPCS) injection permissive
- Closure of a pair of MSIVs in a common steam line (in response to containment isolation signal)

E.3.2 EXTERNAL EVENTS SUMMARY

The external events include internal fires, seismic, and other external events such as high wind events, external flooding, transportation, and nearby facility accidents. PSA models were employed to assess internal fires and seismic risk. However, detailed modeling of other external events has not been quantitatively employed to assess their risk at CGS. The following sections provide additional information on the Fire and Seismic PSA models.

E.3.2.1 Fire PSA Level 1

The external events evaluation for internal fires in the IPEEE was performed with PSA technology but also utilized some portions of the EPRI FIVE [**13**] methodology for systematic screening and ignition source frequency determination. The internal fire analysis began by identifying and locating all equipment critical to plant safety and tracing the supporting electrical cable.

Fire areas were identified based on work performed for compliance with Appendix R requirements. A detailed walkdown of the plant fire areas was conducted to identify areas of vulnerability, confirm fire suppression system details, and identify combustibles and ignition sources. Seismic/fire interactions were also assessed during plant walkdowns. FIVE methodology was employed to screen fire areas and to determine ignition source frequencies. The COMPBRN IIIe computer code [**14**] was utilized to determine fire growth and spread characteristics in critical fire areas. Fire initiating events in each fire area and the resulting equipment damage was combined with random equipment failure modes using the PSA model to determine CDF estimates.

The Fire PSA followed guidelines of NUREG/CR-6850 [**15**], to update the IPEEE Fire PSA. In general, the Fire PSA results dominate the risk evaluation for SAMA due to conservatisms from NUREG/CR-6850. However, they give insight into areas for improvement. The CGS Fire PSA used the following approach to quantify the fire risk.

Fire event trees for each compartment were developed incorporating extinguishment and propagation split fractions from NSAC/178L, Revision 1 [**16**], automatic suppression when applicable, and likelihood of plant trip for different compartment and loss scenarios. For these screening fire event trees, the loss scenarios were simplified into loss of the single worst equipment or cable (for example, as indicated by the RAW importance measure), or loss of all equipment and cables in the compartment.

Therefore, each compartment has a fire initiating event tree, and two conditional fire event trees for single equipment or cable or compartment losses. The conditional fire event trees are either turbine trip or loss of feedwater event trees, as appropriate for the compartment losses.

These screening fire event trees are therefore conservative, and are used for initial evaluation to identify those compartments that are not significant contributors to fire risk. They are quantified as an initial step in this overall quantification process.

In performing the fire analysis, consideration was given to all fire damage mechanisms, including smoke, loss of lighting and indication, and fire suppression system impacts on equipment. The CGS Post Fire Safe Shutdown (PFSS) evaluation and documentation considered each of these items for each compartment. However, this Fire PSA explicitly examined the human error probabilities (HEPs) used for the fire scenarios to ensure that equipment and indication losses, fire induced stress, communications difficulties, and potential impacts from smoke and heat were included.

In many fire compartment scenarios, operator actions would not be significantly impacted since the fire would not impact the control room envelope or cause significant damage to equipment or indications. The CGS fire brigade does not include any of the operating shift staff, so that sufficient operations crew would be available for necessary actions. The operators are cautioned that indications during a fire may be misleading, and are trained to crosscheck with alternate indications. There are specific procedural actions for each fire area that include considerations such as equipment losses, indication, communications, lighting, and smoke/heat impacts, Heating, Ventilation, and Air Conditioning (HVAC) actions, and smoke removal [**17**]. In the case of control room evacuation, a specific procedure (ABN-CR-EVAC) covers immediate actions, and provides detailed guidance for safe shutdown using actions, indications, and communications outside the control room. Timeline verification has been performed to document the basis for the manual actions required to support design basis fire safe shutdown, provide guidance to Operations as to the sequence and timing of actions, and verifies that sufficient personnel are available.

Each of the operator actions from the internal events PSA was examined to determine if it was relevant to the Fire PSA and if it would be impacted by the fire event. These modified human errors were included in the system fault trees using house events for the fire scenarios.

The original CGS Fire IPEEE performed and documented the fire barrier review as specified in the FIVE methodology. This evaluation demonstrated that only a few fire compartments had the potential for propagation from one compartment to another. Based on this, a detailed evaluation of potential fire propagation between compartments has not been performed for the Fire PSA. Although a detailed quantitative evaluation of fire propagation between compartments was not performed, the following qualitative

assessments demonstrated that such scenarios would likely be insignificant contributors to fire CDF.

- The CGS cable is IEEE-383 qualified and failure of a fire seal through a wall would be very unlikely to propagate due to the size of the seal, and the inability to propagate along the cable insulation through the fire seal.

- Although a room-by-room analysis of fire damper failure was not performed, it was judged that the probability of fire damper failure combined with the probability of significant equipment or cable damage would reduce potential propagation scenarios to insignificant frequency. For fire dampers in the HVAC system, small failures to close would be very unlikely to allow sufficient hot gases to flow into an adjacent compartment to cause fire propagation. Even with a complete fire damper failure, it is considered unlikely that the fire would propagate, since the flames would be confined to the originating compartment, and only hot gases and smoke would travel to the adjacent compartment. In order to cause significant damage, these hot gases would need to be released directly under an important cable run, or time would be needed to build up a significant hot gas layer, allowing time for the fire brigade to prevent fire spread.

- A detailed analysis of fire door failure was not performed based on the following judgments. The fire doors are designed and maintained to close completely. However, if a fire door is left ajar, it still performs its function to limit the spread of flames to another compartment, although some smoke and hot gases may escape. Such a failure would be unlikely to cause significant damage in the adjacent compartment. If a fire door is intentionally blocked open, then the administrative procedures require a regular fire watch. The likelihood that a specific door is inadvertently open, and that significant combustibles are near the door (in both compartments) was judged to be sufficiently low such that, combined with the large fire scenario, potential propagation leading to a severe damage scenario would be negligible. Thus, a room-by-room evaluation was not performed.

- The cable spreading room, which had originally been evaluated as three compartments, is now evaluated as one main compartment, and this evaluation considers potential fire spread through the sub-compartments.

- Several elevations in the Reactor Building are divided into quadrants based on the original Fire IPEEE. While these quadrants are retained for the Fire PSA, the interfaces between the quadrants were specifically examined to ensure that the definition of the quadrant boundaries did not impact the fire damage assessments. All scenarios with fixed combustibles near a quadrant "boundary" were checked to ensure that the potential for fire propagation was included. Since the cable is IEEE-383 qualified, horizontal fire propagation would be limited. The scenarios specifically identified potential areas where propagation

could cause additional equipment or cable damage. Walkdowns confirmed these assessments.

- Also in the Reactor Building, there are some open hatches between the elevations. These hatches have been previously evaluated in the PFSS documents and determined not to be potential propagation paths between compartments. This determination is based on considerations of the combustible types, combustible loads and locations, height of the ceilings, and large room size preventing formation of a significant hot gas layer. Therefore, propagation up through the hatches was judged not to be significant for the Fire PSA.

- There were a few compartments in the Turbine Building that did not have physical fire barriers such as walls. As with the Reactor Building quadrants, specific evaluations were performed to ensure that there was no significant mechanism for propagation that would cause a more severe fire scenario (in terms of equipment lost or cables damaged). Walkdowns were used to verify that there were no intervening combustibles that could cause propagation.

After quantification of the fire event trees, those compartments found to have an initial CDF greater than 5.0E-7/yr were analyzed in more detail to be more realistic. Typically, the approach was to identify more scenarios for each compartment, and model each scenario with its own conditional fire event tree. The method proceeded as follows for each compartment:

- The compartment loss conditional fire event tree was requantified with the compartment loss basic event data (BED) file parameters changed from logical failure (Type 6 basic event) to a demand failure (Type 3 basic event) of 1.0 for quantification. It was recognized that the CDF results would not be correct when using demand failures, but, in this way, the cutsets and importance factors could be analyzed to identify the most important equipment and cable losses.

- The dominant cutsets and fire loss basic events were reviewed, and the associated cables were traced using the cable routing database, and the Location Plan, Conduit and Tray Nodes for the compartment.

- The Conduit and Tray Node Location Plans were then marked to show the routings of critical cables and the locations of fixed ignition sources.

- Generic COMPBRN analyses were performed to develop screening distances for typical cabinets and other equipment, using the information in the EPRI Fire PSA Implementation Guide EPRI TR-105928 [**18**].

- Based on the location of the cables and equipment, and the location of the fixed ignition sources, different scenarios were developed to represent groups of potential fire losses that would not propagate to the entire compartment. In

general, the areas where compartment losses could occur were identified, and then areas with lesser losses were grouped. Often this separated into train A versus train B loss areas. In many cases, cables are only passing through from the floor below to the floor above, so the cable exposure to most fixed combustible fires is very limited.

- For each compartment, one event tree, termed the compartment fire initiating event tree, was used to divide the total compartment fire frequency into the detailed scenarios. These individual scenarios could then be quantified with the turbine trip or loss of feedwater event trees (termed conditional fire event trees), with the appropriate scenario equipment losses.

For the fire initiating event tree, split fractions were developed for each group of fixed ignition sources that defined a scenario. The split fractions are single basic events added to the fault tree.

As with the screening event trees, early extinguishment (de-energization, self-extinguishment, or manual suppression not by the fire brigade) and automatic extinguishment were considered as appropriate.

For transient fire ignition sources, the relative area of locations that could impact overhead or nearby combustibles was determined. Hot gas layer formation was considered qualitatively, and it was found to be either not credible (due to room size or ceiling height above critical cable runs) or included in scenarios involving loss of all equipment and cables in applicable compartments.

The initiators for the compartment conditional fire event trees were developed by summing the appropriate event tree sequences and correspond with the first event of the conditional fire event tree.

For each scenario, equipment losses were developed, including hot short events that could spuriously actuate components to undesired configurations. The hot short events are logical events that turn on or off the hot short basic events in the system fault trees. To identify the potential hot shorts that should be included in the Fire PSA, the internal events basic events were reviewed. Those basic events that represented failure of a valve (or damper) to remain open, or remain closed were considered susceptible to hot shorts. Hot short failures (> 120 locations) were identified and explicitly included in this fire evaluation. These hot shorts included failure of minimum-flow valves for the emergency core cooling injection systems. The potential for hot shorts included impacting containment isolation.

The detailed analysis of the main control room was similar to the method above, but with some additions to reflect the potential effects of control room evacuation. After the detailed analysis was performed, an importance analysis was performed.

Table E.3-7 provides a listing for the top 20 quantified compartments, ordered by their contribution to CDF. Compartments that contribute less than 0.1% were not included.

After quantification of the individual compartments, the core damage sequence equations were combined to develop an equation for total fire CDF. An importance analysis was performed with this equation, with the top 30 results base on RRW given in Table E.3-8. The components damaged by the fire are not explicitly included in this importance list, since they are Boolean events (equal to logical 1.0) that do not show up in the cutset equations. The importance analysis is based on those components that are not impacted by the fire, and whose failure would contribute to core damage cutsets.

E.3.2.2 Seismic PSA Level 1

The seismic probabilistic safety assessment (SPSA) was developed in accordance with accepted industry techniques and is consistent with the guidance provided in the following industry references:

- American Nuclear Society (ANS) Standard for External Events PRA Methodology, ANSI/ANS-58.21-2003 [**19**] (both with respect to the "SPRA Primer" provided in Appendix B to the Standard, and as outlined in the requirements of Section 3.7 of the Standard)

- ERPI Report TR-1002989, Seismic Probabilistic Risk Assessment Implementation Guide [**20**]

Consistent with the ANS Standard, the CGS SPSA addresses both core damage accident sequences (i.e., Level 1 PSA) and large-early release sequences (i.e., LERF).

Major inputs to the SPSA include:

- A plant-specific hazard curve was developed.

- Results and insights obtained from seismic plant walkdowns conducted in support of the IPEEE. The walkdowns were conducted in accordance with the guidance included in the Generic Implementation Procedure [**21**] and the EPRI seismic margins methodology [**22**]. The walkdown activity also provided a means to investigate issues related to seismic-induced fires and floods.

- Plant-specific structural and component seismic fragility analyses developed. Consistent with the ANS Standard, generic fragilities are employed where appropriate (e.g., highly rugged equipment for which plant-specific high-confidence-low-probability-of-failures (HCLPFs) were not calculated).

- Relay chatter evaluation results were factored into the SPSA fragility analysis and models.
- CGS Level 1 PSA, Revision 6.2 accident sequence progression modeling, system modeling, and component and human failure rates (adjusted as appropriate to account for seismic issues).
- CGS Level 2 PSA Revision 6.2 LERF accident sequence progression modeling and results (adjusted as appropriate to account for seismic issues).

The key elements of a seismic PSA are as follows:

1. Seismic hazard analysis - estimation of the frequency of various levels of seismic ground motion (acceleration) for the site. Table E.3-9 provides the various levels and assumed frequencies of occurrence derived through expert consensus. The hazard analysis is the same as submitted for the IPEEE with the addition of an extrapolation from maximum peak ground acceleration (PGA) of 0.7g to 1.5g per the guidance of NUREG-1407 [**23**].
2. Seismic fragility analysis - estimation of the conditional probabilities of structural or equipment failure for given levels of ground acceleration.
3. Systems/accident sequence analysis - modeling of the various combinations of structural and equipment failures that could initiate and propagate a seismic core damage accident sequence. Table E.3-11 provides the seismic damage accident sequence (SDS) and corresponding CDF results.
4. Evaluation of CDF and public risk - assembly of the results of the seismic hazard, fragility, and systems analyses to estimate the frequencies of core damage and off-site consequences (in this case, LERF).

The baseline CDF point estimate for the CGS SPSA is calculated to be 5.25E-6/yr. The SPSA CDF results by SDS event tree initiator that contribute 0.1% or more are summarized in Table E.3-10.

SDS42 (structural failures of RPV or category 1 buildings) represents 45% of the CDF. Another 31% is contributed by SDS41, which is safety system failures assumed to result in core damage. These safety systems had seismic capacities at least as large as the HCLPF screening level of 0.5g. With further fragility analysis, these structure and systems might be found to have significantly higher capacity, with decreased CDF contribution.

SDS6 and SDS4 each contribute about 4%, and represent failures of the Division 1 and Division 2 power supplies, resulting in SBO. SDS2 also contributes about 4% to seismic CDF, and represents a seismic LOOP, with subsequent random failures of Division 1 and Division 2, resulting in SBO.

Table E.3-11 provides the results by PDS, including both seismic CDF and seismic LERF. Approximately 45% of the SPSA CDF is due to containment bypass scenarios caused by structural failures of the RPV pedestal or category 1 buildings. This result is in contrast to the CGS internal events PSA results where Class 5 (large LOCAs outside containment with failure to isolate) type accidents are low-significance contributors (~3%) to the internal events CDF.

PDS 1A3 and PDS 2B each contribute about 16% to seismic CDF. PDS 1A3 is a short-term loss of high pressure injection sequence with failure to depressurize. PDS 2B is a LOCA with long-term loss of containment heat removal.

The short and long-term SBO PDS 6A1, 6A2, 6B1, and 6B2 contribute an additional 23% to seismic CDF. The remaining PDSs contribute less than 1% to seismic CDF.

Seismic risk is typically dominated by key building failures and RPV failures that have high failure probabilities at the higher seismic magnitudes. For example, the failure probability of the primary containment at 1.0g PGA is approximately 7E-2, and the annual exceedance frequency of a 1.0g PGA earthquake at CGS is approximately 2E-6/yr.

Such scenarios are assumed to lead directly to core damage and their contribution to core damage is essentially defined by the annual exceedance frequency of very high magnitude seismic events at the site. The long-term SBO contribution is high for the CGS SPSA as the recovery of off-site alternating current (AC) power following a high magnitude seismic event is very unlikely.

The large uncertainty for these high magnitude seismic events and the high uncertainty of their occurrence frequencies results in conservative treatment of this potential hazard. The use of these conservative seismic hazard results for SAMA evaluation application is acceptable. The conclusions of the SAMA evaluation should not be overly influenced by the conservatism.

E.3.2.3 Other External Events

Other initiating events were considered and presented in the IPEEE Section 5.0. These included

1. High winds and tornadoes
2. External floods (high water, high precipitation, dam failures, and combinations of high rains and dam failures)
3. Transportation and nearby facility accidents (aircraft crashes on the power plant site, ship/barge collisions with power plant structures and ship/barge, truck, railroad, gas/oil/chemical pipeline accidents near the power plant site

which release hazardous materials, and facility accidents near the power plant site which release hazardous materials) and

4. Site specific hazards

- Extreme heat,
- Extreme cold,
- Ice,
- Hail,
- Snowstorms,
- Dust storms, sandstorms,
- Lightning strikes,
- External fires (i.e., brush fires, grass fires),
- Extraterrestrial activity (i.e., meteorite strikes, satellites),
- Volcanic activity,
- Damage or destruction due to military action,
- Avalanche, landslide,
- Release of hazardous materials from on-site storage, and
- Accidents from nearby industrial or military facilities.

These hazards are addressed in the IPEEE submittal letter to the NRC [**24**].

E.3.2.4 IPEEE Improvement

The improvements identified with the IPEEE were completed or resolved and reported to the NRC in January 2001 [**25**]. The NRC review of these improvements was provided in a letter dated February 26, 2001 [**26**]. Excerpts from this letter associated with the improvements are provided below.

Fire-Related Improvements

- The licensee reviewed existing procedures for control of transient combustibles in certain areas (most notably the cable spreading room and cable chase area) where the fire assessment indicated that large amounts of strategically placed materials can cause multi-division damage and have a large impact on risk. The licensee stated that this was completed.

- Existing procedures and training were evaluated to determine if information on the location of isolation valves in the fire water system was available since isolation of

portions of the system in non-safety related structures may be required during a seismic event.

- Due to the presence of nine relays of unknown seismic ruggedness of the HALON systems in the control room and the potential for inadvertent system actuation, the control room crews were advised to take further steps to confirm an actual fire exists before accepting the HALON actuation at face value.

- A recommendation was made to include the proceduralized recovery of two critical AC buses, identified as an important recovery action in the fire assessment, in the operator training program. In their January 24, 2001, letter the licensee stated that this improvement was completed.

High Winds, Floods, Other-Related Improvement

- Procedures were revised concerning the placement of the C-Vans to assure the containers are not stacked on top of one another in close proximity to safety-related buildings."

Seismic-Related Improvements

- Anchorage nuts or washers missing in two air handling units in the Division 1 diesel generator room. Units were restored to design anchorage configuration.

- The connection between cabinets of E-SM-7 and E-SM-7/75/2 was located at the center of the panel, rather than edge-connected, which may cause banging between cabinets. The IPEEE submittal stated that the cabinets will be edge connected. In their January 24, 2001, letter the licensee stated that the cabinets will not be edge-connected. The licensee performed an engineering evaluation that concluded that no further actions were necessary since the seismic qualifications are maintained.

- Three motor control centers (MCCs) and two instrument racks had hangers installed in close enough proximity to potentially cause banging during a seismic event. The IPEEE submittal stated that the hanger situation will be remedied via normal plant processes. In their January 24, 2001, letter the licensee stated that an engineering evaluation was performed and they concluded that instrument racks were seismically qualified and that no action was necessary.

- The batteries for the diesel driven fire pumps were not tied down. Action is being taken to tie down the batteries. In their January 24, 2001, letter the licensee stated that this was completed in July 1995.

- The MCC base connections are relatively weak, although they meet design basis requirements. A cost-benefit analysis for strengthening the MCC base connections was recommended. In their January 24, 2001, letter the licensee stated that they had completed the cost-benefit analysis and determined that it was not cost-beneficial.

- Alternate switchgear room cooling could be beneficial. A procedural direction for opening the doors to a critical switchgear room will be explored. In their January 24, 2001, letter the licensee stated that this was completed.

The NRC's conclusions regarding the adequacy of the CGS IPEEE as stated in the Safety Evaluation Report (SER) that was enclosed with Reference **[26]** was:

> .....the staff notes that: (1) the licensee's IPEEE is complete with regard to the information requested by Supplement 4 to Generic Letter (GL) 88-20 (and associated guidance in NUREG-1407), and (2) the IPEEE results are reasonable given the Columbia Generating Station design, operation, and history. Therefore, the staff concludes that
>
> (1) the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities from external events, and
>
> (2) the Columbia Generating Station IPEEE has met the intent of Supplement 4 to GL 88-20 and the resolution of specific generic safety issues discussed in this SER.
>
> It should be noted that the staff focused its review primarily on the licensee's ability to examine the CGS for severe accident vulnerabilities from external events. Although certain aspects of the IPEEE were explored in more detail than others, the review was not intended to validate the accuracy of the licensee's detailed findings (or quantification estimates) that underlie or stemmed from the examination. Therefore, this SER does not constitute NRC approval or endorsement of any IPEEE material for purposes other than those associated with meeting the intent of Supplement 4 to GL 88-20 and the resolution of specific generic safety issues discussed in this SER.

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E.4 CGS PSA MODEL – LEVEL 2 PSA SUMMARY

E.4.1 INTERNAL EVENT LEVEL 2 (LERF) SUMMARY

E.4.1.1 Level 2 Methodology Overview

The general approach used in the quantification of the containment performance for CGS utilized the following analytical steps:

First, all core damage sequences were assigned to a PDS based on the functional characteristics of the sequences and the status of systems that were important to the containment performance assessment. This process was achieved using sequence descriptions and correlated tabulations of the status of all relevant systems to provide the basis for comparison. The frequency of the PDS was tabulated based on the individual frequencies of the sequences. The information developed during the grouping process was used to establish the unique set of conditions that were superimposed on the Containment Event Tree (CET) node models during quantification of the CET.

Second, CETs were developed to model accident progression and provide a description of the possible outcomes or containment damage states. The time frame for the Level 2 analysis is assumed to extend for 40 hours after the initiating event. CETs were developed for each PDS. Quantification of the CETs to provide the estimated frequency for each individual sequence was accomplished by the insertion of the appropriate conditional probabilities at each of the CET branch nodes. Final quantification was the result of propagation of each initiating PDS and its associated occurrence frequency through its respective CET and accumulating these frequencies for each release category.

The CET branch node probabilities are calculated in one of two ways:

1. from fault trees developed to identify the individual functional failures that were important to resolution of the node and

2. split fractions which could be assigned to each CET branch node.

The quantification of the CETs ensured that the dependencies between events were treated correctly so that Boolean algebra correctly calculated the sequence frequencies. This was accomplished by using portions of the fault trees to represent sequence specific structures which reflect sequence dependencies correctly and return CET node probabilities which were independent.

The conditional probabilities used to quantify each CET are adjusted to match the specific conditions represented by the PDSs. For example, if the Level 1 sequence

cutsets show that the unavailability of high-pressure injection was caused by hardware failure, the failure probability was assigned to be 1 in Level 2.

The final functional task performed during the construction of the overall Level 2 model involved the definition of a set of criteria that could be used as the basis for grouping containment event tree end states into a limited, but complete, set of unique release categories. These categories were equally applicable to each CET, i.e. damage state descriptors that are initiator independent. The sequence characteristics ultimately adopted to characterize these release categories were:

- containment failure mode (large/small*)
- time of containment failure (early/late)
- fission products (scrubbed/not scrubbed)

* note – for the Level 2 Revision 6.2, all containment failure modes are categorized as large.

Logical criteria were developed to use these characteristics to consistently sort and accumulate the frequency contribution from each sequence into one of the defined source term bins.

MAAP cases were binned into the appropriate Level 2 Release Category based on the inputs and results of the MAAP run (i.e., where containment failure was assumed and the resulting time and magnitude of the release).

For input into Level 3, representative MAAP cases were chosen primarily upon three criteria:

1. The MAAP case represents an accident class that would be expected to be included in the release category.
2. The MAAP case timing represents the appropriate timing characteristic of the release category (i.e., early vs. late).
3. The MAAP CsI release fraction is representative of the release category (i.e., > 0.1 for large release).

Where options exist for the potential assignment of various MAAP cases, cases were selected to include reasonable, but not undue conservatism. Thus, the LEN (large, early, non-scrubbed) case has a CsI release fraction of 0.2, which is well above the 0.1 threshold, but is less than a more extreme value of 0.5 as might be found for a break outside containment MAAP case.

To determine a representative source term for the LERF bin that had an occurrence frequency greater than the assigned cut-off value, a representative sequence was used to define a MAAP simulation, which would provide an estimate of the fission product release.

The total internal events LERF for CGS is 6.53E-7/year. This frequency is divided among the PDS and presented in Table E.4-1.

The Internal Events Level 2 Release Categories are provided in Table E.4-3. About 46% of the releases are late, and do not contribute to LERF. However, about 13.6% are early releases, which do contribute to LERF. Table E.4-2 provides further detail for PDSs that provide a challenge to the containment. Approximately 74% of the LERF derives from PDSs for which the LERF split fraction is assumed to be 1.00. The remainder of the sequences contribute 26% to LERF. These important PDSs are listed in Table E.4-2.

The remaining important LERF contributors include high-pressure transients and small LOCAs (LERF split fraction = 1.1E-1) and SBO (LERF split fraction = 6.8E-2). Containment isolation failure probability (leading to LERF) is 7.8E-4 per demand dominated by in-series MSIV failures. While in-series MSIV failure can lead to containment bypass, hold-up and deposition would be expected in the steam lines outside containment except for cases involving main steam line breaks (PDS 5 in Table E.4-2). Accordingly, the containment isolation failure probability of 7.8E-4 per demand is conservative for general containment isolation failure.

E.4.2 FIRE LEVEL 2

The fire LERF is calculated according to the fire PDSs. The process was achieved using Internal Events Level 2 PSA, and resultant damage state frequencies from the fire CDF analysis as shown in Table E.4-4. Quantifying the Level 2 model using fire damage state frequencies yielded a fire LERF of 2.46E-07/yr.

The Fire PSA Level 2 release categories are provided in Table E.4-5. About 88% of the releases are late and do not contribute to LERF. However, about 3.3 % are early releases, which do contribute to LERF.

The Fire PSA assumes that LOOP will not be recovered for 24 hours. The non-recovery events associate with off-site power have been changed so that credit is not taken for recovering AC power before containment failure or before vessel failure. Additionally, it is assumed that HPCS failure due to fire cannot be recovered.

The internal events LERF analysis uses 7.8E-04 for failure of containment isolation for all PDSs. It is dominated by CCF of a pair of MSIVs to close, multiplied by the 4 pairs of MSIVs.

For fire scenarios there is an added issue of fire damage impacts to containment isolation, both for failure to close and spurious actuation. However, the internal events containment isolation failure probability given above is applicable to fire scenarios and the rationale is discussed in the following sections.

E.4.2.1 Fire-induced Failure of Containment Isolation Valve (CIV) to Close

For some fire compartments, the power or control cables to the normally open CIVs may be damaged by the fire, causing the CIV to fail to close. There are a number of special design features that have been used to prevent failure of isolation, including:

- Fail closed valves (on loss of power or air)
- Use of check valves (which would not be impacted by fire)
- Valves normally closed, with power racked out at the breaker.

However, the most important feature is that a pair of CIVs is powered by opposite trains, and the cables are routed separately. Therefore, even though the fire may damage cables to one CIV, the other CIV would not be impacted.

Second, there is time between the containment isolation signal and core damage or vessel failure to identify the loss of containment isolation, and travel to the outside CIV and manually close the valve. In most core damage sequences, the operator has at least 2 hours before core damage.

Therefore, if the fire damages CIV cables, a random failure of the opposite train CIV to close (about 2.0E-3) would still have to occur, and the operator would also have to fail to manually close the valve (about 6.0E-3 for action within 1 hour). Thus, the likelihood of containment isolation failure would be about 1.2E-5. This is a factor of 50 less than the dominant failure mode of the MSIVs, and thus not significant. Even if a number of CIVs were failed by the fire, the overall containment isolation failure probability would not be significantly raised. Therefore, the internal events probability is used for containment isolation failure.

E.4.2.2 Spurious Opening of CIVs

In some cases, the fire could cause a hot short, which could spuriously open a CIV. Several design features would tend to reduce this possibility, including:

- The routing of cables in grounded conduit or with other cables that are not powered.
- Motor Operated Valves would require 3-phase hot shorts, which is very unlikely.

- Hot shorts eventually are grounded or open.

However, even assuming these design features are not considered, the hot short would still be subject to the opposite train pairing discussed above, and could be corrected by manual operator action. Thus, the probability of a hot short (0.3) times loss of the opposite train valve to close, times operator action to close would be about 4E-6, which is not significant compared to the dominant failure of the MSIVs to close.

Hence, based on the above discussions, the internal events containment isolation failure probability of 7.8E-04 is used for the fire LERF estimate.

E.4.2.3 Further Discussion on Containment Isolation and Hot Shorts

For the fire LERF calculation, the following evaluations were performed:

- For the valves and dampers modeled in the containment isolation fault tree, 47 were identified by the PFSS as not protected.
- The PFSS documentation ([**27**][**28**]) was reviewed, and 45 of these were justified as not requiring protection, for reasons including:
  - Justified as failsafe, since actuation would cause containment isolation, which could not be reversed by a hot short (this is primarily for the MSIV solenoid valves)
  - Justified by a normally closed manual valve in series
  - Justified by a locked normally closed valve in series
  - Justified by locked closed during power operation with power removed.
- The final two valves were on the reactor water cleanup (RWCU) system. They are normally open motor operated valves in series on the suction line from the vessel, and are powered by opposite trains. Therefore, the power and actuation cables would be routed by train to prevent double failure.
- As a backup, even if there were other random failures which combined to fail automatic isolation for a penetration there is adequate time to defeat the hot short, or to manually close valves before core damage.

Therefore, it is concluded that, hot shorts would not significantly impact containment isolation for these valves.

E.4.3 SEISMIC LEVEL 2 (LERF)

Consistent with the ANS external events PRA standard [**19**], the CGS SPSA evaluates (in addition to CDF) the LERF risk measure. The LERF risk measure for post-core damage accident sequences is evaluated in the CGS internal events Level 2 PSA (along with other release categories). Appropriately, the ANS Standard directs use of the internal events LERF analysis as the starting point for the SPSA LERF assessment:

The approach to any external-events PRA typically uses as its starting point the internal-events PRA model both the part of the internal-events model dealing with CDF and the part dealing with LERF are used as starting points.

The CGS SPSA calculates the LERF risk measure for seismic events by modifying the internal events Level 2 CETs.

The seismic-specific CETs are:

PDS 1A3 CET represents a short-term TUX sequence (transient with loss of high pressure coolant injection (HPCI) and failure to depressurize) with LOOP and at least Division 1 or Division 2 power available. The internal events 1A3-B CET was used as a template, with the changes to account for seismic-induced isolation failure contribution and offsite AC and emergency diesel generator (EDG) recoveries removed This resulted in no credit for recovery of low pressure injection or containment spray. The CET sequences with LEN releases (large, early, non-scrubbed releases) contribute to LERF. These are either sequences with failure of containment isolation, or with high pressure melt ejection (HPME) failing containment.

PDS 1B0 CET represents a LOOP with loss of containment heat removal, failure of high pressure injection, but at least Division 1 or Division 2 power available. The internal events 1B0 CET was used to account for seismic-induced isolation failure contribution and modification, to partially credit operation action for recovery of containment isolation failure due to seismic containment isolation failures. All of the sequences are either large, late scrubbed releases (LLS) or large, late non-scrubbed releases (LLN), and do not contribute to LERF.

PDS 1H CET represents a LOOP with long-term failure of high and low pressure injection, but at least Division 1 or Division 2 power available. The internal events 1H-B CET was used directly, with changes to account for seismic-induced isolation failure contribution, to modification to partially credit operation action for recovery of containment isolation failure due to seismic containment isolation failures, and to remove crediting recovery for both off-site and on-site AC power. Only the failure of containment isolation sequence contributes to LERF.

PDS 2B CET represents a LOCA with long-term failure of containment heat removal, and the reactor vessel at low pressure at core melt. The internal events 2B CET was

used directly, with no changes. All of the sequences are LLN and do not contribute to LERF.

PDS 2D CET represents a transient with long-term failure of containment heat removal, and the reactor vessel at high pressure at core melt. The internal events 2D CET was used directly, with no changes. All of the sequences are LLN and do not contribute to LERF.

PDS 3C CET represents a large LOCA with failure of injection, and the reactor vessel at low pressure at core melt. The internal events 3C CET was used to account for seismic-induced isolation failure contribution and modification and not credit containment venting. PDS 3C does not have any frequency for the SPSA, and is not quantified. Only the failure of containment isolation sequence would contribute to LERF.

PDS 4BA CET represents an ATWS, with the reactor vessel intact at core melt. The internal events 4BA CET was used, with no changes. All sequences are assumed to result in LEN and contribute to LERF.

PDS 5 CET In the internal events, PDS 5 represents a containment bypass event, leading directly to LERF. However, for SDS42, some of the seismic failures assigned to PDS 5 would not result in containment bypass. Therefore, a new CET was developed for PDS 5 for the SPSA, based on the 6A1-B internal events CET. Seismic failures that are assumed to directly fail containment and cause core damage (structural failures of the Reactor Building, Containment, or Reactor Vessel Pedestal) represented a basic event with an unavailability of 0.75. The availability of DC power in order to depressurize the reactor vessel before core damage, and prevent HPME is based on the failure of the Radwaste/Control Building. The failure of the Diesel Generator Building would not cause battery failure (although depletion would occur in 4-6 hours). The failure of the Radwaste/Control Building represented 60% of the remaining frequency. The potential for early containment failure is revised in the SPSA for SBO events to reflect that RHR is not available for injection or containment spray. The RHR-AVAILABLE basic event was revised to a failure of 9.9E-01. This precludes water in the pedestal prior to vessel failure, and removes this mode of ex-vessel steam explosion causing early containment failure. AC power recovery is assumed failed for seismic events, also failing low pressure injection or spray, and debris cooling. Venting is also assumed to have failed for seismic events. All sequences are assumed to result in LEN and contribute to LERF.

PDS 6A1 CET represents a short-term (<2 hrs) SBO sequence, with direct current (DC) power and ADS available at time of core damage. The internal events 6A1-B CET was used to account for seismic-induced isolation failure contribution, to remove crediting recovery for AC power with failing low pressure injection or spray and debris cooling, and removed ex-vessel steam explosion causing early containment failure. Venting is

also failed for seismic events. Failure of containment isolation and HPME shell failure sequences are classified as LEN and contribute to LERF.

PDS 6A2 CET represents a long-term (>6 hrs) SBO sequence with small LOCA, with DC power and ADS unavailable at time of core damage, but the reactor vessel is depressurized by the SLOCA. The internal events 6A2 CET was used to account for seismic-induced isolation failure contribution, AC power not recoverable with failing low pressure injection or spray, and debris cooling, and not crediting containment venting. All of the sequences are LLN and do not contribute to LERF.

PDS 6B1 CET represents a long-term (>6 hrs) SBO sequence with HPCS operating until containment failure. DC power and ADS are unavailable at time of core damage. The internal events 6B1 CET was used to account for seismic-induced isolation failure contribution and AC power not recoverable with failing low pressure injection or spray, and debris cooling. All of the sequences are LLN and do not contribute to LERF.

PDS 6B2 CET represents a long-term (>6 hrs) SBO sequence with RCIC initially operating. DC power and ADS are unavailable at time of core damage. The internal events 6B2 CET was used to account for seismic-induced isolation failure contribution and AC power not recoverable with failing low pressure injection or spray, and debris cooling. All of the sequences are LLN and do not contribute to LERF.

The dominate accident sequences and PDSs leading to Seismic CDF and LERF are presented in Table E.3-10 and Table E.3-11. The revised seismic CET were quantified and the resulting release categories are provided in Table E.4-6. The Seismic LERF is estimated at 2.15E-06/yr, as shown for the LEN category. About 59% of the releases are late, and do not contribute to LERF. However, about 41% are early releases, which do contribute to LERF.

The LERF results by accident class are also summarized in Table E.3-11. The dominant core damage sequence in Table E.3-10, SDS42, is the same for LERF as that for CDF, contributing almost 84% of the LEN release category. The only other significant LERF contributor is PDS 1A3, which contributes about 15%.

The seismic contribution to LERF is judged to be conservative for SAMA purposes. This conservatism is primarily due to the uncertainty associated with the seismic level necessary to directly fail RPV supports (3%), Primary Containment (40%), Reactor Building (32%), Radwaste/Control Building (15%), and Diesel Generator Building (10%). The portion of accident sequence SDS42 leading to direct containment failure represents 75% of the LERF. A sensitivity study assessed the quantitative impact of the base results to a CGS safe shutdown earthquake (SSE) of 0.25g.

The CGS SPSA base quantification was performed using earthquake magnitudes from 0.10g PGA through 1.5g PGA (well beyond the CGS design basis). The base results

indicate that the seismic CDF is approximately 5.25.E-6/yr and dominated by seismic-induced failures of the RPV, key buildings, and major support systems.

Whereas, when the earthquakes up to the design basis SSE were analyzed, the results were much different, including a much lower CDF and different significant contributions to risk. This sensitivity case was performed by re-calculating the SDS Event Tree sequences and instructing the code in the control file to only quantify earthquakes up to 0.25g. The new SDS damage state frequencies were then used and the accident sequences re-quantified.

The resulting CDF (4.29E-8/yr) is significantly reduced compared to the base CDF results. In addition, the risk contributors are also markedly different. Whereas the base results indicate that approximately 60% of the CDF is due to seismic-induced failures of the RPV, key buildings, and major support systems, quantification up through the SSE appropriately shows a negligible (<<1%) contribution to CDF from seismic-induced failures of the RPV or major buildings or support systems. In this sensitivity case, 97% of the CDF at the CGS SSE level is due to a single seismic damage state, SDS2. This damage state involves (in addition to the unavailability of the condensate storage tank (CST) and balance of plant (BOP)) only a seismic-induced LOOP and Small Small LOCA. The dominant basic events remain those related to the EDGs, RCIC, and HPCS. This is expected since this is still a seismic scenario and involves LOOP. This conservatism in CDF produces a similar conservatism in LERF and the results would overstate the potential benefit and there would be an increased likelihood of the SAMA candidate being cost-beneficial. Thus, using a conservative seismic CDF with a resultant LERF of 2.15E-6/yr is appropriate for determining the SAMA candidates' cost-benefit.

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E.5 PSA MODEL REVIEW SUMMARY

E.5.1 SUMMARY OF CHANGES SINCE THE IPE

Table E.5-1 lists the specific activity associated with updating and upgrading the CGS PSA from IPE to the model used in the SAMA evaluation.

E.5.2 DISCUSSION OF INTERNAL EVENTS PSA

CGS's PSA model is maintained to reflect plant as-built and as-operated conditions to the extent required to support this submittal. The internal events PSA model has undergone six revisions since the original IPE model was developed for GL 88-20. Revisions 3 and 4 were major updates performed to improve modeling after the 1997 BWROG Certification Peer Review. Revision 5.0 through Revision 6.2 include changes that enhance the model realism to support the risk-informed applications and the resolutions of 2004 peer review findings associated with the pilot plant program for RG 1.200.

Internal Events PSA Features and Reviews

- Features a CDF = 4.77E-6/yr
- Features a LERF = 6.53E-7/yr

CGS's Internal Events PSA model has benefited from the following technical reviews:

- Scientech (previously NUS) review in 1994.
- Selective review by independent consultants in 1998 (LOOP and SBO), and in 2002 (MOC Switch model).
- Scientech review and upgrade in 2002 and 2003.
- Selective self assessment in 2003 for elements SY and IE.
- Human Reliability Analysis (HRA) by ERIN 2004, included observation of mixed operator and trainer crew response to dominate SBO initiating events using the plant simulator.
- MSPI supporting requirements Capability Self Assessment.
- RG 1.200 Revision 1 [**29**] Self Assessment for ASME PRA Standard supporting requirements important to LPCS and LPCI-C Completion Time Extension.

Four external reviews of CGS's internal events PSA that provided a comprehensive treatment of the models, inputs, and maintenance and update process are:

- 1997 BWROG PRA peer review.
- 2004 PSA peer review using the American Society Mechanical Engineers (ASME) Standard RA-Sa-2003 as modified by the RG 1.200 (for Trial Use).
- NRC RG 1.200 [**30**] pilot plant inspection of CGS's PSA-2004.
- NRC MSPI Inspection

A comprehensive model review of all supporting requirements according to the ASME standard RA-Sa-2003 and RG 1.200 (for Trial Use) was conducted in February 2004 for the internal events and Fire PSA.

During the PSA updating process, as described in CGS's procedures for PSA quality configuration and control [**31**] [**32**], plant modifications and procedure changes that could have an impact on the PSA model, data, or documentation were reviewed for incorporation into the PSA. Plant specific equipment failure data (June 2002) was incorporated into the PSA. System and component unavailability was updated with input from the Maintenance Rule Database. The CCF were recalculated based on the revised failure rates.

The PSA model is highly detailed and includes a wide variety of initiating events, modeled systems, operator actions, and common-cause events. The PSA model quantification process is based on the linked fault tree methodology, which is a standard methodology in the industry. The model quantification is performed using the WinNUPRA software.

CGS's PSA model and documentation are maintained as living documents and are periodically updated to reflect change to the plant configuration, accumulation of additional plant operating history, and component failure data. The risk significant BWROG PRA Peer Review comments and those identified internally through the PSA maintenance and update process [**32**] [**33**] were incorporated into the quantified PSA model.

Additionally, Energy Northwest participated in the NRC's RG 1.200 pilot program. Within this pilot program, the CGS internal events and Fire PSA were upgraded and peer reviewed to the ASME RA-Sa-2003 and RG 1.200 (Trial Use). Peer review team F&O comments were established by these reviews and a formal resolution process was performed on all F&Os that were assigned an A or B importance level. These were dispositioned and action plans put in place to resolve the comments. Also as part of this process, the NRC performed an inspection of the CGS PSA in the 2nd quarter 2004 as part of the RG 1.200 pilot program. Comments from their review were also used in

upgrading the internal events Level 1 PSA. There were no Category A F&Os requiring immediate upgrade for the Internal Events Level 1 or Level 2 PSA.

The CGS PSA contains detailed model of mitigating systems features. Information detailing this was provided to the NRC as part of the MSPI upgrade revision to the CGS PSA. This revision included both the internal events and the Fire PSA. An inspection by the NRC using Temporary Instruction (TI) 2515/169 - Mitigating Systems Performance Index Verification on CGS's adequacy was performed. For convenience appropriate excerpts from the NRC inspection report [**34**] are present below.

a. Inspection Scope

On November 30, 2006, the inspectors completed an inspection in accordance with Temporary Instruction 2515/169, "Mitigating Systems Performance Index Verification," to verify that the licensee correctly implemented the Mitigating System Performance Index (MSPI) guidance.

The inspectors reviewed the data the licensee used to generate the basis document unavailability and unreliability values. The licensee entered the values into a spreadsheet which was used to perform various calculations. The inspectors also used the following licensee source documents to verify the validity of the input data:

- Control Room Logs
- Surveillance Test Procedures
- Maintenance Procedures

b. Findings

No findings of significance were identified. The inspectors concluded that the licensee is monitoring, collecting and entering the appropriate data in accordance to the prescribed guidance.

Per the temporary instruction, the inspectors assessed and answered the following questions:

Question /Answer

For the sample selected, did the licensee accurately document the baseline planned unavailability hours for the MSPI systems? Yes

For the sample selected, did the licensee accurately document the actual unavailability hours for the MSPI systems? Yes

For the sample selected, did the licensee accurately document the actual unreliability information for each MSPI monitored component? Yes

Did the inspector identify significant errors in the reported data, which resulted in a change to the indicated index color? No

Did the inspector identify significant discrepancies in the basis document which resulted in (1) a change to the system boundary; (2) an addition of a monitored component; or (3) a change in the reported index color? No

There are no permanent plant changes or changes to the operation of CGS that are not appropriately modeled in the PSA that would impact the SAMA conclusions. Plant changes since Revision 6.2 include the addition of a portable diesel generator for battery charging, the ability to cross connect the Division 3 diesel generator to Division 1 or Division 2 electrical buses in response to a LOOP or SBO, and the upgrade to the main turbine digital hydraulic control system along with associated procedures upgrades. These plant changes will improve the risk profile to SBO and turbine trip events. The SAMA results would remain conservative if these changes were reflected in the model. These updates are planned for the next revision of the model.

E.5.3 SUMMARY OF CHANGES SINCE THE IPEEE (FIRE)

Table E.5-2 lists the specific activity associated with updating and upgrading the CGS PSA from IPEEE to the model used in the SAMA evaluation.

Fire PSA Features and Review:

- Features a CDF = 7.40E-6/yr
- Features a LERF = 2.46E-7/yr
- Has been updated three times

In February 2004, Erin Engineering performed a peer review using high level importance requirements derived from ASME RA-Sa-2003 that were applicable to a Fire PSA to evaluate the CGS Fire PSA associated with the following specific items:

- Fire Area definitions and boundaries
- Equipment and cable location treatment
- Sampling of ignition frequency estimates
- Sampling of fire scenario treatment including crew interface
- Fire growth modeling
- Model quantification

- MSPI supporting requirements Capability Self Assessment

Changes based on this peer review were incorporated into the fire PSA model and documentation.

E.5.4 SUMMARY OF CHANGES SINCE THE IPEEE (SEISMIC)

Table E.5-3 lists the specific activity associated with updating and upgrading the CGS Seismic PSA from IPE to the model used in the SAMA evaluation.

No external Peer reviews have been performed on the CGS Seismic PSA. Internal reviews have been performed and changes incorporated based on those internal reviews. The review was performed to ANSI/ANS-58.21-2003 [**19**].

- Features a CDF = 5.24E-6/yr
- Features a LERF = 2.15E-6/yr
- Has been updated two times from the IPEEE
- Consistent with ANSI/ANS 58.21-2003

E.5.5 SUMMARY OF PEER REVIEW(S)

An owner's group peer review was performed in 1997. All comments produced by this review were resolved.

A peer review of the Internal Events Revision 5.0 PSA was performed in 2004 against the ASME Standard Addendum A [**30**]. Subsequent to the peer review, the CGS PSA underwent an extensive upgrade to address and resolve all B level F&Os (there were no A level F&Os) for the IE, AS, SC, SY, HR, and QU elements, including addressing the MSPI program. In addition, all A and B level F&Os for the Fire PSA were addressed and resolved. Further, numerous C and D level F&Os have been addressed. This upgrade was performed as part of producing Revision 6.2 of the PSA.

E.5.5.1 Internal Events PSA

The following changes were implemented to resolve 2004 internal events peer review F&Os:

- The availability of RCIC was modeled where applicable for LOOP sequences that involve stuck open relief valves to reduce conservatism.
- ATWS modeling was refined to be consistent with the emergency operating procedures (EOP), which included the following revisions:

1. Operator interviews were held to gather information on the ATWS procedures and implementation and HEPs were revised;
2. The reactor feedwater and power conversion system/turbine (PCS), RHR, and HPCS fault trees were revised to include operator actions for ATWS (LPCS was included as an external transfer in the RHR fault tree);
3. Turbine trip ATWS modeling was revised such that the potential closure of the MSIVs and failure of feedwater/PCS is directly modeled. Also, an operator action to bypass the low level MSIV closure signal was modeled;
4. Use of RHR-SDC for injection is directly modeled as the preferred source if reactor feedwater/condensate system is not available;
5. HPCS, LPCS, and LPCI-C were modeled after failure of RHR-SDC;
6. RCIC was removed as a potential injection success criterion;
7. Reopening the MSIVs and using the PCS was removed as a potential containment heat removal success criterion for the loss of condenser, loss of feedwater and MSIV closure ATWS event trees;
8. Turbine trip ATWS from less than twenty-five percent power now includes potential to maintain long-term shutdown, either by individually driving the rods, or through long-term standby liquid control (SLC) injection;
9. The need for depressurization is addressed given ATWS with HPCS available.

- Use of HPCS from the CST if available: Based on comments by the operations staff, HPCS would not be switched back to the CST once automatic switchover to the suppression pool had occurred. However, if suction switchover is not successful, then the operator can continue with suction from the CST. This operator action was added.
- The potential for RCIC backpressure trip was addressed for non-SBO sequences in which containment heat removal is unavailable. There is no procedural direction to bypass RCIC backpressure trip for non-SBO sequences. Based on MAAP calculations, the use of control rod drive (CRD) as a late source of injection when the trip of RCIC occurs was added for these sequences.
- Influences on the operation of ECCS systems from flooding and steam release were included in the interfacing system LOCA model (ISLOCA).

- The annual average out-of-service values were calculated and incorporated into the PSA. The PSA previously used the highest unavailability year of the data collected.

- The CGS HRA was significantly reanalyzed to revise HEPs modeled that could influence the diesel generator allowed outage time (AOT) extension, including: updating the HRA against the latest versions of the EOPs, human interaction timing, operator interviews, and the HEP dependency evaluation.

- The timing and modeling for recovery of switchgear room HVAC losses was revised based on analysis of the time available to perform the actions for transient and LOCA initiating events. A potential CCF of air handling units that provide switchgear room cooling was added to the PSA model.

- The drywell spray was added to the stuck open relief valve event tree to enhance modeling realism.

The following Internal Events peer review findings and other self-identified areas are in progress for the next revision, but are not expected to significantly alter the SAMA analysis findings:

- For the RPV rupture accident sequence modeling, modeling of the core spray systems is recommended for mitigation. Also, vapor suppression capability of the CGS containment should be addressed.

- The LOCA outside containment modeling upgrades are recommended to address: 1) the initiating event frequency is roughly estimated and should be refined, 2) include consideration for environmental impacts to plant equipment in the turbine building and reactor building.

- Refine the ISLOCA modeling to apply more realistic probabilities for rupture or leak of the low pressure piping following failure of the high/low pressure boundary. Also, remove credit for early isolation of the RHR shutdown cooling line for ISLOCA flow paths that contain no check valves.

- Include an initiating event for CCF of both 125 VDC power Divisions 1 and 2.

- Update the PSA component CCF probabilities using more current data.

- The following additional upgrades were recommended by the peer review: 1) refine the assessment of equipment impacted by spray to better account for spatial location relative to the spray source, 2) RCIC pump flood damage height is 3 inches, which is considered too low based on walkdown observations, 3) assess potential conservatisms related to equipment that is assumed to be damaged and revise the modeling as applicable, 4) develop refinements of the

flood isolation HEPs to address the type and location of the break and clarify the timing assumed.

- Revise the Level 2 PSA model to address:

  1. Revise the time definition for LERF to be consistent with plant procedures;
  2. For some of these sequences ex-vessel steam explosion conditional failure probabilities are used characteristic of cases with flooded pedestals, which is an excessive conservatism;
  3. All internal flooding core damage sequences result in LERF, which is excessively conservative;
  4. Containment flooding is not modeled;
  5. Certain early phenomena that can lead to LERF are not included in the Level 2 model such hydrogen burn and in-vessel steam explosion;
  6. The crew actions included in the LERF assessment are not explicitly tied to procedural direction, do not account for failures that have previously occurred in the Level 1, and are all assessed individually to be 0.1 regardless of dependency issues;
  7. Survivability of systems for Level 2 mitigation are in some cases considered to be conservative and in other instances potentially non-conservative (do not take into account potential environmental impacts);
  8. Improve Level 2 analysis to explicitly model the systems credited in Level 2 with fault tree models;
  9. Re-examine the assumptions regarding containment venting and the ability to preserve adequate core cooling following venting;
  10. Conservative treatment of ATWS appears to be performed because of the lack of MAAP calculations;
  11. Source term scrubbing is included in the model (non-LERF end states) despite no MAAP calculation to assess the pool bypass effect when the pedestal floor or drain lines fail;
  12. Transfers of dependencies from Level 1 are not performed except at the PDS level;
  13. ATWS sequences without any reactivity control do not consider hydrodynamic loads;

14. Incorporate the probability that a pre-existing containment leakage failure exists, such as in a hatchway, seal, penetration, or the steel shell that would be revealed during a containment pressurization event.

E.5.5.2 Fire PSA

A review of the Fire PSA performed as part of the 2004 peer review produced 33 findings. The findings with potential to impact the fire risk profile (all A and B level F&Os) were addressed and resolved.

- Justifications for screening any circuits that have been screened from consideration in the Fire PSA have been clarified for circuits identified to be Appendix R-related. Bases for screening are documented for all circuits.
- Circuits related to differential relay protection for off-site power supply transformers were reviewed to incorporate credible fire impacts that had been overlooked in the previous Fire PSA revision.
- The cable database utilized by the PSA to route cables and assign fire impacts was updated with the 2005 version of the plant's cable and raceway database.
- The dispositions associated with each cable were reviewed again to ensure the Fire PSA fully accounted for the as-built plant.
- The likelihood for spurious actuation of equipment due to hot short was increased to be 0.3, rather than 0.1.
- Documentation was enhanced to clarify the approach used to develop and model the Fire PSA. For example, documentation of the methods and results for applying multipliers to post-initiating event HEPs to account for the affects of fire scenarios were enhanced and clarified.
- The PSA modeling for Division 1 switchgear room fires was enhanced to more realistically model fire scenarios and to ensure that transformer fires were modeled appropriately (revised non-conservative modeling).
- Modeling of detailed fire scenarios was refined to enhance modeling realism and to ensure that the treatment was not overly conservative. For example cables assigned as damaged were identified to be less than that modeled in the previous PSA version based on more detailed assessments of specific cable raceway locations.
- The main control room fire analysis was revised and documentation was enhanced to address:

- The HEP development associated with executing the control room evacuation procedure
- Re-evaluation of the equipment available to safely shut down the plant after control room evacuation
- The bases for PDS assignments was documented in greater detail

The following areas of improvement are still outstanding, but are not expected to significantly alter the SAMA analysis findings:

- A regulatory issue that has identified needed changes in models or increased levels of uncertainty in models relevant to this application is the multiple fire-induced spurious equipment operations (MSO) issue [**35**]. The CGS Fire PSA models approximately 130 individual hot short events. These hot short events correspond to all single spurious actuations modeled by the internal events PSA and include, for example, spurious closure of a valve in the RCIC flow path, spurious closure of a valve in the HPCS flow path, or spurious closure of a valve in the RHR flow path to the suppression pool. The Fire PSA sequence quantification captures all combinations of these 130 individual hot short events that contribute to the accident sequences above the quantitative truncation limit. This approach captures most, but not all of the MSOs that will need to be modeled in the PSA. Additional work will be needed to perform an expert panel review to identify combinations of events not reflected in the PSA models (for example, flow diversions not credible to internal events analyses such as those isolated by multiple normally closed valves).
- Better documentation of the fire compartment interaction analysis was recommended to more clearly justify the acceptability of the fire zone definitions.
- Credit for fire brigade response to manually suppress and extinguish fires was recommended to be applied.
- Improve the documentation of modeling uncertainties and corresponding assumptions.
- There are several specific disparities between PFSS analysis and the Fire PSA. The PSA fails components or functions that are considered protected for PFSS.
- Several electrical conduit pathways must still be traced using cable raceway diagrams, and fire damage impacts must be included in the Fire PSA for circuits that are routed entirely within conduit. The PSA cable routing database does not include the routing for all conduits installed in the plant.

- A transformer fire scenario must be re-evaluated for switchgear Division 2 to remove non-conservatism from the current modeling.
- Perform and document a thorough review to consider situations where the Fire PSA credits systems or trains that fire-related plant procedures instruct operators to defeat. The control room fire analysis applies a 0.1 human error probability (HEP) to indicate that the Division A or HPCS equipment might need to be restarted. Develop any additional modeling that accounts for these situations as applicable.

E.5.5.3 Seismic PSA

The seismic PSA was updated in 2007 to incorporate internal events Level 1 Rev 6.2 changes and to make modeling refinements. See Table E.5-3.

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E.6 CGS PSA MODEL – LEVEL 3 PSA INPUTS

E.6.1 INTRODUCTION

This section describes the development of the inputs needed to perform a Level 3 PSA for CGS. For the SAMA analysis, the cost-benefit analysis required comparison of comparable quantities; dose results from the CGS Level 3 PSA were converted into dollars for the purpose of comparison.

The Level 3 PSA relied on the results of the severe accident consequence code MELCOR Accident Consequence Code System (MACCS2) [**36**] [**37**]. Version 1.12 of MACCS2 was used for this analysis. MACCS2 simulates the impact of severe accidents at nuclear power plants on the surrounding environment. The principal phenomena considered are atmospheric transport, mitigative actions (based on dose thresholds), dose accumulation via a number of pathways (e.g., food and water ingestion), early and latent health effects, and economic costs.

The scope of a Level 3 PSA is generally driven by the nature of the release categories, which are the end states of a Level 2 PSA. The release categories are viewed as the initiating events of a Level 3 PSA. Accordingly, to use the output results of MACCS2 on a comparative basis, the release category consequence parameters were weighted by the likelihood of that release category to create a consequence. The risk metric was created by using the results of the Level 1 PSA and the Level 2 PSA, in the form of a release category frequency vector, containing the release frequency of each release category and the Level 3 PSA consequence parameters for each release category. Because the breadth of the scope of CGS's PSA, release category frequency vectors were available for internal events, seismic events, and (internal) fire events. As with the initiating events and CDF for a Level 1 PSA, the risk results of a Level 3 PSA were summed over all of the release categories.

This analysis considered a base case and eleven sensitivity cases to account for variation in data and assumptions. The following list describes the sensitivity cases, which are discussed in Section E.7.2:

- Case S1 – Use estimated 2060 site population data (with an escalation rate of 14.2%/decade); the same escalation rate for the base case population to 2045
- Case S2 – Increase the base population by sixteen people in the 0 to 1 mile ring
- Case S3 – Increase the population by 20% per decade to 2060
- Case S4 – Set all watershed indexes to "1"
- Case M1 – Use 2003 meteorological data
- Case A1 – Use conservative meteorological boundary conditions

- Case A2 – Sensitivity Case A2 not used
- Case A3 – Increase the height of release
- Case A4 – Increase the release duration
- Case E1 – Set evacuation speeds to estimates during adverse conditions
- Case E2 – Set sheltering shielding factors to a minimum value
- Case E3 – Use minimum evacuation speeds

E.6.2 POPULATION DATA

The source of the population data was from Chapter 2 in the FSAR [**38**]. Table 2.1-2 from the FSAR presents the population data that are based on the 2000 census. The population was adjusted to account for transient population within ten miles of CGS. The transient population was determined from the Transient Population table in Appendix A of Reference [**39**] as those people in parks, people fishing, or people working (migrant workers). The population escalation factor was developed considering different sets of population data, e.g., state-wide versus within a 50-mile radius of the plant.

The year 2045 was selected as the year to estimate the population since a 20-year license renewal for CGS will extend its operating license from December 2023 to December 2043. For the Level 3 PSA model, the estimated population for 2045 overestimated the population at the end of the extended operating license, and therefore generated conservative results because the population dose and economic impact costs are a function of increasing population. The escalated population estimate is conservative for a second reason since an accident could only occur between now and 2043, the actual population would be less than what is used in the Level 3 PSA model, and the benefit of each SAMA evaluated is over-estimated.

Washington State census data are provided in Table E.6-1. Table E.6-2 shows population data for the 50-mile radius area around the CGS site. The population estimates were taken from Table 2.1-1 of the CGS FSAR.

To be conservative, the state-wide data were used to estimate an escalation factor for the population. Despite the decreasing population rate trend indicated for the population within the 50-mile radius of the plant, a constant escalation rate (per decade) was assumed based on the state-wide data presented in Table E.6-1. A constant escalation rate of 14.2%/decade was used to estimate the population for 2045 (base case) and for 2060 (sensitivity case).

The population data used in the base case was conservative, since the transient population was included and escalated in a manner similar to the resident population. Table E.6-3 shows the 2045 population used in the base case.

E.6.3 METEOROLOGICAL DATA

Meteorological data from 2003 to 2006 recorded at the Energy Northwest permanent on-site meteorological tower (located approximately 2500 feet west of the plant site) were evaluated for this analysis [**40**]. Meteorological data included wind speed, wind direction, delta-temperature, and precipitation for each hour of the year.

An initial review identified long sequences of unusable (or bad) delta temperature meteorological data for 2005. As it was not reasonable to replace such a long sequence using the data substitution strategy, the 2005 meteorological data were deemed to be not viable as MACCS2 input. Accordingly, only the data for years 2003, 2004, and 2006 were reviewed. It was determined which of these years contained the least number of unusable meteorological data entries. This was the criterion used to determine which year would be the base case meteorological data. The second best year was used for a sensitivity case.

The meteorology data from 2006 were found to have the least amount of unusable data, therefore the 2006 data were used as the base case and the meteorological data from 2003 were used as a sensitivity case. Results of the sensitivity case confirmed that the 2006 meteorological data were representative and typical.

The mixing height values were estimated from Figures 2-5 (morning), and Figures 7-10 (afternoon) from Reference [**41**], as shown in Table E.6-4. The values were provided as real numbers in 100s of meters in the MET file.

E.6.4 OTHER SITE CHARACTERISTICS

Other site characteristics include land fraction, region index, watershed index, crop and season share, and building dimensions. These are each discussed below.

The **land fraction** is the fraction of land in each section [**42**]. Using topographical maps and a graphing tool, the water area of each section in square miles was estimated. For MACCS2, which requires land fraction as its input, the water area was subtracted from the section area, and then divided by the total section area – yielding the fraction of land for each section. These results were compared to FSAR Figures 2.1-1 and 2.1-2 (taken from Chapter 2 of the CGS FSAR [**38**]) showing the 50-mile radius around CGS, and estimating the land fraction. The provided data were a consistent characterization of the land fraction.

The **region index** equates the counties for which economic data have been specified for with each section of the grid. The region index block was developed from Figures 2.1-4 and 2.1-5 of the CGS FSAR. These figures showed the ten concentric rings and 16 wind directions overlaid on the Washington and Oregon State counties. Each section was evaluated to determine which county occupied the most land in the sector; this was then used as the region index.

The **watershed index** is either a one or a two [**42**]. An index of "2" was assigned for the segment if there was no runoff to a public water supply. Because rainfall in the site area is six to eight inches/year and because soils have relatively high permeability, runoff is negligible in most sections without irrigated agriculture. Generally, the assignment of the watershed index assumed there was no runoff from sectors that are 100% land. Exceptions included sections E and ENE at 5-10 miles, WSW at 10-20 miles, S and SSW at 20-30 miles, and SW and WNW at 40-50miles. In these sections, an index of "1" was assigned because of agricultural activities or features related to agriculture (e.g., canals, drainage ditches).

The **growing season** used was the default growing season specified by MACCS2. The default growing season for pasture is March 1 to August 30; for all other crops, the season is April 30 to July 30.

The **fraction of farmland** devoted to specific crops was calculated from the total acres of farmland in the region and acres devoted to each crop. This input was generated using the 2002 Census of Agriculture Data for Oregon [**43**] and Washington [**44**]. The total farm land in the region was summed from the acres of farmland in each county.

Seven categories of crops were accounted for: pasture, forage, grains, vegetables, other food crops, legumes and seeds, and roots and tubers. To calculate the other food crops harvested, the crops mentioned above less the pasture was subtracted from the total farmland harvested. This difference was assumed to be other crops that were not accounted for in the six categories.

The ATMOS file also required reactor **building dimensions** to determine the parameters SIGYINIT (σ_y) and SIGZINIT (σ_z). Building dimensions were taken from Reference [**45**] for the MACCS2 base case. As the reactor building is roughly square, the larger dimension was used as the reactor building width (i.e., 45 meters). The building height was 70 meters.

E.6.5 RELEASE CATEGORIES CHARACTERISTICS (FROM MAAP)

Each release category was processed in the MACCS2 code. The input that differentiates each release category is the information that is extracted from the MAAP run (for each release category). One of the outputs of the Level 2 PSA is the definition of the release categories and their frequencies. Each release category with a non-zero frequency is characterized by a MAAP run. The correspondence and definition of each release category is presented in Table E.6-5.

There are some differences in how radioisotopes are grouped in MAAP and MACCS2. The MAAP grouping is as follows:

Group	Description
1	Nobles & Inert Gases
2	CsI, RbI
3	TeO_2
4	SrO
5	MoO_2
6	CsOH, RbOH
7	BaO
8	La_2O_3, Nd_2O_3, Y_2O_3, Pr_2O_3, Sm_2O_3
9	CeO_2
10	Sb
11	Te
12	NpO_2, PuO_2

The MACCS2 grouping is as follows:

Group	Description
1	Xe, Kr
2	I
3	Cs
4	Te, Sb
5	Sr
6	Ru, Co, Mo, Tc, Rh
7	La, Y, Zr, Nb, Am, Cm, Pr, Nd
8	Ce, Pu, Np
9	Ba

Based on these groups, the following mapping was used between the MAAP and MACCS2 radioisotopic groups:

MACCS2	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
MAAP	**1**	**2**	**6**	**3, 10, 11**	**4**	**5**	**8**	**9, 12**	**7**

Table E.6-6 summarizes the data extracted from MAAP. All MAAP data were obtained from Reference [**46**]. The data was collected in the Excel Spreadsheet, in which some simple calculations were performed to support the base case and some of the sensitivity cases.

This table shows the correspondence between the MAAP runs and the release categories (as identified in Table E.6-5). Warning time (in seconds) was extracted from MAAP as the time to core uncovery. PLHEAT is the heat of release (in watts), which was used in that form as input to MACCS2. Likewise, PLHITE, height of release (in meters) was used directly as input. RFEL(x) are the release fractions for each of 12 radioisotopic groups defined in MAAP. To be used in MACCS2, the release fractions (MACCS2 variable FREFRC(x)) were mapped to the nine radioisotopic groups defined for MACCS2. PLUDUR (in seconds) is the duration of the release that was used as input to MACCS2.

The time to core uncovery for release category LEN is 36 seconds. This may be an unrealistically short time to expect CGS to declare a General Emergency. A sensitivity case was performed extending the OALARM parameter to 900 seconds (15 minutes); there was no change in the consequence metrics used to support the SAMA analysis. Accordingly, the SAMA analysis results were not sensitive to this parameter and the MAAP value of 36 seconds remained in the base case.

E.6.6 EVACUATION MODEL PARAMETERS

E.6.6.1 Weighting Fraction

A weighting fraction of 95% of the people was used, i.e., 95% of the people are evacuated and five percent of the populations remains within the emergency planning zone (EPZ) during the entire problem time.

E.6.6.2 Evacuation Speed

The travel speed can be defined during the three phases of the evacuation: initial, middle, and late. Because TRAVELPOINT = BOUNDARY, all three values of ESPEED are identical. The "Evacuation Time Estimates for Plume Exposure Pathway Emergency Planning Zone" [**39**] estimates that full evacuation of the EPZ in normal weather conditions could be accomplished in 2 hours and 41 minutes in normal weather, and in 2 hours and 57 minutes in adverse weather. This includes the delay time of notification, preparation, and mobilization activities. Assuming the delay for these activities is 50 minutes; this was subtracted from the overall evacuation time. The EPZ covers ten miles so assuming the entire ten miles is traveled, the evacuation speeds are 5.4 mph (2.4 meters/second) for normal weather and 4.7 mph (2.1 meters/second) for adverse weather. The normal weather speed of 2.4 m/s was used for the base case and a sensitivity case was performed with the adverse weather case with a speed of 2.1 meter/second).

E.6.6.3 Evacuation Delay Time

Based on the information provided in Section 5.2 of Reference [**39**], the delay times for 50% of various populations can be estimated as: residents – 57 minutes (day)/53 minutes (night); area workers – 48 minutes; schools – 45 minutes; transients – 60 minutes; and CGS workers – 41 minutes. An average delay time of 50 minutes (3000 seconds) was assumed for this analysis. However, it was not clear whether the 50 minutes delay included a possible delay of public officials to issue an evacuation. Such a delay could be no longer than 30 minutes. A sensitivity case was run extending the delay time 30 minutes to determine the sensitivity of the delay time. There was no change in the consequence metrics used to support the SAMA analysis. Therefore, the base case delay time remains at 50 minutes. It was assumed that the shelter delay time is one hour (3600 seconds).

E.6.6.4 Shielding

The shielding factors used in the base case were the default values given by Reference [**36**, Section 6.5]. The cloudshine and groundshine shielding factors, protections factors, and breathing rates for normal activities, evacuation, and shielding are presented in Table E.6-7.

The shielding factors for sheltering are dependent on the buildings constructed in the area. As a sensitivity case the shielding factors for sheltering were set to a minimum value suggested by Reference [**47**, Appendix A] since the evacuation zone around CGS has a very low population and therefore a very low number of housing for sheltering.

E.6.7 CORE INVENTORY

The core inventory for CGS was taken from Appendix A of "Nominal Reactor Core Isotopic Inventory for MAAP and MACCS2 Input to SAMA" [**48**]. The core inventory was calculated by ORIGEN for cycle 19 at nominal power. This information was presented in curies in the document and was converted to becquerels for MACCS2 purposes. Table E.6-8 shows the core inventories as provided (in curies) and as converted in to becquerels, to be used as input into MACCS2.

E.6.8 ECONOMIC DATA

Using the 2002 Census of Agriculture Data of References [**43**] and [**44**] and 2002 census data from Reference [**49**][1] , the following site-specific (averaged per county) inputs in Table E.6-9 were generated: fraction of land devoted to farming, fraction of dairy farm sales, total annual farm sales, farmland property value, and non-farmland property value. The last two values were averaged to provide input to the CHRNC file.

[1] The population data used for this analysis were extracted from the 2006 Population Estimates.

Additional site-specific economic parameters are given below. While many of the parameters were obtained from a government website (extracted in February 2008), these values are considered to be a snapshot in time to perform this analysis. The source of this information does not imply that these values need to be updated as the websites are revised.

EVACST – The daily cost of compensation for evacuees and short-term relocates who are removed from their homes as a result of radiation exposure during the emergency-phase relocation period. This value includes the following components: food, housing, transportation, and lost income.

The daily cost was calculated by using the 2000 census economic data (of per capita income for each state [**50**] and the default government per-diem rate for meals, expenses and lodging of $109/day [**51**]. The per capita income was found in the quickfacts section of the website: $22,973 (Washington) and $20,940 (Oregon).

For Washington State, **EVACST** is $171.94/person-day; for Oregon State, **EVACST** is $166.37/person-day. The average of the Washington and Oregon EVACST values was used as input in the CHRONC file.

RELCST – The daily cost of compensation for evacuees and short-term relocates who are removed from their homes as a result of radiation exposure during the intermediate-phase relocation period. This value includes the following components: food, housing, transportation, lost income, and replacement of personal property.

This was estimated using the evacuation costs plus the average property cost per person. The average property cost per person was calculated from the total property value in the state, which can be found on the individual state's Department of Revenue websites:

- $532,296,067,571 for Washington [**52**, Table 24]
- $219,780,958,000 for Oregon [**53**, Table B.1]

The total property cost was divided by the total population (5,894,121 for Washington and 3,421,399 for Oregon) [**49**].

For Washington State, **RELCST** is $419.36/person-day; for Oregon State, **RELCST** is $342.36/person-day. The average of the Washington and Oregon RELCST values was used as input in the CHRONC file.

Other economic input parameters used in the CHRONC file are provided in Table E.6-10.

E.7 CGS PSA MODEL – LEVEL 3 PSA RESULTS

The results are presented via a set of two output parameters that are used to support the SAMA analysis. These parameters are described as followed:

Whole Body Dose (person-rem) (population dose) – this is defined as the sum of the whole body dose received by the population with x miles of the site, where x=1, 10, 50 miles. (MACCS2 parameter L-EDEBODY from TYPE5OUT)

Economic impact ($) – this risk is defined as the sum of the population- and farm-dependent costs; because of the uncertainties associated with the cost input parameters (in CHRONC), the economic impact results were only used in a relative manner (never considered as an absolute dollar amount) for SAMA analysis to compare the cost of an alternative to the base case. (MACCS2 parameter defined as TYP10OUT)

To estimate risk, each consequence parameter was weighted by the frequency of the release categories in which the consequence was manifested. These risk results are presented on a per-release category basis, on a rolled-up release category basis, or as a total risk (the sum over all the release categories). Typically, the risk is presented for each parameter from zero to 50 miles summed over all of the release categories.

The Level 1 and Level 2 PSA results are summarized in the release category frequency vector, which contains the frequency (from initiating event) of an individual release category occurring. The frequency vector is presented in Table E.4-3, Table E.4-5, and Table E.4-6. Values for the output parameters were manually extracted from the MACCS2 output file and placed in an Excel Spreadsheet, in which the release category frequency vector was also placed. The weighting of consequences per release category was performed by multiplying by the release category frequency, and then summing the products. The results from the sensitivity cases were also placed in this spreadsheet and processed similarly to the base case. For the sensitivity cases, the further step of comparison against the base case was performed.

E.7.1 BASE CASE

The results for the Base Case are presented in Table E.7-1 through Table E.7-5. The results show the estimated population dose (whole body dose in person-rem/year) and the economic impact in dollars/year. While there are a variety of other consequence metrics that are estimated by MACCS2, these consequence metrics are the ones needed for the SAMA cost-benefit analysis.

The frequency for the Large Early Scrubbed (LES) release category is zero, as this sequence of events has been ruled out as a possible contributor to the total CDF. It is

included in the results because the consequences of LES offer insight into the sensitivities of the site-specific data.

Base case results for internal events, fires, and seismicity (per release category) are reported in Table E.7-1, Table E.7-2, and Table E.7-3. Table E.7-4 provides a summary of the results for the three different PSA scopes.

Table E.7-5 gives the consequences for each release category for whole body dose and economic impact at 50 miles. These data are used as input into the SAMA analysis.

E.7.2 SENSITIVITY CASES

E.7.2.1 Site

Case S1 - The population used in the base case was for the year 2045. Case S1 used the 2060 population, which is population of the site in a 50-mile radius around the plant more than 15 years after the extended license expires. Thus, this represented the most conservative estimate of population around the plant.

The results in Table E.7-6 show a slight increase in the risk for the two risk metrics used to support the SAMA cost-benefit analysis. Because the total population of the 50-mile radius around the plant is so low, escalating the population to 2060 did not have a large effect on the results.

Case S2 - Case S2 increases the population by 16 individuals, who are placed in the zero-to-one mile ring with one person per wind direction. The results in Table E.7-7 show only an insignificant increase in the economic impact. This sensitivity case showed that the risks metrics used to support the SAMA cost-benefit analysis were not sensitive to population close to the plant.

Case S3 – Case S3 increases the population by 20% per decade to 2060. This growth factor was determined from the census data from 1990 to 2000 as the most conservative growth rate plausible. The results showed, in Table E.7-8, that there is an increase in the population dose and economic impact. This was expected as these risk metrics are directly impacted by the population around the plant.

Case S4 – The base case was run with two watershed indices since the plant is located in a very arid part of the country. This sensitivity case determined the impact of assuming all the watershed indices are set to 1, e.g., maximum runoff consequences. The results in Table E.7-9 showed there was no impact when all the watershed indices are set to 1.

E.7.2.2 Meteorological

Case M1 – The base case was performed with CGS weather data from 2006, which had the least number of bad meteorological data points. A sensitivity case was performed to demonstrate the typical nature of any particular year's worth of meteorological data. Data from 2003 were chosen as being the second best with respect to the number of bad meteorological data points. Thus, this case, M1, totally replaced the 8760 lines of input in the meteorological file with data from 2003.

The results in Table E.7-10 showed that the two years worth of meteorological data were very similar and are representative of any year of meteorological data.

E.7.2.3 ATMOS

Case A1 – A sensitivity case was run with more extreme values of the meteorological boundary parameters, e.g., BNDMXH (mixing height), IBDSTB (stability class), BNDRAN (rain rate), BDNWND (wind speed). In general, the sensitivity case considered all of these boundary parameters collectively (e.g., all considered in one case). The rain rate boundary condition was set at 0.0 mm/hour for the base case; there is no value more conservative than that. The conservative boundary parameters had no impact on the results as shown in Table E.7-11.

Cases A3 & A4 – After the base case was run, it was observed that the immediate consequences for the scrubbed release categories were greater than for the non-scrubbed release categories. This was not an intuitive result since scrubbing generally reduces the release fractions. Upon further investigation, two possible contributing factors were identified: the height of release, and the duration of release. The height of release for the scrubbed cases was lower than that of the non-scrubbed cases, which could cause less mixing and therefore greater consequences. Also for the scrubbed cases, the duration of release was much shorter than the non-scrubbed case, which could cause a more acute effect on the consequences.

Case A3 increased the height of release from 13 meters to 44 meters for the release categories LES and LLS; as shown in Table E.7-12, the risk metrics used to support the SAMA cost-benefit analysis were not sensitive to the change in the height of release. Case A4 increased the duration of the release to the maximum value, 86400 seconds, for release categories LES and LLS. As with Case A3, the results, as shown in Table E.7-13, showed no sensitivity to the change in the duration of release.

E.7.2.4 EARLY

Case E1 – The base case was performed with the evacuation speed during normal conditions. A sensitivity case was performed with the evacuation speed during adverse conditions. The evacuation speed was reduced from 2.4 meters/second to 2.1 meters/second. This change did not have an effect on the results, as shown in Table

E.7-14, because the population within the evacuation zone is so low that decreasing the evacuation time by a small amount had no effect.

Case E2 – The base case was performed with the suggested shielding factors from Reference [**36**, Section 6.5]. This sensitivity case set the sheltering shielding factors to the minimum value suggested by Reference [**47**, Appendix A]. Since CGS has a very low population around the site and no residential population within three miles of the site, there are few houses that can be used for sheltering as compared to most other nuclear plants. The results in Table E.7-15 showed that the reduction in the shielding factors had no impact on the results, primarily because the population within the evacuation zone is so low.

Case E3 – Case E1 was performed with the adverse conditions evacuation speed. From the results of that sensitivity case, it was observed that the change in evacuation speed did not increase the risk results. This was not the expected results based on previous Level 3 PSAs -- even a small reduction in the evacuation speed usually causes some increase in the risk results. Another sensitivity case was run using a minimum evacuation speed to determine the sensitivity of the site data to the evacuation speed.

The results, in Table E.7-16, showed no change in the risk results. This further confirmed the conclusion from Case S1 that the population in the evacuation zone is so low that the evacuation time, even when changed by a factor of two had no significant impact on the results.

E.8 COST OF SEVERE ACCIDENT RISK

The SAMA candidates placed in the *Considered for Further Evaluation* category in Section E.9 required a cost-benefit evaluation. The cost-benefit evaluation of each SAMA candidate was based on the comparison of the cost of implementing a specific SAMA candidate (in U.S. dollars) with the benefit of the averted on-site and off-site risk (in U.S. dollars) from the implementation of that particular SAMA candidate. The methodology used for this evaluation was based on regulatory guidance for a cost-benefit evaluation as described in Section 5 of Reference [**1**]. This regulatory guidance determines the net value for each potential SAMA candidate according to the following equation:

$$\text{Net Value} = (\text{APE} + \text{AOC} + \text{AOE} + \text{AOSC}) - \text{COE} \qquad \text{(E.8-1)}$$

where,

APE = present value of the averted public exposure ($)

AOC = present value of the averted off-site property damage costs ($)

AOE = present value of the averted occupational exposure ($)

AOSC = present value of the averted on-site costs ($)

COE = cost of the enhancement ($)

The purpose of this section was to quantitatively determine the maximum benefit for CGS. The maximum benefit was defined as the maximum benefit a SAMA candidate could achieve if it eliminated all risk. If the estimated cost of implementation of a specific SAMA candidate was greater than the maximum benefit, then the alternative was not considered economically viable and was eliminated from further consideration. This section showed the maximum benefit evaluation for internal events. The same evaluation was also completed for fire and seismic events.

E.8.1 OFF-SITE EXPOSURE COST

The term used for off-site exposure cost was designated as averted public exposure (APE) cost. The off-site dose within a 50-mile radius of the site was determined using the MACCS2 model developed for the CGS PSA Level 3 analysis in Section E.7. Table E.8-1 provides the off-site dose for each release category obtained for the base case of the CGS Level 3 PSA weighted by the release category frequency. The total off-site dose for internal events (D_t) was estimated to be 3.68 person-rem/year. The APE cost was determined using Equation E.8-2 [**1**, Section 5.7.1].

$$APE = W_{pha} = (C)(Z_{pha}) \quad \text{(E.8-2)}$$

where,

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

C = present value factor (yr)

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

The present worth factor (C) was determined using Equation E.8-3, which was provided in Section 5.7.1 of Reference [**1**].

$$C = \frac{1 - e^{-rt}}{r} \quad \text{(E.8-3)}$$

where,

r is the discounted rate (%/yr)

t is the time to expiration of the renewed CGS license (yr)

The best estimate present worth factor (C_{be}) was calculated using Equation E.8-4. This present worth factor was used throughout the document.

$$C_{be} = \frac{1 - e^{-\left(\frac{0.07}{yr}\right)(35yrs)}}{\left(\frac{0.07}{yr}\right)} = 13.05yr \quad \text{(E.8-4)}$$

where,

r = 7%/yr = 0.07/yr

t = 35 yrs (2008 to 2043)

The monetary value of public health risk per year before discounting (Z_{pha}) was determined using Equation E.8-5 [**2**, Section 4.1].

$$Z_{pha} = (R)(D_t) \quad \text{(E.8-5)}$$

where,

R = monetary equivalent of unit dose ($/person-rem)

D_t = total off-site dose for internal events (person-rem/yr)

The conversion factor used to establish the monetary value of a unit of radiation exposure was $2,000 per person-rem averted. This monetary value was used for the year in which the exposure occurs and then discounted to the present value to evaluate the values and impacts. The monetary value of public health risk per year before discounting (Z_{pha}) for CGS was calculated using Equation E.8-6.

$$Z_{pha} = \left(2{,}000 \frac{\$}{\text{person} - \text{rem}}\right)\left(3.68 \frac{\text{person} - \text{rem}}{\text{yr}}\right) = \$7360/\text{yr} \qquad \text{(E.8-6)}$$

where,

R = $2,000/person-rem

D_t = 3.68 person-rem/year

The values for the **best estimate** case are:

C_{be} = 13.05 yr

Z_{pha} = $7360/yr

$$\text{APE} = (13.05\text{yr})\left(\frac{\$7360}{\text{yr}}\right) = \$96{,}035 \qquad \text{(E.8-7)}$$

E.8.2 OFF-SITE ECONOMIC COST

The term used for off-site exposure cost was designated as averted off-site property damage costs (AOC). The off-site economic loss for a 50-mile radius of the site was determined using the MACCS2 model developed for the CGS Level 3 PSA in Section E.7. Table E.8-2 provides the economic loss for each release category obtained for the base case of the Level 3 PSA weighted by the release category frequency. The total economic loss from internal events (I_t) was estimated to be $\$6.14 \cdot 10^3$ per year. The averted off-site property damage cost was determined using Equation E.8-8 [**1**, Section 5.7.5].

$$\text{AOC} = (\text{C})(\text{I}_t) \qquad \text{(E.8-8)}$$

where,

AOC = off-site economic costs associated with a severe accident ($)

C = present value factor (yr)

I_t = monetary value of economic loss per year from internal events before discounting ($/yr)

The values for the **best estimate** case are:

C_{be} = 13.05 yr

I_t = $\$6.14 \cdot 10^3$ /yr

$$AOC_{be} = (13.05\text{yr})\left(6.14 \cdot 10^3 \frac{\$}{\text{yr}}\right) = \$80{,}128 \qquad \text{(E.8-9)}$$

E.8.3 ON-SITE EXPOSURE COST

The term used for on-site exposure cost was designated as averted occupational exposure (AOE). The NRC methodology used to estimate the AOE consists of two components: (1) the calculation of immediate dose cost (short-term) and (2) long-term dose cost [**1**, Section 5.7.3]. The development of the two contributions is discussed in Sections E.8.3.1 and E.8.3.2.

E.8.3.1 Immediate Dose Cost

The immediate doses were those doses received at the time of the accident and during the immediate management of the accident. The immediate on-site dose cost was determined using Equation E.8-10.

$$W_{IO} = (R)(F)(D_{IO})(C) \qquad \text{(E.8-10)}$$

where,

W_{IO} = monetary value of accident risk avoided from immediate doses, after discounting ($)

R = monetary equivalent of unit dose ($/person-rem)

F = CDF (events/yr)

D_{IO} = immediate occupational dose (person-rem/event)

C = present value factor (yr)

The values for the **best estimate** case are:

R = $2,000 /person-rem

$F = 4.8 \cdot 10^{-6}$ events/yr [Table E.3-3] (internal events)

D_{IO} = 3,300 person-rem/event

C_{be} = 13.05 yr

$$W_{IO} = \left(2{,}000 \frac{\$}{\text{person-rem}}\right)\left(4.80 \cdot 10^{-6} \frac{\text{events}}{\text{yr}}\right)\left(3{,}300 \frac{\text{person-rem}}{\text{event}}\right)(13.05\text{yr}) = \$413.42 \cong \$413 \quad \text{(E.8-11)}$$

E.8.3.2 Long-Term Dose Cost

The long-term doses were those doses received during the process of cleanup and refurbishment or decontamination. The long-term on-site dose cost was determined using Equation E.8-12.

$$W_{LTO} = (R)(F)(D_{LTO})(C)\left(\frac{1-e^{-rm}}{rm}\right) \quad \text{(E.8-12)}$$

where,

W_{LTO} = monetary value of accident risk avoided long-term doses, after discounting ($)

R = monetary equivalent of unit dose ($/person-rem)

F = CDF (events/yr)

D_{LTO} = long-term occupational dose (person-rem/event)

r = discount rate (%/yr)

m = on-site cleanup period (yrs)

The values for the **best estimate** case are:

R = $2,000 /person-rem

$F = 4.8 \cdot 10^{-6}$ events/yr [Table E.3-3] (internal events)

D_{LTO} = 20,000 person-rem/event

C_{be} = 13.05 yr

r = 7%/yr = 0.07/yr

m = 10 yrs

$$W_{LTO} = \left(2{,}000\,\frac{\$}{\text{person}\cdot\text{rem}}\right)\left(4.80\cdot10^{-6}\,\frac{\text{events}}{\text{yr}}\right)\left(20{,}000\,\frac{\text{person}\cdot\text{rem}}{\text{event}}\right)(13.05\text{yr})\left(\frac{1-e^{-\left(\frac{0.07}{\text{yr}}\right)(10\text{yrs})}}{\left(\frac{0.07}{\text{yr}}\right)(10\text{yrs})}\right) \quad \text{(E.8-13)}$$

$W_{LTO} \cong \$1801$

E.8.3.3 Total Accident-Related Occupational Exposure Costs

The AOE costs were estimated by combining the immediate on-site dose cost (W_{IO}) and long-term dose cost (W_{LTO}) equations and using the numerical values calculated in Sections E.8.3.1 and E.8.3.2.

The **best estimate** case accident-related occupational exposure cost is:

$$AOE_{be} = W_{IO} + W_{LTO} = \$413 + \$1{,}801 = \$2{,}214 \quad \text{(E.8-14)}$$

E.8.4 ON-SITE ECONOMIC COST

The term used for on-site economic cost was designated as averted on-site costs (AOSC). To determine the AOSC, the estimation consists of three components: (1) the estimation of cleanup and decontamination costs, (2) repair and refurbishment cost, and (3) the replacement power costs over the remaining life of the facility [**1**, Section 5.7.6]. The repair and refurbishment costs are only considered for a recoverable accident and not for a severe accident. Therefore, this component did not need to be evaluated for this analysis. The development of the remaining two contributions is discussed in Sections E.8.4.1 and E.8.4.2.

E.8.4.1 Cleanup/Decontamination

The present value of the cost of cleanup and decontamination over the remaining life of the facility (U_{CD}) was determined by using Equation E.8-15.

$$U_{CD} = (PV_{CD})(C)(F) \qquad \text{(E.8-15)}$$

where,

PV_{CD} = present value of the cost of cleanup/decontamination ($)

C = present value factor (yr)

F = CDF (events/yr)

Section 5.7.6 of Reference [**1**] assumes a total cleanup/decontamination cost of $\$1.5\text{x}10^9$ as a reasonable estimate and this same value was adopted for these analyses. Assuming a ten-year cleanup period, the present value of this cost was determined by using Equation E.8-16.

$$PV_{CD} = \left(\frac{C_{CD}}{m}\right)\left(\frac{1-e^{-rm}}{r}\right) \qquad \text{(E.8-16)}$$

where,

PV_{CD} = present value of the cost cleanup/decontamination

C_{CD} = total cost of the cleanup/decontamination effort ($)

m = cleanup period (years)

r = discount rate (%/yr)

The values for the **best estimate** case are:

$C_{CD} = \$1.5 \cdot 10^9$

m = 10 years

r = 7%/yr = 0.07/yr

C_{be} = 13.05 yr

$F = 4.8 \cdot 10^{-6}$ events/yr [Table E.3-3] (internal events)

$$U_{CD} = \left(\frac{\$1.5 \cdot 10^9}{10}\right)\left(\frac{1-e^{-(0.07)(10\text{yrs})}}{0.07}\right)(13.05\text{yr})\left(4.80 \cdot 10^{-6}\right) \cong \$67{,}545 \qquad \text{(E.8-17)}$$

E.8.4.2 Replacement Power Costs

Replacement power costs were calculated in accordance with Reference [**1**, Section 5.7.6]. The replacement power is needed for the time period following a severe accident and for the remainder of the expected generating plant life. Therefore, the long-term power replacement equations were used to calculate replacement power costs. The present value of replacement power was calculated using Equation E.8-18. Equation E.8-18 was developed for discount rates between 5% and 10%.

$$PV_{RP} = \frac{B}{r}\left(1 - e^{-rt_f}\right)^2 \qquad \text{(E.8-18)}$$

where,

PV_{RP} = present value of the cost of replacement power for a single event ($)

t_f = years remaining until end of facility life (yr)

r = discount rate (%/yr)

and B is a constant representing a string of replacement power costs that occur over the lifetime of a reactor after an event (for a 910 MWe "generic" reactor, uses a value of $\$1.2 \cdot 10^8$ \$/yr). The following equation from Reference [**2**] scaled the constant to the CGS rated electrical power of 1107 MWe.

$$B = \$1.2 \cdot 10^8/\text{yr}\left(\frac{1107\text{MWe}}{910\text{MWe}}\right) = \$1.46 \cdot 10^8/\text{yr} \qquad \text{(E.8-19)}$$

The values for the **best estimate** case are:

t_f = 35 yrs

r = 7%/yr = 0.07/yr

B = $\$1.46\text{x}10^8$/yr

$$PV_{RP} = \frac{\$1.46\text{x}10^8/\text{yr}}{\left(\frac{0.07}{\text{yr}}\right)}\left(1 - e^{-\left(\frac{0.07}{\text{yr}}\right)(35\text{yrs})}\right)^2 = \$1.74\text{x}10^9 \qquad \text{(E.8-20)}$$

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

$$U_{RP} = \frac{PV_{RP}}{r}\left(1 - e^{-rt_f}\right)^2 (F) \qquad \text{(E.8-21)}$$

where,

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

t_f = years remaining until end of facility life (yr)

r = discount rate (%/yr)

F = CDF (events/yr)

Based upon the values previously assumed for the **best estimate** case:

$$U_{RP} = \frac{\$1.74 \cdot 10^9}{\left(\frac{0.07}{yr}\right)}\left(1 - e^{-\left(\frac{0.07}{yr}\right)(35yrs)}\right)^2 \left(4.80 \cdot 10^{-6}\right) \cong \$99{,}627 \qquad \text{(E.8-22)}$$

E.8.4.3 Total Averted On-Site Costs

The AOSCs were estimated by combining the cleanup and decontamination (U_{CD}) and replacement power costs (U_{RP}) equations, and using the numerical values calculated in Sections E.8.4.1 and E.8.4.2.

The **best estimate** case averted on-site cost is:

$$AOSC_{be} = U_{CD} + U_{RP} = \$67{,}545 + \$99{,}627 = \$167{,}172 \qquad \text{(E.8-23)}$$

E.8.5 TOTAL COST

The total cost of severe accident impact for internal events was calculated by summing the occupational exposure cost, on-site economic cost, public exposure cost, and off-site property damage cost. The cost of the impact of a severe accident for internal events was $345,550 as shown in Table E.8-3. CGS has a seismic PSA and a fire PSA from which risk contributions can be combined with the risk associated with internal events. The risk contributions for seismic and fire were estimated using the same parameters discussed in this Section for internal events. Details for each are provided in Table E.11-3 and Table E.11-4, respectively.

An additional hazard group, categorized as "other," was added to include the risk contribution from high winds, external floods, and other external events. The benefit from the "other" hazard group contribution was conservatively estimated to be equivalent to that of internal events. Therefore, the cost of SAMA implementation was compared with a benefit value including the contribution from internal events, fire, seismic, and other hazard groups. This provided a comparison of the cost to the risk reduction estimated for internal, fire, and external events for each SAMA. The maximum benefit for CGS was $1,886,578 as shown in Table E.8-3.

E.9 CANDIDATE SAMA IDENTIFICATION

The first step was to develop a comprehensive list of SAMA candidates to be subjected to the qualitative screening. The comprehensive list of SAMA candidates was developed by completing the following of tasks:

- Review of industry guidance documents and completed SAMA analyses.
- Review of the CGS IPE and IPEEE results.
- A review of the Level 1 PSA and Level 2 PSA results.
- Discussions with CGS personnel.

E.9.1 REVIEW OF INDUSTRY DATA

Since CGS is a BWR, particular interest was paid to existing SAMA candidates for BWRs. Nuclear Energy Institute (NEI) 05-01 [**2**] provides a standard list of BWR SAMA candidates, which was used as the starting point for the potential CGS SAMA candidates.

In addition to the SAMA candidates provided in Reference [**2**], Table 13, a review was undertaken of the BWR SAMA analyses completed and documented as supplements to NUREG-1437 [**54, 55, 56, 57, 58, 59, 60, 61, 62, 63, 64, 65**]. These were reviewed to identify any SAMA candidates that might apply to CGS, but were not included in Reference [**2**]. No additional candidates were identified by the review of the supplements to NUREG-1437.

E.9.2 CGS IPE AND IPEEE REVIEW

A review was performed of the following documents:

- Individual Plant Examination Washington Nuclear Plant 2 Main Report, Revision 1, July 1994 [**66**].
- Individual Plant Examination of External Events Washington Nuclear Plant 2, Main Report Revision 0, June 1995 [**67**].

The IPE identified the major contributors to CDF for plant internal events, including internal floods. The IPE identified the following major contributors to plant CDF [**66**, Section 1.4.1]:

- LOOP (67%)

- Internal flooding (11%)
- Transients initiators (5%) and,
- Transient and failure to scram (ATWS) (3%).

Based on the CDF results and insights, the IPE provided the following recommendations [**66**, Section 6.2]:

- Modify the isolated phase buses to allow expeditious alignment of the 500 kV highline to the plant AC distribution system via the main step-up transformer, following a loss of both the normal 230 kV and 115 kV off-site power sources.
- This modification had not been implemented at the time of this analysis. It was included as a SAMA candidate for evaluation (AC/DC-27).
- Increase the capacity of the 230 kV/115 kV plant bus transfer to maximize the effective availability of the 230 kV off-site power source.
- A cost-benefit analysis had been performed by CGS for this modification and this modification was not cost effective, and no additional SAMA candidates were evaluated.
- Install an additional battery charger that can both provide an additional source of charging to either DC bus and reduce the potential for CCF of the battery chargers.
- The single Division 1 and Division 2 battery chargers were replaced by two battery chargers in each division. One battery charger per division is normally de-energized and then placed into service on failure of the operating battery charger. This recommendation has been partially met. Battery chargers are not a significant contributor to risk, and no additional SAMA candidates were evaluated.
- Evaluate procedures and training for the recognition and isolation of floods identified to cause multiple system failures.
- PSA-2-FL-001, Revision 5 [**68**, Section 5.2.2] states: "Although the impact of a potential flooding accident can be very large, the control room will be alarmed very early, the operators have been trained for these type of plant conditions, and the mitigating process is well proceduralized." Therefore, the intent of the recommendation was met and no additional SAMA candidates were evaluated.

- Review the results from industry research on providing defense against CCFs and confirm the existing CGS operational and maintenance practices take full advantage of the insights that are currently available.

- A SAMA analysis to evaluate reducing the likelihood of CCF between EDG-3 and EDG-1/2 was identified (AC/DC-28).

- The IPE noted that for ATWS scenarios, the water level was lowered to control power. If the ADS setpoint was reached, the operator had to inhibit the ADS function within the 105 second time delay to prevent depressurization and possible low pressure injection that would sweep out boron from SLC [**66**, Section 3.1.2.3-1A]. For non-ATWS scenarios, the use of the inhibit switch was not allowed and, in order to follow emergency procedure guidance, the operators had to invoke the ADS inhibit function every 105 seconds or result in an unwanted depressurization.

- A licensing action to allow the plant the same emergency procedure assumption as the other BWRs was implemented. Procedures were changed to allow the use of the ADS inhibit switch in non-ATWS scenarios. Therefore, the intent of the recommendation was met and no additional SAMA candidates were evaluated.

- The IPE recommended that to provide a longer coping time during SBO scenarios, that the vessel be maintained at pressure, with the vessel not being depressurized until fuel melt starts, but before vessel breach. The additional coping time due to delaying depressurization until fuel melt was evaluated to reduce CDF by up to 34%.

- Emergency procedures [**69**] now instruct that: "If a makeup source is available, AND RPV level can be determined, THEN INITIATE RPV depressurization using SRVs, (minimizing the SRV operations) at a rate not to exceed 100°F per hour, AND MAINTAIN RPV pressure between 100 psig and 200 psig." Therefore, the intent of the recommendation was met and is not considered for further SAMA evaluation.

The CGS IPEEE examines internal fires, seismic events, and external events such as winds/tornadoes, external flooding, transportation accidents, and accident at nearby facilities. The IPEEE provides the following insights:

- Fire: The dominant fire sequences render containment venting, power conversion system (PCS), and one train of RHR or service water unavailable, such that the other decay heat removal train unavailability dominates the sequences. [**67**, Section 1.4.2]

- SAMA analyses were performed to evaluate improving the resistance of cabling to the containment vent valve and to the 230kV start-up transformer (FR-07a and FR-07b).

- Seismic: The IPEEE [**67**, Section 1.4.1] states "The overall impression from the walkdowns and the review of the seismic qualification documentation is that the plant is well constructed and has a high resistance to seismic loading." The plant was conservatively designed for 0.25 g PGA, and most equipment was screened out. A specific evaluation was performed for MCCs. This evaluation determined the most limiting MCCs had a median capacity of 1.03g for anchoraged (0.44g HCLPF) and a median capacity of 1.00g for relay chatter (0.43 HCLPF). Conservative modeling (e.g., no recovery actions) resulted in a seismic CDF of 2.1E-05/year.

- The PSA seismic analysis calculates a seismic CDF of 5.25E-06/year, with the largest contributors being failures to primary containment and the reactor building. Two seismic SAMA candidates were evaluated. Neither of these candidates was considered cost effective.

- Other External Events: Other external events (e.g., severe weather, external flooding, volcanic activity, and accidents at nearby facilities) were examined [**67**, Section 5]. Based on a progressive screening approach recommended in GL 88-20 [**70**], no significant vulnerabilities were identified and these events were screened from further evaluation [**67**, Sections 1.4.3 – 1.4.7]. Therefore, no SAMA candidates related to these external events were added to the list of potential SAMA candidates.

E.9.3 LEVEL 1 INTERNAL EVENTS DOMINANT CUTSETS

A review was performed of the top 100 cutsets for the Revision 6.2 of the CGS Level 1 PSA (internal events, including internal flooding) to identify the significant risk contributors. Table E.9-1 provides a summary of the top 100 Level 1 PSA core damage cutsets. This list of cutsets represents over 56% of the total CDF, and includes all cutsets individually contributing 0.1% or more of the total CDF.

From these cutsets the following significant contributors were identified:

- LOOP with CCF of all three EDGs.

  The initial SAMA candidate list included adding an additional diesel generator (AC/DC-10) and installing a gas turbine generator (AC/DC-15). Also, an additional SAMA (AC/DC-28) was evaluated to examine the benefits of reducing CCFs between the existing EDGs.

- SBO and failure of RCIC before power can be restored.

Loss of RCIC for these cases was dominated by depletion of batteries supplying RCIC control power. SAMA candidates included in the initial list included extending battery (AC/DC-01) or replacing batteries with fuel cells (AC/DC-02), and providing a portable battery charger (AC/DC-03).

- Main Steam Line break with CCF of two in series MSIVs to close.

  This scenario assumed all ECCS injection is lost early due to the harsh environment resulting from the unioslated stream flow. This scenario resulted in the dominant plant V-sequence event. CGS has initiated an extensive MSIV program, including installing improved solenoid valves and a modified preventative maintenance program with scheduled replacement for increased reliability.

- Flooding events with failure of safety relief valves (SRVs) to close and loss of RHR, HPCS or service water.

  CGS has an extensive SRV testing program that tests SRV reseat as part of plant startup. Therefore, no additional SAMA candidate was proposed to enhance SRV reseat capability. SAMA candidates evaluating additional injection capability were included in the initial list of candidates (CC-01, CC-02, and CC-12) and containment decay heat removal (CP-01).

- Failure of switchgear ventilation due to CCF of fans.

  A SAMA candidate to provide a redundant HVAC train was evaluated (HV-02).

- Reactor Vessel Rupture

  A reactor vessel rupture event is assumed to lead directly to core damage. No SAMA candidates addressing a reactor vessel rupture were identified.

E.9.4 LEVEL 1 SYSTEM IMPORTANCE

CGS systems were evaluated with respect to their RRW importance measure. Having a high RRW indicates that improving the reliability of that system results in a greater CDF reduction than systems with a relatively lower RRW value. Therefore, systems with high RRW values were considered as potential SAMA candidates.

Table E.9-2 provides a ranking of systems and trains by RRW. Systems with highest RRW values included:

- HPCS and RCIC
- The initial SAMA candidates list included adding additional high pressure injection capability (CC-01 and CC-02).
- AC Buses
- The initial SAMA candidates included developing a procedure to replace 4 kV breakers and pre-staging the breakers (AC/DC-23).
- EDGs
- The initial SAMA candidate list included adding an additional diesel generator (AC-DC-10) and installing a gas turbine generator (AC/DC-15). Also, an additional SAMA (AC/DC-28) was evaluated to examine the benefits of reducing CCFs between the existing EDGs.
- RHR in Suppression Pool Cooling Mode
- The initial SAMA candidate list included a SAMA candidate to add an additional suppression pool cooling train (CP-01).
- Switchgear Ventilation
- The initial SAMA candidate list included a candidate to provide redundant HVAC train (HV-02).

E.9.5 LEVEL 2 AND LEVEL 3 IMPORTANCE INSIGHTS

The Level 2 PSA model [**71**] analyzes containment performance following core damage accidents. Accident propagation is modeled, with the final result being either the containment intact or one of three release categories. Section E.4 provides the latest Level 2 PSA quantification results. The Level 2 PSA analysis provides the following source release categories, beginning with the most severe release (with given percentage of internal event CDF) [**71**, Section 5]:

<u>LEN: Large, Early, Not-Scrubbed (13.6%)</u>

The LEN category results in the largest and earliest fission product release. The LEN category is characterized by early, large containment failures occurring at containment locations that bypass fission product scrubbing by the suppression pool.

Because of the potential for this category to produce the most significant off-site consequences, special attention has been given to the identification of SAMA candidates that reduce or eliminate system and component failures leading to LEN releases. For example, augmenting emergency core cooling capability (as described below) in a manner that makes the overall capability less vulnerable to flooding was

considered in order to reduce the frequency of sequences such as FLDR2S11 (~1.4% of the internal events CDF and ~10% of the internal events LEN). Similarly, V-sequence events (Sequence AOS05) are dominated by main steam line failure with subsequent failure of MSIVs to close in at least one of the four steam lines. V-sequences account for ~3% of the internal events CDF and ~23% of the internal events LEN. Particular attention was paid to increasing the reliability of MSIV closure, also as described below. Finally, ATWS events such as Sequence T(E)NS78 (~1.7% of the internal events CDF and ~12% of the internal events LEN) were addressed by the consideration of a number of ATWS-related enhancements discussed below, as well.

Taken together, these three specific sequences account for ~5% of the internal events CDF, but ~45% of the internal events LEN releases. Taking the entire PDSs they represent into account, the percentages increase to ~9% and ~63% for CDF and LEN, respectively. Overall, LEN represents ~14% of the CDF, but ~23% of the population dose for internal events. Because of the Level 2/Level 3 importance of the three specific sequences mentioned (~10% of the population dose while accounting for only ~5% of the CDF) and the PDSs they represent, identifying SAMA candidates that can reduce the frequency of these sequences, their respective PDSs, and the likelihood they will lead to LEN releases was of particular importance.

The major contributors to release category LEN are [**71**, Section 5.6]:

- Flooding events that fail all ECCSs (23.3%)

  Numerous SAMA candidates addressing ECCS capability were considered, including high pressure injection (CC-01 and CC-02) and low pressure injection (CC-12).

- Large V-sequence events (23.3%)

  Numerous SAMA candidates addressing V-sequence events were considered (CB-01 through CB-09), in particular CB-04 dealing with enhanced MSIV reliability.

- ATWS (27.1%)

  Numerous SAMA candidates addressing ATWS events were considered (AT-01 through AT-14).

<u>LLN: Large, Late, not-Scrubbed (34.6%)</u>

Release category LLN is similar to release category LEN, with the exception that the release is less, due to fission product decay and deposition over time. Although for each scenario the fission product release is less than that of release category LEN, the frequency of LLN events is greater than the frequency of LEN events. Release category LLN has the greatest frequency, with over one third of internal core damage

events and over one half of all core damage events resulting in release category LLN. Major contributors to release category LLN are:

- Initiating event followed by long-term loss of all ECCS injection
- Long-term loss of suppression pool cooling
- Loss of high pressure injection and suppression pool cooling
- Long-term SBO
- LOOP with long-term loss of high pressure injection and low pressure injection

SAMA candidates addressing all these contributors were evaluated.

LLS: Large, Late, Scrubbed Release (11.9%)

Release Category LLS is characterized by large failures of the containment that are located such that the release path passes through the suppression pool, thereby resulting in fission product scrubbing by the suppression pool water. Of the release categories modeled, this one is of lowest importance due to its smaller release and also its lower frequency of occurrence. Major contributors to Release Category LLS are:

- Reactor vessel rupture
- Initiating event followed by loss of high pressure injection and suppression pool cooling

SAMA candidates addressing high pressure injection and suppression pool cooling were already considered important because of the contribution of that combination of functional losses to LLN. No SAMA candidates to reduce the likelihood of vessel rupture were identified.

COK: Containment Intact (39.8%)

Approximately 40 percent of internal event core damage scenarios terminate with the containment intact. The core damage sequences that result in an intact containment with the highest frequency are:

- Long-term SBO with DC unavailable at the time of core melt and HPCS available.
- Short term SBO, with DC and ADS available at the time of core melt.
- Initiating event with short term loss of HPCS and ADS.
- Long-term SBO with DC not available at the time of core melt.

From a Level 2/Level 3 perspective, events ending with the containment intact are only minor contributors to risk. Nevertheless, SAMA candidates addressing all these contributors were evaluated since there are still on-site costs to consider.

E.9.6 INITIAL SAMA CANDIDATE LIST

Based on the review of the aforementioned sources, an initial list of 150 SAMA candidates was assembled. The comprehensive list of initial SAMA candidates considered for implementation at CGS are provided in Table E.9-3, where each SAMA is categorized and identified according to a global modification identifier.

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E.10 PHASE 1 SAMA ANALYSIS – SCREENING

The cost-benefit evaluation performed as part of this analysis was concerned only with those modifications that reduce the severe accident risk associated with plant operation if implemented at CGS. Therefore, the purpose of the initial (qualitative) screening was to identify the subset of those SAMA candidates identified in Table E.9-3 that warrant a detailed cost-benefit evaluation.

Since most of the SAMA candidates were derived from industry sources, they include a wide variety of potential enhancements that may not be directly applicable to CGS. In addition, several SAMA candidates initially considered may have already been implemented at CGS. Some SAMA candidates were screened on the basis of excessive implementation cost (no cost estimate is necessary) or very low benefit (no PSA case is needed to be run). Each of SAMA candidates was screened consistent with guidance in Reference [**2**]. Table E.10-1 provides the results of the qualitative screening.

E.10.1 NOT APPLICABLE – CRITERION A

The SAMA candidates were identified to determine which ones are definitively not applicable to CGS. Potential enhancements that were not considered applicable to CGS were those developed for systems specifically associated with Pressurized Water Reactors (PWRs) or associated with specific BWR equipment that is not present at CGS. For example, CGS, being a BWR 5 design, has an electric motor-driven HPCS, while the majority of operating BWRs are of the BWR 3 or BWR 4 design, with a steam-driven HPCI. Therefore, modifications to the steam side of the HPCI systems did not apply to CGS. Also, some SAMA candidates addressed the use of systems from a second unit at a multi-unit site, which also did not apply. SAMA candidates meeting this criterion were eliminated from further analysis.

The SAMA candidates that were not applicable to CGS were reviewed to ensure that other potential modifications similar in intent, and applicable to CGS, were identified.

E.10.2 ALREADY IMPLEMENTED – CRITERION B

The remaining SAMA candidates were reviewed to identify those modifications that have already been implemented at CGS. Some of the SAMA candidates had been implemented as a result of insights gained from the CGS IPE and IPEEE studies. Also, because CGS is a relatively more recent BWR design, some of the SAMA candidates had already been achieved in the original plant design. For example, CGS has the capability to transfer AC power automatically from normal to standby power. This satisfies the SAMA candidate that calls for the addition of an automatic feature to

transfer the AC from normal to standby power. The SAMA candidates meeting this criterion were eliminated from further analysis.

E.10.3 CONSIDERED FOR FURTHER EVALUATION – CRITERION C

SAMA candidates that did not meet either Criterion A, B, D, or E were considered for further evaluation and subject to a cost-benefit evaluation.

E.10.4 EXCESSIVE IMPLEMENTATION COST – CRITERION D

Some SAMA candidates were determined to be prohibitively expensive by inspection. An example of this type of SAMA was an extensive and extremely expensive modification to the containment. If a SAMA candidate required extensive changes that obviously exceeded the maximum benefit, the candidate was not retained for further evaluation. The maximum benefit (defined in Section E.8.5 and reported in Table E.8-3) was less than $1,900,000.

E.10.5 VERY LOW BENEFIT – CRITERION E

If a SAMA candidate was related to a non-risk significant system for which the change in reliability has negligible impact on the risk profile, the candidate had a very low benefit and was not retained.

E.10.6 SUBSUMING OF SAMA CANDIDATES

During the screening process, if a particular SAMA candidate was found to be similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or more plant-specific candidate, it was subsumed by the most appropriate SAMA candidate for CGS. The subsumed SAMA candidate was not evaluated further; however, the intent of such SAMA candidates was captured by the SAMA candidate by which they were subsumed.

E.11 PHASE 2 SAMA ANALYSIS – COST-BENEFIT

Those SAMA candidates not eliminated by the qualitative screening were selected for cost-benefit analysis. The first step in the cost-benefit analysis was to use the Level 1 PSA and Level 2 PSA Revision 6.2 models for CGS to evaluate the impact on the CDF and release category frequencies for each SAMA requiring additional consideration.

The Level 1 PSA results are categorized by grouping each sequence into one of 18 PDSs. Each PDS summarizes functional characteristics and the status of systems important to the containment performance assessment. The primary categorization used to define the CGS Level 1 PDS was by accident type, such as (a) loss of containment heat removal, (b) loss of coolant injection, and (c) ATWS. Secondary binning consideration was by the systems that may or may not be available to mitigate the accident after core uncovery (i.e., ADS, HPCS, AC power). Tertiary binning consideration was by the power and system recoverability. The fourth binning consideration was by HPCS failure type.

In the Level 2 PSA analysis, each PDS was evaluated by a set of CETs. Each CET models accident progression and containment performance from the PDS to the eventual source release characterization. Level 2 results were binned into one of five release categories. The frequency and source term characteristic for each release category was provided as input to the subsequent Level 3 analysis. A summary of each Level 2 PSA release category is provided in Section E.9.5. The release category LES (large, early, scrubbed) is not reported in Section E.9.5, since the CGS analysis indicates that scrubbing can not occur for these sequences and the LES frequency is zero.

E.11.1 SAMA BENEFITS

The CGS baseline PSA model provided the CDF and release category frequencies for input into the cost-benefit evaluation. The CDF was used to determine the maximum benefit of eliminating all risk from the plant. The release category frequencies were used in the Level 3 PSA analysis to determine the maximum monetary loss and population dose. These values were then used in the maximum benefit evaluation.

E.11.1.1 SAMA Candidate Evaluation

The benefit of each candidate SAMA was estimated by modifying either the Level 1 PSA or Level 2 PSA model to reflect the benefit that could be derived (by implementing the SAMA). The estimated benefit was determined by applying a bounding modeling assumption in the PSA model. For example, if the objective of a particular SAMA was to reduce the likelihood of a certain component or system failure, that component or system was modeled to be perfectly reliable, even though the SAMA candidate would

likely not completely eliminate failure of that component or system. This bounding treatment is conservative for a SAMA evaluation, since underestimating the risk in the modified PSA case makes the modification looks more attractive than it may be.

Initially applying conservative bounding estimates for an expected SAMA candidate benefit simplified the PSA modeling changes that are required, and therefore improved the efficiency of the entire process. In the majority of cases, a bounding analysis was sufficient to eliminate a SAMA candidate from further consideration. For some SAMA candidates, the results from a bounding assumption did not provide an unambiguous conclusion for the cost-benefit analysis. In this case, an additional case(s) was performed by applying a more detailed analysis and less bounding PSA modifications to better estimate the true benefit.

The PSA model modifications and calculations were performed for the Level 1 and Level 2 PSA model at-power, including internal events, the fire events, and seismic events.

The PSA modifications and Level 1 PSA and Level 2 results for each candidate SAMA are detailed in Reference [**72**]. A summary of the 24 PSA results for each SAMA candidate analyzed is provided in Table E.11-1.

E.11.1.2 Best-Estimate Benefit Calculation

The reference value parameters included the discount rate, time to expiration of the renewed CGS license, cost per person-rem, short term exposure, long-term exposure, on-site cleanup duration, total on-site cleanup cost, replacement power net present value, and present worth factor. These reference values were used in the baseline calculation performed in Section E.8. The CDF for the hazard group varied with the PSA case being modeled. A total of 24 PSA cases were modeled to analyze the benefit of plant-specific SAMA candidates identified in the screening process in Section E.10. The final inputs required were the consequence parameters. The consequence parameters, off-site dose and economic impact, were provided in the Level 3 PSA completed in Section E.7. These consequence parameters were provided for each of the five release categories.

The next step in the analysis was to calculate the benefit (in U.S. dollars) for each modeled PSA case associated with the implementation of a SAMA candidate. The total benefit included the contribution from all hazard groups. Therefore, a worksheet was developed to calculate the benefit for internal events, fire, and seismic hazard groups. The internal events, fire, and seismic worksheets used the equations discussed in Section E.8 to calculate the AOE, AOSC, APE, and AOC. For each case, the benefit from internal events, fire, seismic, and other external events were summed in a worksheet to determine the total benefit of implementing the SAMA. As discussed in Section E.8.5, the "other" hazard group risk contribution was conservatively estimated to be equivalent to internal events risk contribution.

The results of the benefit analysis for all the SAMA cases are presented in Table E.11-2 to Table E.11-4 for each hazard group. Table E.11-5 represents the total benefit for all the SAMA cases. These are the final benefit results used for comparison against the implementation costs.

E.11.2 SAMA IMPLEMENTATION COSTS

To assess the viability of each SAMA candidate considered for a final cost-benefit evaluation, the cost of implementing that particular SAMA was estimated and compared with the estimated benefit. If the cost of implementation was greater than the attainable benefit for a particular SAMA, then the modification was not economically viable and was eliminated from further consideration

The costs of implementation were established from existing estimates of similar modifications and estimates provided by personnel at CGS [**73**] [**74**]. The cost estimates were developed from similar modifications considered in previously performed SAMA and severe accident mitigation design alternative (SAMDA) analyses. The implementation costs for plant-specific SAMA candidates that could not be inferred from other references were estimated by CGS [**73**] [**74**]. In particular, the cost estimates were derived from the following sources:

- CGS Cost Estimates [**73**] [**74**]
- Vermont Yankee License Renewal [**64**]
- Arkansas Nuclear One, Unit 2 License Renewal [**86**]
- Nine Mile Point License Renewal [**59**]
- James A. FitzPatrick License Renewal [**65**]

The implementation costs were scaled for a present day cost using an annual inflation rate of four percent. Equation E.11.2-1 was used to calculate the present day (i.e., calendar year 2008) cost. Table E.11-6 provides the implementation cost estimate and present day value for the SAMA candidates that were derived from the above sources.

$$Cost_{2008} = Cost_n (1 + 0.04)^{(2008-n)} \qquad \text{(E.11.2-1)}$$

Several of the SAMA candidates considered were clearly in excess of the attainable benefit estimated from a particular case. The costs of all SAMA candidates were conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately estimated.

E.11.3 COST-BENEFIT EVALUATION

The results of the cost-benefit evaluation are presented in Table E.11-7. This table provides a comparison of cost with the benefits of SAMA implementation and final conclusions drawn for each SAMA candidate.

E.12 SENSITIVITY ANALYSIS

Sensitivity cases were performed to investigate the sensitivity to the hazard groups PSA results to certain modeling assumptions in the CGS SAMA analysis. Since many calculations were required, worksheets were developed to reduce the complexities of the calculations. The equations and development of the worksheets are consistent with Section E.8.

A total of six sensitivity benefit calculations were performed. Below is a brief description of the six sensitivity cases.

- The first sensitivity case investigated the impact of assuming damaged plant equipment is repaired and refurbished following an accident scenario, as opposed to automatically decommissioning the facility following the event.
- The second sensitivity case investigated the sensitivity of each analysis case to the discount rate by assuming a lower discount rate of three percent.
- The third sensitivity case investigated the sensitivity of each analysis case to the discount rate by assuming a higher discount rate of ten percent.
- The fourth sensitivity case investigated the sensitivity of each analysis case to the on-site dose estimates. This sensitivity case assumed higher short term (14,000 person-rem) and long-term dose (30,000 person-rem) [**1**, Section 5.7.3].
- The fifth sensitivity case investigated the sensitivity of each analysis case to the total on-site cleanup cost. This sensitivity case assumed a higher on-site cleanup cost of $2,000,000,000 [**1**, Section 5.7.6].
- The sixth sensitivity case investigated the sensitivity of each analysis case to replacement power. An inflation rate was determined by assessing the electricity costs in 1993 and in 2008 dollars for the state of Washington. The inflation rate was used to calculate the 2008 dollar value for the string of replacement power costs (B in Equation E.8-19).

The results of the sensitivity studies are summarized in Table E.12-1. This table provides a comparison of the cost with the benefits of SAMA implementation for each sensitivity case and conclusions drawn for each SAMA candidate.

While the results of the sensitivity cases in Section E.7.2 showed the robustness of the Level 3 PSA model, and the sensitivity cases in this section showed the robustness of the SAMA cost-benefit evaluation, these analyses contained a number of conservative assumptions and inputs. No explicit uncertainty was performed since the number of conservative assumptions and input account for any uncertainties in the calculations.

As the SAMA candidates appear to be cost-beneficial when considering the sensitivity cases, the conservatisms add further assurance of the appropriateness of the results and the subsequent conclusions. Thus, the gap between benefit and cost could be increased if some of the conservative assumptions were relaxed. Some of the base case conservatisms included:

- Each of the PSA cases to estimate the change in CDF used bounding assumptions in the manipulation of the PSA model, which offsets the CDF uncertainty. For example, if a SAMA candidate could reduce the likelihood of a large break LOCA, the bounding assumption was that there would be no large break LOCA, overestimating the benefit of the SAMA candidate.

- CGS-specific cost estimates were simply performed. A detailed cost estimation was likely to include factors that were not considered for this analysis; accordingly, the cost estimates are conservatively underestimated. The large, more generic costs far exceed the estimated benefit, which many orders of magnitude of uncertainty would need to be considered without impacting the results.

- The fire PSA and the seismic PSA, known to be conservative, are often "adjusted" using a reducing factor. The CGS analysis did not use a reducing factor and used the reported values for the fire CDF and seismic CDF (as well as the corresponding release category frequencies) in determining (and overestimating) the benefit of the SAMA candidates.

- To estimate the impact of other external events (e.g., high winds, external floods), the maximum benefit of the internal events PSA was used. This was used in addition to not using a reducing factor on the fire and seismic results, further overestimating the benefit.

- In the Level 3 PSA, several of the input parameters were purposely developed in a conservative manner:

    - The value of release fractions were taken from the end of the time traces, rather than when the release was estimated to be terminated. This overestimated the source term.

    - The population was escalated to 2045, two years beyond the end of the requested license renewal period. In addition, the escalation factor used was a constant, despite the census indication that the Washington state population was increasing as a decreasing rate. Such an overestimation of the population impacted the consequence metrics used to estimate off-site dose and economic consequences of the SAMA candidates.

E.13 CONCLUSIONS

The cost-benefit evaluation of SAMA candidates performed for CGS license renewal process provided significant insight into the continued operation of CGS. The results of the evaluation of 150 SAMA candidates indicated no enhancements to be cost beneficial for implementation at CGS. However, the sensitivity cases performed for this analysis found three SAMA candidates to be cost beneficial for implementation at CGS under the assumption of the second sensitivity case (lower discount rate). These additional cost beneficial SAMA candidates are AC/DC-28, which reduced the CCFs between EDG-3 and EDG-1/2, FR-07a, which improved the fire resistance of cables to the containment vent valve, and FR-07b, which improved the fire resistance of cables to transformer E-TR-S. The cost-benefit threshold was exceeded for the lower discount rate sensitivity case. While none of the three SAMA candidates are related to plant aging, Energy Northwest will, nonetheless, consider implementation of these candidates through normal processes for evaluating possible changes to the plant.

The cost-benefit evaluation performed used several conservatisms. The guidance document, Section 5 of Reference [1], used in performing the cost-benefit evaluation is inherently conservative. The PSA cases used a conservative approach to estimate the benefit from a particular SAMA. The estimation of the total benefit assumed, conservatively, that the contribution due to "other" external events was equivalent to the risk contributions of internal events. These conservative assumptions, combined with the results of several sensitivity cases, showed the robustness of the SAMA analysis results.

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E.14 FIGURES

There are no figures in Attachment E.

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E.15 TABLES

Table E.3-1 Summary of CGS PSA

PSA	Documentation Revision Number	Date	Plant Mod	Data / Bayesian Update	Baseline CDF or LERF
Internal Events (including Internal Flooding) Level 1	3.0	8/2006	8/2006	6/2002	4.77E-6
Internal Events Level 2	2.0	1/2004	*	*	6.53E-7
Fire Level 1	2.0	11/2006	*	*	7.40E-6
Fire Level 2	2.0	11/2006	**	**	2.46E-7
Seismic Level 1	1.0	2/2007	*	*	5.25E-6
Seismic Level 2	1.0	2/2007	**	**	2.15E-6

* Plant Modifications and Data based on Internal Events Level 1 Model Revision 6.2
** Plant Modifications and Data based on Internal Events Level 2 Model Revision 6.2

Table E.3-2 Summary of CGS PSA Truncation Limits

	Fault Tree	Event Tree	Global
Internal Events			
Level 1	1E-10	7E-11[1] to 5E-12	5E-12
Level 2	1E-8 to 1E-14[2]	1E-13	1E-13
Fire			
Level 1	2E-9	1E-11	1E-11
Level 2	1E-8 to 1E-14[2]	1E-13	1E-13
Seismic			
Level 1	1E-10	1E-12	1E-12
Level 2	1E-12	1E-12	1E-12

[1] The quantification of six accident sequences is performed at approximately 7E-11 to maintain the number of cutsets for those sequences below a maximum set by the quantification program. All other event tree sequences are solved at a 5E-12 truncation.

[2] Depending on the fault tree, the truncation limit was adjusted to assure sufficient capture of the contributing basic events.

Table E.3-3 Initiating Event Frequency Contribution to Core Damage Frequency

Initiator Types	CDF	Percentage
General Transients		
Turbine Trip	1.15E-07	2.4%
MSIV Closure	4.60E-08	1.0%
Loss of Condenser	2.22E-07	4.6%
Loss of Feedwater	1.89E-07	3.9%
LOOP	3.04E-07	6.4%
Inadvertent/Stuck Open Main Steam Safety Relief Valve (SORV)	2.05E-07	4.3%
Manual Shutdown	1.27E-07	2.7%
SBO	1.58E-06	33.1%
LOCA		
RPV Rupture	3.00E-07	6.4%
Large LOCA	9.37E-11	0.0%
Medium LOCA	3.56E-10	0.0%
Small LOCA	3.95E-09	0.1%
Steam Line Break Outside Containment	1.53E-07	3.2%
ISLOCA	3.78E-10	0.0%
ATWS	8.36E-08	1.8%
Special Initiators (Loss of DC, Loss of AC buses, Loss of HVAC, Loss of Plant Service Water & Control Air Systems (CAS), and Instrument line breaks)	7.17E-07	15.0%
Internal Flooding	7.39E-07	15.3%
Total	4.79E-06	100%

Table E.3-4 Summary of Accident Sequence Quantification Results Top 24 Sequences

	Sequence	CDF	Percentage	Description
1	SBO-RS36	8.99E-07	18.8	SBO with HPCS and RCIC failure and failure to recover AC power within 30 minutes
2	SG1HVS03	4.06E-07	8.5	Loss both divisions of switchgear room cooling with failure of RHR containment heat removal, and failure of injection at containment failure
3	RPVRS02	3.00E-07	6.3	RPV rupture, which is assumed to fail all injection
4	TIS34	2.01E-07	4.2	Transient with a SORV, failure of high pressure injection and failure to depressurize the reactor
5	SBO-IS34	1.87E-07	3.9	Long-term SBO, RCIC operable, HPCS failure, emergency battery depletion at 6 hours
6	IE-F1S03	1.83E-07	3.8	Reactor building flood with SORV
7	TCS14	1.54E-07	3.2	Loss of condenser vacuum with failure of high pressure injection and failure to depressurize the reactor
8	AOS05	1.49E-07	3.1	Large LOCA outside containment with failure to isolate
9	TFS17	1.44E-07	3.0	Loss of main feedwater (MFW) with failure of high pressure injection and failure to depressurize the reactor
10	T(E)NS52	1.24E-07	2.6	LOOP with failure of high pressure injection and failure to depressurize the reactor
11	SBO-IS27	1.21E-07	2.5	Long-term SBO with failure of HPCS to run
12	SBO-RS29	1.11E-07	2.3	Long-term SBO with failure to recover off-site power in 10 hours
13	SBO-IS67	1.08E-07	2.3	SBO with SORV, failure of HPCS and failure to recover AC power in 1 hour
14	FLDR6S04	1.01E-07	2.1	Reactor building flood with loss of injection
15	MSS22	7.81E-08	1.6	Manual shutdown with loss of high pressure injection and failure to depressurize the reactor
16	T(E)NS78	7.76E-08	1.6	LOOP with failure of the RPS to shutdown
17	IE-F1S02	7.39E-08	1.5	Reactor building flood with SORV
18	TTS22	7.06E-08	1.5	Turbine trip with failure of high pressure injection and failure to depressurize the reactor
19	SRS17	6.93E-08	1.4	Instrument line break with failure of HPCS and failure to depressurize the reactor
20	FLDR2S11	6.72E-08	1.4	Reactor building flood with failure to isolate
21	TCASS05	6.15E-08	1.3	Loss of containment instrument air system (CIA) with long-term loss of containment heat removal

Table E.3-4 Summary of Accident Sequence Quantification Results Top 24 Sequences (continued)

	Sequence	CDF	Percentage	Description
22	SBO-IS20	5.38E-08	1.1	SBO with SORV and HPCS failure at containment failure
23	TSM2S17	5.06E-08	1.1	Loss of plant electrical bus SM-2 with failure of high pressure injection and failure to depressurize the reactor
24	FLDR3S21	4.55E-08	1.0	Reactor building flood with failure to isolate

Table E.3-5 Summary of Accident Sequence Quantification Results Grouped by Accident Sequence Class (PDS)

PDS	CDF	Sequence	% of CDF	Sequence CDF	% of PDS CDF
6A1	1.03E-06		21.5%		
		SBO-RS36		8.99E-07	87.3%
		SBO-IS67		1.08E-07	10.5%
		SBO-RS62		2.31E-08	2.2%
1A2	8.43E-07		17.6%		
		TIS34		2.01E-07	23.9%
		TCS14		1.54E-07	18.3%
		TFS17		1.44E-07	17.1%
		MSS22		7.81E-08	9.3%
		TTS22		7.06E-08	8.4%
		SRS17		6.93E-08	8.2%
		TSM2S17		5.06E-08	6.0%
		TM1S17		4.00E-08	4.7%
		TSM1S14		9.36E-09	1.1%
2D	5.06E-07		10.6%		
		SG1HVS03		4.06E-07	80.2%
		MSS06		2.70E-08	5.3%
		TTS06		2.44E-08	4.8%
		TCS04		1.84E-08	3.6%
		TCASS03		6.97E-09	1.4%
		TDC2S06		5.01E-09	1.0%
1G	4.90E-07		10.2%		
		IE-F1S03		1.83E-07	37.3%
		FLDR6S04		1.01E-07	20.6%
		TCS13		4.46E-08	9.1%
		TFS16		4.15E-08	8.5%
		IE-F2S03		3.39E-08	6.9%
		FLDR2S06		1.45E-08	3.0%
		TSM2S16		1.08E-08	2.2%
		FLDR3S31		7.37E-09	1.5%
		MSS21		6.55E-09	1.3%
		TTS21		5.92E-09	1.2%

Table E.3-5 Summary of Accident Sequence Quantification Results Grouped by Accident Sequence Class (PDS)

(continued)

PDS	CDF	Sequence	% of CDF	Sequence CDF	% of PDS CDF
6B1	3.32E-07		6.9%		
		SBO-IS27		1.21E-07	36.4%
		SBO-RS29		1.11E-07	33.5%
		SBO-IS20		5.38E-08	16.2%
		SBO-IS10		2.49E-08	7.5%
		SBO-IS26		7.06E-09	2.1%
		SBO-IS18		5.70E-09	1.7%
1B0	3.07E-07		6.4%		
		IE-F1S02		7.39E-08	24.0%
		TCASS05		6.15E-08	20.0%
		FLDR3S21		4.55E-08	14.8%
		FLDR3S12		2.64E-08	8.6%
		FLDT1S05		1.65E-08	5.4%
		IE-F2S02		9.69E-09	3.2%
		MSS14		7.95E-09	2.6%
		MSS10		7.59E-09	2.5%
		TTS14		7.13E-09	2.3%
		TTS10		6.80E-09	2.2%
3C	3.00E-07		6.3%		
		RPVRS02		3.00E-07	100.0%
6B2	1.97E-07		4.1%		
		SBO-IS34		1.87E-07	95.1%
		SBO-RS34		4.72E-09	2.4%
		SBO-IS33		4.50E-09	2.3%
5A	1.52E-07		3.2%		
		AOS05		1.49E-07	97.7%
		AOS10		3.04E-09	2.0%
1C	1.52E-07		3.2%		
		FLDR2S11		6.72E-08	44.3%
		FLDR3S36		3.23E-08	21.3%

Table E.3-5 Summary of Accident Sequence Quantification Results Grouped by Accident Sequence Class (PDS)

(continued)

PDS	CDF	Sequence	% of CDF	Sequence CDF	% of PDS CDF
		FLDR8S18		1.50E-08	9.9%
		FLDRES18		1.50E-08	9.9%
		FLDR6S09		9.60E-09	6.3%
		FLDR1S27		6.72E-09	4.4%
		FLDR7S18		1.56E-09	1.0%
		FLDRDS18		1.56E-09	1.0%
1A3	1.45E-07		3.0%		
		T(E)NS52		1.24E-07	85.8%
		T(E)NS43		1.05E-08	7.3%
		T(E)NS77		9.96E-09	6.9%
4BA	1.13E-07		2.4%		
		T(E)NS78		7.76E-08	69.0%
		TTCS38		1.64E-08	14.6%
		FLDT1S12		1.13E-08	10.1%
		TCCS36		1.71E-09	1.5%
		TFCS36		1.58E-09	1.4%
The following PDSs Accident Sequences contribute less than 1% to the CDF.					
1H	8.12E-08		1.7%		
4BL	6.38E-08		1.3%		
1A1	5.08E-08		1.1%		
6A2	2.34E-08		0.5%		
2B	1.64E-09		0.0		
1B1	1.35E-11		0.0		
3E	0.00E+00		0.0		

Table E.3-6 CGS PSA Dominant Sequences (>5% contribution to CDF)

Sequence	Brief Description	Frequency	% of CDF
SBO-RS36	SBO with initial (early) failure of HPCS and RCIC. Failure to recover off-site power in 30 minutes leads to core damage.	8.99E-7	18.8
SG1HVS03	Loss of Switchgear Room Cooling, failing Division 1 and PCS. HPCS provides injection, but RHR containment heat removal is failed. All injection sources fail when containment overpressurizes and fails.	4.06E-07	8.5
RPVRS02	RPV Rupture, which is assumed to fail all injection causing core damage.	3.00E-7	6.3

Table E.3-7 Fire Core Damage Frequency (Total CDF = 7.40E-06/yr)

Item #	PSA Fire Compartment	Description	CDF (per year)
1	R-1J	Reactor Building 522 Elevation	1.19E-06
2	RC-14	SWGR Room #1	9.96E-07
3	RC-04	Division 1 Elect Equipment Room	8.39E-07
4	R-1D	Northwest Reactor Building 471 Elevation	7.41E-07
5	RC-11	A A/C Room	7.28E-07
6	RC-3	Cable Chase	4.46E-07
7	RC-08	SWGR Room #2	3.60E-07
8	Y-01	Transformer Yard	3.22E-07
9	RC-10	Main Control Room	3.04E-07
10	RC-5	Battery Room 1	2.52E-07
11	RC-2	Cable Spreading Room	2.21E-07
12	RC-13	Emergency Chiller	2.04E-07
13	TG-1A	Turbine Generator West 441	1.59E-07
14	TG-12	South Corridors	1.33E-07
15	RC-1A	Radwaste Building 437N	1.24E-07
16	RC-07	Division 2 Elect Equipment	8.99E-08
17	R-1B	Northeast RB 471 Elevation	5.77E-08
18	TG-1C	Turbine Generator East 441	5.16E-08
19	TG-1D	Turbine Generator West 471	4.90E-08
20	R-1C	Southeast RB 471 Elevation	2.04E-08

Table E.3-8 Fire Importance Analysis

Rank	Event Name	Description	Risk Reduction
1	FW03	Fire Initiating Event in Zone W03	1.064
2	ADSHUMN--T--H3-F	Operator Fails To Initial Depressurization in Non-ATWS Event [Fire]	1.041
3	FW02	Fire Initiating Event in Zone W02	1.031
4	EDCDIS1-C1-2W4LL	Battery Charger C1-2 TO S1-2 Disconnect Switch Fails	1.013
5	EDCDISCS1-2AW4LL	Failure of 200 Amp. Fused Disconnect TOE-DP-S1/2A	1.013
6	SW-P-MD1A-1BC2	CCF for SW-P-1A,B Fail to Start & Run	1.005
7	EAC-RHR-CCF	CCF for MOC Assy Failure	1.004
8	EACTR--8-83-W4D2	Transformer TR-8-83 Loss of Function	1.003
9	EACCB--8-83-G4D2	Circuit Breaker 8-83 Spurious Trip	1.002
10	EACCB--838F-G4D2	Circuit Breaker from SI-83 to Mc-8F Spurious Trip	1.002
11	EACMC--8F---W4D2	MCC MC-8F Loss of Function	1.002
12	EACSM--8----W4D1	4160 Volt Bus SM-8 Loss of Function	1.002
13	EACSL--83---W4D2	480 Volt AC BUS SL-83 Loss of Function	1.002
14	EACTR--7-73-W4D1	Transformer TR-7-73 Loss of Function	1.002
15	SW-V-MO2AB29C3LL	Failure Of Discharge MOVs SW-2A, SW-2B and SW-29 (ATC 4/18)	1.001
16	EACCB--737F-G4D1	Circuit Breaker from SL-73 TO MC-7F Fails to Remain Closed	1.001
17	EACCB--7-73-G4D1	Circuit Breaker 7-73 FTRC	1.001
18	EACMC--7F---W4D1	MCC MC-7F Loss of Function	1.001
19	EACSM--7----W4D1	4160 Volt Bus SM-7 Loss of Function	1.001
20	EACSL--73---W4D1	480 Volt AC BUS SL-73 Loss of Function	1.001
21	EACCB--83-8AG4D2	Circuit Breaker from SL-83 to MC-8A Spurious Trip	1.001
22	EACMC--8A---W4D2	MCC MC-8A Loss of Function	1.001
23	EACCB--73-7AG4D1	Circuit Breaker from SL-73 TO MC-7A Fail to Remain Closed	1.001
24	EACMC--7A---W4D1	MCC MC-7A Loss of Function	1.001
25	EDCPP--S1-2AW4LL	Failure of Distribution Panel E-DP-S1/2A	1.001
26	EDCPP--S12--W4LL	Failure of Bus E-DP-S1/2	1.001
27	XDPHUMN-INJ-AHR-	Operator Fails to Initiate ADS and Fails to Control HPCS/RCIC	1.001

Table E.3-8 Fire Importance Analysis (continued)

Rank	Event Name	Description	Risk Reduction
28	SW-FL--ST3ACC3	CCF of SW-P-1A & 1B Motor Bearing Strainers (Beta=0.1)	1.001
29	XDPHUMN-INJ-RA--	Operator Fails to Initiate ADS and Fails to Control RCIC	1.001
30	SW-FL-SCRNS-C3LL	CCF Blockage of All SW Intake Screens	1

Table E.3-9 CGS SPSA Seismic Hazard Curve

PGA (g)	5th Percentile	15th Percentile	Median	Mean	85th Percentile	95th Percentile
0.1	3.2E-4	6.1E-4	1.2E-3	1.3E-3	2.1E-3	2.9E-3
0.2	5.0E-5	9.0E-5	2.5E-4	3.0E-4	5.0E-4	7.2E-4
0.3	1.1E-5	2.4E-5	8.4E-5	1.1E-4	1.9E-4	2.8E-4
0.4	3.7E-6	8.0E-6	3.5E-5	4.7E-5	8.7E-5	1.4E-4
0.5	1.4E-6	3.2E-6	1.6E-5	2.3E-5	4.5E-5	7.3E-5
0.6	6.9E-7	1.6E-6	8.9E-6	1.3E-5	2.6E-5	4.3E-5
0.7	3.2E-7	8.1E-7	4.8E-6	7.4E-6	1.5E-5	2.5E-5
0.8	1.7E-7	4.4E-7	2.8E-6	4.5E-6	9.3E-6	1.6E-5
0.9	9.0E-8	2.5E-7	1.7E-6	2.8E-6	5.8E-6	1.0E-5
1.0	5.1E-8	1.4E-7	1.1E-6	1.8E-6	3.8E-6	6.9E-6
1.1	2.8E-8	8.0E-8	6.4E-7	1.1E-6	2.4E-6	4.4E-6
1.2	1.5E-8	4.4E-8	3.8E-7	7.1E-7	1.5E-6	2.8E-6
1.3	8.0E-9	2.5E-8	2.3E-7	4.5E-7	9.6E-7	1.8E-6
1.4	4.3E-9	1.4E-8	1.4E-7	2.8E-7	6.0E-7	1.2E-6
1.5	2.3E-9	7.9E-9	8.3E-8	1.8E-7	3.8E-7	7.5E-7

Table E.3-10 Seismic CDF by SDS Event Tree Initiator

	SDS Sequence	Associated Core Damage Event Tree	Seismic-Induced Failures Description	CDF	Percentage
1	SDS42	SDS42	Fails RPV and key buildings RPV supports (3%), Primary Containment (40%), Reactor Building (32%), Radwaste/Control Building (15%), Diesel Generator Building (10%).	2.38E-06	45.4
2	SDS41	SDS41	Fails Key Safety System Equipment RHR heat exchangers, SSW, pumps, Distributed piping systems (assumed to lead to internal flooding and core damage), Division I and Division II (Div 1, Div 2) DC power, Control Room main panels.	1.64E-06	31.2
3	SDS6	S624	LOOP, small-small LOCA, and Div. 1 & 2 AC distribution, BOP, and CST failure	2.19E-07	4.2
4	SDS4	SDS4	LOOP, small-small LOCA, EDG 1&2, BOP and CST failure without AC recovery	1.85E-07	3.5
5	SDS2	SDS2, S2P2, S2P3	LOOP, small-small LOCA, SBO SBO and RCIC without AC recovery	1.84E-07	3.5
6	SDS5	S523	BOP, CST, LOOP, small-small LOCA, EDG 1&2, Div. III	1.33E-07	2.5
7	SDS17	SLAC	BOP, CST, LOOP, medium LOCA, EDG 1&2, Div. III	1.08E-07	2.1
8	SDS7	S725	BOP, CST, LOOP, small-small LOCA, Div. I&II, Div. III, Off-site AC Not Recoverable	1.04E-07	2.0
9	SDS22	SDS22	BOP, CST, LOOP, N2 Tank, small-small LOCA, EDG 1&2	6.20E-08	1.2
10	SDS38	SDS38	BOP, CST, LOOP, N2 Tank, EDGs stalled and not re-started	5.76E-08	1.1
11	SDS18 SDS36	S1836	BOP, CST, LOOP, medium LOCA, Div. I&II, Off-site AC Not Recoverable	1.99E-08	0.4
12	SDS30	S1230	BOP, CST, LOOP, N2 Tank, SLOCA, Div. I&II, Off-site AC Not Recoverable	1.78E-08	0.3
13	SDS13	S1331	BOP, CST, LOOP, small LOCA, Div. I&II, Div. III, Off-site AC Not Recoverable	1.63E-08	0.3
14	SDS29	S1129	BOP, CST, LOOP, N2 Tank, small LOCA, EDG 1&2, Div. III	1.62E-08	0.3
15	SDS16	SDS16	BOP, CST, LOOP, medium LOCA, EDG 1&2	8.86E-09	0.2
16	SDS10	SDS10	BOP, CST, LOOP, small LOCA, EDG 1&2	8.06E-09	0.2
17	SDS40	SDS40	Failure to Scram and Failure to Mitigate	7.93E-09	0.2
18	SDS34	SDS34	BOP, CST, LOOP, N2 Tank, medium LOCA, EDG 1&2	6.34E-09	0.1
19	SDS28	SDS28	BOP, CST, LOOP, N2 Tank, small LOCA, EDG 1&2	5.97E-09	0.1

Table E.3-10 Seismic CDF by SDS Event Tree Initiator (continued)

	SDS Sequence	Associated Core Damage Event Tree	Seismic-Induced Failures Description	CDF	Percentage
20	SDS3	SDS3, S3P2	BOP, CST, LOOP, small-small LOCA, Div. III	4.56E-09	0.1
21	SDS20	SDS20, S20P2, S20P3	BOP, CST, LOOP, N2 Tank, small-small LOCA	4.36E-09	0.1

Table E.3-11 Seismic CDF and LERF by Plant Damage State

Main Category		Sub-Category		Seismic CDF[3]	% CDF	Seismic LERF	% LERF
1	Transient of Small LOCA sequences with loss of RPV coolant make-up	1A1	Short-term transients with loss of high pressure injection and failure to depressurize (TUX) sequences with loss of containment air	n/a[1]			
		1A2	Short-term TUX sequences with offsite power available	n/a			
		1A3-A	Short-term TUX sequences with LOOP and at least 1 DG (Div. 1 or 2) available (HP injection available)	n/a			
		1A3-B	Short-term TUX sequences with LOOP and at least 1 DG (Div. 1 or 2) available (high pressure injection unavailable) Includes internal flooding contribution from SDS41	8.21E-07	15.7%	3.30E-07	15.4%
		1B0	Loss of containment heat removal with LOOP, at least 1 DG (Div. 1 or Div 2) available and failure of high pressure injection (low pressure injection systems subsequently become ineffective as the containment pressurizes and the SRVs close on high containment	9.31E-09	0.2%	0.00E+00	0.0%
		1C	Loss of all ECCS due to flooding	n/a			
		1G	Long-term TUV sequences with offsite power available	0.00E+00	0.0%	0.00E+00	0.0%
		1H	Long-term TUV sequences with LOOP and at least 1 DG (Div. 1 or 2) available	4.63E-10	0.0%	0.00E+00	0.0%

Table E.3-11 Seismic CDF and LERF by Plant Damage State (continued)

Main Category		Sub-Category		Seismic CDF(3)	% CDF	Seismic LERF	% LERF
2	Transient sequences with loss of containment heat removal	2B	A long-term TW sequence with RPV at low pressure (SORVs or LOCA) at time of core damage includes internal flooding contribution from SDS41.	8.20E-07	15.6%	0.00E+00	0.0%
		2D	Long-term TW sequences with RPV at high pressure at time of core damage	9.50E-09	0.2%	0.00E+00	0.0%
3	LOCAs	3C	Excessive LOCA (RPV Rupture)	0.00E+00	0.0%	0.00E+00	0.0%
		3E	Large LOCA with failure of containment pressure suppression	0.00E+00	0.0%	0.00E+00	0.0%
4	ATWS	4BA	ATWS with RPV intact at time of core damage	8.08E-09	0.2%	8.08E-09	0.4%
		4BL	ATWS with RPV failed at time of core damage	0.00E+00	0.0%	0.00E+00	0.0%
5	LOCAs Outside Containment	5	Large LOCA outside containment	2.38E-06	45.3%	1.79E-06	83.5%
6	SBO	6A1	Short-term (< 2 hrs) SBO, DC power and ADS available at time of core damage. RPV at high pressure.	2.23E-07	4.3%	1.41E-08	0.7%
		6A2	Long-term (> 6 hrs) SBO with SORV or LOCA, DC power and ADS not available at time of core damage. RPV at low pressure.	1.36E-07	2.6%	0.00E+00	0.0%
		6B1	Long-term (> 6 hrs) SBO, DC power and ADS not available at time of core damage. HPCS operating initially.	5.62E-07	10.7%	0.00E+00	0.0%
		6B2	Long-term (> 6 hrs) SBO, DC power and ADS not available at time of core damage. RCIC operating initially.	2.78E-07	5.3%	0.00E+00	0.0%

(1) The "n/a" entries indicate that those accident sequence classifications are not used in the SPSA.

(2) This CDF point estimate is the minimized frequency obtained by merging all the individual sequence equations. The straight sum of the individual accident class totals is a non-minimized total and will be slightly higher than the 5.25E-6/yr point estimate.
(3) Consistent with the ANS Standard supporting requirements SA-A3, the CGS internal events event tree models are used as a starting point for the CGS SPSA. The internal events PSA event trees not applicable to the SPSA accident sequence analysis (e.g., general transient trees, internal flooding trees, ATWS trees) are "trimmed" out of the SPSA model files. Specific event trees are developed, such as SDS41 is used to account for internal flooding, SDS40 is used to account for ATWS, etc. due to seismic.

Table E.4-1 Internal Events LERF Split Fraction for Each Plant Damage State

PDS	Description	PDS Frequency	LERF Split Fraction	Total LERF Contribution (per year)
1A1	Loss of control and service air sequences with early failure of HPCS, RCIC and RPV depressurization. Containment venting is unavailable. The sequences indicate high reactor pressure at the time of core damage with containment intact.	5.1E-8	1.1E-1	5.5E-9
1A2	Transient and small LOCA sequences with early failure of HPCS, RCIC and RPV depressurization. The sequences indicate high reactor pressure at the time of core damage, with the containment intact.	8.4E-7	1.1E-1	9.1E-8
1A3A	LOOP sequences with failure of high pressure injection and failure to depressurize. The sequences indicate high reactor pressure at the time of core damage, with the containment intact. HPCS is recoverable after core damage occurs.	4.7E-8	6.2E-3	2.9E-10
1A3B	LOOP sequences with failure of high pressure injection and failure to depressurize. The sequences indicate high reactor pressure at the time of core damage, with the containment intact. HPCS is not recoverable.	9.8E-8	4.3E-2	4.3E-9
1B0	Transients in which high pressure injection fails and RPV depressurization succeeds. Containment heat removal is unavailable. In the long-term, containment pressure increases to the point that ADS valves cannot operate. The low pressure systems can no longer inject and core damage occurs prior to containment failure. The sequences indicate high reactor pressure at the time of core damage, with the containment intact.	3.1E-7	0.0	0.0E+0
1C	Loss of all ECCS due to flooding. The sequences indicate high reactor pressure at the time of core damage, with the containment failed.	1.5E-7	1.0	1.5E-7
1G	Transient and small LOCA sequences with failure of both high and low pressure injection, but success of emergency depressurization, resulting in core damage before containment failure, with the reactor at low pressure.	4.9E-7	7.8E-4	3.8E-10
1HA	LOOP sequences with no high or low pressure injection, but RPV depressurization is successful. This results in core damage before containment failure, with the reactor at low pressure. HPCS is recoverable after core damage occurs.	3.5E-8	7.7E-4	2.7E-11

Table E.4-1 Internal Events LERF Split Fraction for Each Plant Damage State (continued)

PDS	Description	PDS Frequency	LERF Split Fraction	Total LERF Contribution (per year)
1HB	LOOP sequences with no high or low pressure injection, but RPV depressurization is successful. This results in core damage before containment failure, with the reactor at low pressure. HPCS is not recoverable.	4.7E-8	7.7E-4	3.6E-11
2B	Transient with stuck-open SRV or LOCA with loss of containment heat removal. Containment failure occurs prior to core damage with the reactor vessel at low pressure.	1.6E-9	0.0	0.0E+0
2D	Transient with loss of containment heat removal. Containment fails prior to core damage with the reactor vessel at high pressure.	5.1E-7	0.0	0.0E+0
3C	Medium LOCA with successful depressurization or large LOCA. Early failure of HPCS and low pressure injection. The sequences indicate low reactor pressure at the time of core damage, with the containment intact.	3.0E-7	7.8E-4	2.3E-10
4BA	ATWS with vessel intact at time of core uncovery, which indicates high pressure core damage with containment failed.	1.1E-7	1.0	1.1E-7
4BL	ATWS with vessel failed at time of core uncovery, which indicates low pressure core damage with containment failed.	6.4E-8	1.0	6.4E-8
5	LOCA outside containment with failure to isolate the break. The sequences indicate low reactor pressure at the time of core damage, with the containment bypassed.	1.5E-7	1.0	1.5E-7
6A1A	SBO sequences with early failure of HPCS and RCIC. The sequences indicate high reactor pressure at the time of core damage, with the containment intact. HPCS is recoverable after core damage occurs.	3.0E-7	6.8E-2	2.0E-8
6A1B	SBO sequences with early failure of HPCS and RCIC. The sequences indicate high reactor pressure at the time of core damage, with the containment intact. HPCS is not recoverable.	7.4E-7	6.8E-2	5.0E-8
6A2	SBO sequences with a SORV, no containment heat removal, but successful injection until containment failure. Injection fails at containment failure, resulting in core damage at low reactor pressure with containment failed.	2.3E-8	0.0	0.0E+0
6B1	SBO sequences with initial success of HPCS. If HPCS operation is lost due to HPCS diesel failure, operation is recoverable if ac power is restored. Containment heat removal is unavailable. Core damage occurs at high pressure with containment intact.	3.3E-7	0.0	0.0E+0

Table E.4-1 Internal Events LERF Split Fraction for Each Plant Damage State (continued)

PDS	Description	PDS Frequency	LERF Split Fraction	Total LERF Contribution (per year)
6B2A	SBO sequences with failure of HPCS early, but success of RCIC until battery depletion. Containment heat removal is unavailable. Core damage occurs at high pressure with containment intact. HPCS is recoverable after core damage occurs.	5.7E-8	0.0	0.0E+0
6B2B	SBO sequences with failure of HPCS early, but success of RCIC until battery depletion. Containment heat removal is unavailable. Core damage occurs at high pressure with containment intact. HPCS is not recoverable.	1.4E-7	0.0	0.0E+0
All Sequences		4.8E-6	1.4E-1	6.53E-7

Table E.4-2 PDS with LERF Split Fraction of 1.00

PDS	Description	LERF Split Fraction	% of Total LERF
1C	Internal Flood with failure of all systems	1.00	23.3%
4BA	ATWS with failure of SLC	1.00	17.3%
4BL	ATWS with failure to inhibit ADS	1.00	9.8%
5	LOCA outside containment	1.00	23.3%
	Total		73.6%

Table E.4-3 Internal Events Level 2 Release Category

Release Category	Description	Frequency (per year)	Percentage
COK	Containment Intact, scrubbed release	1.91E-06	39.8%
LEN	Large, early, non-scrubbed release	6.53E-07	13.6%
LLN	Large, late, non-scrubbed release	1.66E-06	34.6%
LLS	Large, late, scrubbed release	5.75E-07	11.9%

Table E.4-4 Fire LERF Contribution for Each Plant Damage State

PDS	Description	PDS Frequency	LERF Split Fraction	Total LERF Contribution (per year)
1A1	Loss of control and service air sequences with early failure of HPCS, RCIC and RPV depressurization. Containment venting is unavailable. The sequences indicate high reactor pressure at the time of core damage with containment intact.	0.0E+0	n/a	0.0E+0
1A2	Transient and small LOCA sequences with early failure of HPCS, RCIC and RPV depressurization. The sequences indicate high reactor pressure at the time of core damage, with the containment intact.	8.3E-7	1.1E-1	9.0E-8
1A3A	LOOP sequences with failure of high pressure injection and failure to depressurize. The sequences indicate high reactor pressure at the time of core damage, with the containment intact. HPCS is recoverable after core damage occurs.	0.0E+0	n/a	0.0E+0
1A3B	LOOP sequences with failure of high pressure injection and failure to depressurize. The sequences indicate high reactor pressure at the time of core damage, with the containment intact. HPCS is not recoverable.	3.2E-7	4.0E-1	1.3E-7
1B0	Transients in which high pressure injection fails and RPV depressurization succeeds. Containment heat removal is unavailable. In the long-term, containment pressure increases to the point that ADS valves cannot operate. The low pressure systems can no longer inject and core damage occurs prior to containment failure. The sequences indicate high reactor pressure at the time of core damage, with the containment intact.	2.4E-6	0.0	0.0E+0
1C	Loss of all ECCS due to flooding. The sequences indicate high reactor pressure at the time of core damage, with the containment failed.	0.0E+0	n/a	0.0E+0
1G	Transient and small LOCA sequences with failure of both high and low pressure injection, but success of emergency depressurization, resulting in core damage before containment failure, with the reactor at low pressure.	1.6E-6	7.8E-4	1.231E-09
1HA	LOOP sequences with no high or low pressure injection, but RPV depressurization is successful. This results in core damage before containment failure, with the reactor at low pressure. HPCS is recoverable after core damage occurs.	0.0E+0	n/a	0.0E-+0

Table E.4-4 Fire LERF Contribution for Each Plant Damage State (continued)

PDS	Description	PDS Frequency	LERF Split Fraction	Total LERF Contribution (per year)
1HB	LOOP sequences with no high or low pressure injection, but RPV depressurization is successful. This results in core damage before containment failure, with the reactor at low pressure. HPCS is not recoverable.	7.7E-8	7.8E-4	5.97E-11
2B	Transient with stuck-open SRV or LOCA with loss of containment heat removal. Containment failure occurs prior to core damage with the reactor vessel at low pressure.	2.8E-8	0.0	0.0E+0
2C	Transient with stuck-open SRV or LOCA with loss of containment heat removal. Containment failure occurs prior to core damage with the reactor vessel at low pressure.	1.5E-6	0.0	0.0E+0
2D	Transient with loss of containment heat removal. Containment fails prior to core damage with the reactor vessel at high pressure.	0.0E+0	n/a	0.0E+0
4BA	ATWS with vessel intact at time of core uncovery, which indicates high pressure core damage with containment failed.	2.7E-10	1.0	2.7E-10
4BL	ATWS with vessel failed at time of core uncovery, which indicates low pressure core damage with containment failed.	0.0E+0	n/a	0.0E+0
5	LOCA outside containment with failure to isolate the break. The sequences indicate low reactor pressure at the time of core damage, with the containment bypassed.	0.0E+0	n/a	0.0E+0
6A1A	SBO sequences with early failure of HPCS and RCIC. The sequences indicate high reactor pressure at the time of core damage, with the containment intact. HPCS is recoverable after core damage occurs.	0.0E+0	n/a	0.0E+0
6A1B	SBO sequences with early failure of HPCS and RCIC. The sequences indicate high reactor pressure at the time of core damage, with the containment intact. HPCS is not recoverable.	3.7E-7	6.8E-2	2.5E-8
6A2	SBO sequences with a SORV, no containment heat removal, but successful injection until containment failure. Injection fails at containment failure, resulting in core damage at low reactor pressure with containment failed.	7.6E-8	0.0	0.0E+0
6B1	SBO sequences with initial success of HPCS. If HPCS operation is lost due to HPCS diesel failure, operation is recoverable if AC power is restored. Containment heat removal is unavailable. Core damage occurs at high pressure with containment intact.	2.7E-7	0.0	0.0E+0

Table E.4-4 Fire LERF Contribution for Each Plant Damage State (continued)

PDS	Description	PDS Frequency	LERF Split Fraction	Total LERF Contribution (per year)
6B2A	SBO sequences with failure of HPCS early, but success of RCIC until battery depletion. Containment heat removal is unavailable. Core damage occurs at high pressure with containment intact. HPCS is recoverable after core damage occurs.	0.0E+0	n/a	0.0E+0
6B2B	SBO sequences with failure of HPCS early, but success of RCIC until battery depletion. Containment heat removal is unavailable. Core damage occurs at high pressure with containment intact. HPCS is not recoverable.	3.7E-8	0.0	0.0E+0
All Sequences		7.4E-6	3.3E-2	2.46E-7

Table E.4-5 Fire Contribution of Release Category

Release Category	Description	Frequency (per year)	Percentage
COK	Containment Intact, scrubbed release	6.00E-07	8.1%
LEN	Large, early, non-scrubbed release	2.46E-07	3.3%
LLN	Large, late, non-scrubbed release	5.99E-06	80.8%
LLS	Large, late, scrubbed release	5.77E-07	7.8%

Table E.4-6 Seismic Contribution of Release Category

Release Category	Description	Frequency (per year)	Percentage
COK	Containment Intact, scrubbed release	8.29E-12	0.0
LEN	Large, early, non-scrubbed release	2.15E-06	40.9
LLN	Large, late, non-scrubbed release	3.10E-06	59.1
LLS	Large, late, scrubbed release	1.94E-09	0.04

Table E.5-1 CGS Internal Events PSA Revision Records

Rev #	Issue Date	Revisions, Highlights, and Documentation	Results (/yr)
0	8/28/92	• Original submittal to NRC (GL 88-20 requirement) • Documented as WPPSS-FTS-133	CDF=5.42E-5 Level 2 (Release Frequency) = 5.09E-6
1	7/1994	• A request was made to NRC to discontinue reviewing the original submittal, and replaced it with this version as the GL 88-20 requirement. • Reassign this issuance to be Document WPPSS-FTS-133 • Major revisions performed in the following: 1. Common Cause Factor for SRVs, MSIVs, and circuit breakers 2. LOOP initiating frequency, event tree structure, and power recovery factors 3. HRA methodology 4. Enhanced MAAP calculations	CDF=1.75E-5 Level 2 (Release Frequency) = 1.07E-6
2	8/1996	• In response to the NRC's RAI (First round has 39 questions, and second round has 3 questions), the following tasks were performed: 1. Updating the "Initiating Frequency", and developing a Failure Modes Effects Analysis (NE-02-94-36) 2. Adding the following Event Trees: • Loss of Div2 DC • Loss of AC Bus (SM1/2/3, SH5/6) • Loss of Control Room HVAC • Loss of SM-7 HVAC • Loss of SM-8 HVAC 3. Deleting the following Event Trees: • Loss of Service Water • Loss of CN (including Loss of CIA) 4. Adding RCIC as success path in the SORV event tree	CDF=1.43E-5 Level 2 (Release Frequency) did not update
	4/18/97	NRC issued IPE SER	
3	9/1997	• A major documentation enhancement and modeling improvement were performed for the BWROG PSA Certification Program. • The modeling improvements include the following: 1. Updating the "Test and Maintenance" unavailability rate using data up to 3/31/97. 2. Updating all random failure data using Bayesian method 3. Recalculating the CCF Data using Multiple Greek Letter Method 4. Revising the LOCA (large, medium, small) initiating frequency using EPRI/TR-102266 methodology with plant specific data 5. Recalculating the ISLOCA initiating frequency using NSAC-154 methodology Improving the TW sequences in all event trees	CDF=1.71E-5 Level 2 (Release Frequency) = 9.94E-6

Table E.5-1 CGS Internal Events PSA Revision Records (continued)

Rev #	Issue Date	Revisions, Highlights, and Documentation	Results (/yr)
4	9/1999	• This revision was made primarily to incorporate the LOOP related comments received from the BWROG certification inspection report. • The major tasks included the following: 1. Modifying the LOOP Initiating Frequency using NUREG-1032 [**75**] & NUREG/CR-5496 [**76**] 2. Adding the EDG recovery node in the LOOP Tree 3. Implementing the DHR success after AC recovery in the LOOP Tree 4. Adding the "Load Shed" node and 30 minutes Off-site Recovery" node to the LOOP Tree 5. Deleting the success path of using water make-up from the Diesel Fire Pump in the LOOP Tree based on the MAAP calculations 6. Updating the EDG failure rate data using plant specific data collected from 1/1/88 to 8/25/98 7. Improving the data base (CCF, failure mode consistency)	CDF=2.1E-5 Level 2 (Release Frequency) did not update
4.1	9/2001	• Update Level 1 data based on M-Rule	CDF=2.24E-5
4.2	6/2002	• Add MOC Switch model • Add firewater for post containment failure injection	CDF=1.83E-5
5.0	1/2004	• In order to prepare the DG-AOT extension licensing submittal, the following revisions were made: 1. Add the RPV rupture as an initiating event. 2. Revise the LOOP event tree sequence (reducing DG-1 and DG-2 mission time, separating HPCS FTS from FTR, applying average power recovery, using new off-site power recovery curves) 3. Revise the SBO event tree sequence (reducing HPCS-DG mission time, using new battery life calculations, performing the MAAP4 results for recovery timing) 4. Update the transient and LOCA initiating event frequency based on NUREG/CR-5750 [**77**] 5. Revise the AC fault tree to include a second battery charger 6. Apply the ECCS pump room HVAC engineering calculations 7. Add Rx Building HVAC fault tree 8. Add success criteria to certain systems 9. Update the failure data using 2003 M-Rule results (plant failure data as of 6/2002) 10. Redo Level 2 analysis focusing on LERF 11. Edit the PSA documentation	CDF=7.33E-6, LERF=6.86E-7

Table E.5-1 CGS Internal Events PSA Revision Records (continued)

Rev #	Issue Date	Revisions, Highlights, and Documentation	Results (/yr)
5.1	4/2005	• Incorporate the revised HRA results, flooding analysis, and update the CGS T&M data: 1. Incorporate the analysis results documented for addressing F&Os developed from the 2004 Peer Review (based on ASME RA-Sa-2003 Appendix A) [**6**]. 2. Reviewing and sub-dividing the flooding sequences to better represent the flooding scenarios. 3. Update the test and maintenance data using M-Rule tracking record from 2000 to 2004.	CDF=5.62E-6 LERF=6.4E-7
5.2	4/2005	• An error was found and corrected for a gate located in the RHR fault tree.	CDF=5.661E-6 LERF=6.4E-7
6.0	1/2006	• Numerous modeling changes were made to address the requirements of MSPI implementation. The major changes have been made to the following accident sequences/event trees: 1. ATWS 2. ISLOCA 3. SG HVAC 4. LOOP • Minor changes have been made to the following PSA Elements: 1. Initiating Events frequency for TF, TM, TC. 2. RCIC removal from SLOCA 3. Taking CRD, SLC credits for inventory makeup 4. Reconstructing the DAM equation 5. Reducing the RCIC credible time in LOOP 6. Battery charger credit reduced for LOC and TTSW 7. Revising the HPCS and RCIC faults trees about the suction source (CST and suppression pool)	CDF=4.74E-6 LERF=6.42E-7
6.1	5/2006	• Remove "Failure to Remain Closed" event for RHR-V-48A from the RHR fault tree • Add a command line in the batch file for calculating W2TT-R	CDF=4.74E-6 LERF=6.53E-7
6.2	8/2006	• Revised the power sources for WMA-AH-53A/B from SL-71/81 to MC-7F/8F respectively	CDF=4.77E-6 LERF=6.53E-7

Table E.5-2 CGS Fire PSA Revision Records

Rev #	Issue Date	Revisions, Highlights, and Documentation	Results (per year)
IPPEE	7/1994	Original submittal (GL 88-20 [70] requirement) Important Fire Areas Control Room	CDF=9.16E-6 CDF=8.4 E-6 Total=1.76E-5
0	4/2002	Major upgrade to NRC review of IPEEE	CDF=1.24E-5
1	6/2004	Incorporated the Latest EPRI Fire Events database [78] (11/2001) Incorporated the Rev 5.0 Level 1 PSA model Reevaluated Cable Spreading Rooms (RC 2A, 2B, and 2C) as one area. Reanalyzed the detailed analysis Included Level 2 PSA	CDF=1.40 E-5 LERF=3.36E-07
2	11/2006	1. Documented the quantification and results of the Rev. 6.2 Fire PSA, which incorporates the following: • Incorporated the Rev 6.2 Internal Events Level I PSA changes, o Fault tree revisions o Basic event data file, including new events for WMA, and HEP changes o Event trees, particularly for LOOP/SBO revisions; • Incorporated the updated compartment fire loss data obtained from the revised cable database [79]; and • Refined certain compartment fire scenarios that previously modeled LOOP using the loss of feedwater event tree with off-site power unavailable to utilize the Rev. 6.2 Internal Events Level I PSA LOOP and SBO event trees for more realistic modeling. 1. Documented the revised control room fire analysis including: • New control room evacuation human error events • Detailed descriptions of the control room scenario definition event trees • Revised results 2. Revised Attachments D, E, F, G, I and J to reflect the Rev. 6.2 Fire PSA model modifications. 3. Created Attachment K to document potential Fire PSA model modifications / upgrades for future revisions of the Fire PSA.	CDF=7.40E-6 LERF=2.46E-7

Table E.5-3 CGS Seismic PSA Revision Records

Rev #	Issue Date	Revisions, Highlights, and Documentation	Results (per year)
IPPEE	6/1995	Original submittal (GL 88-20 requirement)	CDF=2.1E-5
0	12/2004	Upgrade Seismic IPEEE to Level 1 and Level 2 consistent with 1. ANSI/ANS-58.21-2003 **[19]** (both with respect to the SPRA Primer provided in Appendix B to the Standard, and as outlined in the requirements of Section 3.7 of the Standard) 2. EPRI Report 1002989, Seismic Probabilistic Risk Assessment Implementation Guide, Dec 2003 **[20]**	CDF= 6.67E-6 LERF=6.67E-6
1	2/2007	1. Updated to incorporate internal events Level 1 Rev 6.2 changes;: • Fault tree revisions (see internal events revision page for details) • Corrected transfer error for CCF for 2AC and X2E fault trees • Basic event data file, including new basic events for WMA, and HEP changes • Event trees, particularly for LOOP/SBO revisions 2. Deleted LERF multipliers and incorporated new seismic LERF model based on Level 2 Rev 6.2 3. Requantified SPSA with new/revised models 4. Revised importance, sensitivity and uncertainty analyses 5. Updated EDG-3 mission time 6. Revised and added new HEPs 7. Updated new batch and output files 8. Updated DAM file 9. Updated new importance analyses 10. Added new seismic event trees	CDF = 5.24E-6 LERF = 2.15E-6

Table E.6-1 Washington State Census Data

Year	Population[a]	Estimated Escalation (per decade)	Decade for Escalation	Comment
1990	4,866,692	--		
2000	5,894,121	21.11%	1990 to 2000	
2007	6,468,424	14.20%	2000 to 2010	Equivalent escalation from 2000 to 2010 assuming uniform escalation per each year in the decade. From 2000 to 2007, the per-year escalation rate is 1.337% per year. For a per-decade rate, $(1.01337)^{10}$ = 1.1420, or a rate of 14.20% per decade.

[a] Population data were taken from **[50]** for Washington State.

Table E.6-2 Population Data within 50-Mile Radius of CGS

Year	Population	Estimated Escalation (per decade)
1980	251,684	--
1990	301,943	19.97
2000	336,115	11.32
2010	360,395	7.22
2020	379,930	5.42
2030	383,828	1.03

Table E.6-3 Total (Resident and Transient) Population (50-Mile Radius – CGS) 2045

	1	2	3	4	5	10	20	30	40	50
N	0	0	0	0	0	100	307	2105	1958	54843
NNE	0	0	0	0	0	550	1236	19384	6623	1296
NE	0	0	0	313	336	1125	2790	913	456	1333
ENE	0	0	0	504	545	935	1658	5616	673	325
E	0	0	0	133	182	1393	1031	135	260	167
ESE	0	0	0	45	83	1079	871	771	1743	391
SE	0	0	0	10	16	1777	23900	26871	665	5299
SSE	0	0	0	0	0	396	118613	76578	742	7046
S	0	0	0	0	0	1420	49256	1529	9988	35711
SSW	0	0	0	0	0	1011	11847	260	338	7012
SW	0	0	0	0	0	31	2592	17379	2541	380
WSW	0	0	0	0	0	0	38	2838	65807	6910
W	0	0	0	0	0	0	0	147	1734	38056
WNW	0	0	0	0	0	0	0	382	7019	15
NW	0	0	0	0	0	0	0	965	3399	1049
NNW	0	0	0	0	0	5	15	738	5981	3103

Table E.6-4 Mixing Heights

Time	Mixing Height (meters)
Morning/Winter	350
Morning/Spring	400
Morning/Summer	200
Morning/Autumn	290
Afternoon/Winter	600
Afternoon/Spring	1800
Afternoon/Summer	2000
Afternoon/Autumn	1200

Table E.6-5 Mapping of Release Categories to MAAP Runs

Release Category	MAAP Run	Description
LLN	CGS08007	Large Late Not Scrubbed Release
LEN	CGS08020	Large Early Not Scrubbed Release
LLS	CGS08003B	Large Late Scrubbed Release
LES	CGS08021	Large Early Scrubbed Release
COK	CGS08003A	Containment Intact, Scrubbed Release

Table E.6-6 MAAP Output for MACCS2

MAAP Run		CGS08007	CGS08020	CGS08003B	CGS08021	CGS08003A
Release Category		LLN	LEN	LLS	LES	COK
RDOALARM (uncovery) (hrs)	Core Uncovery	0.69	0.01	0.71	0.79	0.71
RDOALARM (sec)		2484	36	2556	2844	2556
RDPLHEAT(watts)	EREL	1.7E+08	2.4E+08	2.0E+08	1.6E+08	7.1E+03
RDPLHITE (meters)	ZJUNC	44	44	13	13	44
RDRELFRC	FREL(1)	1.00E+00	1.00E+00	1.00E+00	1.00E+00	1.60E-02
	FREL(2)	1.44E-01	2.28E-01	1.00E-01	4.70E-01	3.40E-06
	FREL(3)	2.72E-01	7.74E-02	1.70E-01	2.90E-01	2.70E-06
	FREL(4)	3.00E-06	7.80E-04	1.70E-06	1.60E-04	4.60E-11
	FREL(5)	3.00E-07	1.40E-05	2.60E-07	3.10E-05	1.30E-10
	FREL(6)	2.65E-01	1.27E-01	1.70E-01	2.50E-01	2.50E-06
	FREL(7)	1.90E-06	3.40E-04	1.30E-06	1.20E-04	2.60E-10
	FREL(8)	6.20E-08	1.40E-04	3.90E-08	4.30E-06	1.50E-11
	FREL(9)	4.20E-07	3.70E-04	2.60E-07	2.70E-05	6.30E-11
	FREL(10)	2.70E-03	5.20E-01	2.60E-03	1.20E-02	2.70E-08
	FREL(11)	2.30E-04	9.80E-04	2.10E-04	1.10E-03	0.00E+00
	FREL(12)	9.90E-10	4.40E-06	4.30E-10	6.00E-08	0.00E+00
RDPDELAY (hrs)		7.50	3.90	8.10	3.70	4.20
RDPDELAY(sec)		27000	14040	29160	13320	15120
RDPLUDUR (hrs)		31.20	44.10	11.90	16.30	25.80
RDPLUDUR (sec)		112320	158760	42840	58680	92880
End of Release (hrs)		38.7	48	20	20	30

Table E.6-7 Shielding/Protection Factors

Category	Normal Activities	Evaluation	Sheltering
Cloudshine Shielding Factor	1.0	0.75	0.6
Groundshine Shielding Factor	0.5	0.33	0.2
Protection Factor for Inhalation	1.0	0.41	0.33
Skin Protection Factor	1.0	0.41	0.33
Breathing Rate (meter^3 per second)	2.66E-4	2.66E-4	2.66E-4

Table E.6-8 Average Core Inventory, CGS Cycle 19, 3486 MWt

Isotope	Activity (Curies)	Activity (Bq)	Isotope	Activity (Curies)	Activity (Bq)
Kr-85	1.45E+06	5.36E+16	Te-132	1.34E+08	4.96E+18
Kr-85m	2.39E+07	8.85E+17	I-131	9.41E+07	3.48E+18
Kr-87	4.72E+07	1.75E+18	I-132	1.37E+08	5.08E+18
Kr-88	6.31E+07	2.33E+18	I-133	1.93E+08	7.13E+18
Rb-86	1.75E+05	6.46E+15	I-134	2.16E+08	7.99E+18
Sr-89	8.76E+07	3.24E+18	I-135	1.84E+08	6.80E+18
Sr-90	1.15E+07	4.24E+17	Xe-133	1.88E+08	6.96E+18
Sr-91	1.11E+08	4.12E+18	Xe-135	5.45E+07	2.02E+18
Sr-92	1.20E+08	4.43E+18	Cs-134	1.72E+07	6.37E+17
Y-90	1.19E+07	4.38E+17	Cs-136	5.50E+06	2.04E+17
Y-91	1.15E+08	4.26E+18	Cs-137	1.51E+07	5.58E+17
Y-92	1.21E+08	4.48E+18	Ba-139	1.70E+08	6.30E+18
Y-93	1.37E+08	5.08E+18	Ba-140	1.65E+08	6.10E+18
Zr-95	1.58E+08	5.83E+18	La-140	1.72E+08	6.37E+18
Zr-97	1.59E+08	5.90E+18	La-141	1.54E+08	5.71E+18
Nb-95	1.59E+08	5.87E+18	La-142	1.49E+08	5.50E+18
Mo-99	1.75E+08	6.47E+18	Ce-141	1.56E+08	5.76E+18
Tc-99m	1.55E+08	5.73E+18	Ce143	1.44E+08	5.33E+18
Ru-103	1.49E+08	5.53E+18	Ce-144	1.32E+08	4.90E+18
Ru-105	1.04E+08	3.83E+18	Pr-143	1.40E+08	5.19E+18
Ru-106	5.67E+07	2.10E+18	Nd-147	6.21E+07	2.30E+18
Rh-105	9.69E+07	3.58E+18	Np-239	1.81E+09	6.70E+19
Sb-127	8.65E+06	3.20E+17	Pu-238	3.06E+05	1.13E+16
Sb-129	2.68E+07	9.91E+17	Pu-239	4.11E+04	1.52E+15
Te-127	8.53E+06	3.16E+17	Pu-240	6.55E+04	2.42E+15
Te-127m	1.45E+06	5.37E+16	Pu-241	1.50E+07	5.54E+17
Te-129	2.51E+07	9.28E+17	Am-241	1.97E+04	7.30E+14
Te-129m	4.82E+06	1.78E+17	Cm-242	4.72E+06	1.75E+17
Te-131m	1.83E+07	6.79E+17	Cm-244	2.07E+05	7.66E+15

Table E.6-9 Economic Data

Region Name	Fraction of Land Devoted to Farming in Region	Fraction of Farm Sales Resulting from Dairy in Region	Total Annual Farm Sales for the Region ($/hectare)	Farmland Property Value for the Region ($/hectare)	Nonfarm Property Value for the Region ($/person)
Adams	0.866	0	470	1841	24543
Benton	0.558	0	1628	4203	49391
Franklin	0.836	0.047	1303	3578	30714
Grant	0.626	0.046	2029	4752	35077
Kittitas	0.157	0.019	604	6677	59079
Klickitat	0.506	0.043	213	2241	45472
Walla Walla	0.862	0	1196	3286	41435
Yakima	0.611	0.213	1242	3141	36894
Morrow	0.865	0	521	902	62789
Umatilla	0.647	0	382	1890	34329

Table E.6-10 MACCS2 Economic Parameters used in CHRONC

Variable	Description	Value (in CGS model)
DPRATE	Property depreciation rate (/year)	0.20
DSRATE	Investment rate of return (/year)	0.12
POPCST	Population relocation cost ($/person)	$5000/person
CDFRM0	Cost of farm decontamination for various levels of decontamination ($/hectare)	$562.50/hectare, $1250/hectare
CDNFRM	Cost of non-farm decontamination per person for various levels of decontamination ($/person)	$3000/person, $8000/person
DLBCST	Average cost of decontamination labor ($/person-year)	$35,000/person-year

Table E.7-1 Base Case Results for Internal Events

Release Category	Whole Body Dose (50 miles, person-rem/year)	Economic Impact (50 miles, $/year)
COK	1.45E-03	6.65E-02
LLN	2.09E+00	3.88E+03
LEN	8.62E-01	1.17E+03
LLS	7.25E-01	1.09E+03
LES	0.00E+00	0.00E+00
Total	**3.68E+00**	**6.14E+03**

Table E.7-2 Base Case Results for Fires

Release Category	Whole Body Dose (50 miles, person-rem/year)	Economic Impact (50 miles, $/year)
COK	4.56E-04	2.09E-02
LLN	7.55E+00	1.40E+04
LEN	3.25E-01	4.40E+02
LLS	7.27E-01	1.09E+03
LES	0.00E+00	0.00E+00
Total	**8.60E+00**	**1.55E+04**

Table E.7-3 Base Case Results for Seismic Events

Release Category	Whole Body Dose (50 miles, person-rem/year)	Economic Impact (50 miles, $/year)
COK	6.30E-09	2.88E-07
LLN	3.91E+00	7.25E+03
LEN	2.84E+00	3.85E+03
LLS	2.44E-03	3.67E+00
LES	0.00E+00	0.00E+00
Total	**6.75E+00**	**1.11E+04**

Table E.7-4 Base Case Summary Table

	Internal Events	Fires	Seismic Events
Whole Body Dose (50) (person-rem/year)	3.68E+0	8.60E+00	6.75E+00
Economic Impact (50) ($/year)	6.14E+3	1.55E+04	1.11E+04

Table E.7-5 Base Case Consequence Input to SAMA Analysis

Release Category	Wholebody Dose (50 miles) (person-rem)	Economic Impact (50 miles) ($)
COK	7.60E+02	3.48E+04
LLN	1.26E+06	2.34E+09
LEN	1.32E+06	1.79E+09
LLS	1.26E+06	1.89E+09
LES	1.40E+06	2.31E+09
Total	**5.24E+06**	**8.33E+09**

Table E.7-6 Comparison of Base Case and Case S1

	Internal Events			Fires			Seismic Events		
	Base	S1	% diff.	Base	S1	% diff.	Base	S1	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	4.36E+00	18.6	8.60E+00	1.02E+01	18.3	6.75E+00	8.02E+00	18.9
Economic Impact (50) ($/yr)	6.14E+03	7.07E+03	15.1	1.55E+04	1.79E+04	15.3	1.11E+04	1.28E+04	14.9

Table E.7-7 Comparison of Base Case and Case S2

	Internal Events			Fires			Seismic Events		
	Base	S2	% diff.	Base	S2	% diff.	Base	S2	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	3.68E+00	0.0	8.60E+00	8.60E+00	0.0	6.75E+00	6.75E+00	0.0
Economic Impact (50) ($/yr)	6.14E+03	6.16E+03	0.3	1.55E+04	1.56E+04	0.4	1.11E+04	1.11E+04	0.3

Table E.7-8 Comparison of Base Case and Case S3

	Internal Events			Fires			Seismic Events		
	Base	S3	% diff.	Base	S3	% diff.	Base	S3	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	5.78E+00	57.0	8.60E+00	1.35E+01	56.4	6.75E+00	1.06E+01	57.8
Economic Impact (50) ($/yr)	6.14E+03	8.95E+03	45.8	1.55E+04	2.28E+04	46.4	1.11E+04	1.61E+04	45.3

Table E.7-9 Comparison of Base Case and Case S4

	Internal Events			Fires			Seismic Events		
	Base	S4	% diff.	Base	S4	% diff.	Base	S4	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	3.68E+00	0.0	8.60E+00	8.60E+00	0.0	6.75E+00	6.75E+00	0.0
Economic Impact (50) ($/yr)	6.14E+03	6.14E+03	0.0	1.55E+04	1.55E+04	0.0	1.11E+04	1.11E+04	0.0

Table E.7-10 Comparison of Base Case and Case M1

	Internal Events			Fires			Seismic Events		
	Base	M1	% diff.	Base	M1	% diff.	Base	M1	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	3.87E+00	5.2	8.60E+00	9.06E+00	5.3	6.75E+00	7.16E+00	6.1
Economic Impact (50) ($/yr)	6.14E+03	6.55E+03	6.6	1.55E+04	1.64E+04	5.6	1.11E+04	1.18E+04	6.3

Table E.7-11 Comparison of Base Case and Case A1

	Internal Events			Fires			Seismic Events		
	Base	A1	% diff.	Base	A1	% diff.	Base	A1	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	3.68E+00	0.0	8.60E+00	8.60E+00	0.0	6.75E+00	6.75E+00	0.0
Economic Impact (50) ($/yr)	6.14E+03	6.14E+03	0.0	1.55E+04	1.55E+04	0.0	1.11E+04	1.11E+04	0.0

Table E.7-12 Comparison of Base Case and Case A3

	Internal Events			Fires			Seismic Events		
	Base	A3	% diff.	Base	A3	% diff.	Base	A3	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	3.69E+00	0.2	8.60E+00	8.61E+00	0.1	6.75E+00	6.75E+00	0.0
Economic Impact (50) ($/yr)	6.14E+03	6.14E+03	0.0	1.55E+04	1.55E+04	0.0	1.11E+04	1.11E+04	0.0

Table E.7-13 Comparison of Base Case and Case A4

	Internal Events			Fires			Seismic Events		
	Base	A4	% diff.	Base	A4	% diff.	Base	A4	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	3.67E+00	-0.2	8.60E+00	8.59E+00	-0.1	6.75E+0	6.75E+00	0.0
Economic Impact (50) ($/yr)	6.14E+03	6.15E+03	0.2	1.55E+04	1.56E+04	0.1	1.11E+4	1.11E+04	0.0

Table E.7-14 Comparison of Base Case and Case E1

	Internal Events			Fires			Seismic Events		
	Base	E1	% diff.	Base	E1	% diff.	Base	E1	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	3.68E+00	0.0	8.60E+00	8.60E+00	0.0	6.75E+00	6.75E+00	0.0
Economic Impact (50) ($/yr)	6.14E+03	6.14E+03	0.0	1.55E+04	1.55E+04	0.0	1.11E+04	1.11E+04	0.0

Table E.7-15 Comparison of Base Case and Case E2

	Internal Events			Fires			Seismic Events		
	Base	E2	% diff.	Base	E2	% diff.	Base	E2	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	3.68E+00	0.0	8.60E+00	8.60E+00	0.0	6.75E+00	6.75E+00	0.0
Economic Impact (50) ($/yr)	6.14E+03	6.14E+03	0.0	1.55E+04	1.55E+04	0.0	1.11E+04	1.11E+04	0.0

Table E.7-16 Comparison of Base Case and Case E3

	Internal Events			Fires			Seismic Events		
	Base	E3	% diff.	Base	E3	% diff.	Base	E3	% diff.
Whole Body Dose (50) person-rem/yr	3.68E+00	3.68E+00	0.0	8.60E+00	8.60E+00	0.0	6.75E+00	6.75E+00	0.0
Economic Impact (50) ($/yr)	6.14E+03	6.14E+03	0.0	1.55E+04	1.55E+04	0.0	1.11E+04	1.11E+04	0.0

Table E.8-1 Internal Events Off-site Dose at 50 Miles

Release Category	Frequency (/year)	MACCS2 Dose (person-rem)	Off-site Exposure (person-rem/year)
COK	1.91E-06	7.60E+02	1.45E-03
LEN	6.53E-07	1.32E+06	8.62E-01
LLN	1.66E-06	1.26E+06	2.09E+00
LLS	5.75E-07	1.26E+06	7.25E-01
LES	0.00E+00	1.40E+06	0.00E+00
Total			**3.68E+00**

Table E.8-2 Internal Events Economic Impact at 50 Miles

Release Category	Frequency (/year)	MACCS2 Cost Results (Economic Costs, $)	Off-site Exposure ($/year)
COK	1.91E-06	3.48E+04	6.65E-02
LEN	6.53E-07	1.79E+09	1.17E+03
LLN	1.66E-06	2.34E+09	3.88E+03
LLS	5.75E-07	1.89E+09	1.09E+03
LES	0.00E+00	2.31E+09	0.00E+00
Total			**6.14E+03**

Table E.8-3 Total Cost of Severe Accident Impact

APE	$96,035
AOC	80,128
AOE	$2,214
AOSC	$167,172
Severe Accident Impact (Internal Events)	$345,550
Fire Benefit	$689,049
Seismic Benefit (External Event)	$506,430
Other (External Event)	$345,550
Maximum Benefit (Internal Events, Fire, Seismic, and Other)	**$1,886,578**

Table E.9-1 CGS Top 100 Cutsets

Cutset	CDF	%CDF	Description	
1	4.024E-07	8.4	WMAFN-53A-B—CCF WMAHUMNALTCCINLL CF-FAILS-INJECT	Fans 53A and 53B fail to Run CCF Operator Fails to Supply Alternate Vent (CCF 53A/B Init.) Injection Fails due to Containment Failure
2	3.000E-07	6.3	IE-VESSEL-RUPTUR RPVRM	Reactor Vessel Rupture Failure to Mitigate Reactor Vessel
3	1.702E-07	3.6	TE N30M EACEDG-123FSC3LL RCIHUMNPIS1-P3LL RCIHUMNOVRIDE3LL	LOOP Non-Recovery of Off-site Power in 30 Minutes CCF of all 3 EDGs Fail to Start RCIC-PIS-1 Miscalibration Operator Fails to Override
4	1.516E-07	3.2	TE N30M EACEDG-123FSC3LL RCITDP-----1R3LL	LOOP Non-Recovery of Off-site Power in 30 Minutes CCF of all 3 EDGs Fail to Start RCIC Turbine Driven Pump Fails to Start
5	1.481E-07	3.1	AO MS-V-AOMSIVSC8LL	Large LOCA Outside CCF of a Pair of MSIVs to Close (X4 for all 4 Lines)
6	1.312E-07	2.7	TE EACEDG-123FSC3LL NREAC6 NON. RECOV. AC8	LOOP CCF of all 3 EDGs Fail to Start No Recovery of On-site AC Power within 6 Hours No Recovery of Off-site Power within 8 Hours
7	9.990E-08	2.1	TE EACEDG-123FSC3LL N30M RCI--------T3LL	LOOP CCF of all 3 EDGs Fail to Start Non-Recovery of Off-site Power in 30 Minutes RCIC Unavailability due to Test & Maintenance
8	7.761E-08	1.6	TE CM	LOOP Mechanical Failure of Scram System

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
9	7.680E-08	1.6	TE NON. RECOV. AC1 PTM	LOOP No Recovery of Off-site Power within 1 Hour Failure of SRV Reclosing for MSIV Closure, Loss of Condenser & Loop Initiators
10	7.522E-08	1.57	TE EACEDG-123FRC3LL NREAC6	LOOP Frequency In Events Per CCF of all 3 EDGs Fail to Run No Recovery of On-site AC Power within 6 Hours
11	6.720E-08	1.41	FLDR2 N-OP30M	Plant Service Water System (TSW) flood in area R305 of Reactor Building Operator Fails to Recover
12	4.502E-08	0.94	FLDR3 PTT RHRV-MO--42CP5LL	TSW flood in area R404 or R504 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators RHR-V-42C, Motor Operated Valve, Fails to Open
13	4.240E-08	0.89	TE EACEDG-123FSC3LL N8-AVE RCITDP-6HR-1S4LL	LOOP CCF of all 3 EDGs Fail to Start Average Non-Recovery AC for First 8 Hours RCIC Pump Fails to Run for 6 Hours
14	4.074E-08	0.85	FLDR3 PTT RHR----B----T3LL	TSW flood in area R404 or R504 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators RHR Train B OOS due to Maintenance
15	3.948E-08	0.83	TE EACEDG-123FSC3LL RCIV-MO---13P5LL N30M	LOOP CCF of all 3 EDGs Fail to Start RCIC-V-13, Motor Operated Valve, Fails to Open Non-Recovery of Off-site Power in 30 Minutes
16	3.234E-08	0.68	FLDR3 N-OP20M N-OP30MC N-OP40MC	TSW flood in area R404 or R504 of Reactor Building Operator Fails to Recover Operator Fails to Recover Operator Fails to Recover
17	3.159E-08	0.66	TE EACEDG-123FSC3LL RCIPE------1W2LL RCIHUMNOVRIDE3LL N30M	LOOP CCF of all 3 EDGs Fail to Start RCIC-PIS-1 Miscalibration Operator Fails to Override Non-Recovery of Off-site Power in 30 Minutes
18	3.058E-08	0.64	FLDR6 HPS---------T3LL	SW-A flood in area R206 or R305 of Reactor Building HPCS Unavailability due to Test & Maintenance

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
19	2.446E-08	0.51	FLDR3 PTT RHR----C----T3LL	TSW flood in area R404 or R504 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators RHR Train C OOS for Test & Maintenance
20	2.087E-08	0.44	TC RCITDP-24HR1S4LL HPS---------T3LL ADSHUMNSTARTH3LT	Loss of Condenser RCIC Pump Fails to Run for 24 Hours HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during non-ATWS Event
21	2.063E-08	0.43	TCC CM AIM	Loss of Condenser ATWS Mechanical Failure of Scram System Failure to Inhibit ADS, Reactor Low Water Level (L1) or Top of Active Fuel (TAF) for MSIV Closure Initiator
22	1.955E-08	0.41	TF RCITDP-24HR1S4LL HPS---------T3LL ADSHUMNSTARTH3LT	Loss of Feedwater RCIC Pump Fails to Run for 24 Hours HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during non-ATWS Event
23	1.850E-08	0.39	FLDR3 PTT SW-----B----T3LL	TSW flood in area R404 or R504 of Reactor Building Failure Of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators SW-B OOS for Maintenance
24	1.833E-08	0.38	FLDR3 RHR----B----T3LL N-OP20M	TSW Flood in Area R404 or R504 of Reactor Building RHR Train B OOS due to Maintenance Operator Fails to Recover
25	1.784E-08	0.37	SR HPS---------T3LL ADSHUMNSTARTH3LT	Reactor Level Instrument Line Break HPCS Unavailability due to Test & Maintenance Operator Fails to initiate Depressurization during non-ATWS Event
26	1.722E-08	0.36	TF CM AIM	Loss of Feedwater Mechanical Failure of Scram System Failure to Inhibit ADS, Reactor Low Water Level (L1) or Top of Active Fuel for MSIV Closure Initiator
27	1.617E-08	0.34	TC XDPHUMN-DHR-VSX- CF-FAILS-INJECT	Loss of Condenser Operator Fails to Initiate Suppression Pool Cooling, Venting, HPCS/RCIC and ADS Injection Fails due to Containment Failure

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
28	1.564E-08	0.33	TE EACEDG-123FRC3LL NREAC4 N24-AVE RCITDP-6HR-1S4LL	LOOP CCF of all 3 EDGs Fail to Run Non-Recovery of Diesel in 4 Hours Average Non-Recovery AC for First 24 Hours RCIC Pump Fails to Run for 6 Hours
29	1.562E-08	0.33	MS WMAFN-53A-B--CCF WMAHUMNALTCCF3LL CF-FAILS-INJECT	Manual Shutdown Fans 53A and 53B Fail to Run CCF Operator Fail to Supply Alternative Ventilation Injection Fails due to Containment Failure
30	1.499E-08	0.31	TE EACEDG-123FRC3LL NREAC4 N24-AVE RCIHUMNPIS1-P3LL RCIHUMNOVRIDE3LL	LOOP CCF of all 3 EDGs Fail to Run Non-Recovery of Diesel in 4 Hours Average Non-Recovery AC for First 24 Hours RCIC-PIS-1 Miscalibration Operator Fails to Override
31	1.496E-08	0.31	FLDRE N-OP20M N-OP30MC	Flooding Initiator Case E Operator Fails to Recover 20 Minutes Operator Fails to Recover 30 Minutes
32	1.496E-08	0.31	FLDR8 N-OP20M N-OP30MC	Flooding Initiator Case E Operator Fails to Recover 20 Minutes Operator Fails to Recover 30 Minutes
33	1.441E-08	0.30	TE EACENG-EDG3-R3D3 RCITDP-24HR1S4LL ADSHUMNSTARTH3LT	LOOP EDG-3 Does Not Start RCIC Pump Fails to Run for 24 Hours Operator Fails to Initiate Depressurization during Non-ATWS Event
34	1.425E-08	0.30	TSM2 EACSM--2-----OOS EACENG-EDG3-S424 ADSHUMNSTARTH3LT RCITDP-24HR1S4LL	Loss of SM-2 SM-2 Taken OOS EDG 3 System Does Not Continue to Run for 24 Hours Operator Fails to Initiate Depressurization during Non-ATWS Event RCIC Pump Fails to Run for 24 Hours
35	1.412E-08	0.30	TT WMAFN-53A-B—CCF WMAHUMNALTCCF3LL CF-FAILS-INJECT	LOOP Fans 53A and 53B Fail to Run CCF Operator Fail to Supply Alternative Ventilation Injection Fails due to Containment Failure

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
36	1.336E-08	0.28	TE EACEDG-123FRC3LL NREAC4 RCITDP-----1R3LL N24-AVE	LOOP CCF of all 3 EDGs Fail to Run Non-Recovery of Diesel in 4 Hours RCIC Turbine Driven Pump Fails to Start Average Non-Recovery AC for First 24 Hours
37	1.131E-08	0.24	FLDT1 CM	Turbine Building Flood Mechanical Failure of Scram System
38	1.100E-08	0.23	TE EACEDG-123FSC3LL RCIAV-----15W2LL N30M	LOOP CCF of all 3 EDG Fail to Start Pressure Control Valve RCIC-PCV-15 Fails to Function Non-Recovery of Off-site Power in 30 Minutes
39	1.029E-08	0.22	FLDR3 PTT RHRV-MO--6B-O2LL	TSW flood in area R404 or R504 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators Motor-Operated Valve V-6B Fails to Remain Closed
40	1.029E-08	0.22	FLDR3 PTT RHRV-MO---21O2LL	TSW Flood in Area R404 or R504 of Reactor Building Failure of SRV to Reclose for Turbine Trip and Loss of Feedwater Initiators RHR-V-21, Motor Operated Valve, Normally Closed, Fails to Remain Closed
41	1.001E-08	0.21	TI RCITDP-24HR1S4LL HPS---------T3LL ADSHUMNSTARTH3LT	Inadvertent Opening of Relief Valve/Stuck Open Relief Valve RCIC Pump Fails to Run for 24 Hours HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during Non-ATWS Event
42	9.765E-09	0.20	MS EACTRL-ASHE-W3D1 EACENG-EDG3-S424 CITDP-24HR1S4LL ADSHUMNSTARTH3LT	Manual Shutdown Loss of Power To TR-S from the Ashe Substation EDG System Does Not Continue to Run for 24 Hours RCIC Pump Fails to Run for 24 Hours Operator Fails to Initiate Depressurization during Non-ATWS Event
43	9.60E-09	0.20	FLDR6 N-OP30M	SW-A Flood in Area R206 or R305 of Reactor Building Operator Fails to Recover
44	9.126E-09	0.19	TCAS SW-V-MO2AB29C3LL	Loss of Control & Service Air Failure of Discharge Motor Operated Valves SW-2A, SW-2B and SW-29
45	8.906E-09	0.19	FLDR3 MS-PE---413DW2LL PTT	TSW flood in area R404 or R504 of Reactor Building Failure of Pressure Sensor MS-PS-413D Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
46	8.828E-09	0.18	TT EACTRL-ASHE-W3D1 EACENG-EDG3-S424 ADSHUMNSTARTH3LT	Turbine Trip Loss of Power to TR-S from the Ashe Substation EDG System Does Not Continue to Run for 24 Hours Operator Fails to Initiate Depressurization during Non-ATWS Event
47	8.799E-09	0.18	TE EACEDG-123FRC3LL NREAC4 N24-AVE RCI---------T3LL	LOOP CCF of all 3 EDGs Fail to Run Non-Recovery Of Diesel in 4 Hours Average Non-Recovery AC for First 24 Hours RCIC Unavailability due to Test & Maintenance
48	8.689E-09	0.18	TTC CM SLC---------T3LL	Turbine Trip ATWS Mechanical Failure of Scram System SLC Unavailable due to Test & Maintenance
49	8.324E-09	0.17	FLDR3 N-OP20M SW-----B----T3LL	TSW Flood in Area R404 or R504 of Reactor Building Operator Fails to Recover 20 Minutes SW-B OOS for Maintenance
50	8.192E-09	0.17	TC RCITDP-24HR1S4LL SW-V-MO2AB29C3LL	Loss of Condenser RCIC Pump Fails to Run for 24 Hours Failure of Discharge Motor Operated Valves SW-2A, SW-2B AND SW-29
51	7.997E-09	0.17	FLDR6 HPSV-CH----5P5LL	SW-A Flood in Area R404 or R504 of Reactor Building HPCS-V-5, Check Valve Fails to Open
52	7.811E-09	0.16	TE EACEDG-123FSC3LL RCIPE----13AW2LL N30M	LOOP CCF of all 3 EDGs Fail to Start RCIC-DPIS-13A Differential Pressure Sensor Unavailable Non-Recovery of Off-site Power in 30 Minutes
53	7.811E-09	0.16	TE EACEDG-123FSC3LL RCIPE-----9AW2LL N30M	LOOP CCF of all 3 EDGs Fail to Start RCIC-PS-9A Pressure Sensor Unavailable Non-Recovery of Off-site Power in 30 Minutes
54	7.811E-09	0.16	TE RCIPE----13BW2LL N30M	LOOP RCIC-DPIC-13B Differential Pressure Sensor Unavailable Non-Recovery of Off-site Power in 30 Minutes
55	7.811E-09	0.16	TE EACEDG-123FSC3LL RCIPE-----9BW2LL N30M	LOOP CCF of all 3 EDGs Fail to Start RCIC-PS-9B Pressure Sensor Unavailable Non-Recovery of Off-site Power in 30 Minutes

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
56	7.811E-09	0.16	TE EACEDG-123FSC3LL RCIPE-----7BW2LL N30M	LOOP CCF of all 3 EDGs Fail to Start RCIC-DPIS-7B Differential Pressure Sensor Unavailable Non-Recovery of Off-site Power in 30 Minutes
57	7.811E-09	0.16	TE EACEDG-123FSC3LL RCIPE------6W2LL N30M	LOOP CCF of all 3 EDGs Fail to Start RCIC-PS-6 Pressure Sensor Unavailable Non-Recovery of Off-site Power in 30 Minutes
58	7.808E-09	0.16	TE EACEDG-123FRC3LL PTM NREAC6 N24-AVE	LOOP CCF of all 3 EDGs Fail to Run Failure of SRV Reclosing for MSIV Closure, Loss of Condenser & LOOP No Recovery of On-site AC Power within 6 Hours Average Non-Recovery AC for First 24 Hours
59	7.768E-09	0.16	WMAFN-53A-B—CCF WMAHUMNALTCCINLL HPS---------T3LL	Fans 53A and 53B Fail to Run CCF Operator Fail to Supply Alternative Vent CCF 53A – 53B HPCS Unavailability due to Test & Maintenance
60	7.762E-09	0.16	FLDR3 PTT PRAFN--1B---R3	TSW flood in area R404 or R504 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators Fan PRA-FN-1B Does Not Start on Demand
61	7.689E-09	0.16	TE RCITDP-24HR1S4LL HPS---------T3LL ADSHUMNSTARTH3LT	LOOP RCIC Pump Fails to Run for 24 Hours HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during Non-ATWS Event
62	7.674E-09	0.16	TF RCITDP-24HR1S4LL SW-V-MO2AB29C3LL	Loss of Feedwater RCIC Pump Fails to Run for 24 Hours Failure of Discharge Motor Operated Valves SW-2A, SW-2B and SW-29
63	7.633E-09	0.16	FLDR6 HPSV-MO---23O2LL	SW-A Flood in Area R206 or 305 of Reactor Building HPCS-V-23 MO Globe Valve, Normally Closed-Fail To Remain Closed (NC-FTRC)
64	7.464E-09	0.16	MS RCITDP-24HR1S4LL HPS-CTL-COND---- XDPHUMN-INJ-HRFA	Manual Shutdown RCIC Pump Fails to Run for 24 Hours HPCS Control Required Operator Fails to Initiate ADS and Fails to Control Reactor Feedwater, HPCS, and RCIC

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
65	7.444E-09	0.16	TE RCITDP-24HR1S4LL EACEDG-3----T3D3 ADSHUMNSTARTH3LT	LOOP RCIC Pump Fails to Run for 24 Hours EDG-3 OOS for Maintenance Operator Fails to Initiate Depressurization during Non-ATWS Event
66	7.395E-09	0.15	TTC CM AI	Turbine Trip ATWS Mechanical Failure of Scram System Failure to Inhibit ADS or Keep Reactor Low Water Level (L1) or Top of Active Fuel for MSIV Closure Initiator for Turbine Trip ATWS
67	7.075E-09	0.15	TE EACEDG-123FSC3LL RCIV-CH---65P2LL	LOOP CCF of all 3 EDGs Fail to Start Check Valve RCIC-V-65 Does Not Close
68	7.075E-09	0.15	TE EACEDG-123FSC3LL RCIV-CH---66P2LL N30M	LOOP CCF of all 3 EDGs Fail to Start RCIC-V-66 Check Valve Fails to Open Non-Recovery of Off-site Power in 30 Minutes
69	6.747E-09	0.14	TT RCITDP-24HR1S4LL HPS-CTL-COND---- XDPHUMN-INJ-HRFA	Turbine Trip RCIC Pump Fails To Run for 24 Hours HPCS Control Required Operator Fails to Initiate ADS and Fails to Control Reactor Feedwater, HPCS, and RCIC
70	6.720E-09	0.14	FLDR1 N-OP30M N-OP60MC	TSW flood in R206 of Reactor Building Operator Fails to Recover Operator Fails to Recover
71	6.115E-09	0.13	TE EACEDG-123FSC3LL RCICC----HX2W2LL N30M	LOOP CCF of all 3 EDGs Fail to Start RCIC-HX-2 Lube Oil Cooler Failure Non-Recovery of Off-site Power in 30 Minutes
72	5.857E-09	0.13	MS PTT RCITDP-24HR1S4LL HPS---------T3LL ADSHUMNSTARTH3LT	Manual Shutdown Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators RCIC Pump Fails to Run for 24 Hours HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during non-ATWS Event
73	5.760E-09	0.13	FLDR6 DMAFN--31---R3	SW-A Flood in Area R206 or R305 of Reactor Building Fan DMA-FN-31 Does Not Start on Demand

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
74	5.760E-09	0.12	FLDR6 RRAFN--RFC04R3D3	SW-A Flood in Area R206 Or R305 of Reactor Building Motor for Fan RRA-FN-04 Does Not Start
75	5.687E-09	0.12	TM RCITDP-24HR1S4LL HPS---------T3LL ADSHUMNSTARTH3LT	MSIV Closure RCIC Pump Fails to Run for 24 Hours HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during Non-ATWS Event
76	5.459E-09	0.12	TC RCITDP-24HR1S4LL HPSV-CH----5P5LL ADSHUMNSTARTH3LT	Loss of Condenser RCIC Pump Fails to Run for 24 Hours HPCS-V-5, Check Valve Fails to Open Operator Fails to Initiate Depressurization during Non-ATWS Event
77	5.295E-09	0.12	TT PTT RCITDP-24HR1S4LL HPS---------T3LL ADSHUMNSTARTH3LT	Turbine Trip Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators RCIC Pump Fails to Run for 24 Hours HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during Non-ATWS Event
78	5.266E-09	0.11	TC CITDP-24HR1S4LL HPS-CTL-COND---- XDPHUMN-INJ-AHR-	Loss of Condenser RCIC Pump Fails to Run for 24 Hours HPCS Control Required Operator Fails to Initiate ADS and Control HPCS/RCIC
79	5.244E-09	0.11	TC RCIHUMNPIS1-P3LL RCIHUMNOVRIDE3LL HPS---------T3LL ADSHUMNSTARTH3LT	Loss of Condenser RCIC-PIS-1 Miscalibration Operator Fails to Override HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during Non-ATWS Event
80	5.211E-09	0.11	TC RCITDP-24HR1S4LL HPSV-MO---23O2LL ADSHUMNSTARTH3LT	Loss of Condenser RCIC Pump Fails to Run for 24 Hours HPCS-V-23 MO Globe Valve, NC-FTRC Operator Fails to Initiate Depressurization during Non-ATWS Event
81	5.145E-09	0.11	FLDR1 PTT RHRV-MO--42CP5LL	TSW flood in R206 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators RHR-V-42C, Motor Operated Valve, Fails to Open
82	5.145E-09	0.11	FLDR2 PTT LPSV-MO----5P5LL	TSW flood in R305 or Reactor Building Failure Of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators LPCS-V-5, Motor Operated Valve, Fails to Open

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
83	5.114E-09	0.11	TF RCITDP-24HR1S4LL HPSV-CH----5P5LL ADSHUMNSTARTH3LT	Loss of Feedwater RCIC Pump Fails to Run for 24 Hours HPCS-V-5, Check Valve Fails to Open Operator Fails to Initiate Depressurization during Non-ATWS Event
84	5.008E-09	0.10	TM CM AIM	MSIV Closure Mechanical Failure of Scram System Failure to Inhibit ADS, Keep Reactor Low Water Level (L1) or Top of Active Fuel
85	4.933E-09	0.10	TF RCITDP-24HR1S4LL HPS-CTL-COND---- XDPHUMN-INJ-AHR-	Loss of Feedwater RCIC Pump Fails to Run for 24 Hours HPCS Control Required Operator Fails to Initiate ADS and Control HPCS/RCIC
86	4.912E-09	0.10	TF RCIHUMNPIS1-P3LL RCIHUMNOVRIDE3LL HPS---------T3LL ADSHUMNSTARTH3LT	Loss of Feedwater RCIC-PIS-1 Miscalibration Operator Fails to Override HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during Non-ATWS Event
87	4.908E-09	0.10	TE RHR----A----T3LL EACENG-EDG3-S424 EACENG-EDG2-S4D2 N24-AVE	LOOP RHR Train A OOS for Test & Maintenance EDG System Does Not Continue to Run for 24 hours Emergency EDG-2 Does Not Continue to Run for 6 Hours Average Non-Recovery AC for First 24 Hours
88	4.881E-09	0.10	TF RCITDP-24HR1S4LL HPSV-MO---23O2LL ADSHUMNSTARTH3LT	Loss of Feedwater RCIC Pump Fails to Run for 24 Hours HPCS-V-23 MO Globe Valve, NC-FTRC Operator Fails to Initiate Depressurization during Non-ATWS Event
89	4.672E-09	0.10	TC RCITDP-----1R3LL HPS---------T3LL ADSHUMNSTARTH3LT	Loss of Condenser RCIC Turbine Driven Pump Fails to Start HPCS Unavailability due to Test & Maintenance Operator Fails to Initiate Depressurization during Non-ATWS Event
90	4.665E-09	0.10	SR HPSV-CH----5P5LL ADSHUMNSTARTH3LT	Reactor Level Instrument Line Break HPCS-V-5, Check Valve Fails to Open Operator Fails to Initiate Depressurization during Non-ATWS Event

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
91	4.655E-09	0.10	FLDR1 PTT RHR----B----T3LL	TSW flood in area R206 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators RHR Train B OOS due to Maintenance
92	4.655E-09	0.10	FLDR3 PTT SW-P-MDSWP1BS4LB	TSW flood in area R404 or R504 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators Failure of SSW Pump motor to Keep Running for 24 Hours
93	4.655E-09	0.10	FLDR3 PTT RHRP-MD---2BS4LL	TSW flood in area R404 or R504 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators RHR-P-2B Motor Driven Pump Fails to Run 24 Hours
94	4.655E-09	0.10	FLDR3 PTT RHRP-MD---2CS4LL	TSW flood in area R404 or R504 of Reactor Building Failure of SRV Reclosing for Turbine Trip and Loss of Feedwater Initiators RHR-P-2C Motor Driven Pump Fails to Run 24 Hours
95	4.629E-09	0.10	FLDR3 RHRV-MO--6B-O2LL N-OP20M	TSW flood in area R404 or 504 of Reactor Building RHR Motor-Operated Valve V-6B Fails to Remain Closed Operator Fails to Recover 20 Minutes
96	4.621E-09	0.10	TE NON. RECOV. AC10-24AVE EACENG-EDG2-S4D2 EACENG-EDG1-S4D1 NREAC6 PP-1 CF-FAILS-INJECT	LOOP Average Probability Non-Recovery AC Between 10 and 24 Hours Emergency EDG-2 Does Not Continue to Run for 6 Hours Emergency EDG-1 Does Not Continue to Run for 6 Hours No Recovery of On-site AC Power within 6 Hours Probability of SORV in Period From 12-24 Hours Injection Fails due to Containment Failure
97	4.500E-09	0.09	SR HPS-CTL-COND---- XDPHUMN-INJ-AHR-	Reactor Level Instrument Line Break HPCS Control Required Operator Fails to Initiate ADS and Control HPCS/RCIC
98	4.453E-09	0.09	SR HPSV-MO---23O2LL ADSHUMNSTARTH3LT	Reactor Level Instrument Line Break HPCS-V-23 MO Globe Valve, NC-FTRC Operator Fails to Initiate Depressurization during Non-ATWS Event
99	4.405E-09	0.09	TM XDPHUMN-DHR-VSX- CF-FAILS-INJECT	MSIV Closure Operator does not Initiate Suppression Pool Cooling, Venting, HPCS/RCIC and ADS Injection Fails due to Containment Failure

Table E.9-1 CGS Top 100 Cutsets (continued)

Cutset	CDF	%CDF	Description	
100	4.377E-09	0.09	TF	Loss of Feedwater
			RCITDP-----1R3LL	RCIC Turbine Driven Pump Fails to Start
			HPS---------T3LL	HPCS Unavailability due to Test & Maintenance
			ADSHUMNSTARTH3LT	Operator Fails to Initiate Depressurization during Non-ATWS Event

Table E.9-2 System Ranked by Risk Reduction Worth (RRW)

Rank	System/Train	RRW
1	HPCS	2.18
2	RCIC	1.67
3	AC Power Bus SM-7	1.49
4	AC Power Bus SM-1	1.47
5	EDG Division 1	1.44
6	AC Power Bus SM-4	1.41
7	EDG Division 3 (HPCS)	1.40
8	AC Power Bus SM-2	1.37
9	AC Power Bus SM-3	1.29
10	AC Power Bus SM-8	1.29
11	EDG Division 2	1.27
12	RHR Division A (SPC mode)	1.17
13	RHR Division B (SPC mode)	1.16
14	DC Power Bus S-1/1	1.12
15	DC Power Bus S-1/1A	1.11
16	DC Power Bus S-1/2	1.11
17	DC Power Bus S-1/2A	1.11
18	Air Handling WMA-53A	1.11
19	Air Handling WMA-53B	1.11
20	RHR Division C (LPCI mode)	1.07
21	SSW Division B	1.06
22	SSW Division A	1.05
23	LPCS	1.05
24	SSW Division C (HPCS)	1.04
25	RHR Division A (LPCI mode)	1.04
26	RHR Division B (LPCI mode)	1.03
27	DC Power Bus S-1/7	1.00
28	DC Power Bus S-1/1C	1.00
29	DC Power Bus S-1/1F	1.00
30	DC Power Bus S-1/2D	1.00
31	CIA Safety Related Division 1	1.00
32	CIA Safety Related Division 2	1.00
33	Reactor Feedwater-Division A	1.00
34	Reactor Feedwater-Division B	1.00

Table E.9-3 List of Initial SAMA Candidates

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Reference
Enhancements Related to AC and DC Power				
AC/DC-01	Provide additional DC battery capacity.	This SAMA would provide longer battery lifetime during SBO events. Increasing battery capacity will extend RCIC operation and increase the time available for recovery of off-site or on-site power.	1.12 (DC Bus S-1/1) 1.11 (DC Bus S-1/1A) 1.11 (DC Bus S-1/2) 1.11 (DC Bus S-1/2A)	[**2**, Table 13], [**58**, Table G-4], [**64**, Table G-5], [**65**, Table G-5]
AC/DC-02	Replace lead-acid batteries with fuel cells.	Replacing batteries with fuel cells will extend RCIC operating time and increase the time available for recovery of off-site power. Therefore, the likelihood of recovery of off-site power will be increased.	1.12 (DC Bus S-1/1) 1.11 (DC Bus S-1/1A) 1.11 (DC Bus S-1/2) 1.11 (DC Bus S-1/2A)	[**2**, Table 13], [**58**, Table G-4], [**64**, Table G-5], [**65**, Table G-5]
AC/DC-03	Add a portable, diesel-driven battery charger to existing DC system.	This SAMA would provide longer battery lifetime during SBO events. Increasing battery capacity will extend RCIC operation and increase the time available for recovery of off-site or on-site power.	1.12 (DC Bus S-1/1) 1.11 (DC Bus S-1/1A) 1.11 (DC Bus S-1/2) 1.11 (DC Bus S-1/2A)	[**2**, Table 13], [**59**, Table G-3], [**65**, Section G.6]
AC/DC-04	Improve DC bus load shedding.	This SAMA would extend battery lifetime during an SBO scenario, and thereby increase the likelihood of recovering on-site or off-site power.	1.12 (DC Bus S-1/1) 1.11 (DC Bus S-1/1A) 1.11 (DC Bus S-1/2) 1.11 (DC Bus S-1/2A)	[**2**, Table 13], [**58**, Section G.6]
AC/DC-05	Provide DC bus cross-ties.	Improved availability of DC power system.	1.12 (DC Bus S-1/1) 1.11 (DC Bus S-1/1A) 1.11 (DC Bus S-1/2) 1.11 (DC Bus S-1/2A)	[**2**, Table 13], [**65**, Table G-5]
AC/DC-06	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.		[**2**, Table 13]
AC/DC-07	Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.	Increased availability of the 120 V vital AC bus.		[**2**, Table 13]
AC/DC-08	Increase training on response to loss of two 120V AC buses which causes inadvertent actuation signals.	Improved chances of successful response to loss of two 120V AC buses.		[**2**, Table 13]
AC/DC-09	Reduce DC dependence between high-pressure injection system and ADS.	Improved RPV depressurization and high-pressure injection following DC failure.		[**2**, Table 13]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
AC/DC-10	Provide an additional diesel generator.	By using the same diesel design, the three CGS EDGs are susceptible to CCF. Adding a fourth diverse EDG would improve the reliability of emergency power through added redundancy, and more importantly, by adding diversity.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	[**2**, Table 13], [**58**, Table G-4], [**59**, Table G-4]
AC/DC-11	Revise procedure to allow bypass of diesel generator trips.	This SAMA would reduce the likelihood of unnecessary diesel generator trips during LOOP events.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	[**2**, Table 13], [**64**, Table G-5]
AC/DC-12	Improve 4.16-kV bus cross-tie ability.	Increased availability of on-site AC power.	1.49 (AC Bus SM-7) 1.47 (AC Bus SM-1) 1.41 (AC Bus SM-4) 1.37 (AC Bus SM-2) 1.29 (AC Bus SM-3) 1.29 (AC Bus SM-8)	[**2**, Table 13]
AC/DC-13	Create AC power cross-tie capability with other unit (multi-unit site).	Increased availability of on-site AC power.	CGS is a single unit site.	[**2**, Table 13]
AC/DC-14	Install an additional, buried off-site power source.	Reduced probability of LOOP.	1.49 (AC Bus SM-7) 1.47 (AC Bus SM-1) 1.41 (AC Bus SM-4) 1.37 (AC Bus SM-2) 1.29 (AC Bus SM-3) 1.29 (AC Bus SM-8)	[**2**, Table 13]
AC/DC-15	Install a gas turbine generator.	By using the same diesel design, the three CGS EDGs are susceptible to CCF. Adding a gas turbine powered generator would improve the reliability of emergency power through added redundancy, and more importantly, by adding diversity.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	[**2**, Table 13], [**64**, Table G-5]
AC/DC-16	Install tornado protection on gas turbine generator.	Typically, additional on-site power sources have been classified as non-safety, and as such may not be housed in tornado resistant structures. For those designs, this SAMA would upgrade that structure to be tornado resistant.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	[**2**, Table 13]
AC/DC-17	Install a steam-driven turbine generator that uses reactor steam and exhausts to the suppression pool.	Increased availability of on-site AC power. This SAMA would have benefits similar to adding an additional diverse diesel or a gas turbine.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	[**2**, Table 13], [**64**, Table G-5]
AC/DC-18	Improve uninterruptible power supplies.	Increased availability of power supplies supporting front-line equipment.		[**2**, Table 13]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
AC/DC-19	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	[2, Table 13]
AC/DC-20	Develop procedures for replenishing diesel fuel oil.	Increased diesel generator availability.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	[2, Table 13]
AC/DC-21	Use fire water system as a backup source for diesel cooling.	This SAMA would provide an alternate cooling water supply to an EDG in the event of a LOOP concurrent with a loss of service water flow associated with the diesel.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	[2, Table 13], [58, Table G-4], [59, Table G-4], [61, Table G-4]
AC/DC-22	Add a new backup source of diesel cooling.	Increased diesel generator availability.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	[2, Table 13]
AC/DC-23	Develop procedures to repair or replace failed 4 kV breakers.	In the event of a loss of bus due to a failed breaker, this SAMA would provide the ability to repair or replace 4 kV breakers in a timely manner to restore AC power to the affected division.	1.49 (AC Bus SM-7) 1.47 (AC Bus SM-1) 1.41 (AC Bus SM-4) 1.37 (AC Bus SM-2) 1.29 (AC Bus SM-3) 1.29 (AC Bus SM-8)	[2, Table 13], [58, Table G-4]
AC/DC-24	In training, emphasize steps in recovery of off-site power after an SBO.	Reduced HEP during off-site power recovery.		[2, Table 13]
AC/DC-25	Develop a severe weather conditions procedure.	Improved off-site power recovery following external weather-related events.		[2, Table 13]
AC/DC-26	Bury off-site power lines.	This SAMA would reduce the likelihood of LOOP from severe weather by burying the cables.		[2, Table 13]
AC/DC-27	Install permanent hardware changes that make it possible to establish 500 kV backfeed through the main step-up transformer.	This SAMA will model the installation of a breaker that can disconnect the main generator from the 500 kV line. CGS specific SAMA candidate developed from PSA insights and input from CGS personnel.		
AC/DC-28	Reduce CCFs between EDG-3 and EDG1/2.	A significant risk contributor to CGS is the CCF of EDG-1/2/3 to start. This SAMA would examine the benefit of reducing CCFs among the EDGs by such actions as: providing separate fuel supplies, separate maintenance crews, diverse instrumentation, etc. CGS-specific SAMA candidate developed from PSA insights and input from CGS personnel.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
AC/DC-29	Replace EDG-3 with a diesel diverse from EDG-1 and EDG-2.	A significant risk contributor to CGS is the CCF of EDG-1/2/3 to start. This SAMA would examine the benefit of replacing EDG-3 with a diesel of a different manufacturer from EDG-1 and EDG-2. CGS-specific SAMA candidate developed from PSA insights and input from CGS personnel.	1.44 (EDG Div. 1) 1.40 (EDG Div. 3 – HPCS) 1.27 (EDG Div.2)	
Enhancements Related to ATWS Events				
AT-01	Create cross-connect ability for SLC trains.	Improved availability of boron injection during ATWS.	ATWS events comprise 30% of LERF.	[**2**, Table 13]
AT-02	Revise procedures to control vessel injection to prevent boron loss or dilution following SLC injection.	Improved availability of boron injection during ATWS.	ATWS events comprise 30% of LERF.	[**2**, Table 13], [**60**, Table G-4]
AT-03	Provide an alternate means of opening a pathway to the RPV for SLC injection.	Improved probability of reactor shutdown.	ATWS events comprise 30% of LERF.	[**2**, Table 13], [**57**, Table G-3]
AT-04	Increase boron concentration in the SLC system.	This will increase the time available for the operator to successfully initiated SLC.	ATWS events comprise 30% of LERF.	[**2**, Table 13], [**57**, Table G-3]
AT-05	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	ATWS events comprise 30% of LERF.	[**2**, Table 13]
AT-06	Provide ability to use CRD or RWCU for alternate boron injection.	Improved availability of boron injection during ATWS.	ATWS events comprise 30% of LERF.	[**2**, Table 13], [**58**, Table G-4], [**59**, Table G-3]
AT-07	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	ATWS events comprise 30% of LERF.	[**2**, Table 13]
AT-08	Increase SRV reseat reliability.	Reduced risk of dilution of boron due to SRV failure to reseat after SLC injection.	ATWS events comprise 30% of LERF.	[**2**, Table 13], [**58**, Table G-4], [**64**, Table G-5], [**65**, Table G-5]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
AT-09	Provide an additional control system for rod insertion (e.g., ATWS Mitigation System Actuation Circuitry (AMSAC).	Improved redundancy and reduced ATWS frequency.	ATWS events comprise 30% of LERF.	[2, Table 13]
AT-10	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	ATWS events comprise 30% of LERF.	[2, Table 13], [58, Table G-4], [65, Table G-5]
AT-11	Revise procedure to bypass MSIV in turbine trip ATWS scenarios.	Affords operators more time to perform actions. Discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower HEPs.	ATWS events comprise 30% of LERF.	[2, Table 13]
AT-12	Revise procedure to allow override of LPCI during an ATWS event.	Allows immediate control of LPCI. On failure of HPCI and condensate, some plants direct reactor depressurization followed by five minutes of automatic LPCI.	ATWS events comprise 30% of LERF.	[2, Table 13]
AT-13	Automate SLC injection in response to ATWS event.	Improved reliability of initiation of SLC injection.	ATWS events comprise 30% of LERF.	[58, Table G-4]
AT-14	Diversify SLC explosive valve operation.	Increased SLC reliability.	ATWS events comprise 30% of LERF.	[64, Table G-5]
Enhancements Related to Containment Bypass				
CB-01	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.		[2, Table 13]
CB-02	Add redundant and diverse limit switches to each CIV.	Reduced frequency of containment isolation failure and ISLOCAs.		[2, Table 13], [64, Table G-5]
CB-03	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.		[2, Table 13], [64, Table G-5], [65, Table G-5]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
CB-04	Improve MSIV design.	Decreased likelihood of containment bypass scenarios.	Main steam line break with failure of two in-series MSIVs is the dominant V-sequence event.	[**2**, Table 13], [**64**, Table G-5], [**65**, Table G-5]
CB-05	Install self-actuating CIVs.	Reduced frequency of isolation failure.		[**2**, Table 13]
CB-06	Locate RHR inside containment.	Reduced frequency of ISLOCA outside containment.		[**2**, Table 13], [**64**, Table G-5], [**65**, Table G-5]
CB-07	Ensure ISLOCA releases are scrubbed. One method is to plug drains in potential break areas so that break point will be covered with water.	Scrubbed ISLOCA releases.		[**2**, Table 13]
CB-08	Revise EOPs to improve ISLOCA identification.	Increased likelihood that LOCAs outside containment are identified as such.		[**2**, Table 13]
CB-09	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.		[**2**, Table 13]
Enhancements Related to Core Cooling Systems				
CC-01	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	2.18 HPCS	[**2**, Table 13], [**65**, Table G-5]
CC-02	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	2.18 HPCS	[**2**, Table 13], [**61**, Table G-4], [**64**, Table G-5], [**65**, Table G-5]
CC-03a	Raise HPCI backpressure trip set points.	Increased HPCI availability when high suppression pool temperature exists.	2.18 HPCS	[**2**, Table 13]
CC-03b	Raise RCIC backpressure trip set points.	Increased RCIC availability when high suppression pool temperature exists.	1.67 RCIC	[**2**, Table 13]
CC-04	Revise procedure to allow bypass of RCIC turbine exhaust pressure trip.	Extended RCIC operation.	1.67 RCIC	[**2**, Table 13]
CC-05	Revise procedure to allow intermittent operation of HPCI and RCIC.	Extended HPCS and RCIC operation.	2.18 HPCS	[**2**, Table 13]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
CC-06	Revise procedure to control torus temperature, torus level, and primary containment pressure to increase available net positive suction head (NPSH) for injection pumps.	Increased probability that injection pumps will be available to inject coolant into the vessel.		[2, Table 13]
CC-07	Revise procedure to manually initiate HPCI and RCIC given auto initiation failure.	Increased availability of HPCS and RCIC given auto initiation signal failure.	2.18 HPCS 1.67 RCIC	[2, Table 13]
CC-08	Modify ADS components to improve reliability.	Reduced frequency of high pressure core damage sequences.		[2, Table 13], [58, Table G-4]
CC-09	Add signals to open SRVs automatically in an MSIV closure transient.	Reduced likelihood of SRV failure to open in an MSIV closure transient reduces the probability of a medium LOCA.		[2, Table 13]
CC-10	Revise procedure to allow manual initiation of emergency depressurization.	Improved prevention of core damage during transients, small and medium LOCAs, and ATWS.		[2, Table 13]
CC-11	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Extended HPCS and RCIC operation.	2.18 HPCS 1.67 RCIC	[2, Table 13]
CC-12	Add a diverse low pressure injection system.	Improved injection capability.	1.07 (RHR Div. C LPCI) 1.05 (LPCS) 1.04 (RHR Div. A LPCI) 1.03 (RHR Div. B LPCI)	[2, Table 13]
CC-13	Increase flow rate of suppression pool cooling.	Improved suppression pool cooling.	1.17 (RHR Div. A SPC) 1.16 (RHR Div. B SPC)	[2, Table 13]
CC-14	Provide capability for alternate low pressure injection via diesel-driven fire pump.	Improved injection capability.	1.07 (RHR Div. C LPCI) 1.05 (LPCS) 1.04 (RHR Div. A LPCI) 1.03 (RHR Div. B LPCI)	[2, Table 13]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
CC-15	Provide capability for alternate injection via RWCU.	Improved injection capability.	1.07 (RHR Div. C LPCI) 1.05 (LPCS) 1.04 (RHR Div. A LPCI) 1.03 (RHR Div. B LPCI)	[2, Table 13], [59, Table G-4]
CC-16	Revise procedure to align EDG and allow use of essential CRD for vessel injection.	Improved injection capability.	2.18 HPCS 1.67 RCIC	[2, Table 13]
CC-17	Revise procedure to allow use of condensate pumps for injection.	Improved injection capability.	1.07 (RHR Div. C LPCI) 1.05 (LPCS) 1.04 (RHR Div. A LPCI) 1.03 (RHR Div. B LPCI)	[2, Table 13]
CC-18	Revise procedure to allow use of suppression pool jockey pump for injection.	Improved injection capability.	1.07 (RHR Div. C LPCI) 1.05 (LPCS) 1.04 (RHR Div. A LPCI) 1.03 (RHR Div. B LPCI)	[2, Table 13]
CC-19	Revise procedure to re-open MSIVs.	Regains the main condenser as a heat sink.		[2, Table 13], [57, Table G-3]
CC-20	Improve ECCS suction strainers.	During energetic large LOCA events, debris such as insulation could be dislodged and potentially block the ECCS strainers in the suppression pool, thereby failing ECCS suction. This SAMA would reduce the likelihood of strainer blockage during LOCA events.	LLOCA is not risk significant.	[2, Table 13]
CC-21	Revise procedure to align LPCI or Core Spray to CST on loss of suppression pool cooling.	High suppression pool temperature can result in loss of injection and can challenge containment integrity. This SAMA would allow injection of cold water from the CST. With the loss of suppression pool cooling, containment venting would eventually be required for decay heat removal.	1.07 (RHR Div. C LPCI) 1.05 (LPCS) 1.04 (RHR Div. A LPCI) 1.03 (RHR Div. B LPCI)	[2, Table 13], [57, Table G-3]
CC-22	Remove LPCI loop select logic.	Enables use of LPCS A loop for injection in the event of a B train injection path failure.	1.03 (RHR Div. B LPCI)	[2, Table 13]
CC-23	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced CCF of the safety injection system. The intent of this SAMA is to provide diversity within the high- and low-pressure safety injection systems.		[2, Table 13], [61, Table G-4]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
Enhancements Related to Containment Phenomena				
CP-01	Install an independent method of suppression pool cooling.	This SAMA will evaluate a modification to implement decay heat removal capability to LPCI Train C.	1.17 (RHR Div. A SPC) 1.16 (RHR Div. B SPC)	[2, Table 13] , [58, Table G-4], [64, Table G-5], [65, Table G-5]
CP-02	Revise procedure to initiate suppression pool cooling during transients, LOCAs and ATWS.	Improved containment pressure control and containment heat removal capability.	1.17 (RHR Div. A SPC) 1.16 (RHR Div. B SPC)	[2, Table 13]
CP-03	Cross-tie open cycle cooling system to enhance drywell spray system.	Increased availability of containment heat removal.	1.17 (RHR Div. A SPC) 1.16 (RHR Div. B SPC)	[2, Table 13]
CP-04	Enable flooding of the drywell head seal.	Reduced probability of leakage through the drywell head seal.		[2, Table 13], [64, Table G-5], [65, Table G-5]
CP-05	Create a reactor cavity flooding system.	Enhanced debris coolability, reduced core concrete interaction, and increased fission product scrubbing.		[2, Table 13], [65, Table G-5]
CP-06	Install a passive drywell spray system.	Improved drywell spray capability.		[2, Table 13], [58, Table G-4], [64, Table G-5], [65, Table G-5]
CP-07	Use the fire water system as a backup source for the drywell spray system.	Improved drywell spray capability.		[2, Table 13], [57, Table G-3], [58, Table G-4]
CP-08	Enhance procedures to refill CST from demineralized water or service water system.	This SAMA would examine the installation of a cross connection from the demineralized water to the CST with sufficient capacity to meet the requirements of RCIC.		[2, Table 13]
CP-09	Enhance procedure to maintain ECCS suction on CST as long as possible.	This SAMA would allow continued ECCS injection following loss of suppression pool cooling.	1.17 (RHR Div. A SPC) 1.16 (RHR Div. B SPC)	[2, Table 13]
CP-10	Modify containment flooding procedure to restrict flooding to below the top of active fuel.	Reduced forced containment venting.		[2, Table 13]
CP-11	Install an unfiltered, hardened containment vent.	Increased decay heat removal capability for non-ATWS events, without scrubbing released fission products.		[2, Table 13]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
CP-12	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber	Increased decay heat removal capability for non-ATWS events, with scrubbing of released fission products.	1.17 (RHR Div. A SPC) 1.16 (RHR Div. B SPC)	[**2**, Table 13], [**64**, Table G-5], [**65**, Table G-5]
CP-13	Enhance fire protection system and standby gas treatment (SGBT) system hardware and procedures.	Improved fission product scrubbing in severe accidents.		[**2**, Table 13], [**64**, Table G-5]
CP-14	Modify plant to permit suppression pool scrubbing.	Increased scrubbing of fission products by directing vent path through water in the suppression pool.	1.17 (RHR Div. A SPC) 1.16 (RHR Div. B SPC)	[**2**, Table 13]
CP-15	Enhance containment venting procedures with respect to timing, path selection, and technique.	Improved likelihood of successful venting.		[**2**, Table 13], [**59**, Table G-4]
CP-16	Control containment venting within a narrow band of pressure.	Reduced probability of rapid containment depressurization thus avoiding adverse impact on low pressure injection systems that take suction from the suppression pool.		[**2**, Table 13], [**64**, Table G-5], [**65**, Table G-5]
CP-17	Improve wetwell to drywell vacuum breaker reliability by installing redundant valves in each line.	Decreased consequences of a vacuum breaker failure to reseat.		[**2**, Table 13], [**65**, Table G-5]
CP-18	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.		[**2**, Table 13]
CP-19	Create a large concrete crucible with heat removal potential to contain molten core debris.	Increased cooling and containment of molten core debris. Molten core debris escaping from the vessel is contained within the crucible and a water cooling mechanism cools the molten core in the crucible, preventing melt-through of the base mat.		[**2**, Table 13], [**64**, Table G-5], [**65**, Table G-5]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
CP-20	Create a core melt source reduction system.	Increased cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur.		[2, Table 13], [64, Table G-5], [65, Table G-5]
CP-21	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Reduced probability of containment over-pressurization.		[2, Table 13], [64, Table G-5], [65, Table G-5]
CP-22	Increase depth of the concrete base mat or use an alternate concrete material to ensure melt-through does not occur.	Reduced probability of base mat melt-through.		[2, Table 13], [64, Table G-5], [65, Table G-5]
CP-23	Provide a reactor vessel exterior cooling system.	Increased potential to cool a molten core before it causes vessel failure, by submerging the lower head in water.		[2, Table 13], [64, Table G-5], [65, Table G-5]
CP-24	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Reduced probability of containment over-pressurization.		[2, Table 13], [64, Table G-5], [65, Table G-5]
CP-25	Institute simulator training for severe accident scenarios.	Improved arrest of core melt progress and prevention of containment failure.		[2, Table 13]
CP-26	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.		[2, Table 13]
CP-27	Install an independent power supply to the hydrogen control system using either new batteries, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies, such as the security system diesel.	Reduced hydrogen detonation potential.		[2, Table 13]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
CP-28	Install a passive hydrogen control system.	Reduced hydrogen detonation potential.		[2, Table 13]
CP-29	Erect a barrier that would provide enhanced protection of the containment walls (shell) from ejected core debris following a core melt scenario at high pressure.	Reduced probability of containment failure.		[2, Table 13]
Enhancements Related to Cooling Water				
CW-01	Change procedures to allow cross connection of motor cooling for residual heat removal service water (RHRSW) pumps.	Continued operation of both RHRSW pumps on failure of one train of service water.	1.06 (SSW Div. B) 1.05 (SSW Div. A)	[2, Table 13]
CW-02	Add redundant DC control power for pumps.	Increased availability of service water.	1.06 (SSW Div. B) 1.05 (SSW Div. A)	[2, Table 13], [58,Table G-4]
CW-03	Replace ECCS pump motors with air-cooled motors.	Of the low pressure ECCS pumps, only the LPCS pump has a water cooled motor. This SAMA would replace the LPCS pump with an air-cooled pump.	1.06 (SSW Div. B) 1.05 (SSW Div. A)	[2, Table 13], [58, Table G-4]
CW-04	Provide self-cooled ECCS seals.	This SAMA would eliminate the dependency of ECCS pump on seals.	1.06 (SSW Div. B) 1.05 (SSW Div. A)	[2, Table 13], [64, Table G-5]
CW-05	Enhance procedural guidance for use of cross-tied component cooling or service water pumps.	Reduced frequency of loss of component cooling water and service water.	1.06 (SSW Div. B) 1.05 (SSW Div. A)	[2, Table 13], [58, Table G-4]
CW-06	Implement modifications to allow manual alignment of the fire water system to RHR heat exchangers.	Improved ability to cool RHR heat exchangers.	1.06 (SSW Div. B) 1.05 (SSW Div. A)	[2, Table 13], [65, Table G-5]
CW-07	Add a service water pump.	This SAMA would increase the availability of cooling water to one of the two safety divisions.	1.06 (SSW Div. B) 1.05 (SSW Div. A)	[2, Table 13], [64, Table G-5], [65, Table G-5]
CW-08	Enhance the screen wash system.	Reduced potential for loss of service water due to clogging of screens.	1.06 (SSW Div. B) 1.05 (SSW Div. A)	[2, Table 13]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
Enhancements Related to Internal Flooding				
FL-01	Seal the penetrations between turbine building basement and switchgear rooms.	Increased flood propagation prevention.		[2, Table 13]
FL-02	Improve inspection of rubber expansion joints on main condenser.	Reduced frequency of internal flooding due to failure of circulating water system expansion joints.	Turbine building floods are not risk significant initiators at CGS.	[2, Table 13], [58, Table G-4]
FL-03	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Prevents flood propagation.		[2, Table 13]
Enhancements to Reduce Fire Risk				
FR-01	Replace mercury switches in fire protection system.	Decreased probability of spurious fire suppression system actuation.		[2, Table 13]
FR-02	Upgrade fire compartment barriers.	Decreased consequences of a fire.		[2, Table 13], [58, Table G-4], [60, Table G-4]
FR-03	Install additional transfer and isolation switches.	Reduced number of spurious actuations during a fire.		[2, Table 13]
FR-04	Enhance procedures to use alternate shutdown methods if the control room becomes uninhabitable.	Increased probability of shutdown if the control room becomes uninhabitable.		[2, Table 13], [60, Table G-4]
FR-05	Enhance fire brigade awareness.	Decreased consequences of a fire.		[2, Table 13]
FR-06	Enhance control of combustibles and ignition sources.	Decreased fire frequency and consequences.		[2, Table 13]
FR-07	Improve the fire resistance of critical cables.	Decreased probability of loss of power, control or instrumentation cables during a fire. Reduced probability of hot shorts during a fire.		
Enhancements Related to Feedwater and Condensate				
FW-01	Install a digital feedwater upgrade.	Reduced chance of loss of MFW following a plant trip.	1.00 (Reactor Feedwater Div. A) 1.00 (Reactor Feedwater Div. B)	[2, Table 13]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
FW-02	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	1.00 (Reactor Feedwater Div. A) 1.00 (Reactor Feedwater Div. B)	[2, Table 13], [65, Table G-5]
FW-03	Install an independent diesel for the CST makeup pumps.	Extended inventory in CST during an SBO.		[2, Table 13], [64, Table G-5], [65, Table G-5]
FW-04	Add a motor-driven feedwater pump.	Increased availability of feedwater.	1.00 (Reactor Feedwater Div. A) 1.00 (Reactor Feedwater Div. B)	[2, Table 13], [58, Table G-4]
Enhancements Related to Heating, Ventilation and Air Conditioning				
HV-01	Provide reliable power to control building fans.	Increased availability of control room ventilation.	1.11 (SWGR Fan 53A) 1.11 (SWGR Fan 53B)	[2, Table 13]
HV-02	Provide a redundant train or means of ventilation.	This SAMA would model either a redundant cooling train to the critical switchgear room or an implemented crosstie to the critical switchgear room from another cooling train.	1.11 (SWGR Fan 53A) 1.11 (SWGR Fan 53B)	[2, Table 13], [58, Table G-4]
HV-03	Enhance procedures for actions on loss of HVAC.	Increased availability of components dependent on room cooling.	1.11 (SWGR Fan 53A) 1.11 (SWGR Fan 53B)	[2, Table 13]
HV-04	Add a diesel building high temperature alarm or redundant louver and thermostat.	Improved diagnosis of a loss of diesel building HVAC.		[2, Table 13], [64, Table G-5]
HV-05	Create ability to switch HPCS and RCIC room fan power supply to DC in an SBO event.	Increased availability of HPCS and RCIC in an SBO event.	RCIC is not dependent on HVAC.	[2, Table 13]
HV-06	Enhance procedure to trip unneeded RHR or core spray pumps on loss of room ventilation.	Extended availability of required RHR or core spray pumps due to reduction in room heat load.		[2, Table 13], [58, Table G-4]
HV-07	Stage backup fans in switchgear rooms.	Increased availability of ventilation in the event of a loss of switchgear ventilation.	1.11 (SWGR Fan 53A) 1.11 (SWGR Fan 53B)	[2, Table 13]
HV-08	Add a switchgear room high temperature alarm.	Improved diagnosis of a loss of switchgear HVAC.	1.11 (SWGR Fan 53A) 1.11 (SWGR Fan 53B)	[2, Table 13], [58, Table G-4]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
Enhancements Related to Instrument Air and Nitrogen Supply				
IA-01	Provide cross-unit connection of uninterruptible compressed air supply. (multi-unit)	Increased ability to vent containment using the hardened vent.		[2, Table 13], [56, Table G-3]
IA-02	Modify procedure to provide ability to align diesel power to more air compressors.	Increased availability of instrument air after a LOOP.		[2, Table 13], [65, Table G-5]
IA-03	Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.	Elimination of instrument air system dependence on TSW and service water cooling.		[2, Table 13]
IA-04	Install nitrogen bottles as backup gas supply for SRVs.	Extended SRV operation time.	Nitrogen system not risk significant.	[2, Table 13]
IA-05	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.		[2, Table 13], [58, Table G-4], [64, Table G-5]
Other Enhancements				
OT-01	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	LLOCA not risk significant.	[2, Table 13], [64, Table G-5], [65, Table G-5]
OT-02	Enhance procedures to mitigate large break LOCA.	Reduced consequences of a large break LOCA.	LLOCA not risk significant.	[2, Table 13]
OT-03	Install computer aided instrumentation system to assist the operator in assessing post-accident plant status.	Improved prevention of core melt sequences by making operator actions more reliable.		[2, Table 13]
OT-04	Improve maintenance procedures.	Improved prevention of core melt sequences by increasing reliability of important equipment.		[2, Table 13]
OT-05	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.		[2, Table 13]
OT-06	Develop procedures for transportation and nearby facility accidents.	Reduced consequences of transportation and nearby facility accidents.		[2, Table 13]

Table E.9-3 List of Initial SAMA Candidates (continued)

	SAMA Description	Derived Benefit	System Importance (Num. Val. = RRW)	Source
Enhancements Related to Seismic Risk				
SR-01	Increase seismic ruggedness of SSW pumps and RHR heat exchangers.	Increased availability of necessary plant equipment during and after seismic events.	Not risk significant.	[**2**, Table 13], [**57**, Table G-3]
SR-02	Provide additional restraints for CO_2 tanks.	Increased availability of fire protection given a seismic event.	Not risk significant.	[**2**, Table 13]
SR-03	Modify safety related CST.	Improved availability of CST following a seismic event.	Not risk significant.	[**2**, Table 13]
SR-04	Replace anchor bolts on diesel generator oil cooler.	Improved availability of diesel generators following a seismic event.	Not risk significant.	[**2**, Table 13]

Table E.10-1 Qualitative Screening of SAMA Candidates

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
Enhancements Related to AC and DC Power				
AC/DC-01	Provide additional DC battery capacity.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. It is assumed that with DC power available, RCIC could continue to run for 10 hours, at which time containment pressure would be too high for continued RCIC operation.	
AC/DC-02	Replace lead-acid batteries with fuel cells.	Subsumed Subsumed by SAMA AC/DC-01	Considered for a final cost-benefit evaluation. It is assumed that with DC power available, RCIC could continue to run for 10 hours, at which time high containment pressure would be too high for continued RCIC operation.	
AC/DC-03	Add a portable, diesel-driven battery charger to existing DC system.	Subsumed Subsumed by SAMA AC/DC-01	A fourth diesel generator (EDG-4) has been added at CGS. EDG-4 has the ability to align to either 480 VAC MC-7A or MC-8A. Currently EDG-4 is only utilized for extended EDG outages. This SAMA would consist of permanently placing EDG-4 outside of the interior fence but inside the protected area, with underground cable installed to the EDG building. This modification would result in EDG-4 being more readily available to extend RCIC operation during SBO conditions and increase the likelihood of recovering off-site power. It is assumed that with DC power available, RCIC could continue to run for 10 hours, at which time high containment pressure would be too high for continued RCIC operation.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
AC/DC-04	Improve DC bus load shedding.	Criterion B Already Implemented at CGS	CGS operators are instructed by procedure to remove non-essential equipment to extend battery lifetime. Safety loads are separated from non-safety loads, making load shedding easy to accomplish. Therefore, the intent of this SAMA has already been implemented at CGS.	[80]
AC/DC-05	Provide DC bus cross-ties.	Criterion E Very Low Benefit	With the ability to provide alternate power from EDG-3 or EDG-4, this SAMA would provide little risk reduction. Therefore, this SAMA is not considered for further evaluation.	[81]
AC/DC-06	Provide additional DC power to the 120/240V vital AC system.	Criterion E Very Low Benefit	120/240 V AC is not risk significant at CGS. Therefore, this SAMA is determined to have a very low benefit and will not be considered.	[82]
AC/DC-07	Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.	Criterion B Already Implemented at CGS	On loss of normal power, Divisions 1 and 2 Class 1E 120/240 V AC power is automatically transferred to standby AC power. Therefore, the intent of this SAMA has already been implemented at CGS.	[83]
AC/DC-08	Increase training on response to loss of two 120V AC buses that causes inadvertent actuation signals.	Criterion E Very Low Benefit	120/240 V AC is not risk significant at CGS. Therefore, this SAMA is determined to have a very low benefit and will not be considered.	[82]
AC/DC-09	Reduce DC dependence between high-pressure injection system and ADS.	Criterion B Already Implemented at CGS	ADS is dependent on Division 1 and Division 2 DC power while HPCS is dependent on Division 3 DC power. There is no DC dependence between Division 3 and Divisions 1 or 2 during operational conditions where ADS is required to be operable. Therefore, the intent of this SAMA has already been implemented at CGS.	[83]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
AC/DC-10	Provide an additional diesel generator.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA will examine the addition of a diverse diesel generator with the capacity to supply all safety loads on either Division 1 or Division 2. Model Change – Modify the model to make EDG-1 perfectly reliable to start and run.	
AC/DC-11	Revise procedure to allow bypass of diesel generator trips.	Criterion B Already Implemented at CGS	Non-safety EDG trips are bypassed on high drywell pressure or low RPV level and in the event of a LOOP. Therefore, the intent of this SAMA has already been implemented at CGS.	[**38**, Sections 8.3.1.1.7.2.8 and 8.3.1.1.7.1.8]
AC/DC-12	Improve 4.16-kV bus cross-tie ability.	Criterion B Already Implemented at CGS	CGS has the capability to cross-connect 4.16 kV power from Division 3 to the Division 1 or Division 2 buses via permanently installed cables. This provides adequate power to critical Division 1 or 2 components required to maintain safe shutdown conditions. Therefore, the intent of the SAMA has already been implemented at CGS.	**[84], [85]**
AC/DC-13	Create AC power cross-tie capability with other unit (multi-unit site).	Criterion A Not Applicable to CGS	CGS is a single unit site. Therefore, this SAMA is not applicable to CGS.	**[38]**
AC/DC-14	Install an additional, buried off-site power source.	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Arkansas Nuclear One Unit 2 was estimated by Entergy Operations to require more than $25,000,000 in 2005. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[**86**, Table G-3]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
AC/DC-15	Install a gas turbine generator.	Subsumed Subsumed by SAMA AC/DC-10	Considered for a final cost-benefit evaluation. This SAMA involves the installation of a full capacity non-safety-related combustion turbine generator. This modification would reduce the likelihood of a SBO and in addition to the two full-capacity diesel generators and the HPCS diesel generator, provide diversity and additional redundancy to the plant.	
AC/DC-16	Install tornado protection on gas turbine generator.	Subsumed Subsumed by SAMA AC/DC-10	This SAMA is similar in intent to AC/DC-10 and will be incorporated into the cost-benefit evaluation for AC/DC-10.	
AC/DC-17	Install a steam-driven turbine generator that uses reactor steam and exhausts to the suppression pool.	Criterion A Not Applicable to CGS	This plant modification would negatively impact the functionality of the RCIC because of resulting in a more rapid depressurization of the primary system. Therefore, the intent of the SAMA is not applicable to CGS.	
AC/DC-18	Improve uninterruptible power supplies.	Criterion B Already Implemented at CGS	The 120/240-Volt Critical (Class 1E) Instrumentation Power Systems for Division 1 (IN-3) and Division 2 (IN-2) were upgraded in 2003. Therefore, the intent of the SAMA has already been implemented at CGS.	[**38**, Section 8.3.1.1.5]
AC/DC-19	Create a cross-tie for diesel fuel oil (multi-unit site).	Criterion A Not Applicable to CGS	CGS is a single unit site. Therefore, this SAMA is not applicable to the CGS site.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
AC/DC-20	Develop procedures for replenishing diesel fuel oil.	Criterion B Already Implemented at CGS	Each EDG has a minimum of seven days supply of fuel oil its associated storage tank. In addition, the auxiliary boiler storage tank is available as an additional source of diesel oil. Also, fuel oil can be delivered to the site within 12-24 hours from a remote source. Therefore, the intent of the SAMA has already been implemented at CGS.	[38, Section 9.5.4.1]
AC/DC-21	Use fire water system as a backup source for diesel cooling.	Criterion E Very Low Benefit	This would likely only be considered if power were lost to critical loads such as service water. In that case, only the diesel fire pump would be available, with limited inventory available. It is judged that for this scenario, the fire water inventory would be better used for core flooding, containment spray and other fuel cooling uses. Therefore, this SAMA is not considered for further evaluation.	
AC/DC-22	Add a new backup source of diesel cooling.	Criterion E Very Low Benefit	This SAMA is similar in intent to AC/DC-21. Therefore, this SAMA is not considered for further evaluation.	
AC/DC-23	Develop procedures to repair or replace failed 4 kV breakers.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. Model Change – Make 4.16 kV breakers perfectly reliable in the PSA.	
AC/DC-24	In training, emphasize steps in recovery of off- site power after an SBO.	Criterion B Already Implemented at CGS	CGS procedures address restoration of off-site power in the event of degraded off-site power or an SBO event, with highest priority on restoration of off-site power. Therefore, the intent of the SAMA has already been implemented at CGS.	[69], [81]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
AC/DC-25	Develop a severe weather conditions procedure.	Criterion B Already Implemented at CGS	CGS has in place procedures for extensive damage, High Winds/Tornado and External Floods. Therefore, the intent of the SAMA has already been implemented at CGS.	[87], [88], [89]
AC/DC-26	Bury off-site power lines.	Criterion D Excessive Implementation Cost	To realize a significant benefit from this SAMA, the length of power lines buried must be significant. The cost of implementing a similar SAMA at Arkansas Nuclear One Unit 2 was estimated by Entergy Operations to require more than $25,000,000 in 2005. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[86, Table G-3]
AC/DC-27	Install permanent hardware changes that make it possible to establish 500 kV backfeed through the main step-up transformer. This SAMA will model the installation of a breaker that can disconnect the main generator from the 500 kV line.	Criterion C Considered for Further Evaluation.	Considered for a final cost-benefit evaluation. This SAMA would allow the recovery of off-site power for selected scenarios. Model Change – The availability of the 500 kV line was assigned as 1E-2 and applied to increase the probability of restoration of off-site power. This was not applied for seismic cases, where extensive damage of off-site power could result.	
AC/DC-28	Reduce CCFs between EDG-3 and EDG1/2.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. Model Change –The CCF probability was reduced for combinations of EDG-1 and EDG-3 as well as EDG-2 and EDG-3. These values were reduced by a factor of two.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
AC/DC-29	Replace EDG-3 with a diesel diverse from EDG-1 and EDG-2.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. Model Change – EDG-3 was removed from the common cause group of EDG-1 and EDG-2.	
Enhancements Related to ATWS Events				
AT-01	Create cross-connect ability for SLC trains.	Criterion B Already Implemented at CGS	SLC discharge piping is cross-tied to ensure full flow in the event that one squib valve fails. Therefore, the intent of this SAMA has already been implemented at CGS.	[**38**, Section 9.3.5.2]
AT-02	Revise procedures to control vessel injection to prevent boron loss or dilution following SLC injection.	Criterion B Already Implemented at CGS	The intent of this SAMA has already been implemented at CGS.	[**90**]
AT-03	Provide an alternate means of opening a pathway to the RPV for SLC injection.	Criterion B Already Implemented at CGS	CGS has the capability of injecting boron using the RCIC system. Therefore, the intent of the SAMA has already been implemented at CGS.	[**91**]
AT-04	Increase boron concentration in the SLC system.	Criterion E Very Low Benefit	Although this could provide some additional time for the operator to initiate SLC, the amount of time would not be extended significantly, due to the short time available to achieve shutdown. Therefore, this SAMA is not considered for further evaluation.	[**92**]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
AT-05	Add an independent boron injection system.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. CGS has the capability to use the RCIC system as an alternate for boron injection. This is independent from the normal boron injection system. To inject boron via the RCIC requires connecting a hose from the SLC system to the suction of RCIC and therefore could not be initiated quickly. This SAMA would examine improving this system by installing a hard pipe connection from the SLC system to the RCIC suction.	
AT-06	Provide ability to use CRD or RWCU for alternate boron injection.	Criterion B Already Implemented at CGS	Using the CRD system for boron injection could adversely affect its control rod insertion function. However, CGS does have the capability to use the RCIC system as an alternate for boron injection. Therefore, the intent of the SAMA has already been implemented at CGS.	[91]
AT-07	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. CGS has 18 SRVs, available for pressure relief during an ATWS. It is assumed that 14 of 18 must open for successful depressurization. By adding additional diverse relief valves, the contribution to CCF of SRVs can be reduced. Model Change – The CCF of SRV's was removed from the model.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
AT-08	Increase SRV reseat reliability.	Criterion B Already Implemented at CGS	CGS has an extensive SRV testing program. As part of plant startup, each SRV is opened and verified to reseat. Therefore, the intent of the SAMA has already been implemented at CGS.	
AT-09	Provide an additional control system for rod insertion (e.g., AMSAC).	Criterion B Already Implemented at CGS	CGS includes the Alternate Rod Insertion system. Therefore, the intent of the SAMA has already been implemented at CGS.	[**38**, Section 7.4.1.6]
AT-10	Install an ATWS sized filtered containment vent to remove decay heat.	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Vermont Yankee was estimated by Entergy Nuclear to require more than $2,000,000 in 2007. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[**64**, Table G-5]
AT-11	Revise procedure to bypass MSIV isolation in turbine trip ATWS scenarios.	Criterion B Already Implemented at CGS	EOPs direct the operator, once power is below 5%, to maintain water level, with MFW being the preferred system. To ensure MFW and the condenser are available, the operator is instructed to bypass the low reactor vessel and high steam tunnel temperature interlocks to maintain MSIVs open. Therefore, the intent of this SAMA has already been implemented at CGS.	[**90**]
AT-12	Revise procedure to allow override LPCI during an ATWS event.	Criterion B Already Implemented at CGS	CGS procedures allow operators to take, as necessary, control of low pressure injection during an ATWS event. Therefore, the intent of the SAMA has already been implemented at CGS.	[**90**]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
AT-13	Automate SLC injection in response to ATWS event.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA would increase the likelihood of initiating SLC injection by adding an automatic actuation in addition to the current manual actuation. Model Change – Make operator action to initiate SLC perfectly reliable.	
AT-14	Diversify SLC explosive valve operation.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA would add diversity between the two SLC explosives valves to increase the reliability of SLC. Model Change – Remove CCF of the two SLC explosive valves.	
Enhancements Related to Containment Bypass				
CB-01	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA would reduce the risk from ISLOCA events by providing early detection of leakage through interfacing systems.	
CB-02	Add redundant and diverse limit switches to each CIV.	Criterion E Very Low Benefit	Isolation at CGS is considered quite reliable. Therefore, this SAMA is not considered for further evaluation.	
CB-03	Increase leak testing of valves in ISLOCA paths.	Subsumed Subsumed by SAMA CB-01	Considered for a final cost-benefit evaluation. This SAMA would reduce the risk from ISLOCA events by providing early detection of leakage through interfacing systems.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CB-04	Improve MSIV design.	Criterion B Already Implemented at CGS	Review of the IPE indicated that isolation failure of MSIVs was estimated to be 7.4E-4. CGS has initiated an extensive MSIV program, including installing improved solenoid valves and a modified preventative maintenance program with scheduled replacement for increased reliability.	[66]
CB-05	Install self-actuating CIVs.	Criterion E Very Low Benefit	Isolation at CGS is considered very reliable. Therefore, this SAMA is not considered for further evaluation.	
CB-06	Locate RHR inside containment.	Criterion D Excessive Implementation Cost	It is unlikely that RHR could be placed within primary containment. If possible, it is judged that the cost would be several million dollars. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	
CB-07	Ensure ISLOCA releases are scrubbed. One method is to plug drains in potential break areas so that break point will be covered with water.	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Vermont Yankee was estimated by Entergy Nuclear to require more than $2,500,000 in 2007. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[64, Table G-5]
CB-08	Revise EOPs to improve ISLOCA identification.	Subsumed Subsumed by SAMA CB-01	Considered for a final cost-benefit evaluation. This SAMA would involve changes to the EOPs to improve ISLOCA identification. This SAMA would also involve additional operator training to cope with ISLOCAs.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CB-09	Improve operator training on ISLOCA coping.	Subsumed Subsumed by SAMA CB-01	This SAMA is similar in intent to CB-08 and would involve implementing additional operator training in order to reduce the frequency of operator error while coping with ISLOCA events.	
Enhancements Related to Core Cooling System				
CC-01	Install an independent active or passive high pressure injection system.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. CGS has a high pressure injection pump with a dedicated diesel. The proposed modification would consist of adding redundant electric driven or steam driven high pressure injection pump to Division 2. Model Change – HPCS event tree functions were set to an unavailability of 1E-8.	
CC-02	Provide an additional high pressure injection pump with independent diesel.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. CGS has a high pressure injection pump with a dedicated diesel. The proposed modification would consist of adding redundant electric driven or steam driven high pressure injection pump to Division 2. Model Change – This model is quantified by Case CC-01.	
CC-03a	Raise HPCI backpressure trip set points.	Criterion A Not Applicable to CGS	CGS has a HPCS system instead of a HPCI system. The HPCS system uses a motor driven pump; therefore, backpressure trip does not apply. Therefore, the intent of the SAMA is not applicable to CGS.	[38]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CC-03b	Raise RCIC backpressure trip set points.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. Operators per procedure can bypass the RCIC high exhaust pressure trip during SBO conditions. However, raising the backpressure trip set points for the RCIC is considered for a final cost-benefit evaluation. Model Change – Reduce the RCIC failure to run probability be a factor of three.	
CC-04	Revise procedure to allow bypass of RCIC turbine exhaust pressure trip.	Criterion B Already Implemented at CGS	By procedure, operators can bypass the RCIC high exhaust pressure trip during SBO conditions. This SAMA will not be considered for further evaluation.	[69]
CC-05	Revise procedure to allow intermittent operation of HPCI and RCIC.	Criterion B Already Implemented at CGS	CGS does not have a HPCI system. The CGS operating procedures direct the operators to take manual control of RCIC in order to maintain water level. Therefore, the intent of the SAMA has already been implemented at CGS.	[93], [94]
CC-06	Revise procedure to control torus temperature, torus level, and primary containment pressure to increase available NPSH for injection pumps.	Criterion B Already Implemented at CGS	Minimum NPSH is maintained on the RHR pumps even with the containment at atmospheric pressure, the suppression pool at a maximum temperature, and post-accident debris entrained on the beds of the suction strainers. Therefore, the intent of the SAMA is considered to have been already implemented at CGS.	
CC-07	Revise procedure to manually initiate HPCI and RCIC given auto initiation failure.	Criterion B Already Implemented at CGS	Procedures exist to initiate HPCS or RCIC if auto-initiation fails. Therefore, the intent of the SAMA has already been implemented at CGS.	[93], [94]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CC-08	Modify ADS components to improve reliability.	Criterion E Very Low Benefit	The ADS system at CGS is very reliable and not risk significant. Therefore, this SAMA is not considered to be applicable to CGS.	[82]
CC-09	Add signals to open SRVs automatically in an MSIV closure transient.	Criterion E Very Low Benefit	For an MSIV closure event, one or more SRV's may open briefly. Opening of SRVs is very reliable and not a significant contributor to risk. Automatically opening the SRVs will increase the chance of failure to close and a resulting loss of RPV inventory. Therefore, this SAMA is not considered for further evaluation.	[82]
CC-10	Revise procedure to allow manual initiation of emergency depressurization.	Criterion B Already Implemented at CGS	Operators can manually initiate emergency depressurization when conditions so dictate, such as small LOCA with HPCS failure. Therefore, the intent of the SAMA has already been implemented at CGS.	[95]
CC-11	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Criterion B Already Implemented at CGS	Operators can inhibit automatic ADS in non-ATWS scenarios through procedural guidance. Therefore, the intent of the SAMA has already been implemented at CGS.	[90]
CC-12	Add a diverse low pressure injection system.	Criterion E Very Low Benefit	CGS has significant redundancy of low pressure systems, and they are not risk significant. Since, this SAMA is considered to be very low benefit for CGS it will not be considered. Therefore, this SAMA is not considered for further evaluation.	[82]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CC-13	Increase flow rate of suppression pool cooling.	Criterion E Very Low Benefit	The only impact identified for this SAMA would be to extend the time for the operators to initiate SLC during MSIV closure ATWS events. This operator action is already highly reliable and does not significantly contribute to risk. Therefore, this SAMA is not considered for further evaluation.	[82]
CC-14	Provide capability for alternate low pressure injection via diesel-driven fire pump.	Criterion B Already Implemented at CGS	CGS has the capability to use the fire protection water as a source for low pressure injection. This capability is credited in the CGS PSA. Therefore, the intent of the SAMA has already been implemented at CGS.	[96]
CC-15	Provide capability for alternate injection via RWCU.	Criterion E Very Low Benefit	RWCU has no source of water other than the RPV. It receives cooling from the TSW, therefore, if other sources of injection were unavailable, it is likely that RCWU would also be unavailable. Therefore, this SAMA is not considered for further evaluation.	[38, Section 5.4.8.1]
CC-16	Revise procedure to align EDG to CRD pumps for vessel injection.	Criterion B Already Implemented at CGS	The CRD pumps are powered from Divisions 1 and 2, and are backed up by the respective EDGs. EOPs direct the use of the CRD pumps for injection when required. Therefore, the intent of the SAMA has already been implemented at CGS.	[38, Section 8.3], [97]
CC-17	Revise procedure to allow use of condensate pumps for injection.	Criterion B Already Implemented at CGS	CGS has the capability to utilize condensate water as a source of low pressure injection. This capability is credited in the CGS PSA. Therefore, the intent of the SAMA has already been implemented at CGS.	[97]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CC-18	Revise procedure to allow use of suppression pool jockey pump for injection.	Criterion A Not Applicable	CGS does not have a suppression pool jockey pump. Therefore, the intent of the SAMA is not applicable to CGS.	[38, Section 6]
CC-19	Revise procedure to re-open MSIVs.	Criterion B Already Implemented at CGS	Re-opening of MSIV's in non-LOCA events is addressed per procedures. Therefore, the intent of the SAMA has already been implemented at CGS.	[90], [98]
CC-20	Improve ECCS suction strainers or replace insulation in containment.	Criterion C Considered for Further Evaluation	Considered for final cost-benefit evaluation. Enhancements have already been made to the strainers. The existing strainers are as large as possible based on downcomer clearing loads and in the suppression pool. Therefore, improvements to the strainers will not be considered. Replacing the existing insulation within the containment could reduce the likelihood of strainer clogging. This will be considered for a final cost-benefit evaluation. Model Change – ECCS suction strainer plugging was set to zero.	
CC-21	Revise procedure to align LPCI or core spray to CST on loss of suppression pool cooling.	Criterion C Considered for Further Evaluation	Considered for final cost-benefit evaluation. This SAMA would allow continued injection following loss of suppression pool cooling scenarios. Model Change – Model suppression pool cooling to be perfectly reliable.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CC-22	Remove LPCI loop select logic.	Criterion A Not Applicable to CGS	CGS has divisions of LPCS and LPCI, each of which injects directly into the reactor vessel, not the recirculation loops. Therefore, the loop select logic does not apply and the SAMA is not applicable for CGS.	
CC-23	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Criterion E Very Low Benefit	CGS has ample diversity of coolant injection systems, which are backed up by independent diesels. Therefore, this SAMA is not considered for further evaluation.	[38, Section 6]
Enhancements Related to Containment Phenomena				
CP-01	Install an independent method of suppression pool cooling.	Criterion C Considered for Further Evaluation	Considered for final cost-benefit evaluation. CGS is evaluating additional suppression pool cooling for shutdown conditions. This SAMA will be evaluated at power conditions to evaluate any further benefit. Model Change – Failure of Train 1 suppression pool cooling functions were set to 1E-8.	
CP-02	Revise procedure to initiate suppression pool cooling during transients, LOCAs and ATWS.	Criterion B Already Implemented at CGS	Suppression pool cooling is always initiated for cases where closed loop RHR cooling is unavailable. Therefore, the intent of the SAMA has already been implemented at CGS.	[99]
CP-03	Cross-tie open cycle cooling system to enhance drywell spray system.	Criterion B Already Implemented at CGS	CGS has the capability to cross-tie service water B to the lower drywell sprays. The service water system takes suction from the spray ponds that have sufficient inventory to accomplish decay heat removal for 30 days without makeup. Therefore, the intent of the SAMA has already been implemented at CGS.	[100]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CP-04	Enable flooding of the drywell head seal.	Criterion E Very Low Benefit	For containment overpressure or overtemperature, failure at four locations is considered credible for scenarios that do not result in effective pool or spray scrubbing. Three of the locations, 1) upper cylinder-cone junction, 2) equipment hatch, and 3) wetwell above the water line, are all considered the most likely and with equal probability. The drywell head, although possible, is considered less likely. Therefore, this SAMA is not considered for further evaluation.	[71]
CP-05	Create a reactor cavity flooding system.	Criterion B Already Implemented at CGS	CGS has the capability to flood the RPV and primary containment. Therefore, the intent of the SAMA has already been implemented at CGS.	[71], [101]
CP-06	Install a passive drywell spray system.	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Vermont Yankee was estimated by Entergy Nuclear to require more than $5,800,000 in 2007. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[64, Table G-5]
CP-07	Use the fire water system as a backup source for the drywell spray system.	Criterion B Already Implemented at CGS	CGS has the ability to supply drywell spray from the fire protection system. Therefore, the intent of the SAMA has already been implemented at CGS.	[102]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CP-08	Enhance procedures to refill CST from demineralized water or service water system.	Criterion E Very Low Benefit	Refilling the CST is already modeled in the PSA. CST inventory is not a significant contributor to RCIC unavailability. Therefore, this SAMA is not considered for further evaluation.	[92]
CP-09	Enhance procedure to maintain ECCS suction on CST as long as possible.	Criterion E Very Low Benefit	CST inventory is not a significant contributor to RCIC or HPCS unavailability. Therefore, this SAMA is not considered for further evaluation.	[103]
CP-10	Modify containment flooding procedure to restrict flooding to below the top of active fuel.	Criterion A Not Applicable to CGS	From PPM 5.7.1 "An accident in which the RPV is breached at an elevation below the top of the active fuel can be considered controlled only after the primary containment has been flooded to above the top of the active fuel." Therefore, the intent of the SAMA is not applicable to the CGS site.	[101]
CP-11	Install an unfiltered, hardened containment vent.	Criterion E Very Low Benefit	A sensitivity study performed as part of the CGS IPE concluded that a hardened vent would not significantly reduced off-site releases following core damage. Venting currently is an option for decay heat removal following loss of suppression pool cooling. Therefore, this SAMA is not considered for further evaluation.	[66]
CP-12	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Vermont Yankee was estimated by Entergy Nuclear to require $3,000,000 in 2007. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[64, Table G-5]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CP-13	Enhance fire protection system and SGBT system hardware and procedures.	Criterion D Excessive Implementation Cost	The current design of the fire protection sprinklers is not well suited for fission product scrubbing (e.g., no deluge systems). The Alternative Source Term (AST) project has reduced the importance of SBGT by enhancing wetwell spray. Therefore, this SAMA is not considered cost beneficial to implement at CGS	
CP-14	Modify plant to permit suppression pool scrubbing.	Criterion B Already Implemented at CGS	Current CGS procedures direct both drywell and wetwell venting. Wetwell venting will result in fission product scrubbing. Therefore, the intent of the SAMA has already been implemented at CGS.	[104], [105]
CP-15	Enhance containment venting procedures with respect to timing, path selection, and technique.	Criterion B Already Implemented at CGS	Per procedure, operators are instructed to use venting to control primary containment pressure below Primary Containment Pressure Limit (PCPL) and 40 psig. Also, primary containment venting does not adversely affect the NPSH of injection systems which are located in the lower levels of the reactor building. Venting can be from either the wetwell or drywell. Therefore, the intent of the SAMA is considered to have been already implemented at CGS.	[106]
CP-16	Control containment venting within a narrow band of pressure.	Criterion B Already Implemented at CGS	Per procedure, operators are instructed to use venting to control primary containment pressure below PCPL and 40 psig. Also, primary containment venting does not adversely affect the NPSH of injection systems which are located in the lower levels of the reactor building. Therefore, the intent of this SAMA has already been implemented at CGS.	[97]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CP-17	Improve wetwell–to–drywell vacuum breaker reliability by installing redundant valves in each line.	Criterion E Very Low Benefit	The wetwell-to-drywell vacuum breakers have been shown to not be risk significant at CGS. Therefore, this SAMA is not considered for further evaluation.	[82]
CP-18	Provide post-accident containment inerting capability.	Criterion E Very Low Benefit	The CGS containment is inerted at power conditions. The PSA quantifies hydrogen combustion as 5E-3. Therefore, this SAMA is not considered for further evaluation.	[66]
CP-19	Create a large concrete crucible with heat removal potential to contain molten core debris.	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Vermont Yankee was estimated by Entergy Nuclear to require more than $100,000,000 in 2007. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[64, Table G-5]
CP-20	Create a core melt source reduction system.	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at J.A. Fitzpatrick was estimated to cost more than $5,000,000. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[65, Table G-5]
CP-21	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Vermont Yankee was estimated by Entergy Nuclear to require more than $12,000,000 in 2007. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[64, Table G-5]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CP-22	Increase depth of the concrete base mat or use an alternate concrete material to ensure melt-through does not occur.	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Vermont Yankee was estimated by Entergy Nuclear to require more than $5,000,000 in 2007. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[**64**, Table G-5]
CP-23	Provide a reactor vessel exterior cooling system.	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Vermont Yankee was estimated by Entergy Nuclear to require more than $2,500,000 in 2007. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[**64**, Table G-5]
CP-24	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Criterion D Excessive Implementation Cost	The cost of implementing a similar SAMA at Vermont Yankee was estimated by Entergy Nuclear to require more than $2,100,000 in 2007. The cost associated with the implementation of this SAMA exceeds the attainable benefit for all SAMA candidates. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	[**64**, Table G-5]
CP-25	Institute simulator training for severe accident scenarios.	Criterion B Already Implemented at CGS	Operators at CGS are trained to severe accident guidelines (SAGs). No further evaluation is warranted. Therefore, the intent of the SAMA has already been implemented at CGS.	[**101**]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CP-26	Improve leak detection procedures.	Criterion E Very Low Benefit	CGS has leak detection and associated procedures. No additional modifications to this procedure have been identified that would significantly improve the procedure. Therefore, this SAMA is not considered for further evaluation.	
CP-27	Install an independent power supply to the hydrogen control system using either new batteries, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies, such as the security system diesel.	Criterion E Very Low Benefit	The CGS containment is inerted at power conditions. The PSA quantifies hydrogen combustion as 5E-3. Therefore, this SAMA is not considered for further evaluation.	[66]
CP-28	Install a passive hydrogen control system.	Criterion A Not Applicable to CGS	The CGS containment is inerted except for short durations at low power during power ascension and prior to shutdown. Therefore, the intent of the SAMA is not applicable to CGS.	[38]
CP-29	Erect a barrier that would provide enhanced protection of the containment walls (shell) from ejected core debris following a core melt scenario at high pressure.	Criterion D Excessive Implementation Cost	Significant modifications to the primary containment, if possible, are considered prohibitively expensive. Therefore, this SAMA is not considered cost beneficial to implement at CGS.	
Enhancements Related to Cooling Water				
CW-01	Change procedures to allow cross-connection of motor-cooling for service water pumps.	Criterion A Not applicable to CGS	The service water pumps are air cooled. Therefore, the intent of the SAMA is not applicable to CGS.	[38, Section 9.2]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CW-02	Add redundant DC control power for pumps.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA would increase the availability of service water. Model Change – Gate 'Failure of Control Power' was set to guaranteed success for ECCS pumps.	
CW-03	Replace ECCS pump motors with air-cooled motors.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA would eliminate the dependency of ECCS on the component cooling system. Model Change – Remove ECCS pump cooling dependency.	
CW-04	Provide self-cooled ECCS seals.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA would eliminate the LPCS pump dependence on service water cooling. Model Change – This SAMA will be evaluated in CW-03	
CW-05	Enhance procedural guidance for use of cross-tied component cooling or service water pumps.	Criterion A Not Applicable	Service water consists of separate trains with no cross-tie capability. Therefore, the intent of the SAMA is not applicable to CGS.	[**38**, Section 9.2]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
CW-06	Implement modifications to allow manual alignment of the fire water system to RHR heat exchangers.	Criterion A Very Low Benefit	This would likely only be considered if power were lost to critical loads such as service water. In that case, only the diesel fire pump would be available, with limited inventory available. It is judged that for this scenario, the fire water inventory would be better used for core flooding, containment spray and other fuel cooling uses. Therefore, this SAMA is not considered for further evaluation.	[38, Section 9.2]
CW-07	Add a service water pump.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. Model Change – One train of service water was made perfectly reliable.	
CW-08	Enhance the screen wash system.	Criterion E Very Low Benefit	The service water ponds at CGS are a semi closed system and screen clogging is highly unlikely. Also, the screens are excessively oversized for the service water flow rates. Therefore, this SAMA is not considered for further evaluation	
Enhancements Related to Internal Flooding				
FL-01	Seal penetrations between turbine building basement and switchgear rooms.	Criterion A Not Applicable	For large flooding events in the turbine building, the water will eventually flow out of the west side of the turbine building through a large equipment door. No safety related switchgear rooms are impacted by the flood. Switchgear in the turbine building is located on the mezzanine level. It is unlikely that flooding in the turbine building could reach the mezzanine level, due to flow out exterior turbine building doors. Therefore, the intent of the SAMA is not applicable to CGS.	[66]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
FL-02	Improve inspection of rubber expansion joints on main condenser.	Criterion B Already Implemented at CGS	Expansion joints are periodically inspected. It is judged highly unlikely that there are any potential improvements to this program that would significantly reduce the likelihood of expansion joint failure. Therefore, the intent of this SAMA has already been implemented at CGS.	[107]
FL-03	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Criterion A Not Applicable	For large flooding events in the turbine building, the water will eventually flow out of the west side of the turbine building through a large equipment door. No safety related equipment is impacted by the flood. Therefore, the intent of the SAMA is not applicable to CGS.	
Enhancements Related to Fire Risk				
FR-01	Replace mercury switches in fire protection system.	Criterion E Very Low Benefit	A seismic event could cause a mercury switch to start a fire protection pump. This does not present any concerns. All of the safety-related equipment areas/rooms supplied by fire protection system water which is auto-initiated are of the dry-pipe pre-action type system fitted with fusible sprinkler heads. Water flow into the dry pipe is initiated by thermal/smoke detectors and sensible heat from an ongoing fire must fuse a sprinkler head or heads for sprinkler head flow to occur. Therefore, this SAMA is not considered for further evaluation.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
FR-02	Upgrade fire compartment barriers.	Criterion E Very Low Benefit	The CGS IPEEE conclusions cited no weaknesses in fire barriers that contributed to any significant risk. Therefore, this SAMA is not considered for further evaluation. Note: See FR-07 for evaluation of adding more fire resistant cable.	[67]
FR-03	Install additional transfer and isolation switches.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA will evaluate enhanced operator actions and/or installation of additional transfer switches. Model Change – The hot shorts for HS-RHR-MO-23, HS-CIAV-MO20, HS-CIAV-MO30A, HS-RHRV-MO-6B, and HS-EAC-TRS were set to zero.	
FR-04	Enhance procedures to use alternate shutdown methods if the control room becomes uninhabitable.	Criterion B Already Implemented at CGS	CGS procedures adequately address a control room fire and subsequent evacuation. Therefore, the intent of the SAMA has already been implemented at CGS.	[108]
FR-05	Enhance fire brigade awareness.	Criterion B Already Implemented at CGS	CGS fire brigade is staffed, supplied and trained per procedures and processes in accordance with NRC guidance and National Fire Protection Standards. The IPEEE fire analysis found no fire brigade weakness. Therefore, the intent of the SAMA has already been implemented at CGS.	[67]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
FR-06	Enhance control of combustibles and transient combustibles (ignition sources).	Criterion B Already Implemented at CGS	CGS IPEEE fire analysis identified areas for which enhanced combustible control would be warranted. Therefore, the intent of the SAMA has already been implemented at CGS.	[67]
FR-07a	Improve the fire resistance of cables to the containment vent valve.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA would examine replacing specific cables with more fire resistant cables to reduce or eliminate the possibility of hot shorts during fire events. Model – The cables to the containment vent valve were set to be perfectly reliable.	Note: FR-07 is broken down into FR-07a and b to reflect specific modifications
FR-07b	Improve the fire resistance of cables to transformer E-TR-S.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. This SAMA would examine replacing specific cables with more fire resistant cables to reduce or eliminate the possibility of hot shorts during fire events. Model – The cables to transformer E-TR-S were set to be perfectly reliable	
Enhancements Related to Feedwater and Condensate				
FW-01	Install a digital feedwater upgrade.	Criterion B Already Implemented at CGS	CGS already has digital feedwater control. Therefore, the intent of the SAMA has already been implemented at CGS.	[38, Section 7.7.1.5]
FW-02	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Criterion B Already Implemented at CGS	CGS has the ability to connect the fire water system to the suction of a condensate booster pump for RPV makeup. Therefore, the intent of the SAMA has already been implemented at CGS.	[96]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
FW-03	Install an independent diesel for the CST makeup pumps.	Criterion E Very Low Benefit	CGS has the ability to connect the diesel driven fire water pump to the suction of a condensate booster pump for RPV makeup. Therefore, it is judged that this SAMA would be of very low benefit. Therefore, this SAMA is not considered for further evaluation.	[96]
FW-04	Add a motor-driven feedwater pump.	Criterion E Very Low Benefit	A motor-driven reactor feedwater pump would still be dependent on the lower pressure Condensate and Condensate booster pumps for NPSH. Therefore, this SAMA is not considered for further evaluation.	[82]
Enhancements Related to Heating, Ventilation, and Air Conditioning				
HV-01	Provide reliable power to control building fans.	Criterion B Already Implemented at CGS	EDG backed power is provided to control building fans that serve the control room, cable spreading room, critical switchgear rooms and remote shutdown room. Therefore, the intent of this SAMA has already been implemented at CGS.	[38, Table 8.3-1]
HV-02	Provide a redundant train or means of ventilation.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. Simultaneous loss of cooling to both critical switchgear rooms is a significant contributor to risk. Model Change – Remove the switchgear dependency on HVAC and eliminate the loss of HVAC initiating event. Loss of switchgear HVAC IE sequences were set to zero.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
HV-03	Enhance procedures for actions on loss of HVAC.	Criterion B Already Implemented at CGS	CGS procedures address loss of ventilation in the Turbine Building, Reactor Building, Control Room, cable Spreading Room, Critical Switch Gear Room and Remote Shutdown Rooms. . Therefore, the intent of the SAMA has already been implemented at CGS.	[**109**]
HV-04	Add a diesel building high temperature alarm or redundant louver and thermostat.	Criterion B Already Implemented at CGS	Temperature sensors in the diesel generator rooms and in the exhaust ducts annunciate alarms in the event of abnormally high or low temperatures. Therefore, the intent of the SAMA has already been implemented at CGS.	[**38**, Section 9.4.7.5]
HV-05	Create ability to switch HPCS and RCIC room fan power supply to DC in an SBO event.	Criterion E Very Low Benefit	Room cooling is not required for RCIC. If electric power is unavailable to HPCS room cooling, it is highly likely that electric power would be unavailable to HPCS components. Therefore, this SAMA is not considered for further evaluation.	[**38**]
HV-06	Enhance procedure to trip unneeded RHR or core spray pumps on loss of room ventilation.	Criterion E Very Low Benefit	Each ECCS pump is located in a separate room. Each room has a room cooler with fans powered from the associated division and cooling water supplied by the respective divisions of SSW. Failures in the HVAC of one division would not impact the operability of components in the other divisions. Therefore, this SAMA is not considered for further evaluation.	[**38**, Section 9.2]
HV-07	Stage backup fans in switchgear rooms.	Criterion B Already Implemented at CGS	The switchgear rooms have staged backup fans. Therefore, the intent of the SAMA has already been implemented at CGS.	[**109**]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
HV-08	Add a switchgear room high temperature alarm.	Criterion B Already Implemented at CGS	CGS has high temperature alarms in the critical switchgear rooms. Therefore, the intent of the SAMA has already been implemented at CGS.	[**38**, Section 9.4.1.5.3]
Enhancements Related to Instrument Air and Nitrogen Supply				
IA-01	Provide cross-unit connection of uninterruptible compressed air supply. (multi-unit)	Criterion A Not Applicable to CGS	CGS is a single unit site. Therefore, the intent of the SAMA is not applicable to CGS.	
IA-02	Modify procedure to provide ability to align diesel power to more air compressors.	Criterion E Very Little Benefit	Two of three CAS compressors are backed up by emergency diesels. The only safety-related components supplied from CAS are the outboard MSIV solenoids. On LOOP, opening of the MSIVs would not be an option, because BOP systems would be unavailable. Therefore, this SAMA is not considered for further evaluation.	[**38**, Section 9.3.1]
IA-03	Replace service and instrument air compressors with more reliable compressors which that have self-contained air cooling by shaft-driven fans.	Criterion E Very Little Benefit	The CAS compressors are cooled by the TSW system, which is backed up by the EDGs. In the event that TSW fails, the compressors can be cooled by fire water. The only safety-related components supplied from CAS are the outboard MSIV solenoids. Therefore, this SAMA is not considered for further evaluation.	[**82**]
IA-04	Install nitrogen bottles as backup gas supply for SRVs.	Criterion B Already Implemented at CGS	CGS SRVs and ADS valves are supplied by nitrogen from either the cryogenic nitrogen source or one of two backup nitrogen cylinder banks. Therefore, the intent of the SAMA has already been implemented at CGS.	[**38**, Section 9.3.1.2.2]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
IA-05	Improve SRV and MSIV pneumatic components.	Criterion E Very Low Benefit	SRVs and MSIVs are very reliable, and further improvement would not contribute significantly to plant risk. Therefore, this SAMA is not considered for further evaluation.	[82]
Other Enhancements				
OT-01	Install digital large break LOCA protection system.	Criterion E Very Low Benefit	Large LOCA is not a large risk contributor, and this modification is not considered to significantly reduce the risk of a large LOCA. Therefore, this SAMA is not considered for further evaluation.	[82]
OT-02	Enhance procedures to mitigate large break LOCA.	Criterion E Very Low Benefit	Large break LOCAs are dominated by automatic initiation of mitigating systems. Operator actions are not significant contributors. Therefore, this SAMA is not considered for further evaluation.	[66]
OT-03	Install computer aided instrumentation system to assist the operator in assessing post-accident plant status.	Criterion B Already Implemented at CGS	The CGS Safety Parameter and Display System (SPDS) and Graphics Display System (GDS) provide status of plant safety functions and support information for emergency response. Therefore, the intent of this SAMA has already been implemented at CGS.	[110]
OT-04	Improve maintenance procedures.	Criterion E Very Low Benefit	No plant maintenance procedures have been identified as being significant contributors to plant risk. Therefore, this SAMA is not considered for further evaluation.	[66]
OT-05	Increase training and operating experience feedback to improve operator response.	Criterion E Very Low Benefit	No plant training or feedback issues have been identified as being significant contributors to plant risk. Therefore, this SAMA is not considered for further evaluation.	[66]

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
OT-06	Develop procedures for transportation and nearby facility accidents.	Criterion B Already Implemented at CGS	CGS has procedures to address accidents on the Hanford site and shipping accidents. Therefore, the intent of this SAMA has already been implemented at CGS.	[110]
Enhancements to Reduce Seismic Risk				
SR-01	Increase seismic ruggedness of SSW pumps and RHR heat exchangers.	Criterion C Considered for Further Evaluation	This SAMA candidate was screened as "Considered for Further Evaluation" (Criterion C) on the basis that sequence SDS41S01 contributes 15.6% to the total seismic CDF. CDF results from seismic failure of SSW pumps and RHR heat exchangers. Typically a "Criterion C" screened SAMA candidate would be evaluated by obtaining the delta CDF, delta-release category vector, and cost of implementation. However, this SAMA was treated differently. In subsequent discussions, it was apparent that a qualitative argument existed to reconcile this SAMA candidate. The sequence of SDS 41 includes loss of piping, DC panels, and MCR panels (relays), in addition to losses of RHR heat exchangers or the SSW pumps. It was concluded that just strengthening RHR heat exchangers and service water pumps would not be beneficial. On this qualitative basis, it was not necessary to pursue the CDF/cost of implementation approach, and this SAMA was not considered for further evaluation on the basis of low benefit.	

Table E.10-1 Qualitative Screening of SAMA Candidates (continued)

SAMA ID	Modification (Potential Enhancement)	Screening Criterion	Basis for Screening/ Modification Enhancements	Source
SR-02	Provide additional restraints for CO_2 tanks.	Criterion B Already Implemented at CGS	CGS uses a CO_2 system for protection of the turbine generator. The IPEEE seismic fire analysis stated "No unusual or unique seismic vulnerabilities were observed." Therefore, the intent of the SAMA has already been implemented at CGS.	[67]
SR-03	Modify safety related CST.	Criterion C Considered for Further Evaluation	Considered for a final cost-benefit evaluation. The CST is not safety related and is considered unavailable during seismic events. This SAMA would evaluate making the CST a seismic structure. Model Change – The CST was credited during seismic events.	
SR-04	Replace anchor bolts on diesel generator oil cooler.	Criterion B Already Implemented at CGS	The anchor bolts on diesel generator oil cooler were not identified by the IPEEE as a seismic vulnerability at CGS. Therefore, the intent of the SAMA has already been implemented at CGS.	[67]

Table E.11-1 Summary of PSA Cases

Case #	Description	Model Approach	Risk Reduction Delta-CDF (Base CDF – Case CDF) (1/yr)			Total Delta-CDF (1/yr)
			Internal	Fire	Seismic	
Base	***CGS PSA Baseline CDF***		***4.80E-06***	***7.41E-06***	***5.25E-06***	***1.75E-05***
AC/DC-01	Provide additional DC battery capacity.	Period for off-site / on-site recovery of power extended to 10 hours during SBO when RCIC successfully starts and runs on dc power.	2.52E-07	0.00E+00	7.00E-08	3.22E-07
AC/DC-10	Provide an additional diesel generator.	EDG-1 was selected due to RCIC dependency on EDG-1. Gate G1AC544 set to zero.	1.54E-06	8.19E-07	2.21E-07	2.58E-06
AC/DC-23	Develop procedures to repair or replace failed 4 kV breakers.	BED data was changed to make 4kV breakers perfectly reliable.	3.40E-08	1.62E-07	1.00E-08	2.06E-07
AC/DC-27	Install permanent hardware changes that make it possible to establish 500 kV backfeed through the main step-up transformer.	An unavailability of 1E-2 is assumed for the 500 kV backfeed basic event: EAC---- 500KVFEED. Assumed to not be available for seismic analysis.	1.15E-06	2.05E-06	0.00E+00	3.21E-06
AC/DC-28	Reduce CCFs between EDG-3 and EDG1/2.	CCF combinations of EDG-1 and EDG-3 as well as EDG-2 and EDG-3 were reduced, in addition to CCF of all three. The values were reduced by a factor of two.	5.95E-07	1.20E-07	1.00E-08	7.25E-07

Table E.11-1 Summary of PSA Cases (continued)

Case #	Description	Model Approach	Risk Reduction Delta-CDF (Base CDF – Case CDF) (1/yr)			Total Delta-CDF (1/yr)
			Internal	Fire	Seismic	
AC/DC-29	Replace EDG-3 with a diesel diverse from EDG-1 and EDG-2.	Only the CCFs for EDG-1 and EDG-2 common cause group of two will be used. All others will be set to zero.	1.23E-06	2.76E-07	2.00E-08	1.52E-06
CC-01	Install an independent active or passive high pressure injection system.	HPCS event tree functions set to a low value (1E-8).	3.00E-06	5.46E-06	2.32E-07	8.70E-06
CC-02	Provide an additional high pressure injection pump with independent diesel.	Model HPCS pumps to be perfectly reliable to start and run and make EDG-3 perfectly reliable to start and run.	3.00E-06	5.46E-06	2.32E-07	8.70E-06
CC-03b	Raise RCIC backpressure trip set points.	The various RCIC Failure To Run events will be reduced by a factor of three (see RCIC FTR tab).	4.23E-07	8.60E-08	9.98E-09	5.19E-07
CC-20	Improve ECCS suction strainers or replace insulation in containment.	ECCS suction strainer plugging events set to zero.	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CW-02	Add redundant DC control power for pumps.	Gate GHPS852, GRHR652, GRHR1552, GRHR3452, and GLPS372 will be set to false. DC power dependencies for RCIC were retained, as there is little risk benefit from such a modification (unavailability of the pump itself dominates the results for RCIC).	1.30E-08	2.40E-07	1.00E-08	2.63E-07
CW-03	Replace ECCS pump motors with air-cooled motors.	GRHR520, GRHR1420, GRHR3320; pump cooling input to GLPS402 set to false; pump cooling input to GHPS712 set to false. No pump cooling modeled for RCIC.	2.13E-07	7.05E-07	1.00E-08	9.28E-07

Table E.11-1 Summary of PSA Cases (continued)

Case #	Description	Model Approach	Risk Reduction Delta-CDF (Base CDF – Case CDF) (1/yr)			Total Delta-CDF (1/yr)
			Internal	Fire	Seismic	
CW-07	Add a service water pump.	GSWB123, GXWB123, GYWB123 and GZWB123 set to false.	2.77E-07	1.27E-06	2.00E-08	1.57E-06
HV-02	Provide a redundant train or means of ventilation.	GXWA1112, GXWB1112, GYWA1112, GYWB1112, GZWA1112, GZWB1112 set to false. Loss of switchgear HVAC IE sequences set to false (SG1HV and SG2HV sequences set removed from the PSA results).	5.21E-07	1.17E-06	1.00E-08	1.70E-06
CP-01	Install an independent method of suppression pool cooling.	The W(1) functions (suppression pool cooling) were modeled as perfectly reliable.	8.36E-07	3.85E-06	3.18E-08	4.71E-06
CB-01	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	ISLOCA contribution to PSA results (internal events) will be removed.	0.00E+00	0.00E+00	0.00E+00	0.00E+00
AT-05	Add an independent boron injection system.	C(3) functions set to a low value (1E-8) for internal events. For seismic, damage state 40 (SDS40) is set to zero. No change to the fire PSA results (ATWS sequences associated with fire are not risk significant and are not modeled by the PSA).	2.50E-08	0.00E+00	1.00E-08	3.50E-08
AT-07	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	SRV failures set to false, including failure of one valve when seven of seven ADS valves must open.	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Table E.11-1 Summary of PSA Cases (continued)

Case #	Description	Model Approach	Risk Reduction Delta-CDF (Base CDF – Case CDF) (1/yr)			Total Delta-CDF (1/yr)
			Internal	Fire	Seismic	
AT-13	Automate SLC injection in response to ATWS event.	This SAMA would increase the likelihood of initiating SLC injection by adding an automatic actuation in addition to the current manual actuation. Model Change – Make operator actions to initiate SLC perfectly reliable: set SLCHUMN20MINH3XX and SLCHUMN40MINH3XX to zero.	0.00E+00	0.00E+00	0.00E+00	0.00E+00
AT-14	Diversify SLC explosive valve operation.	This SAMA would add diversity between the two SLC explosives valves to increase the reliability of SLC. Set CCF for the valves (SLCV-SQ--4ABC2XX) to zero.	2.00E-09	0.00E+00	0.00E+00	2.00E-09
SR-03	Modify safety related CST.	Basic events HPSV-CH----2P2LL and RCIV-CH---11P2LL will be removed from S-BASE.BED to credit CST availability. Suction source availability is relatively unimportant compared to other system failures.	0.00E+00	0.00E+00	0.00E+00	0.00E+00
FR-03	Install additional transfer and isolation switches.	The hot short probability was reduced to zero for the most risk significant hot shorts: HS-RHRV-MO-23 HS-CIAV-MO20 HS-CIAV-MO30A HS-RHRV-MO-6B HS-EAC-TRS	0.00E+00	2.26E-06	0.00E+00	2.26E-06

Table E.11-1 Summary of PSA Cases (continued)

Case #	Description	Model Approach	Risk Reduction Delta-CDF (Base CDF – Case CDF) (1/yr)			Total Delta-CDF (1/yr)
			Internal	Fire	Seismic	
FR-07a	Improve the fire resistance of cables to the containment vent valves.	Protect cables for containment vent (valves, containment air and power supplies).	0.00E+00	3.41E-06	0.00E+00	3.41E-06
FR-07b	Improve the fire resistance of cables to transformer E-TR-S.	Protect cables for that would disable TR-S due to hot short.	0.00E+00	8.03E-07	0.00E+00	8.03E-04

Table E.11-2 Internal Events Benefit Results for Analysis Case

Case (SAMA Candidate Identifier)	Maximum Benefit	Case 01 (AC/DC-01)	Case 02 (AC/DC-10)	Case 03 (AC/DC-23)	Case 04 (AC/DC-27)	Case 05 (AC/DC-28)
Off-site Annual Dose (person-rem/yr)	3.68E+00	3.55E+00	3.13E+00	3.66E+00	3.35E+00	3.46E+00
Off-site Annual Property Loss ($/yr)	$6,140	$5,907	$5,234	$6,109	$5,627	$5,772
Comparison CDF	----	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06
Comparison Dose (person-rem/yr)	----	3.68E+00	3.68E+00	3.68E+00	3.68E+00	3.68E+00
Comparison Cost ($/yr)	----	$6,140	$6,140	$6,140	$6,140	$6,140
Enhanced CDF	----	4.55E-06	3.26E-06	4.76E-06	3.65E-06	4.20E-06
Reduction in CDF	----	**5.25%**	**32.03%**	**0.71%**	**23.99%**	**12.40%**
Reduction in Off-site Dose	----	**3.50%**	**14.90%**	**0.48%**	**9.07%**	**6.05%**
Immediate Dose Savings (On-site)	$413	$22	$132	$3	$99	$51
Long-term Dose Savings (On-site)	$1,801	$95	$577	$13	$432	$223
Total Accident Related Occupational Exposure **(AOE)**	$2,214	$116	$709	$16	$531	$275
Cleanup/Decontamination Savings (On-site)	$67,544	$3,548	$21,637	$479	$16,203	$8,376
Replacement Power Savings (On-site)	$99,627	$5,233	$31,915	$706	$23,900	$12,355
Averted Costs of On-site Property Damage **(AOSC)**	$167,172	$8,780	$53,552	$1,185	$40,103	$20,731
Total On-site Benefit	**$169,386**	**$8,896**	**$54,261**	**$1,200**	**$40,634**	**$21,006**
Averted Public Exposure **(APE)**	$96,035	$3,357	$14,309	$462	$8,714	$5,809
Averted Off-site Damage Savings **(AOC)**	$80,128	$3,044	$11,829	$403	$6,696	$4,807
Total Off-site Benefit	**$176,163**	**$6,402**	**$26,137**	**$865**	**$15,410**	**$10,616**
Total Benefit (On-site + Off-site)	**$345,550**	**$15,298**	**$80,399**	**$2,065**	**$56,044**	**$31,622**

Table E.11-2 Internal Events Benefit Results for Analysis Case (continued)

Case (SAMA Candidate Identifier)	Case 06 (AC/DC-29)	Case 07 (AT-05)	Case 08 (AT-07)	Case 09 (CB-01)	Case 09 (CB-03)	Case 09 (CB-08)
Off-site Annual Dose (person-rem/yr)	3.23E+00	3.65E+00	3.68E+00	3.68E+00	3.68E+00	3.68E+00
Off-site Annual Property Loss ($/yr)	$5,392	$6,095	$6,140	$6,140	$6,140	$6,140
Comparison CDF	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06
Comparison Dose (person-rem/yr)	3.68E+00	3.68E+00	3.68E+00	3.68E+00	3.68E+00	3.68E+00
Comparison Cost ($/yr)	$6,140	$6,140	$6,140	$6,140	$6,140	$6,140
Enhanced CDF	3.57E-06	4.77E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06
Reduction in CDF	**25.55%**	**0.52%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Reduction in Off-site Dose	**12.31%**	**0.90%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Immediate Dose Savings (On-site)	$106	$2	$0	$0	$0	$0
Long-term Dose Savings (On-site)	$460	$9	$0	$0	$0	$0
Total Accident Related Occupational Exposure **(AOE)**	$566	$12	$0	$0	$0	$0
Cleanup/Decontamination Savings (On-site)	$17,259	$352	$0	$0	$0	$0
Replacement Power Savings (On-site)	$25,457	$519	$0	$0	$0	$0
Averted Costs of On-site Property Damage **(AOSC)**	$42,716	$871	$0	$0	$0	$0
Total On-site Benefit	**$43,282**	**$883**	**$0**	**$0**	**$0**	**$0**
Averted Public Exposure **(APE)**	$11,819	$861	$0	$0	$0	$0
Averted Off-site Damage Savings **(AOC)**	$9,760	$584	$0	$0	$0	$0
Total Off-site Benefit	**$21,578**	**$1,445**	**$0**	**$0**	**$0**	**$0**
Total Benefit (On-site + Off-site)	**$64,860**	**$2,328**	**$0**	**$0**	**$0**	**$0**

Table E.11-2 Internal Events Benefit Results for Analysis Case (continued)

Case (SAMA Candidate Identifier)	Case 09 (CB-09)	Case 10 (CC-01)	Case 11 (CC-02)	Case 12 (CC-03b)	Case 13 (CC-20)	Case 15 (CP-01)
Off-site Annual Dose (person-rem/yr)	3.68E+00	2.19E+00	2.19E+00	3.50E+00	3.68E+00	2.65E+00
Off-site Annual Property Loss ($/yr)	$6,140	$3,614	$3,614	$5,842	$6,140	$4,260
Comparison CDF	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06
Comparison Dose (person-rem/yr)	3.68E+00	3.68E+00	3.68E+00	3.68E+00	3.68E+00	3.68E+00
Comparison Cost ($/yr)	$6,140	$6,140	$6,140	$6,140	$6,140	$6,140
Enhanced CDF	4.80E-06	1.79E-06	1.79E-06	4.38E-06	4.80E-06	3.96E-06
Reduction in CDF	**0.00%**	**62.63%**	**62.63%**	**8.82%**	**0.00%**	**17.42%**
Reduction in Off-site Dose	**0.00%**	**40.52%**	**40.52%**	**4.96%**	**0.00%**	**27.94%**
Immediate Dose Savings (On-site)	$0	$259	$259	$36	$0	$72
Long-term Dose Savings (On-site)	$0	$1,128	$1,128	$159	$0	$314
Total Accident Related Occupational Exposure **(AOE)**	$0	$1,387	$1,387	$195	$0	$386
Cleanup/Decontamination Savings (On-site)	$0	$42,300	$42,300	$5,955	$0	$11,769
Replacement Power Savings (On-site)	$0	$62,393	$62,393	$8,783	$0	$17,359
Averted Costs of On-site Property Damage **(AOSC)**	$0	$104,693	$104,693	$14,738	$0	$29,128
Total On-site Benefit	**$0**	**$106,080**	**$106,080**	**$14,933**	**$0**	**$29,514**
Averted Public Exposure **(APE)**	$0	$38,917	$38,917	$4,765	$0	$26,835
Averted Off-site Damage Savings **(AOC)**	$0	$32,970	$32,970	$3,891	$0	$24,536
Total Off-site Benefit	**$0**	**$71,887**	**$71,887**	**$8,656**	**$0**	**$51,372**
Total Benefit (On-site + Off-site)	**$0**	**$177,967**	**$177,967**	**$23,589**	**$0**	**$80,886**

Table E.11-2 Internal Events Benefit Results for Analysis Case (continued)

Case (SAMA Candidate Identifier)	Case 18 (CW-02)	Case 19 (CW-03)	Case 19 (CW-04)	Case 20 (CW-07)	Case 21 (FR-03)	Case 22 (FR-07a)
Off-site Annual Dose (person-rem/yr)	3.66E+00	3.47E+00	3.47E+00	3.37E+00	3.68E+00	3.68E+00
Off-site Annual Property Loss ($/yr)	$6,111	$5,761	$5,761	$5,570	$6,140	$6,140
Comparison CDF	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06
Comparison Dose (person-rem/yr)	3.68E+00	3.68E+00	3.68E+00	3.68E+00	3.68E+00	3.68E+00
Comparison Cost ($/yr)	$6,140	$6,140	$6,140	$6,140	$6,140	$6,140
Enhanced CDF	4.79E-06	4.59E-06	4.59E-06	4.52E-06	4.80E-06	4.80E-06
Reduction in CDF	**0.27%**	**4.44%**	**4.44%**	**5.77%**	**0.00%**	**0.00%**
Reduction in Off-site Dose	**0.45%**	**5.59%**	**5.59%**	**8.46%**	**0.00%**	**0.00%**
Immediate Dose Savings (On-site)	$1	$18	$18	$24	$0	$0
Long-term Dose Savings (On-site)	$5	$80	$80	$104	$0	$0
Total Accident Related Occupational Exposure **(AOE)**	$6	$98	$98	$128	$0	$0
Cleanup/Decontamination Savings (On-site)	$183	$2,999	$2,999	$3,900	$0	$0
Replacement Power Savings (On-site)	$270	$4,423	$4,423	$5,752	$0	$0
Averted Costs of On-site Property Damage **(AOSC)**	$453	$7,421	$7,421	$9,651	$0	$0
Total On-site Benefit	**$459**	**$7,520**	**$7,520**	**$9,779**	**$0**	**$0**
Averted Public Exposure **(APE)**	$429	$5,369	$5,369	$8,125	$0	$0
Averted Off-site Damage Savings **(AOC)**	$378	$4,953	$4,953	$7,442	$0	$0
Total Off-site Benefit	**$807**	**$10,323**	**$10,323**	**$15,567**	**$0**	**$0**
Total Benefit (On-site + Off-site)	**$1,266**	**$17,842**	**$17,842**	**$25,346**	**$0**	**$0**

Table E.11-2 Internal Events Benefit Results for Analysis Case (continued)

Case (SAMA Candidate Identifier)	Case22a (FR-07b)	Case 23 (HV-02)	Case 25 (SR-03)	Case 26 (AT-13)	Case 27 (AT-14)
Off-site Annual Dose (person-rem/yr)	3.68E+00	3.06E+00	3.68E+00	3.68E+00	3.68E+00
Off-site Annual Property Loss ($/yr)	$6,140	$4,996	$6,140	$6,138	$6,137
Comparison CDF	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06
Comparison Dose (person-rem/yr)	3.68E+00	3.68E+00	3.68E+00	3.68E+00	3.68E+00
Comparison Cost ($/yr)	$6,140	$6,140	$6,140	$6,140	$6,140
Enhanced CDF	4.80E-06	4.28E-06	4.80E-06	4.80E-06	4.80E-06
Reduction in CDF	**0.00%**	**10.86%**	**0.00%**	**0.02%**	**0.04%**
Reduction in Off-site Dose	**0.00%**	**16.82%**	**0.00%**	**0.04%**	**0.07%**
Immediate Dose Savings (On-site)	$0	$45	$0	$0	$0
Long-term Dose Savings (On-site)	$0	$196	$0	$0	$1
Total Accident Related Occupational Exposure **(AOE)**	$0	$240	$0	$0	$1
Cleanup/Decontamination Savings (On-site)	$0	$7,334	$0	$14	$28
Replacement Power Savings (On-site)	$0	$10,818	$0	$21	$42
Averted Costs of On-site Property Damage **(AOSC)**	$0	$18,153	$0	$35	$70
Total On-site Benefit	**$0**	**$18,393**	**$0**	**$35**	**$71**
Averted Public Exposure **(APE)**	$0	$16,154	$0	$34	$69
Averted Off-site Damage Savings **(AOC)**	$0	$14,924	$0	$23	$47
Total Off-site Benefit	**$0**	**$31,078**	**$0**	**$57**	**$116**
Total Benefit (On-site + Off-site)	**$0**	**$49,471**	**$0**	**$93**	**$186**

Table E.11-3 Fire Benefit Results for Analysis Cases

Case (SAMA Candidate Identifier)	Maximum Benefit	Case 01 (AC/DC-01)	Case 02 (AC/DC-10)	Case 03 (AC/DC-23)	Case 04 (AC/DC-27)	Case 05 (AC/DC-28)
Off-site Annual Dose (person-rem/yr)	8.60E+00	8.60E+00	7.79E+00	8.41E+00	6.35E+00	8.51E+00
Off-site Annual Property Loss ($/yr)	$15,547	$15,547	$14,083	$15,207	$11,477	$15,399
Comparison CDF	----	7.41E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06
Comparison Dose (person-rem/yr)	----	8.60E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00
Comparison Cost ($/yr)	----	$15,547.49	$15,547.49	$15,547.49	$15,547.49	$15,547.49
Enhanced CDF	----	7.41E-06	6.59E-06	7.25E-06	5.36E-06	7.29E-06
Reduction in CDF	----	0.00%	11.05%	2.19%	27.71%	1.62%
Reduction in Off-site Dose	----	0.00%	9.37%	2.16%	26.19%	0.99%
Immediate Dose Savings (On-site)	$638	$0	$71	$14	$177	$10
Long-term Dose Savings (On-site)	$2,783	$0	$307	$61	$771	$45
Total Accident Related Occupational Exposure **(AOE)**	$3,421	$0	$378	$75	$948	$55
Cleanup/Decontamination Savings (On-site)	$104,357	$0	$11,530	$2,281	$28,915	$1,689
Replacement Power Savings (On-site)	$153,926	$0	$17,006	$3,364	$42,650	$2,492
Averted Costs of On-site Property Damage **(AOSC)**	$258,284	$0	$28,536	$5,644	$71,565	$4,181
Total On-site Benefit	**$261,705**	**$0**	**$28,914**	**$5,719**	**$72,513**	**$4,236**
Averted Public Exposure **(APE)**	$224,449	$0	$21,029	$4,838	$58,787	$2,219
Averted Off-site Damage Savings **(AOC)**	$202,895	$0	$19,106	$4,445	$53,121	$1,934
Total Off-site Benefit	**$427,344**	**$0**	**$40,134**	**$9,283**	**$111,908**	**$4,153**
Total Benefit (On-site + Off-site)	$689,049	$0	$69,048	$15,002	$184,421	$8,389

Table E.11-3 Fire Benefit Results for Analysis Cases (continued)

Case (SAMA Candidate Identifier)	Case 06 (AC/DC-29)	Case 07 (AT-05)	Case 08 (AT-07)	Case 09 (CB-01)	Case 09 (CB-03)	Case 09 (CB-08)
Off-site Annual Dose (person-rem/yr)	8.39E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00
Off-site Annual Property Loss ($)	$15,177	$15,547	$15,547	$15,547	$15,547	$15,547
Comparison CDF	7.41E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06
Comparison Dose (person-rem/yr)	8.60E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00
Comparison Cost ($/yr)	$15,547.49	$15,547.49	$15,547.49	$15,547.49	$15,547.49	$15,547.49
Enhanced CDF	7.14E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06
Reduction in CDF	**3.72%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Reduction in Off-site Dose	**2.45%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Immediate Dose Savings (On-site)	$24	$0	$0	$0	$0	$0
Long-term Dose Savings (On-site)	$104	$0	$0	$0	$0	$0
Total Accident Related Occupational Exposure **(AOE)**	$127	$0	$0	$0	$0	$0
Cleanup/Decontamination Savings (On-site)	$3,885	$0	$0	$0	$0	$0
Replacement Power Savings (On-site)	$5,731	$0	$0	$0	$0	$0
Averted Costs of On-site Property Damage **(AOSC)**	$9,616	$0	$0	$0	$0	$0
Total On-site Benefit	**$9,744**	**$0**	**$0**	**$0**	**$0**	**$0**
Averted Public Exposure **(APE)**	$5,493	$0	$0	$0	$0	$0
Averted Off-site Damage Savings **(AOC)**	$4,832	$0	$0	$0	$0	$0
Total Off-site Benefit	**$10,324**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Benefit (On-site + Off-site)	**$20,068**	**$0**	**$0**	**$0**	**$0**	**$0**

Table E.11-3 Fire Benefit Results for Analysis Cases (continued)

Case (SAMA Candidate Identifier)	Case 09 (CB-09)	Case 10 (CC-01)	Case 11 (CC-02)	Case 12 (CC-03b)	Case 13 (CC-20)	Case 15 (CP-01)
Off-site Annual Dose (person-rem/yr)	8.60E+00	2.46E+00	2.46E+00	8.55E+00	8.60E+00	3.75E+00
Off-site Annual Property Loss ($/yr)	$15,547	$4,564	$4,564	$15,455	$15,547	$6,758
Comparison CDF	7.41E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06
Comparison Dose (person-rem/yr)	8.60E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00
Comparison Cost ($/yr)	$15,547.49	$15,547.49	$15,547.49	$15,547.49	$15,547.49	$15,547.49
Enhanced CDF	7.41E-06	1.95E-06	1.95E-06	7.33E-06	7.41E-06	3.57E-06
Reduction in CDF	**0.00%**	**73.69%**	**73.69%**	**1.16%**	**0.00%**	**51.90%**
Reduction in Off-site Dose	**0.00%**	**71.42%**	**71.42%**	**0.62%**	**0.00%**	**56.35%**
Immediate Dose Savings (On-site)	$0	$470	$470	$7	$0	$331
Long-term Dose Savings (On-site)	$0	$2,051	$2,051	$32	$0	$1,444
Total Accident Related Occupational Exposure **(AOE)**	$0	$2,521	$2,521	$40	$0	$1,776
Cleanup/Decontamination Savings (On-site)	$0	$76,901	$76,901	$1,211	$0	$54,157
Replacement Power Savings (On-site)	$0	$113,428	$113,428	$1,786	$0	$79,880
Averted Costs of On-site Property Damage **(AOSC)**	$0	$190,330	$190,330	$2,996	$0	$134,037
Total On-site Benefit	**$0**	**$192,851**	**$192,851**	**$3,036**	**$0**	**$135,813**
Averted Public Exposure **(APE)**	$0	$160,310	$160,310	$1,393	$0	$126,480
Averted Off-site Damage Savings **(AOC)**	$0	$143,340	$143,340	$1,203	$0	$114,709
Total Off-site Benefit	**$0**	**$303,649**	**$303,649**	**$2,596**	**$0**	**$241,188**
Total Benefit (On-site + Off-site)	**$0**	**$496,500**	**$496,500**	**$5,632**	**$0**	**$377,001**

Table E.11-3 Fire Benefit Results for Analysis Cases (continued)

Case (SAMA Candidate Identifier)	Case 18 (CW-02)	Case 19 (CW-03)	Case 19 (CW-04)	Case 20 (CW-07)	Case 21 (FR-03)	Case 22 (FR-07a)
Off-site Annual Dose (person-rem/yr)	8.34E+00	7.73E+00	7.73E+00	7.01E+00	5.97E+00	4.31E+00
Off-site Annual Property Loss ($/yr)	$15,090	$13,884	$13,884	$12,585	$10,888	$7,771
Comparison CDF	7.41E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06
Comparison Dose (person-rem/yr)	8.60E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00
Comparison Cost ($/yr)	$15,547.49	$15,547.49	$15,547.49	$15,547.49	$15,547.49	$15,547.49
Enhanced CDF	7.17E-06	6.71E-06	6.71E-06	6.14E-06	5.16E-06	4.01E-06
Reduction in CDF	3.24%	9.51%	9.51%	17.13%	30.43%	45.95%
Reduction in Off-site Dose	2.99%	10.11%	10.11%	18.53%	30.52%	49.89%
Immediate Dose Savings (On-site)	$21	$61	$61	$109	$194	$293
Long-term Dose Savings (On-site)	$90	$265	$265	$477	$847	$1,279
Total Accident Related Occupational Exposure **(AOE)**	$111	$325	$325	$586	$1,041	$1,572
Cleanup/Decontamination Savings (On-site)	$3,379	$9,925	$9,925	$17,879	$31,755	$47,948
Replacement Power Savings (On-site)	$4,983	$14,639	$14,639	$26,371	$46,838	$70,723
Averted Costs of On-site Property Damage **(AOSC)**	$8,362	$24,564	$24,564	$44,249	$78,593	$118,672
Total On-site Benefit	**$8,473**	**$24,889**	**$24,889**	**$44,835**	**$79,634**	**$120,244**
Averted Public Exposure **(APE)**	$6,717	$22,698	$22,698	$41,595	$68,507	$111,977
Averted Off-site Damage Savings **(AOC)**	$5,965	$21,711	$21,711	$38,664	$60,801	$101,483
Total Off-site Benefit	**$12,682**	**$44,409**	**$44,409**	**$80,259**	**$129,309**	**$213,460**
Total Benefit (On-site + Off-site)	$21,155	$69,298	$69,298	$125,094	$208,943	$333,703

Table E.11-3 Fire Benefit Results for Analysis Cases (continued)

Case (SAMA Candidate Identifier)	Case22a (FR-07b)	Case 23 (HV-02)	Case 25 (SR-03)	Case 26 (AT-13)	Case 27 (AT-14)
Off-site Annual Dose (person-rem/yr)	7.65E+00	7.18E+00	8.60E+00	8.60E+00	8.60E+00
Off-site Annual Property Loss ($/yr)	$13,837	$12,983	$15,547	$15,547	$15,547
Comparison CDF	7.41E-06	7.41E-06	7.41E-06	7.41E-06	7.41E-06
Comparison Dose (person-rem/yr)	8.60E+00	8.60E+00	8.60E+00	8.60E+00	8.60E+00
Comparison Cost ($/yr)	$15,547.49	$15,547.49	$15,547.49	$15,547.49	$15,547.49
Enhanced CDF	6.61E-06	6.24E-06	7.41E-06	7.41E-06	7.41E-06
Reduction in CDF	10.83%	15.80%	0.00%	0.00%	0.00%
Reduction in Off-site Dose	11.04%	16.47%	0.00%	0.00%	0.00%
Immediate Dose Savings (On-site)	$69	$101	$0	$0	$0
Long-term Dose Savings (On-site)	$301	$440	$0	$0	$0
Total Accident Related Occupational Exposure **(AOE)**	$371	$540	$0	$0	$0
Cleanup/Decontamination Savings (On-site)	$11,304	$16,485	$0	$0	$0
Replacement Power Savings (On-site)	$16,674	$24,315	$0	$0	$0
Averted Costs of On-site Property Damage **(AOSC)**	$27,978	$40,800	$0	$0	$0
Total On-site Benefit	**$28,349**	**$41,340**	**$0**	**$0**	**$0**
Averted Public Exposure **(APE)**	$24,777	$36,977	$0	$0	$0
Averted Off-site Damage Savings **(AOC)**	$22,320	$33,468	$0	$0	$0
Total Off-site Benefit	**$47,097**	**$70,445**	**$0**	**$0**	**$0**
Total Benefit (On-site + Off-site)	$75,446	$111,785	$0	$0	$0

Table E.11-4 Seismic Benefit Results for Analysis Cases

Case (SAMA Candidate Identifier)	Maximum Benefit	Case 01 (AC/DC-01)	Case 02 (AC/DC-10)	Case 03 (AC/DC-23)	Case 04 (AC/DC-27)	Case 05 (AC/DC-28)
Off-site Annual Dose (person-rem/yr)	6.75E+00	6.66E+00	6.47E+00	6.73E+00	6.75E+00	6.73E+00
Off-site Annual Property Loss ($/yr)	$11,106	$10,948	$10,595	$11,088	$11,106	$11,088
Comparison CDF	----	5.25E-06	5.25E-06	5.25E-06	5.25E-06	5.25E-06
Comparison Dose (person-rem/yr)	----	6.75E+00	6.75E+00	6.75E+00	6.75E+00	6.75E+00
Comparison Cost ($/yr)	----	$11,106.17	$11,106.17	$11,106.17	$11,106.17	$11,106.17
Enhanced CDF	----	5.18E-06	5.03E-06	5.24E-06	5.25E-06	5.24E-06
Reduction in CDF	----	**1.33%**	**4.20%**	**0.19%**	**0.00%**	**0.19%**
Reduction in Off-site Dose	----	**1.32%**	**4.13%**	**0.20%**	**0.00%**	**0.20%**
Immediate Dose Savings (On-site)	$452	$6	$19	$1	$0	$1
Long-term Dose Savings (On-site)	$1,972	$26	$83	$4	$0	$4
Total Accident Related Occupational Exposure **(AOE)**	$2,424	$32	$102	$5	$0	$5
Cleanup/Decontamination Savings (On-site)	$73,935	$985	$3,108	$141	$0	$141
Replacement Power Savings (On-site)	$109,053	$1,454	$4,585	$208	$0	$208
Averted Costs of On-site Property Damage **(AOSC)**	$182,988	$2,439	$7,693	$348	$0	$349
Total On-site Benefit	**$185,412**	**$2,471**	**$7,795**	**$353**	**$0**	**$353**
Averted Public Exposure **(APE)**	$176,082	$2,318	$7,277	$345	$0	$345
Averted Off-site Damage Savings **(AOC)**	$144,935	$2,066	$6,666	$234	$0	$234
Total Off-site Benefit	**$321,018**	**$4,383**	**$13,943**	**$578**	**$0**	**$579**
Total Benefit (On-site + Off-site)	**$506,430**	**$6,855**	**$21,738**	**$931**	**$0**	**$932**

Table E.11-4 Seismic Benefit Results for Analysis Cases (continued)

Case (SAMA Candidate Identifier)	Case 06 (AC/DC-29)	Case 07 (AT-05)	Case 08 (AT-07)	Case 09 (CB-01)	Case 09 (CB-03)	Case 09 (CB-08)
Off-site Annual Dose (person-rem/yr)	6.72E+00	6.73E+00	6.75E+00	6.75E+00	6.75E+00	6.75E+00
Off-site Annual Property Loss ($/yr)	$11,065	$11,088	$11,106	$11,106	$11,106	$11,106
Comparison CDF	5.25E-06	5.25E-06	5.25E-06	5.25E-06	5.25E-06	5.25E-06
Comparison Dose (person-rem/yr)	6.75E+00	6.75E+00	6.75E+00	6.75E+00	6.75E+00	6.75E+00
Comparison Cost ($/yr)	$11,106.17	$11,106.17	$11,106.17	$11,106.17	$11,106.17	$11,106.17
Enhanced CDF	5.23E-06	5.24E-06	5.25E-06	5.25E-06	5.25E-06	5.25E-06
Reduction in CDF	**0.38%**	**0.19%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Reduction in Off-site Dose	**0.38%**	**0.20%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Immediate Dose Savings (On-site)	$2	$1	$0	$0	$0	$0
Long-term Dose Savings (On-site)	$8	$4	$0	$0	$0	$0
Total Accident Related Occupational Exposure **(AOE)**	$9	$5	$0	$0	$0	$0
Cleanup/Decontamination Savings (On-site)	$282	$141	$0	$0	$0	$0
Replacement Power Savings (On-site)	$415	$208	$0	$0	$0	$0
Averted Costs of On-site Property Damage **(AOSC)**	$697	$348	$0	$0	$0	$0
Total On-site Benefit	**$706**	**$353**	**$0**	**$0**	**$0**	**$0**
Averted Public Exposure **(APE)**	$674	$345	$0	$0	$0	$0
Averted Off-site Damage Savings **(AOC)**	$539	$234	$0	$0	$0	$0
Total Off-site Benefit	**$1,213**	**$578**	**$0**	**$0**	**$0**	**$0**
Total Benefit (On-site + Off-site)	**$1,919**	**$931**	**$0**	**$0**	**$0**	**$0**

Table E.11-4 Seismic Benefit Results for Analysis Cases (continued)

Case (SAMA Candidate Identifier)	Case 09 (CB-09)	Case 10 (CC-01)	Case 11 (CC-02)	Case 12 (CC-03b)	Case 13 (CC-20)	Case 15 (CP-01)
Off-site Annual Dose (person-rem/yr)	6.75E+00	6.45E+00	6.45E+00	6.73E+00	6.75E+00	6.71E+00
Off-site Annual Property Loss ($/yr)	$11,106	$10,570	$10,570	$11,088	$11,106	$11,038
Comparison CDF	5.25E-06	5.25E-06	5.25E-06	5.25E-06	5.25E-06	5.25E-06
Comparison Dose (person-rem/yr)	6.75E+00	6.75E+00	6.75E+00	6.75E+00	6.75E+00	6.75E+00
Comparison Cost ($/yr)	$11,106.17	$11,106.17	$11,106.17	$11,106.17	$11,106.17	$11,106.17
Enhanced CDF	5.25E-06	5.02E-06	5.02E-06	5.24E-06	5.25E-06	5.22E-06
Reduction in CDF	**0.00%**	**4.41%**	**4.41%**	**0.19%**	**0.00%**	**0.60%**
Reduction in Off-site Dose	**0.00%**	**4.34%**	**4.34%**	**0.20%**	**0.00%**	**0.60%**
Immediate Dose Savings (On-site)	$0	$20	$20	$1	$0	$3
Long-term Dose Savings (On-site)	$0	$87	$87	$4	$0	$12
Total Accident Related Occupational Exposure **(AOE)**	$0	$107	$107	$5	$0	$15
Cleanup/Decontamination Savings (On-site)	$0	$3,263	$3,263	$140	$0	$447
Replacement Power Savings (On-site)	$0	$4,813	$4,813	$207	$0	$660
Averted Costs of On-site Property Damage **(AOSC)**	$0	$8,075	$8,075	$348	$0	$1,107
Total On-site Benefit	**$0**	**$8,182**	**$8,182**	**$352**	**$0**	**$1,122**
Averted Public Exposure **(APE)**	$0	$7,637	$7,637	$344	$0	$1,060
Averted Off-site Damage Savings **(AOC)**	$0	$6,995	$6,995	$233	$0	$888
Total Off-site Benefit	**$0**	**$14,633**	**$14,633**	**$577**	**$0**	**$1,948**
Total Benefit (On-site + Off-site)	**$0**	**$22,815**	**$22,815**	**$929**	**$0**	**$3,069**

Table E.11-4 Seismic Benefit Results for Analysis Cases (continued)

Case (SAMA Candidate Identifier)	Case 18 (CW-02)	Case 19 (CW-03)	Case 19 (CW-04)	Case 20 (CW-07)	Case 21 (FR-03)	Case 22 (FR-07)
Off-site Annual Dose (person-rem/yr)	6.73E+00	6.73E+00	6.73E+00	6.72E+00	6.75E+00	6.75E+00
Off-site Annual Property Loss ($/yr)	$11,088	$11,088	$11,088	$11,065	$11,106	$11,106
Comparison CDF	5.25E-06	5.25E-06	5.25E-06	5.25E-06	5.25E-06	5.25E-06
Comparison Dose (person-rem/yr)	6.75E+00	6.75E+00	6.75E+00	6.75E+00	6.75E+00	6.75E+00
Comparison Cost ($/yr)	$11,106.17	$11,106.17	$11,106.17	$11,106.17	$11,106.17	$11,106.17
Enhanced CDF	5.24E-06	5.24E-06	5.24E-06	5.23E-06	5.25E-06	5.25E-06
Reduction in CDF	**0.19%**	**0.19%**	**0.19%**	**0.38%**	**0.00%**	**0.00%**
Reduction in Off-site Dose	**0.20%**	**0.20%**	**0.20%**	**0.38%**	**0.00%**	**0.00%**
Immediate Dose Savings (On-site)	$1	$1	$1	$2	$0	$0
Long-term Dose Savings (On-site)	$4	$4	$4	$8	$0	$0
Total Accident Related Occupational Exposure **(AOE)**	$5	$5	$5	$9	$0	$0
Cleanup/Decontamination Savings (On-site)	$141	$141	$141	$282	$0	$0
Replacement Power Savings (On-site)	$208	$208	$208	$415	$0	$0
Averted Costs of On-site Property Damage **(AOSC)**	$348	$349	$349	$697	$0	$0
Total On-site Benefit	**$353**	**$354**	**$354**	**$706**	**$0**	**$0**
Averted Public Exposure **(APE)**	$345	$345	$345	$674	$0	$0
Averted Off-site Damage Savings **(AOC)**	$234	$234	$234	$539	$0	$0
Total Off-site Benefit	**$578**	**$579**	**$579**	**$1,213**	**$0**	**$0**
Total Benefit (On-site + Off-site)	**$931**	**$933**	**$933**	**$1,919**	**$0**	**$0**

Table E.11-4 Seismic Benefit Results for Analysis Cases (continued)

Case (SAMA Candidate Identifier)	Case22a (FR-07)	Case 23 (HV-02)	Case 25 (SR-03)	Case 26 (AT-13)	Case 27 (AT-14)
Off-site Annual Dose (person-rem/yr)	6.75E+00	6.73E+00	6.75E+00	6.75E+00	6.75E+00
Off-site Annual Property Loss ($/yr)	$11,106	$11,088	$11,106	$11,106	$11,106
Comparison CDF	5.25E-06	5.25E-06	5.25E-06	5.25E-06	5.25E-06
Comparison Dose (person-rem/yr)	6.75E+00	6.75E+00	6.75E+00	6.75E+00	6.75E+00
Comparison Cost ($/yr)	$11,106.17	$11,106.17	$11,106.17	$11,106.17	$11,106.17
Enhanced CDF	5.25E-06	5.24E-06	5.25E-06	5.25E-06	5.25E-06
Reduction in CDF	**0.00%**	**0.19%**	**0.00%**	**0.00%**	**0.00%**
Reduction in Off-site Dose	**0.00%**	**0.20%**	**0.00%**	**0.00%**	**0.00%**
Immediate Dose Savings (On-site)	$0	$1	$0	$0	$0
Long-term Dose Savings (On-site)	$0	$4	$0	$0	$0
Total Accident Related Occupational Exposure **(AOE)**	$0	$5	$0	$0	$0
Cleanup/Decontamination Savings (On-site)	$0	$141	$0	$0	$0
Replacement Power Savings (On-site)	$0	$208	$0	$0	$0
Averted Costs of On-site Property Damage **(AOSC)**	$0	$349	$0	$0	$0
Total On-site Benefit	**$0**	**$353**	**$0**	**$0**	**$0**
Averted Public Exposure **(APE)**	$0	$345	$0	$0	$0
Averted Off-site Damage Savings **(AOC)**	$0	$234	$0	$0	$0
Total Off-site Benefit	**$0**	**$579**	**$0**	**$0**	**$0**
Total Benefit (On-site + Off-site)	**$0**	**$932**	**$0**	**$0**	**$0**

Table E.11-5 Total Benefit Results for Analysis Cases

	Maximum Benefit	Case 01 (AC/DC-01)	Case 02 (AC/DC-10)	Case 03 (AC/DC-23)	Case 04 (AC/DC-27)	Case 05 (AC/DC-28)	Case 06 (AC/DC-29)	Case 07 (AT-05)
Internal Events	$345,550	$15,298	$80,399	$2,065	$56,044	$31,622	$64,860	$2,328
Fire	$689,049	$0	$69,048	$15,002	$184,421	$8,389	$20,068	$0
Seismic	$506,430	$6,855	$21,738	$931	$0	$932	$1,919	$931
Other	$345,550	$15,298	$80,399	$2,065	$56,044	$31,622	$64,860	$2,328
Total Benefit	$1,886,578	$37,451	$251,584	$20,064	$296,509	$72,565	$151,708	$5,587

	Case 08 (AT-07)	Case 09 (CB-01)	Case 09 (CB-03)	Case 09 (CB-08)	Case 09 (CB-09)	Case 10 (CC-01)	Case 11 (CC-02)	Case 12 (CC-03b)
Internal Events	$0	$0	$0	$0	$0	$177,967	$177,967	$23,589
Fire	$0	$0	$0	$0	$0	$496,500	$496,500	$5,632
Seismic	$0	$0	$0	$0	$0	$22,815	$22,815	$929
Other	$0	$0	$0	$0	$0	$177,967	$177,967	$23,589
Total Benefit	$0	$0	$0	$0	$0	$875,249	$875,249	$53,740

Table E.11-5 Total Benefit Results for Analysis Cases (continued)

	Case 13 (CC-20)	Case 15 (CP-01)	Case 18 (CW-02)	Case 19 (CW-03)	Case 19 (CW-04)	Case 20 (CW-07)	Case 21 (FR-03)	Case 22 (FR-07a)
Internal Events	$0	$80,886	$1,266	$17,842	$17,842	$25,346	$0	$0
Fire	$0	$377,001	$21,155	$69,298	$69,298	$125,094	$208,943	$333,703
Seismic	$0	$3,069	$931	$933	$933	$1,919	$0	$0
Other	$0	$80,886	$1,266	$17,842	$17,842	$25,346	$0	$0
Total Benefit	$0	$541,841	$24,618	$105,916	$105,916	$177,704	$208,943	$333,703

	Case22a (FR-07b)	Case 23 (HV-02)	Case 25 (SR-03)	Case 26 (AT-13)	Case 27 (AT-14)
Internal Events	$0	$49,471	$0	$93	$186
Fire	$75,446	$111,785	$0	$0	$0
Seismic	$0	$932	$0	$0	$0
Other	$0	$49,471	$0	$93	$186
Total Benefit	$75,446	$211,659	$0	$186	$372

Table E.11-6 Implementation Cost Estimates

SAMA ID	Potential Enhancement	Cost Estimate	Date of Cost Estimate	Present Day Estimate (2008)	Reference
AC/DC-01	Provide additional DC battery capacity.	$1,730,000	2007	$1,799,200	[**64**, Table G-5]
AC/DC-10	Provide an additional diesel generator.	$10,000,000	2006	$10,816,000	[**59**, Table G-4]
AC/DC-23	Develop procedures to repair or replace failed 4 kV breakers.	$375,000	2008	$375,000	[**73**]
AC/DC-27	Install permanent hardware changes that make it possible to establish 500 kV backfeed through the main set-up transformer.	$1,700,000	2008	$1,700,000	[**73**]
AC/DC-28	Reduce CCFs between EDG-3 and EDG 1/2.	$100,000	2008	$100,000	[**73**]
AC/DC-29	Replace EDG-3 with a diesel diverse from EDG-1 and EDG-2.	$4,200,000	2008	$4,200,000	[**73**]
AT-05	Add an independent boron injection system.	$800,000	2008	$800,000	[**73**]
AT-07	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	$1,000,000	2005	$1,124,864	[**86**, Table G-4]
AT-13	Automate SLC injection in response to ATWS event.	$660,000	2008	$660,000	[**73**]
AT-14	Diversify SLC explosive valve operation.	$370,000	2008	$370,000	[**73**]
CB-01	Install an additional pressure or leak monitoring instruments for detection of ISLOCAs.	$5,600,000	2008	$5,600,000	[**73**]
CB-03	Increase leak testing of valves in ISLOCA paths.	$400,000	2008	$400,000	[**73**]
CB-08	Revise EOPs to improve ISLOCA identification.	$20,000	2008	$20,000	[**73**]
CB-09	Improve operator training on ISLOCA coping.	$30,000	2008	$30,000	[**73**]
CC-01	Install an independent active or passive high pressure injection system.	$28,000,000	2007	$29,120,000	[**64**, Table G-5]
CC-02	Provide an additional high pressure injection pump with independent diesel.	$5,000,000	2007	$5,200,000	[**64**, Table G-5]

Table E.11-6 Implementation Cost Estimates (continued)

SAMA ID	Potential Enhancement	Cost Estimate	Date of Cost Estimate	Present Day Estimate (2008)	Reference
CC-03b	Raise RCIC backpressure trip set points.	$82,000	2008	$82,000	[73]
CC-20	Improve ECCS suction strainers or replace insulation in containment.	$10,000,000	2008	$10,000,000	[73]
CP-01	Install an independent method of suppression pool cooling.	$6,000,000	2008	$6,000,000	[73]
CW-02	Add redundant DC control power for pumps.	$650,000	2008	$650,000	[73]
CW-03	Replace ECCS pump motors with air-cooled motors.	$1,000,000	2005	$1,124,864	[86, Table G-3]
CW-04	Provide self-cooled ECCS seals.	$675,000	2008	$675,000	[73]
CW-07	Add a service water pump.	$5,900,000	2007	$6,136,000	[64, Table G-5]
FR-03	Install additional transfer and isolation switches.	$2,000,000	2008	$2,000,000	[73]
FR-07a	Improve the fire resistance of cables to the containment vent valve.	$400,000	2008	$400,000	[74]
FR-07b	Improve the fire resistance of cables to transformer E-TR-S.	$100,000	2008	$100,000	[74]
HV-02	Provide a redundant train or means of ventilation.	$480,000	2008	$480,000	[73]
SR-03	Modify safety related CST.	$980,000	2008	$980,000	[73]

Table E.11-7 Final Results of the Cost-benefit Evaluation

SAMA ID	Modification	Analysis Cases	Estimated Benefit	2008 Estimated Cost	Conclusion
AC/DC-01	Provide additional DC battery capacity.	Case 01	$37,451	$1,799,200	Not Cost Effective
AC/DC-10	Provide an additional diesel generator.	Case 02	$251,584	$10,816,000	Not Cost Effective
AC/DC-23	Develop procedures to repair or replace failed 4 kV breakers.	Case 03	$20,064	$375,000	Not Cost Effective
AC/DC-27	Install permanent hardware changes that make it possible to establish 500 kV backfeed through the main step-up transformer.	Case 04	$296,509	$1,700,000	Not Cost Effective
AC/DC-28	Reduce CCFs between EDG-3 and EDG1/2.	Case 05	$72,565	$100,000	Not Cost Effective
AC/DC-29	Replace EDG-3 with a diesel diverse from EDG-1 and EDG-2.	Case 06	$151,708	$4,200,000	Not Cost Effective
AT-05	Add an independent boron injection system.	Case 07	$5,587	$800,000	Not Cost Effective
AT-07	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Case 08	$0	$1,124,864	Not Cost Effective
AT-13	Automate SLC injection in response to ATWS event.	Case 26	$186	$660,000	Not Cost Effective
AT-14	Diversify SLC explosive valve operation.	Case 27	$372	$370,000	Not Cost Effective
CB-01	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Case 09	$0	$5,600,000	Not Cost Effective
CB-03	Increase leak testing of valves in ISLOCA paths.	Case 09	$0	$400,000	Not Cost Effective
CB-08	Revise EOPs to improve ISLOCA identification.	Case 09	$0	$20,000	Not Cost Effective

Table E.11-7 Final Results of the Cost Benefit Evaluation (continued)

SAMA ID	Modification	Analysis Cases	Estimated Benefit	2008 Estimated Cost	Conclusion
CB-09	Improve operator training on ISLOCA coping.	Case 09	$0	$30,000	Not Cost Effective
CC-01	Install an independent active or passive high pressure injection system.	Case 10	$875,249	$29,120,000	Not Cost Effective
CC-02	Provide an additional high pressure injection pump with independent diesel.	Case 11	$875,249	$5,200,000	Not Cost Effective
CC-03b	Raise RCIC backpressure trip set points.	Case 12	$53,740	$160,000	Not Cost Effective
CC-20	Improve ECCS suction strainers.	Case 13	$0	$10,000,000	Not Cost Effective
CP-01	Install an independent method of suppression pool cooling.	Case 15	$541,841	$6,000,000	Not Cost Effective
CW-02	Add redundant DC control power for pumps.	Case 18	$24,618	$650,000	Not Cost Effective
CW-03	Replace ECCS pump motors with air-cooled motors.	Case 19	$105,916	$1,124,864	Not Cost Effective
CW-04	Provide self-cooled ECCS seals.	Case 19	$105,916	$675,000	Not Cost Effective
CW-07	Add a service water pump.	Case 20	$177,704	$6,136,000	Not Cost Effective
FR-03	Install additional transfer and isolation switches.	Case 21	$208,943	$2,000,000	Not Cost Effective
FR-07a	Improve the fire resistance of critical cables.	Case 22	$333,703	$400,000	Not Cost Effective
FR-07b	Improve the fire resistance of critical cables.	Case 22a	$75,446	$100,000	Not Cost Effective
HV-02	Provide a redundant train or means of ventilation.	Case 23	$211,659	$480,000	Not Cost Effective
SR-03	Modify safety related CST.	Case 25	$0	$980,000	Not Cost Effective

Table E.12-1 Total Benefit Results for the Sensitivity Cases

SAMA ID	Sensitivity Case #1	Sensitivity Case #2	Sensitivity Case #3	Sensitivity Case #4	Sensitivity Case #5	Sensitivity Case #6	2008 Estimated Cost	Conclusion
AC/DC-01	$27,916	$54,065	$25,640	$37,719	$40,145	$47,309	$1,799,200	Not Cost Effective
AC/DC-10	$183,247	$359,543	$171,256	$253,505	$270,888	$322,235	$10,816,000	Not Cost Effective
AC/DC-23	$16,077	$29,920	$13,994	$20,176	$21,190	$24,186	$375,000	Not Cost Effective
AC/DC-27	$224,150	$430,712	$203,718	$298,543	$316,950	$371,320	$1,700,000	Not Cost Effective
AC/DC-28	$50,637	$101,815	$48,886	$73,181	$78,759	$95,234	$100,000	Cost Effective
AC/DC-29	$106,060	$213,027	$102,249	$152,991	$164,603	$198,903	$4,200,000	Not Cost Effective
AT-05	$4,590	$8,428	$3,923	$5,615	$5,868	$6,617	$800,000	Not Cost Effective
AT-07	$0	$0	$0	$0	$0	$0	$1,124,864	Not Cost Effective
AT-13	$153	$281	$131	$187	$196	$221	$660,000	Not Cost Effective
AT-14	$306	$562	$262	$374	$391	$441	$370,000	Not Cost Effective
CB-01	$0	$0	$0	$0	$0	$0	$5,600,000	Not Cost Effective
CB-03	$0	$0	$0	$0	$0	$0	$400,000	Not Cost Effective
CB-08	$0	$0	$0	$0	$0	$0	$20,000	Not Cost Effective
CB-09	$0	$0	$0	$0	$0	$0	$30,000	Not Cost Effective
CC-01	$680,828	$1,287,724	$605,749	$880,714	$930,171	$1,076,255	$29,120,000	Not Cost Effective
CC-02	$680,828	$1,287,724	$605,749	$880,714	$930,171	$1,076,255	$5,200,000	Not Cost Effective
CC-03b	$38,092	$75,906	$36,340	$54,180	$58,160	$69,918	$82,000	Not Cost Effective
CC-20	$0	$0	$0	$0	$0	$0	$10,000,000	Not Cost Effective
CP-01	$449,635	$821,170	$381,473	$544,434	$567,889	$637,171	$6,000,000	Not Cost Effective
CW-02	$20,033	$36,972	$17,241	$24,747	$25,913	$29,358	$650,000	Not Cost Effective
CW-03	$86,962	$159,725	$74,345	$106,449	$111,270	$125,512	$1,124,864	Not Cost Effective
CW-04	$86,962	$159,725	$74,345	$106,449	$111,270	$125,512	$675,000	Not Cost Effective

Table E.12-1 Total Benefit Results for the Sensitivity Cases (continued)

SAMA ID	Sensitivity Case #1	Sensitivity Case #2	Sensitivity Case #3	Sensitivity Case #4	Sensitivity Case #5	Sensitivity Case #6	2008 Estimated Cost	Conclusion
CW-07	$147,073	$268,981	$125,019	$178,566	$186,358	$209,374	$6,136,000	Not Cost Effective
FR-03	$171,472	$315,026	$146,662	$209,996	$219,528	$247,682	$2,000,000	Not Cost Effective
FR-07a	$277,125	$505,910	$234,985	$335,294	$349,686	$392,198	$400,000	Cost Effective
FR-07b	$62,107	$113,913	$53,001	$75,821	$79,214	$89,237	$100,000	Cost Effective
HV-02	$174,732	$319,999	$148,806	$212,697	$222,091	$249,837	$480,000	Not Cost Effective
SR-03	$0	$0	$0	$0	$0	$0	$980,000	Not Cost Effective

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